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Azerbaijan
Issues and Options Associated with Energy Sector Reform

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Note on the data in the report: The Bank has used the most up to date data that was available to it in preparing this report. More recent data may well change some of the analysis. Consequently, when the Bank receives more recent data it will update its analyses.

Abbreviations and Acronyms

ACG	Azeri, Chirag, Guneshli
AIOC	Azerbaijan International Operating Company
AZM	Azerbaijan Manats
BCM	Billion Cubic Meters
BTC	Baku-Tbilisi-Ceyhan
CAS	Country Assistance Strategy
EBRD	European Bank for Reconstruction and Development
EITI	Extractive Industries Transparency Initiative
FSU	Former Soviet Union
GDP	Gross Domestic Product
HBS	Household Budget Survey
IBTA	Institution Building Technical Assistance
IPP	Independent Power Producer
IMF	International Monetary Fund
JV	Joint Venture
KfW	Kreditanstalt fur Wiederaufbau (German Development Bank)
Km	Kilometers
kv	Kilovolt
kWh	Kilowatt hour
LoI	Letter of Intent
MCM	Thousand Cubic Meters
MED	Ministry of Economic Development
MoF	Ministry of Finance
MoIE	Ministry of Industry and Energy
MTEF	Medium Term Expenditure Framework
PIP	Public Investment Program
PPA	Power Purchase Agreement
PRSP	Poverty Reduction Strategy Paper
PSA	Production Sharing Agreement
PSIA	Poverty and Social Impact Analysis
SCADA	Supervisory Control and Data Acquisition
SCF	Standard Cubic Feet
SCP	South Caucasus Pipeline
SOCAR	State Oil Company of the Azerbaijan Republic
SOFAZ	State Oil Fund of the Azerbaijan Republic
SPPRED	State Program for Poverty Reduction and Economic Development
SSP	Social Support Program
SSPF	State Social Protection Fund
UGS	Underground Storage
URA	Utility Regulatory Agency
VAT	Value Added Tax

Azerbaijan
Issues and Options Associated with Energy Sector Reform

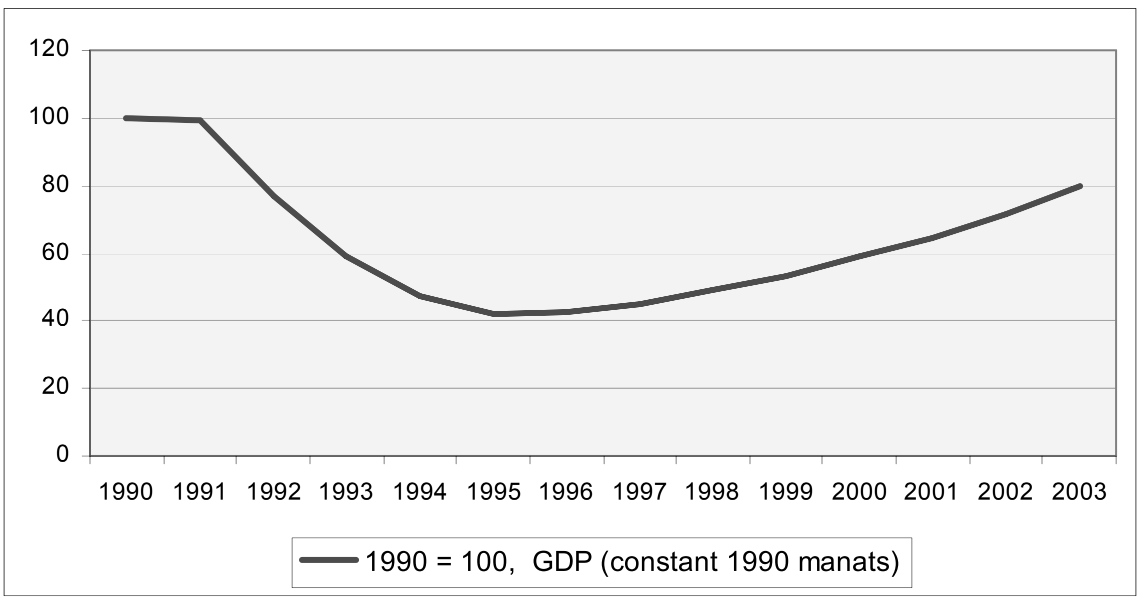
Introduction and Executive Summary

Introduction

i. Azerbaijan is now more than 12 years into a transition process that commenced immediately after the country became independent. As elsewhere in the former Soviet Union (FSU) the process in Azerbaijan can be characterized as reflecting three transitions rolled into one:

i. A political transition – from a highly controlled centralized political system to a more decentralized and democratic form of government;
ii. An institutional transition – from the institutional framework of central planning towards the institutions of a market economy; and
iii. An economic transition – involving the disintegration of the highly integrated economic space of the FSU, with the resultant disruptions in trade, financial and labor market connections.

Figure 1
Changes in Real Output – Azerbaijan



ii. For each of these areas there have been broadly two stages of transition in the FSU countries:

i. A first stage of economic decline, involving the disintegration and destruction of existing political, institutional and economic relations;

ii. Followed by a stage of recovery, involving rebuilding, reform and integration with the world economy.

iii. As shown in Figure 1 above, Azerbaijan initially experienced five years of dramatic economic decline starting in 1990, losing almost 60 % of its measured GDP. It then began to experience a turnaround which accelerated in 2000 as Azerbaijan started to benefit from both increases in oil export revenues as a result of (a) the price increases that began in 1999 and (b) the vigorous economic recovery that began for the region as a whole in 1999 and is set to continue in 2004 and beyond. However, GDP in 2003 was still about 20 % below its 1990 level in real terms.

iv. The energy sector has a critical role to play in the continuing transition process. The energy sector plays a significant role in the overall economy of Azerbaijan, as in other transition countries, and the World Bank's experience suggests that without energy sector reform and financial viability the transition process is much more difficult and delayed. The objective of this report, therefore, is to outline the issues and options facing Azerbaijan as it develops and implements its agenda for reform of the energy sector in order to inform the country's dialogue on this subject and the associated decision making process.

v. The report focuses on seven key topics and each section of the report can be read as a standalone document, as a result there is some duplication between sections. Each section includes a summary followed by a more detailed discussion of the issues and options. The seven sections are as follows:

- Oil Revenue Management
- The Petroleum Sector
- The Gas Sector
- The Power Sector
- The Regulatory Environment
- Energy and the Environment
- Social Issues in the Energy Sector

vi. In addition three appendices are included. The first discusses the factors influencing oil prices, the second outlines the liberalization process and the regulatory models adopted for the gas sector in a number of locations and the third summarizes *The State Program for the Development of the Fuel and Energy Sector of the Azerbaijan Republic (2005 – 2015)* which has been endorsed by the government.

Executive Summary

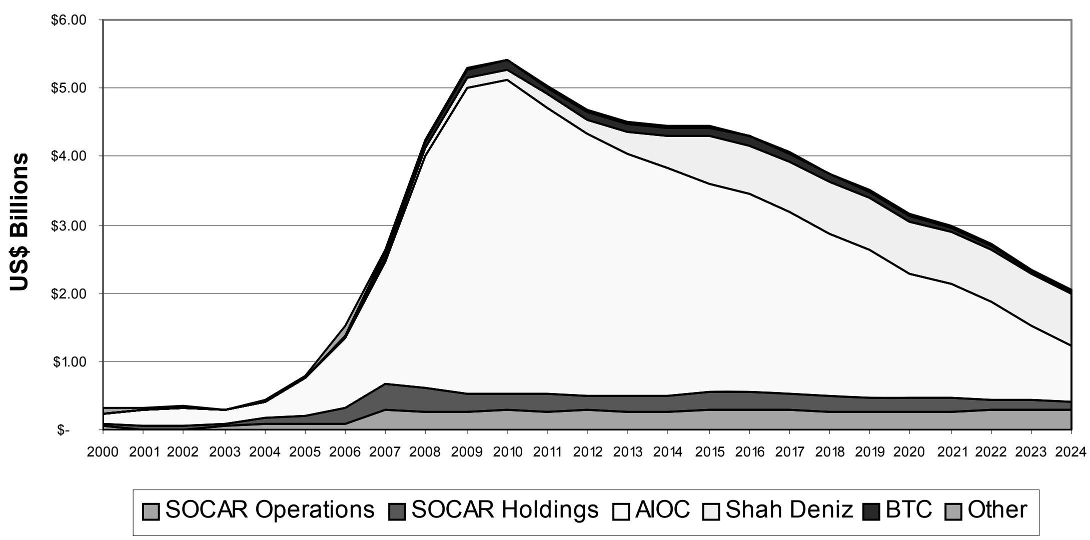
Avoiding the "Resource Curse"

1. At the time of independence, Azerbaijan inherited a significant hydrocarbon resource base and an extensive domestic network for transmission and distribution of electricity and natural gas. Azerbaijan has been very effective in attracting foreign direct investment to develop its hydrocarbon resources and major development programs are underway. This offers the prospect of considerable wealth generation. Based on the World Bank's 2004 oil price forecast[1], fiscal revenues related to oil and gas development are projected to total over US$70 billion for the period 2004 through 2024.

2. Oil revenues, however, are finite. Absent any new discoveries, Azerbaijan's oil production is projected to peak in 2010 at about 71 million tons. Oil and gas related fiscal revenues will also peak at that time and both production and fiscal revenues will subsequently begin a steady decline.

Figure 2

Azerbaijan Revenue Contributions



Source: World Bank analysis

3. With these revenues in prospect, a critical challenge will be finding ways to avoid the "resource curse" that affects many resource rich countries that have failed to achieve the rates of economic growth that their non resource rich neighbors have attained. Azerbaijan should seek to deploy these revenues in a fashion that promotes the sustained development of the non-oil economy. At the same time the government needs to be

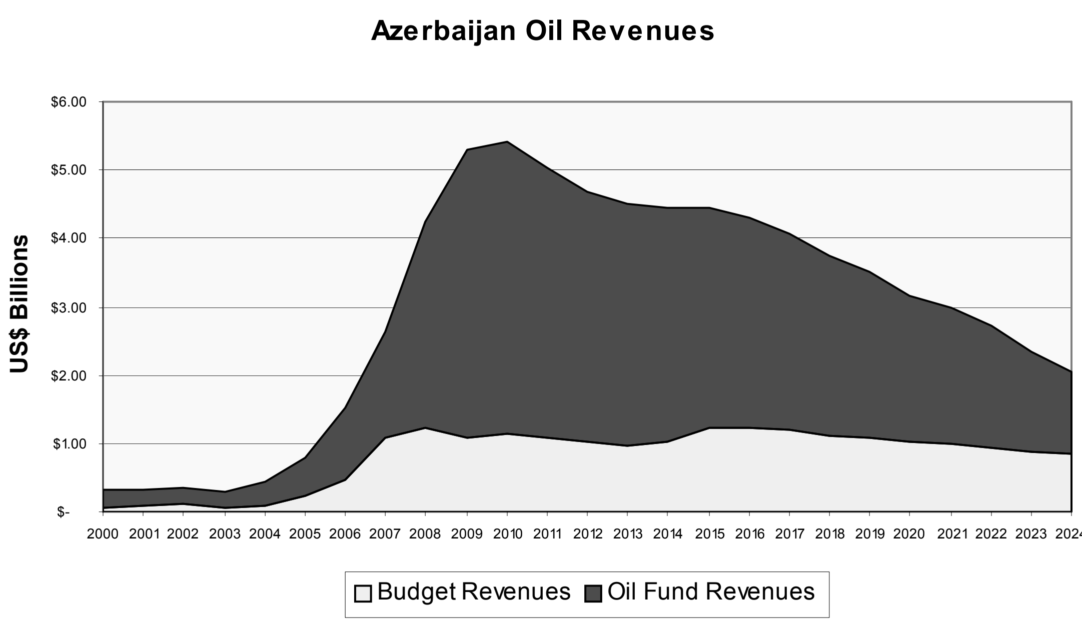
[1] The World Bank's 2004 forecast for oil prices was $39/barrel in 2004 dropping to $36/barrel in 2005, $32 in 2006 and then declining to $26/barrel in the 2009-2010 timeframe.

cognizant of the fact that the high revenue generating window may be relatively small and it, therefore, needs to develop and implement a strategy for oil revenue management.

4. The key to avoiding the "resource curse" is good governance of the oil revenues. An initial element of good governance is a high level of transparency with regard to both the sources of the oil revenues and their uses. In establishing the State Oil Fund of the Republic of Azerbaijan (SOFAZ) Azerbaijan has taken an important first step towards effective governance of oil revenues. Of particular note are the transparency requirements associated with SOFAZ' operations.

5. Oil related fiscal revenues, however, currently flow to both SOFAZ and directly to the budget (see Figure 3 below) and there is much less transparency associated with the funds that flow directly to the budget. This is particularly the case with regard to tax payments by SOCAR, the State owned oil and gas company, which are associated with its operating activities[2]. SOCAR is moving forward with plans to adopt international financial reporting standards, but this will take some time. In the meantime, it would be appropriate for SOCAR and the Ministry of Finance to work out a mechanism for more transparent reporting of SOCAR's financial results.

Figure 3



Source: World Bank analysis

[2] SOCAR makes fiscal contributions from both the operating activities it manages and from holdings in production sharing agreements and joint ventures. There is considerable transparency around the "holding company" interests since these flow either to SOFAZ or into an escrow account required to support SOCAR's borrowing for its share of investment in the Shah Deniz and SCP gas development and gas pipeline investments. There is, however, very little transparency around SOCAR's other revenue generating activities.

6. One option available to the government to improve the overall transparency of its oil related fiscal revenues is to channel all these revenues through a single agency. SOFAZ would be the logical agency to receive the revenues. Channeling all these revenues through SOFAZ would ensure a high level of transparency around both the oil revenues and their uses.

7. The second critical element of good governance is to ensure that the revenues are appropriately deployed. The centerpiece of an expenditure program should be a medium term expenditure framework (MTEF) designed to accommodate the absorptive capacity of Azerbaijan's economy and focus on the non oil sectors of the economy according to the priorities set out in the State Program for Poverty Reduction and Economic Development (SPPRED).

8. Azerbaijan's fiscal outlook suggests that adequate funds will be available to fund the MTEF. Budget allocations should be based on the MTEF and should not be impacted in the short term by oil price fluctuations.

SOCAR's Function

9. SOCAR is a major State owned asset. As the equity owner of SOCAR, the government faces a number of specific challenges: (i) To effect a clear separation of the regulatory functions currently performed by SOCAR as the de facto "competent authority" dealing with the upstream oil sector and the commercial functions SOCAR performs as an operator in the sector; (ii) To ensure the State receives the full benefit associated with SOCAR's equity interest in production sharing agreements (PSAs) and joint ventures; (iii) To facilitate the transition of SOCAR from a Soviet style State owned enterprise to a commercially focused organization operating in accordance with best international practice; (iv) To ensure SOCAR's ongoing financial viability; and (v) to address the legacy of environmental problems that were inherited from the Soviet Union along with the hydrocarbon assets.

10. In order to address these challenges a restructuring of SOCAR's operations will be required and the government has made a commitment to restructure the company. There are, however, certain decisions that the government should make with regard to the restructuring:

i. The "competent authority" role that SOCAR performs should be established as a separate agency reporting directly to the top levels of government. The government, however, will need to determine the exact nature of and reporting structure for this agency.

ii. In addition to the regulatory role it plays, SOCAR also has a minority ownership role in a number of production sharing agreements and joint ventures. These, in effect, represent State ownership in these activities that is effected through SOCAR. The government will need to decide what ownership arrangement will ensure that the State receives the full benefit associated with these ownership interests. Options to be considered include (i) transferring the holdings into a separate holding company, which would be the optimum approach; (ii) maintaining the status quo; and (iii) allowing SOCAR full control over the holding's revenues.

iii. An important early part of the restructuring process is to develop and implement a plan to transition to international financial reporting standards. The costs of this transition will not be insignificant and appropriate provision should be made in SOCAR's own budget and, as appropriate, the State budget to cover these costs.

iv. Sustained viability of SOCAR's core operations is predicated on eliminating the subsidies that SOCAR now provides the Azerbaijan economy. This can be effected by bringing prices for the refined products and the gas supplied by SOCAR to the domestic market up to levels that reflect their true economic value. The government will need to make a determination as to how that can be best effected and this should be an element of the medium term tariff policy the government is committed to introduce. In the meantime, provisions should be made in the State budget to compensate SOCAR for shortfalls in recovering the full economic value of the products it delivers to the domestic market.

v. There is an urgent need to address the legacy of environmental problems associated with over 100 years of oil production in Azerbaijan. Onshore oil contamination affects a region of about 100 square kilometers and is one of the most serious examples of environmental degradation in the country. A determination is needed with regard to both liability for past contamination and responsibility for effecting the clean up. Although SOCAR has legal responsibility for the land, the land pollution in many of these sites was generated as a result of practices that occurred prior to SOCAR assuming this legal responsibility. It would not be reasonable, therefore to assign this liability to SOCAR and the net cost of clean up should, therefore, be assumed as a budget responsibility. SOCAR, however, is the logical choice to oversee the clean up.

There is, however, a strong likelihood that such a program could pay for itself through (a) the appreciation in the value of the land that is cleaned up and made available for other uses and (b) as a result of reclamation of oil and of steel which can be resold. Consideration should be given to involving the private sector in the clean-up process. Insofar as oil reclamation is concerned, the current high oil price environment has created a window of opportunity to attract private sector participants to assist with remediation measures being compensated, at least in part, through the proceeds of reclamation. Land reclamation and sale, however, offers a much larger potential opportunity. It is important, therefore to establish the principle that the benefits resulting from land sales and other reclamation proceeds accrue to the entity taking on responsibility to finance the clean up. Such a program, which would extend over a ten year timeframe, also has the potential to create new job opportunities, some of which could be used to mitigate the impact of rationalizing SOCAR's heavily over-staffed workforce.

Delivering Quality Electricity and Gas Utility Services to the Domestic Market

11. Although Azerbaijan inherited extensive power and gas networks capable of delivering electricity and gas of acceptable quality to almost the entire population, lack of investment and limited maintenance have resulted in significant deterioration in these networks such that the country is now unable to meet domestic demand for power and the potential demand that exists for gas. In addition, air quality problems are increasing as a result of (a) the use of more polluting fuels since gas is not as widely available as previously and (b) the flaring and venting of natural gas. The key challenges facing the government in these sectors are (i) to restore and maintain acceptable levels of service throughout the country and (ii) to ensure the country secures optimum benefits from its assets in these sectors.

12. Both sectors are increasingly at risk of systemic collapse. This risk could be significantly reduced by rehabilitating facilities and investing in modern control systems. Total investment requirements for publicly owned assets in these sectors are estimated in the range of US$1 billion for gas and between US$ 1.95 billion and US$ 3.6 billion for power[3], of which over US$1.36 billion are urgently required ($450 million for gas and $910 million for power). These investment requirements cover gas treatment, transmission, storage and distribution (including funds to meter all customers) and power generation and transmission. They also include funds for recovery of gas that is currently being flared by SOCAR.

13. Transferring gas distribution activities to the private sector would reduce these public sector requirements by about $100 to $150 million and would reduce the urgent funding requirements by about $30 to $50 million. Similarly, privatizing power generation would reduce the public sector requirements by $1,720 to $3,370 million and the urgent requirements by almost $680 million. There would still remain, however a need for public sector funding totaling about $1.08 billion, with over $630 million being deemed urgent. The government, therefore, needs to establish a program to meet these investment needs and ensure funding is available.

14. Ideally, these investment needs should be funded from the proceeds generated by the sectors. However, both sectors fall well short of covering their financial needs. Both sectors experience excess losses and are subject to tariffs that are well below the levels necessary to recover the true economic value of the gas and electricity supplied. Payment levels are also an issue. However, here, there is a distinction between the power sector and the gas sector. The management contract arrangements in the power sector incorporate a provision allowing the management contractors to defer amounts payable for electricity purchased from Azerenergy. In 2004, for example, Azerenergy only received payment for 40% to 45% of the electricity it supplied to the distribution companies. Hence, collection levels are not directly under Azerenergy's control. However, in the gas sector collection levels are under Azerigaz' control.

[3] Power sector investment estimates up to 2015.

15. Under the terms of the electricity distribution management contracts, payments to Azerenergy for electricity will continue to increase reaching 100% by 2010. In the gas sector the government is considering a similar form of private sector involvement and this would be a mechanism to address the collections issue over time as well as a means of transferring responsibility for distribution investments to the private sector.

16. The government is also considering private sector involvement in power generation. This, however, should be appropriately sequenced. Azerenergy should be unbundled and the generation assets should be corporatized. Rehabilitation of the transmission network should be initiated and the introduction of a SCADA system should be followed by the establishment of a dispatch protocol. The government should avoid the temptation to enter into arrangements with individual generators that could result in contingent liabilities and a sub-optimal cost of electricity supply.

17. SOCAR is acting as the "single buyer" of gas for the domestic market. In the future, significant volumes of associated gas from the ACG fields will be supplied to SOCAR. In addition SOCAR will purchase 1.5 BCM of gas from Shah Deniz. The Shah Deniz gas will be subject to a supplier nomination arrangement (i.e. the supplier will have considerable control over the timing and volume of gas deliveries). There is, therefore, the potential for considerable fluctuations in gas supply levels and the only way SOCAR will be able to manage this will be through the use of a sizable volume of gas storage. The investments required to rehabilitate the two underground gas storage facilities in order to be able to handle these gas supplies are significant – on the order of US$272 million. The government will have to secure the funds to undertake this rehabilitation and will need to assess whether this can be effected more easily by transferring the gas storage assets, along with the responsibility for rehabilitation, to SOCAR.

18. In order to ensure additional private sector involvement in these sectors appropriate incentives will have to be provided, and should be supported by an independent and competitive regulatory regime. One of the key aspects that is needed is an assurance that tariffs will be sufficient to recover the full economic value of the gas and electricity delivered to the domestic market.

19. The government is committed to the development and implementation of a medium term tariff policy that will ultimately raise prices to levels that allow recovery of the full economic value of the gas and electricity supplied to the market. Ideally, an effective social safety net should be in place to ameliorate the impact of tariff increases on the poorest segments of the population. Work needs to continue to put such a safety net in place. However, given the improvements in wages and pensions that have been implemented, an initial increase in gas[4] and electricity tariffs should be affordable. For example, estimates of the potential impact of higher electricity tariffs suggest that a 50% increase in the electricity tariff would result in an average income loss of just under AZM 10,000/month (approximately $2). Since the increase in the minimum wage that took place in July 2004 and the increase in pensions that occurred in 2003 were both about

[4] On November 2nd 2004, gas prices were increased. Details are given in the section of the report on the Gas Sector.

four times this amount, a 50% increase in the unit price of electricity should be affordable. Outside Baku, the impact could be mitigated by adjusting downwards the norms used for billing un-metered customers. Such a measure would be appropriate in view of the fact that a comparison of these norms with consumption levels in areas which are metered (Baku and Sumgayit) suggests these norms may be disproportionately high[5].

20. Low tariffs and shortfalls in collections translate into the provision of subsidies to consumers of gas and electricity. At the beginning of the economic transition period that followed the break up of the Soviet Union, energy supplies throughout the FSU were heavily subsidized. The various FSU countries have had differing degrees of success in reducing these subsidies[6]. Moldova, Belarus and Armenia have been the most successful in eliminating subsidies. Azerbaijan has been among the least successful of the countries. In 2002, Azerbaijan recovered a lower portion of its gas costs than all FSU countries with the exception of Uzbekistan and in the power sector its cost recovery performance only exceeded that of Uzbekistan and Tajikistan. Since then, however, Uzbekistan has increased tariffs significantly allowing it to increase its percentage of cost recovery.

21. In the Bank's dialogue with its client countries the importance of identifying and monitoring performance indicators relative to the reforms being introduced is strongly emphasized. In looking at a country's economy as a whole there are a number of well established measures to assess performance. At the sectoral level, however, such measures are not always as clearly defined. In the energy sector, for example, it is difficult to measure precisely how well a country is meeting the key challenges of energy sector reform:

- Creating an effective legislative and regulatory framework;
- Attracting investment;
- Creating a competitive market;
- Introducing good governance; and
- Assuring financial viability.

The Bank has concluded that perhaps the most effective measure to consider is the level of subsidies (both explicit and implicit) provided by the energy sector to the economy as a whole. This is, in effect, a simple measure of the financial viability of the sector. But it also broadly measures whether the sector will be able to sustain and expand its services over time, whether it allocates scarce resources efficiently, and whether it relies on quasi-fiscal flows that could endanger the macroeconomic stability of the country. It is, therefore, important that the government monitor the level of subsidies in the energy sector and continue to adopt measures to reduce these subsidies.

22. The introduction of a medium term tariff policy and a continued focus on improving collections will help bring down the level of subsidies in the sector. However,

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[5] World Bank (2004) Ex-Ante Evaluation of Residential Electricity Tariff Reform.

[6] Data is available for 2002 on all FSU countries except Turkmenistan. It is likely that Azerbaijan's performance is better than that of Turkmenistan in terms of cost recovery of both gas and electricity given the very low domestic tariffs that have applied in Turkmenistan.

there will likely remain a shortfall in generation by the sector of the funds needed for investment (as discussed above). The government does have the financial capacity to support these investments and provision should, therefore, be made in future budgets to cover the investment requirements that cannot be met from the sectors' own cash flows pending the elimination of sector subsidies.

Introduction of an Independent Regulator

23. The introduction of an independent regulator is an important component of energy sector reform. The government has made a commitment to establish a regulatory agency for the energy sector. It is essential that such an agency be solidly supported by legislation and that the structure and functions of the agency conform to good international practice, in particular:

- The agency should be and should be seen to be independent;
- The agency should be mandated to promote improved transparency and accountability;
- A key role for the agency will be establishing and monitoring quality standards;
- The agency should also have powers to promote competition and prevent anti-competitive behavior.

24. The government's plans contemplate the full implementation of the new regulatory regime by mid-2006. In the meantime, a transition plan should be developed for the period prior to implementation of the new regime. A step that is urgently required is passage of legislation establishing the regulatory agency. However, in order to craft this legislation a number of government decisions are required. The specific issues to be addressed are as follows:

- In which branch (executive, legislative or judicial) should the agency be located?
- How should the Commissioners be appointed?
- How will the agency be funded?
- Who should be responsible for issuing licenses?
- What level of tariff setting responsibility will be assigned to the regulatory agency?
- What form of appeal process should be instituted?

These issues are discussed in more detail in the body of the report. Once the government has taken a position on each of these issues, legislation can be drafted to conform to the government's view.

I - Oil Revenue Management in Azerbaijan

Summary

I-i. Azerbaijan is endowed with a significant hydrocarbon resource base and the potential to generate substantial fiscal revenues from this resource base. The key challenge facing the government is to ensure the optimal utilization of the revenues generated by these resources. This section addresses this challenge and outlines some of the issues and options to be considered by the government. The issues range from revenue collection, to investment of assets and utilization of proceeds.

I-ii. The conclusions and recommendations of this section may briefly be summarized as follows:

- **Oil revenues are finite**. Absent any major new discoveries, Azerbaijan's oil production is projected to peak in 2010 at about 71 million tons. Oil and gas related fiscal revenues will also peak at that time and both production and fiscal revenues will subsequently begin a steady decline. The government needs to develop and implement a strategy for oil revenue management. In doing so, however, it needs to be cognizant of the fact that the high revenue generating window may be relatively small.

- **Judicious use of oil revenues requires a broad institutional support structure on the revenue and expenditure sides, brought together by the Budget Systems Law**. Equal weight needs to be put into safeguarding revenues, management of investments and state assets, and into judiciously drawing down the state assets for the purpose of undertaking public expenditures.

- **Establishment of an oil fund (SOFAZ) has been a very sensible first step in revenue management**. The government made an important step towards effective oil revenue management with the establishment of the State Oil Fund of the Republic of Azerbaijan (SOFAZ). SOFAZ has key roles to play as a savings fund as well as a sterilization mechanism to combat Dutch disease. It is in the forefront of demonstrating Azerbaijan's commitment to oil revenue transparency.

- **Clarification of SOCAR's internal operations is necessary.** SOCAR makes fiscal revenue contributions from both the operating activities it manages and from its holdings in production sharing agreements (PSAs) and joint ventures. There is considerable transparency around the "holding company" interests, but this is not the case with the financial status of the operating activities. SOCAR is moving forward with plans to adopt international financial reporting standards, but this will take some time. In the meantime it would be appropriate for SOCAR and the Ministry of Finance to work out a mechanism for more transparent reporting of SOCAR's financial results.

- **Essential components of a good expenditure management framework are the SPPRED and the MTEF.** The centerpiece of an expenditure program should be a medium term expenditure framework (MTEF) designed to accommodate the absorptive capacity of Azerbaijan's economy and focus on growing the non oil sectors of the economy according to the priorities set out in the State Program for Poverty Reduction and Economic Development (SPPRED).

- **Budget allocations should be based on the MTEF and should not be impacted in the short term by oil price fluctuations.** Azerbaijan's fiscal outlook suggests that adequate funds will be available to fund the MTEF. The MTEF should, therefore, dictate overall budget allocations and, based on the use of a realistic oil price forecast, dictate the level of budget financing allocations from SOFAZ. Over the longer term, significant changes in the oil price outlook may necessitate changes in the MTEF, but the MTEF should still dictate budget allocations.

- **The government needs to decide whether to continue channeling oil-related fiscal revenues both directly to the budget and to SOFAZ, or to channel all oil-related fiscal revenues through a single agency.** If a single agency approach were chosen, SOFAZ would be the logical choice. Such an arrangement would simplify oil revenue management in certain ways: (i) Revenues flowing directly to the budget would come only from the non oil sector and would be less subject to oil price volatility; (ii) SOFAZ would maintain its unique savings role and reinforce its role as a buffer separating commercial oil extraction decisions from public expenditure decisions; (iii) Transfers to the budget from SOFAZ would be dictated by the MTEF and would not be directly related to the level of oil-related revenues – indeed the budget would not need to make a specific oil revenues forecast; and (iv) such an arrangement would ensure a high level of transparency around the oil revenues and their uses.

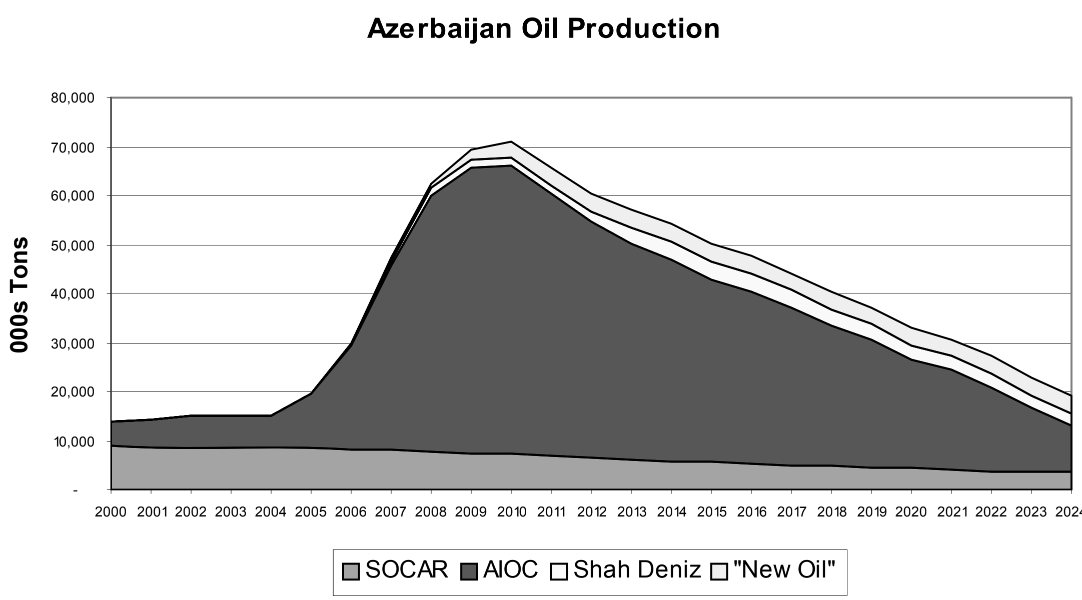
- **In the event the government continues the existing two track system for channeling revenues, oil revenue related surpluses should only be held by the Ministry of Finance until the end of the budget year and should then be transferred to SOFAZ.** Azerbaijan has, in the past, used fairly conservative oil price assumptions in projecting its budget revenues. However, a consequence of conservative price projections that is now being experienced is the generation of a sizable budget surplus. The Ministry of Finance has retained this surplus in a fund it describes as a "stabilization fund". Retaining the surplus within a budget year is entirely appropriate and a necessary step. However, any remaining surplus funds should be transferred to SOFAZ at the end of each budget year. In the future, the government should use realistic price projections but with a tendency to err on the conservative side. Excessively conservative price projections would lead to higher up-front allocations from SOFAZ to the budget than needed and this, in turn, would result in excessive funds accruing within the Ministry of Finance's "stabilization fund".

Oil Revenue Management in Azerbaijan

The Structure of Oil Revenues

I-1. At the time of independence, Azerbaijan inherited a significant hydrocarbon resource base. At the end of 2003, proven oil reserves were estimated at 7 billion barrels and proven gas reserves were estimated at 1.37 trillion cubic meters[7]. The country has been extremely effective in attracting foreign direct investment to the sector and major development programs are underway. Even though there has been only one major discovery in the last 10 years – the Shah Deniz gas field – a significant increase in oil production is anticipated in the next several years (see Figure I-1 below). However, absent a major new discovery, production is projected to peak in 2010 at about 71 million tons and then experience a steady decline, dropping back to less than 20 million tons - the level projected for 2005 – by 2024. This means that Azerbaijan may have only a relatively limited window during which it will generate very significant oil revenues. It is, therefore, important that Azerbaijan establish and maintain programs that ensure the State secures the maximum overall benefit from what may be a relatively short period of oil funded prosperity.

Figure I-1



Source: World Bank analysis

I-2. The projected production increases contemplate a significant capital commitment. Table I-1 summarizes the projected capital requirements for the period 2004 through 2020 for three major projects: (i) the development of Azeri/Chirag/Guneshli (ACG); (ii) the development of the Shah Deniz gas field and the SCP gas pipeline; and (iii) the BTC oil pipeline. Capital investments in Azerbaijan for these three projects during this period

7 Source: BP Statistical Review of World Energy 2004

are projected to exceed $16 billion, with almost $11 billion of spending projected for the five year period 2004 through 2008.

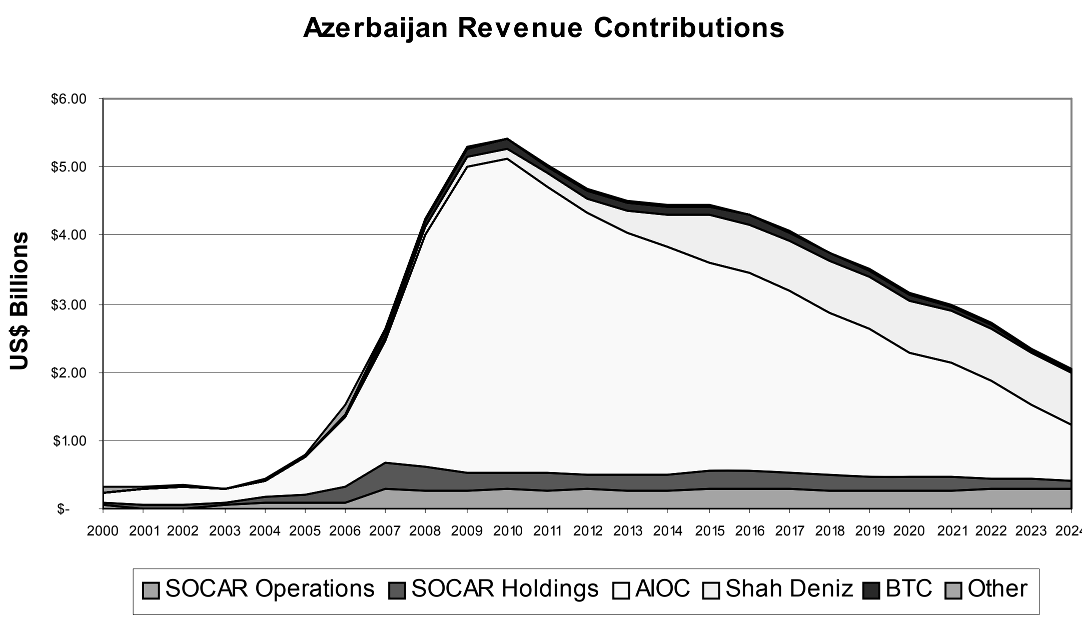
Table I-1
Projected Capital Requirements 2004 – 2020 ($ Millions)

Project	Total Capital Investment	Capital Investment in Azerbaijan
ACG	$12,323	$12,323
Shah Deniz: Upstream	$ 3,724	$ 3,724
Midstream	$ 1,115	$ 618
	$ 4,839	$ 3,342
BTC	$ 1,401	$ 336
Total	**$18,563**	**$16,001**

Source: ACG, Shah Deniz, BTC

I-3. The significant increase in production will translate into a large increase in fiscal revenues. The Bank's 2004 oil price forecast projected a price of $39/barrel in 2004, dropping to $36/barrel in 2005, $32/barrel in 2006, and declining to a price of $26/barrel in the 2009 to 2010 timeframe. Figure I-2 shows the projected level of fiscal revenues from various sources based on this price forecast.

Figure I-2



Source: World Bank analysis

I-4. As the chart indicates, fiscal revenues are projected to peak at a level of almost $5 billion in 2010. For the period 2004 through 2024, fiscal revenues are projected to total over $70 billion. The main contributor is ACG followed by Shah Deniz.

I-5. Fiscal revenues from the upstream oil and gas sector are channeled to the government through the following mechanisms:

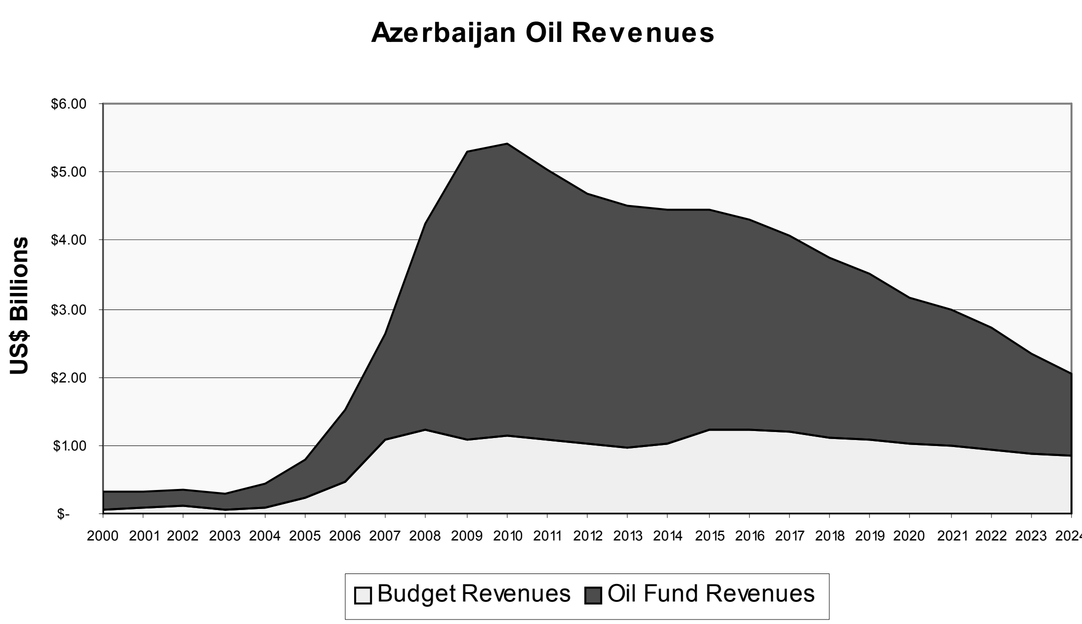
i. Proceeds from the sale of profit oil from the production sharing agreements, bonus payments, royalties (acreage payments), rental fees for the use of state property by foreign companies under oil and gas contracts, revenues generated from the sale of assets under contracts signed with foreign companies and other revenues from joint activities with foreign companies are all paid to the Oil Fund. SOFAZ also retains the revenues generated from the investment of its assets. It is anticipated that dividends payable for the State's interest (both direct and through SOCAR) in the BTC pipeline will be paid to SOFAZ.

ii. Profit tax payments from SOCAR and from the ACG partners, who are required to file individual tax returns, are payable directly to the budget.

iii. SOCAR's earnings from its assigned equity interest in ACG were previously paid to the Oil Fund. At present, however, these are being directed to an escrow account to secure the anticipated borrowings to support the State's investment (through SOCAR) in Shah Deniz and the SCP gas pipeline.

I-6. Figure I-3 provides a projection of funds to be paid to SOFAZ and to the budget (in this figure, SOCAR's equity interest in ACG is assumed paid to SOFAZ).

Figure I-3



Source: World Bank analysis

Revenue Collection and Management

State Oil Fund of the Republic of Azerbaijan

I-7. At the end of 2003, net assets in SOFAZ totaled 3.968 trillion manats, or about $815 million. For the period 2004 through 2024 contributions to SOFAZ (excluding investment earnings) are projected to exceed $50 billion. During the same period, direct contributions to the budget are projected to approach $20 billion. The profile of direct contributions to the budget is much flatter than the overall profile, a reflection of the fact that, under the tax structure incorporated in the PSA, profit tax payments by the ACG partners materialize somewhat later than the large increase in profit oil proceeds that is expected to flow to SOFAZ.

I-8. SOFAZ is currently structured as a savings fund[8]. Transfers are permitted from SOFAZ to the State budget but these are capped in any year at the level of inflows into the fund. The approval of the transfers must also conform to the provisions stipulated in the Budget Systems Law. This has the objective of ensuring that Azerbaijan has a single State budget not multiple parallel budgets. SOFAZ is one of several deficit financing sources. Parliament approves the consolidated budget deficit including Oil Fund expenditures.

I-9. SOFAZ is required to invest its funds outside Azerbaijan in high quality securities. In addition to protecting the principal in the fund this serves to minimize the risk of Dutch disease.

I-10. To date, Azerbaijan has been conservative in the use of the oil revenues accumulated in SOFAZ. The State's oil revenues, however, do represent an important instrument for development of the non oil economy and past analysis undertaken by the Bank suggests that Azerbaijan should be prepared to increase the level of outflows from SOFAZ in order to help stimulate growth in the non oil economy[9]. The government, therefore, needs to establish a comprehensive medium term expenditure framework that takes account of the absorptive capacity of the economy and is designed to promote non oil sector growth. Should this framework result in an approach that is inconsistent with the current SOFAZ rules, appropriate amendments should be made to the rules to accommodate the program.

The Use of a Stabilization Fund

I-11. The State budget for 2004 was established using an oil price assumption of $20/barrel. With prices averaging in the high $30s/barrel in 2004[10], the budget will likely generate significant surpluses. At present, the Ministry of Finance is holding these surpluses in a fund it describes as a stabilization fund. The basic concept of a stabilization fund is to allow the budget to accommodate fluctuations in the price of any

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[8] A summary of the institutional framework for SOFAZ is given in Attachment I-1.
[9] World Bank Public Expenditure Review 2003
[10] The Bank's November 2004 forecast was for an average price of $39/barrel in 2004.

commodity that has a material impact on the budget. In the case of Azerbaijan, the oil price clearly plays a significant role in determining the size of fiscal revenues. With 2004 oil prices averaging in the high $30s per barrel, the surplus generated in 2004 versus the budget projection would have been on the order of $100 million.

I-12. The Ministry of Finance action raises certain questions including:

- Should Azerbaijan have a fund that performs a stabilization function?
- If so, should it be separate from SOFAZ?
- Should the stabilization function be automatic or should it be subject to specific review?
- Should there be a sunset provision on the time funds remain in a stabilization mode and, if so, where should the funds be transferred when the sunset provision is invoked?

I-13. The issue of introducing a stabilization function should not be addressed in isolation. Rather it should be considered in conjunction with the need to establish a full-fledged MTEF that could also set the parameters for any required stabilization adjustments. In the near and medium term the key driver of an MTEF is likely to be the absorptive capacity of the economy rather than the availability of funds. With this in mind, the State Oil Fund has the potential to perform such stabilization functions as may be necessary.

I-14. Consistent with this approach and within the context of the current method of channeling oil revenues, it would be appropriate for the government to continue to use a realistic oil pricing assumption in its budget preparation process, but with a tendency to err on the conservative side. This should result in some likelihood that surplus funds would be generated by the Ministry of Finance relative to the budget projection, but not in excessive amounts. Surplus funds relative to the budget projection should be accounted for and retained by the Ministry of Finance during the budget year. This would enable the Ministry to accommodate a sharp decline in the oil price that might occur during a year that could push revenues below the budget projection level for some period of time. At the end of the year, however, any residual surpluses should be transferred to the State Oil Fund. Excessively cautious assumptions on the oil price would lead to higher up front financing allocations from SOFAZ to the budget than needed and this, in turn, would result in excessive funds being accumulated in the Ministry of Finance's stabilization account.

I-15. In the event a stabilization function is retained by the Ministry of Finance, it would be preferable to avoid introducing an automatic top up mechanism as and when prices drop below the budget forecast level. Rather, the allocation of make up funds to the budget under those circumstances should be subject to specific review and approval.

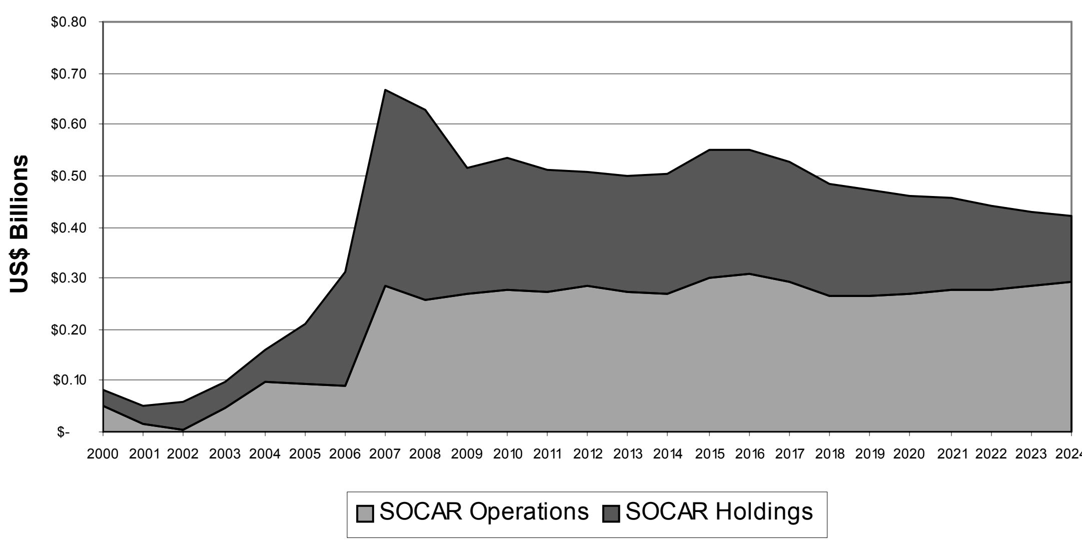
SOCAR's Contribution to Fiscal Revenues

I-16. SOCAR's contributions to fiscal revenues consist of profit taxes related to the operations it manages directly and its share of the proceeds associated with equity interests in PSAs and joint ventures assigned to it by the State. The latter is made up of both net earnings from the PSAs and joint ventures and profit taxes attributable to SOCAR's share of these ventures. As has been noted, at present the net earnings associated with SOCAR's interest in ACG are being placed in an escrow account to secure the funds that SOCAR will borrow to cover its share of investment in Shah Deniz and the SCP gas pipeline. Figure I-4 below provides a comparison of the projected contribution that SOCAR will make to fiscal revenues from both its operating activities and its "holding company" activities.

I-17. There is considerable transparency around SOCAR's holding company activities. These ventures are managed by private sector companies, prepare their accounts in accordance with international financial reporting standards and submit financial and operating information to the various shareholders on a regular basis. This enables the various affected financial agencies in the government to keep close track of the financial performance of these enterprises and of SOCAR's component of that financial performance.

Figure I-4

SOCAR Contributions to Fiscal Revenues



Source: World Bank analysis

I-18. The picture is not so clear; however, where SOCAR's operating activities are concerned. SOCAR is in the very early stages of initiating the process of switching to international financial reporting standards. In the meantime, it is very difficult for the government to get a clear picture of SOCAR's financial performance and of its associated tax obligations.

I-19. The government has demonstrated its commitment to oil revenue transparency by signing on to the Extractive Industries Transparency Initiative (EITI). The State Oil Fund and the Ministry of Finance will both have a role to play in complying with EITI. SOCAR, however, also needs to take near term action to improve the transparency associated with its operating revenues, pending the introduction of international financial reporting standards.

Other Options for Channeling Oil Sector Revenues

I-20. As has been noted, fiscal revenues flow either to the Ministry of Finance or to the State Oil Fund. Figure I-2 shows a sharp increase in oil-related budget revenues starting in 2006. Budget expenditures, however, should be determined by absorptive capacity and inter-generational considerations and should increase along a more linear trend. The amount of expenditure financing out of the Oil Fund clearly depends on these oil-related budget revenues and, as has been noted above, in the event these oil-related budget revenues exceed projections, Ministry of Finance may need to transfer some of the budget revenue to SOFAZ at year-end in order not to end up with two parallel funds accumulating money.

I-21. As an alternative to having two separate flows of oil-related fiscal revenues, one to the budget and one to SOFAZ, an option is to have all the oil sector fiscal revenues gathered in one place. In such event, SOFAZ would be the logical agency. This would simplify oil revenue management in certain ways:

i. Revenues provided directly to the budget would come from the non-oil sector and these would be much less subject to the volatility of oil prices.
ii. SOFAZ would preserve its unique savings role and act a buffer separating commercial oil extraction decisions from public expenditure decisions. It would also act as the single location for gathering all the oil-related revenues.
iii. Transfers to the budget would be dictated by the requirements of the MTEF and would not be directly related to the level of oil-related revenues. Procedures, established and followed as they are today, would make the appropriate transfers to the budget to finance the objectives of the MTEF.
iv. In following its own procedures on the publication of data, SOFAZ would be able to ensure a high degree of transparency around the entire issue of the source and use of all oil-related fiscal revenues.

Utilization of Oil Revenues: the Importance of the SPPRED and the MTEF

I-22. Effective use of Azerbaijan's oil resources is an integral part of an oil revenue management strategy. Azerbaijan has set out its national development strategy in the SPPRED, and is preparing a medium term expenditure framework to prioritize its public expenditures. Maintaining the centrality of the MTEF for the use of oil revenues (as well as other revenues) is the principal way to assure prioritization of public expenditures for Azerbaijan.

I-23. The government's decision to budget according to the SPPRED/MTEF priorities, under the framework provided by the Budget Systems Law suggests that the government correctly wants to maintain a single vehicle for sequencing its reforms and a single listing of priority expenditures to implement. Likewise, with the existence of SOFAZ, the maintenance of an oil price stabilization fund beyond a particular budget year is unnecessary.

Attachment I-1

Institutional Framework for the State Oil Fund of the Azerbaijan Republic (SOFAZ)

Supervision and Control

- The three level management structure consists of the President, SOFAZ's Executive Director, and the Supervisory Board. The President appoints members of the Supervisory Board and the Executive Director.
- The Board consists of key government officials (Prime Minister, ministers), two parliamentary members (nominated by the Speaker), and representatives from academia. It is entrusted with the functions of internal supervision to oversee the composition of the Oil Fund's assets and compliance with the expenditure rules.

Investment Strategy and Operational Management of Assets

- The investment strategy is annually approved by the President based on recommendations of the Executive Director, taking into account recommendations of the Supervisory Board.
- Operational management is delegated to the Executive Director, who chairs the Investment Board (internal structure of the Fund).
- Professional portfolio managers may be contracted for a certain portion of the Fund's assets.
- Investment portfolio guidelines determine currency composition, the balance between liquid (up to 40 percent of the portfolio) and long-term investments, and fixed and equity income instruments. Preference is given to fixed income instruments, while equity income instruments (corporate securities and stakes) are banned unless a highly reputable professional investment manager is hired to handle them.

Transparency, Accountability, and External Oversight

- A highly reputable international auditor is selected to conduct an annual audit of the Oil Fund's accounts. The results from the annual report on the use of the funds and the external audit report are published in the mass media. Pursuant to the Azeri laws, the Chamber of Accounts (the country's Supreme Audit Institute) may also audit the Fund.
- Quarterly reports produced by the Executive Director shall be submitted to the Supervisory Board and the President.
- The annual report is prepared in coordination with the Ministry of Finance (MoF). After recommendations of the Supervisory Board are incorporated, it shall be submitted to the President. The annual report is posted on the official website of SOFAZ.

Governance of Revenues/Expenditure Rules

- While the ultimate decision-making rests with the President, Oil Fund expenditures (other than its own operating expenses) are consolidated with the state budget with the monies allocated to the budget and used for purposes that are consistent with the public investment program (PIP).
- According to the 2002 Budget Systems Law, and the 2003 amendments to the Law Parliament has the authority to set the expenditure and deficit ceilings for the Oil Fund.
- All investment expenditures are to be executed through the Treasury.
- Use of the funds is subject to the State Procurement Law, which governs all budgetary expenditures.
- Investments should be made in projects of national importance; project investments have to be part of the governmental PIP and MTEF and consistent with the SPPRED.

Annual Report 2001, State Oil Fund of the Republic of Azerbaijan, and www.oilfund.az.

II - The Petroleum Sector in Azerbaijan

Summary

II-i. With the break-up of the Soviet Union, Azerbaijan inherited a significant hydrocarbon resource base. The country has been very effective in ensuring optimum exploitation of this resource base. Azerbaijan was in the forefront of the former Soviet Union countries in attracting foreign investment to the upstream oil and gas sector and it has succeeded in establishing a production sharing agreement regime that is consistent with best industry practice.

II-ii. One of the main challenges now facing Azerbaijan in its petroleum sector relates to the State owned oil and gas company – SOCAR. The government has made a commitment to restructure the company and decisions will be required on both the form and the scope of the restructuring. The government also faces the challenge of ensuring the sustainable financial viability of SOCAR following its restructuring. This section addresses these challenges and outlines the issues and options to be considers as the SOCAR restructuring process proceeds.

II-iii. The conclusions and recommendations of this section may briefly be summarized as follows:

- The key objective of the restructuring process is to transform SOCAR from an enterprise that mixes public and commercial roles into a commercially focused company capable of performing at a level defined by good international oil and gas industry practice. A required precursor to this is to effect a clear separation of the regulatory functions performed by SOCAR as the de facto "competent authority" dealing with the upstream oil sector and the commercial functions it performs as an operator in the sector. The "competent authority" role should, therefore, be established as a separate agency reporting directly to the top levels of government.

- In addition to the regulatory role it plays, SOCAR also has a minority ownership role in a number of production sharing agreements and joint ventures. These, in effect, represent State ownership in these activities that is effected through SOCAR. The government will need to decide what ownership arrangement will ensure that the State receives the full benefit associated with these ownership interests. Options to be considered include (i) transferring the holdings into a separate holding company, which would be the optimum approach; (ii) maintaining the status quo; and (iii) allowing SOCAR full control over the holdings' revenues.

- Full implementation of an effective restructuring process for SOCAR could take a number of years to complete. The process, however, should not take place in isolation but should be accompanied by other reforms in the energy sector, for example those designed to reduce and ultimately eliminate subsidies.

- An important early part of the process is to develop and implement a plan to transition to international financial reporting standards. In order to effect this transition SOCAR will require outside assistance. Specifically, SOCAR would benefit significantly from hiring a senior adviser to guide the company through a process that could take several years. The costs of the transition will not be insignificant and appropriate provision should be made in SOCAR's own budget and, as appropriate, the State budget to cover these costs.

- A critical element associated with the restructuring process is the introduction of greater transparency to SOCAR's operations. While a move to international financial reporting standards is an important component of this, certain measures to demonstrate increased transparency can be introduced at an earlier stage.

- It is also important to develop and monitor benchmarks of performance. Performance should be monitored both internally to track improvements over time and externally against best practice performers. The benchmarks should address key aspects of the business and address both revenues and costs.

- Increasing attention is being focused on the legacy of environmental problems that SOCAR inherited and a process should be introduced to address these.

- SOCAR's financial performance will benefit from investment in certain facilities and rationalization of the workforce. Sustained financial viability of the company's core operations, however, is predicated on eliminating the subsidies that SOCAR now provides the Azerbaijan economy. These subsidies are the result of problems with payments for fuel and feedstock delivered into the domestic market (particularly to State owned enterprises such as Azerenergy, Azerigaz and Azerchemia) and also with the fact that price and tariff levels do not reflect the true economic value of the fuel and feedstock supplied.

- In the case of refined products, prices are at a level that is sufficient to cover SOCAR's costs, although they fall short of international price parity levels. In November 2004, the government increased petroleum product prices as an initial step in moving them towards international parity levels (details are provided in Attachment II-2). The government should also open up the market to allow retailers and major consumers to enter into arrangements to import product directly, thereby creating competition with SOCAR.

- In the case of gas, the price in 2004 was well below cost recovery levels. Depending on the level of imports it appears that, even after the November 2004 price increase, the wholesale price would have to at least be doubled if SOCAR is to cover its costs and a three to fourfold increase would be required if the wholesale price is to be brought up to the import parity level.

The Petroleum Sector in Azerbaijan

II-1. Azerbaijan is endowed with a significant hydrocarbon resource base with proven oil reserves totaling 7 billion barrels and proven gas reserves totaling 1.37 trillion cubic meters[11]. Since independence, Azerbaijan has been in the forefront of the former Soviet Union countries in attracting foreign investment to its upstream oil and gas sectors. It has successfully established a production sharing agreement (PSA) regime that is consistent with best industry practice and has supplemented this by creating an effective "competent authority" approach in the form of the Foreign Investment Relations Department of SOCAR. At this point, Azerbaijan has signed over 20 PSAs (see Attachment II-1). The sector plays host to most of the major players in the international oil industry despite the fact that there has been only one major new discovery – the Shah Deniz gas field – since foreign investors entered the sector in 1994 when the so-called "Contract of the Century" was signed with the AIOC consortium.

II-2. The oil sector plays a critical role in Azerbaijan's economy representing over 26% of GDP in 2002. This critical role can be expected to continue. The State's financial interest in the oil sector takes four forms: (i) the receipt of profit oil from the PSAs; (ii) the receipt of taxes associated with oil sector operations; (iii) a direct equity interest in the PSAs which, up to this point, has been assigned to SOCAR[12]; and (iv) its ownership interest in SOCAR as a State owned oil and gas company.

II-3. As the equity owner of SOCAR, the government faces a number of specific challenges:

i. To effect a clear separation of the regulatory functions currently performed by SOCAR as the de facto "competent authority" dealing with the upstream oil sector and the commercial functions SOCAR performs as an operator in the sector;

ii. To ensure the State receives the full benefit associated with SOCAR's equity interest in PSAs and joint ventures;

iii. To facilitate the transition of SOCAR from a Soviet style State owned enterprise to a commercially focused organization operating in accordance with best international practice;

iv. To ensure SOCAR's ongoing financial viability; and

v. To address the legacy of environmental problems that were inherited from the Soviet Union along with the hydrocarbon assets.

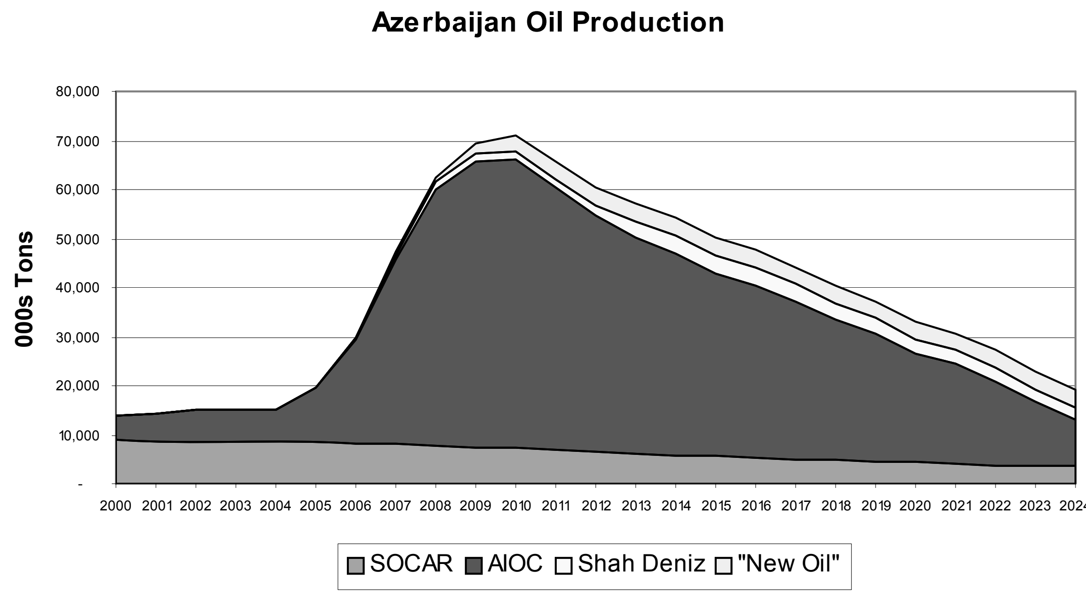
[11] Source: BP Statistical Review of World Energy 2004
[12] SOCAR has an equity stake in all the PSAs

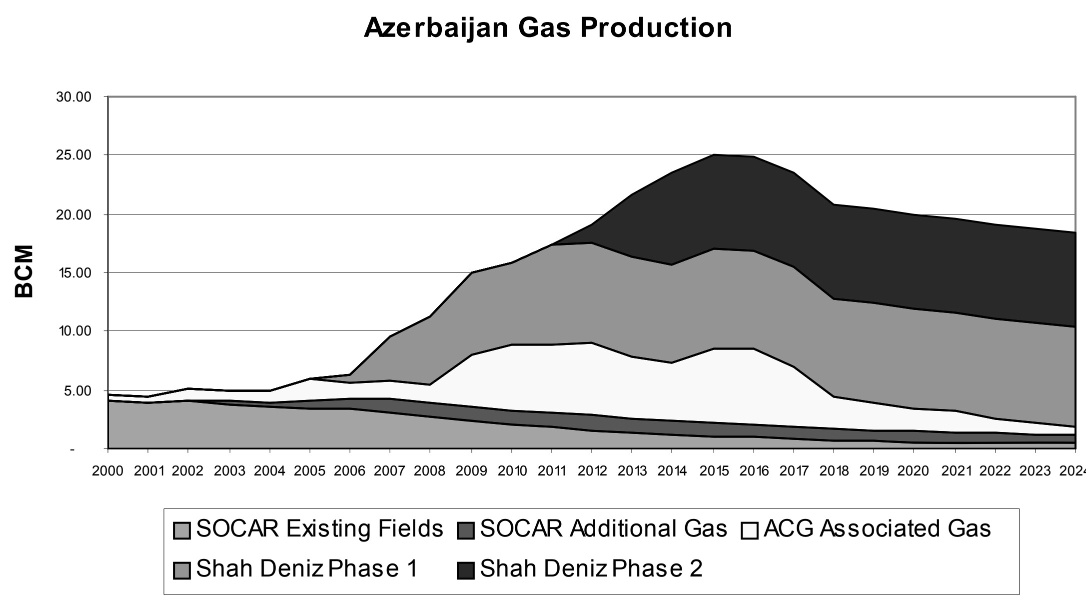
Overview of the Sector

Oil and Gas Production

II-4. SOCAR is the dominant player in the domestic petroleum sector. The company produces approximately 9 million tons of oil per year and 4 billion cubic meters (BCM) of natural gas. It acts as a "single buyer" for the gas sector and is the supplier of all refined oil products sold in the domestic market.

Figures II-1 and II-2





II-5. The major increments of oil and gas production, however, will come from the PSAs operated by international oil companies – see Figures II-1 and II-2 above[13].

The Refining Sector

II-6. SOCAR owns and operates two refineries, Azerneftyag and Azerneftyanajag with a combined design distillation capacity of about 20 million tons per year. The Azerneftyag refinery has a design distillation capacity of 11.7 million tons per year of crude charge but includes refining facilities that commenced operations over 100 years ago. The refinery is essentially a lubricating oil/bitumen plant, with incidental production of straight run kerosene, diesel and mazut. The refinery does not even have a reforming unit and the naphtha it produces is transferred to Azerneftyanajag for processing into gasoline and/or is sold to Azerchemia as petrochemical feedstock. The technology base of all constituent process units and production control systems is obsolete. The 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.

II-7. The Azerneftyanajag refinery commenced operations initially in the 1965/66 timeframe. It has distillation design capacity of 8 million tons per year of crude charge. It does have upgrading capacity with fluid catalytic cracking units, a thermal cracking unit, a coker and an alkylation unit. The facility, however, has also suffered from a lack of funding for maintenance and upgrading.

II-8. The refineries both operate at throughput levels substantially below their distillation capacity levels. However, the output from the two refineries does largely balance the country's requirements for gasoline and naphtha, although some gasoline is exported to Iran. The refineries' production profile results in the country being long (i.e. surplus) kerosene and diesel and, seasonally (i.e. in the summer[14]) mazut. These products are all exported by SOCAR to markets in the South Caucasus, the Black Sea and the Mediterranean.

II-9. The Mediterranean market effectively sets the international parity price for product exports from Azerbaijan. Products moving into the Black Sea and Mediterranean markets have generally been exported via Batumi on the Georgian Black Sea coast. The cost of overland transportation from Baku to Batumi is in the range of $29 to $33 per ton for white products (i.e. gasoline, kerosene and diesel) and $25/ton for dirty products (i.e. mazut and any crude oil that travels overland)[15]. These costs dictate parity price levels netted back to Azerbaijan. SOCAR, however, does tend to secure prices higher than these parity levels for product sold into Georgia since Georgia is a net importer of refined products.

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[13] Source: World Bank analysis

[14] As Azerbaijan continues to substitute natural gas for mazut for power production the long position with mazut is likely to increase.

[15] Source: BP Oil International Limited.

II-10. Notwithstanding the age and inefficiency of the two refineries, their location creates a situation in which they can be viewed as potentially financially viable. As is indicated above, Azerbaijan is balanced to long refined products. However, without these two refineries, the country would have to import product to meet all its domestic needs. This permits a comparison to be made of the potential financial performance of the two refineries if, hypothetically, Azerbaijan were (i) to export all products and (ii) if it had to operate the refineries to avoid imports (in which case, with the exception of gasoline and naphtha, about half the primary products would have to be exported). These two cases are summarized in Tables II-1 and II-2.

Table II-1
Financial Viability of the Azerneftyag Refinery - 2003[16]

Product	Price US$/ton		Yield %	Tons	Values US$/ton	
	Export Parity	Import Parity			Export Parity	Import Parity
Jet Fuel	231.80	315.80	7.50 %	226.9	17.39	20.54
Diesel Fuel	211.14	295.14	26.90 %	813.9	56.80	68.09
Kerosene KO-26	231.80	315.80	3.30 %	99.8	7.65	9.04
Mazut	112.16	177.16	47.10 %	1,425.0	52.83	68.13
Reforming Gasoline	230.64	314.64	5.00 %	151.3	11.53	13.63
Naphtha	221.12	305.12	5.80 %	175.5	12.82	17.70
Engine Fuel DT	72.62	156.62	0.90 %	27.2	0.65	1.03
Bitumen	135.60	219.60	0.90 %	27.2	1.22	1.60
Lubricants	142.37	226.37	0.90 %	27.2	1.28	1.66
Other	75.00	75.00	0.03 %	0.9	0.02	0.02
Total			98.33 %	2,974.9	162.19	201.44
Crude Oil Input	181.77	181.77		3,025.5	181.77	181.77
Refining Cost					14.15	14.15
Net Refinery Margin					(33.73)	5.52

Table II-2
Financial Viability of the Azerneftyanajag Refinery - 2003

Product	Price US$/ton		Yield %	Tons	Values US$/ton	
	Export Parity	Import Parity			Export Parity	Import Parity
Gasoline	250.64	334.64	18.50 %	596.3	46.37	61.91
Jet Fuel	231.80	315.80	6.80 %	219.2	15.76	18.62
Diesel Fuel	211.14	295.14	22.90 %	738.2	48.35	57.97
Household Heating	211.14	295.14	1.70 %	54.8	3.59	4.30
Kerosene KO-26	231.80	315.80	2.50 %	80.6	5.80	6.85
Mazut	112.16	177.16	37.80 %	1,218.4	42.40	54.68
Coke	39.62	39.62	0.70 %	22.6	0.28	0.28
Propane	122.47	122.47	0.03 %	1.0	0.04	0.04
Butane	115.37	115.37	1.20 %	38.7	1.38	1.38
Other	75.00	75.00	0.01 %	0.3	0.01	0.01
Total			92.14 %	2,969.8	163.97	206.03
Crude Oil Input				3,223.4	181.77	181.77
Refining Cost					17.73	17.73
Net Refinery Margin					(35.53)	6.53

Source: Yield data proved by SOCAR to the IMF. Price data from the IEA and World Bank analysis.

[16] The tables are based on production levels in 2001 using average crude oil and product prices for 2003.

II-11. This analysis suggests that, from a financial standpoint, Azerbaijan may well be better off operating the two refineries than relying on imports. However, an assessment should be made of options for improving the performance and efficiency of the refining network.

Downstream Operations

II-12. SOCAR, at present, is the wholesale supplier of oil products to the domestic market. Certain of the neighboring countries are exporters of refined products. Both Turkmenistan and Russia, for example, consistently export refined products and a portion of the Turkmenistan exports transits through Azerbaijan. These volumes are a potential source of competitive supply and it would be to Azerbaijan's benefit to allow product retailers and major consumers to enter into bilateral arrangements to purchase imported product rather rely solely on SOCAR. SOCAR would not be adversely impacted by such an arrangement since it already has the capacity to manage the sale of product exports.

II-13. Refined products are subject to both VAT and, with limited exceptions, excise taxes. The excise tax is levied on the wholesale price charged by SOCAR. Logistical costs are then added and VAT, at 18%, is levied on the resultant retail price, including the excise taxes. The excise tax rates that currently apply to the major products are summarized in Table II-3.

Table II-3
Petroleum Product Excise Tax Rates

Product	Excise Tax %
Gasoline-96	101.4
Gasoline-92	88.1
Gasoline-80	88.4
Diesel	15.0
Household Heating Oil	18.6
Jet Kerosene	12.6
Kerosene	22.3
Naphtha	8.0
Mazut	-
Engine Lubricants	32.0
Industrial Lubricants	29.1
Turbine Lubricants	33.4
Transformer Lubricants	34.2
Bitumen	14.0
Coke	13.9
Liquefied Petroleum Gas	10.7

II-14. When wholesale product prices were increased in early 2003, the government adjusted a number of the excise tax rates downwards so as to minimize the impact of the higher wholesale prices on the retail consumer. The November 2004 price increases were all effected through an increase in the excise tax levels (see Attachment II-2). Excise taxes on petroleum products are a "discretionary" tax. Looking to the future, therefore, the government should consider what objectives it wants to realize from a petroleum products excise tax policy. Elsewhere such taxes have been used to encourage particular behaviors as well as raise revenue.

II-15. Given the significance of the role SOCAR plays in the domestic petroleum sector, as well as its participation in the PSAs, it is clear that the company will have a major role to play in any reform program instigated in the sector. Consequently, SOCAR features prominently in the discussion of the issues and options in the balance of this section.

Management of the State's Interests in PSA and Joint Venture Arrangements

II-16. The government of Azerbaijan has made a commitment to restructure the State oil and gas company – SOCAR. This commitment was embodied in Presidential Decree Number 844, dated January 24, 2003, *On Structural Improvement of the State Oil Company of the Azerbaijan Republic*. SOCAR has since embarked on a restructuring program that has the objective of transforming the company into a commercially focused enterprise capable of performing at a level defined by good international petroleum industry practice. Following its restructuring, Socar could be an attractive candidate for privatization. This restructuring effort, however, raises the question as to where two of SOCAR's current roles - its "competent authority" role and its ownership role in PSAs and joint ventures - fit into the future structure.

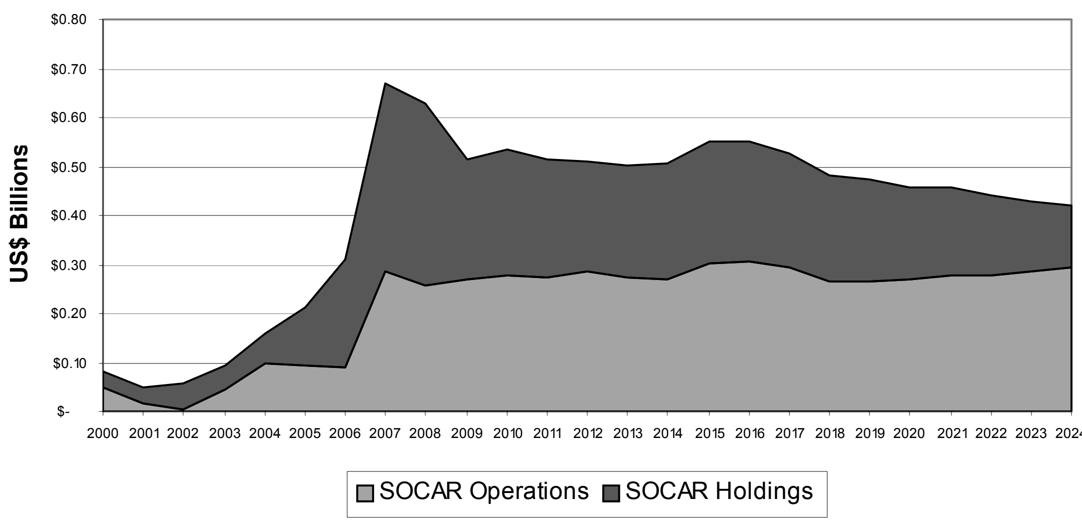
II-17. In the case of the "competent authority" role it is clear that this is a government policy function that should not be included in a commercially focused enterprise. Rather, given the importance of the role, it should be established as a separate agency reporting directly to the top levels of government. The issue of SOCAR's ownership role in PSAs and joint ventures, however, is not quite so clear cut.

II-18. There are various options as to how the ownership issue can be handled, but, before addressing these options, some brief discussion on the role of these holdings is warranted. By taking an equity share in the PSAs, the government has ensured that the State will participate in a direct fashion in the same risks and rewards as the other investors – participation through profit oil and taxes is indirect rather than direct. As the various projects have developed, the value of these equity holdings has appreciated significantly. The State could elect to capitalize on the value of these holdings by trying to sell part or all of the equity and realize a substantial one time payment. Alternatively, the State can maintain an attractive revenue stream for the life of the PSA. Figure II-3 provides a projection of the revenues associated with SOCAR's operations as well as with these "holding company" activities.

II-19. One of the objectives of a privatization process is to create incentives that will promote efficiency of operations. These holdings, however, exist in activities that are already owned and operated by the private sector. Consequently, the only reason for selling these holdings would be to realize a one time capital payment. Under current State revenue guidelines, such a payment would accrue to the State Oil Fund. While it is certainly the prerogative of the State (as owner of these shares) to make its own determination as to the attractiveness of an outright sale, it should be noted that any valuation of these shares will be based on a perception of the net present value of future cash flows. To the extent that any investor seeks a return that is higher than that obtainable by the State Oil Fund, it would be better for the State to retain the shares (and the associated cash flows) rather than sell them to such an investor.

Figure II-3

SOCAR Contributions to Fiscal Revenues



Source: World Bank analysis

II-20. Following the establishment of the State Oil Fund, cash distributions to SOCAR from its PSA holding in Azeri, Chirag, Guneshli (ACG) were directed to the Oil Fund. These are now being directed to an escrow account to secure the anticipated borrowings to support the State's investment (through SOCAR) in Shah Deniz and the SCP gas pipeline. Consequently, these funds have been, and will continue to be kept separate from the funds (and funding requirements) associated with SOCAR's operating activities.

II-21. The State has the following options for managing these holdings:

i. To spin the holdings off from SOCAR and transfer them to a separate holding company. This would be the preferred option.

ii. To maintain the de facto status quo whereby SOCAR maintains ownership but the cash flow is kept independent of SOCAR's other cash flows.

iii. To allow SOCAR to retain ownership, but, ultimately, with full control over the cash flows.

II-22. These options have certain pluses and minuses as follows:

Option 1 – to transfer the holdings into a separate holding company:

Pluses:
- The revenue streams will clearly be identified as being for the benefit of the State and use of the revenues will be under direct government control.
- Management of these activities can be handled by a small management team.
- Plans for privatization of SOCAR would have to proceed strictly on the merits of SOCAR's operations ensuring that full value was received for such operations.
- Full transparency of these cash flows can easily be effected.
- Revenues generated from the holdings could not be used to subsidize SOCAR's other operations.

Minuses:
- Changes will be required in agreements such as the Shah Deniz financing to reflect the changes in the ownership of these holdings.

Option 2 – to maintain the status quo:

Pluses:
- No changes are required in current arrangements and agreements.
- Ownership of these holdings could make SOCAR appear more attractive as a privatization candidate.
- Ownership of these holdings could enhance SOCAR's ability to secure financing.

Minuses:
- There will be uncertainty over the accountability for managing these revenue streams.
- There is no assurance that these cash flows will not at some point in the future be consumed by SOCAR rather than be used to the overall benefit of the State.

Option 3 – To allow SOCAR full control over the holdings' revenues:

Pluses:
- This would create the most attractive case for privatization of SOCAR (but at the potential cost of under-realizing the full value of all SOCAR's assets).
- This would allow SOCAR the opportunity to meet its investment needs and to secure financial support for its activities.
- Accountability for these revenue streams would be clearly defined.

Minuses:
- These cash flows would accrue to the benefit of SOCAR rather than to the overall benefit of the State.
- There is a risk that inadequate transparency will apply to these cash flows.

Restructuring SOCAR

II-23. Full implementation of the SOCAR restructuring process could take a number of years. The process should be accompanied by a significant cultural re-orientation towards a fully commercial focus. Experience both within the former Soviet Union (FSU) and elsewhere demonstrates that significant cultural changes require a minimum of three years and often more than five years. At this stage, the best examples of FSU companies that have effected this transition exist in the oil sector in Russia among some of the privately owned companies, but, even in those cases, the transition process has taken more than five years.

II-24. SOCAR's transition to a fully commercially focused operation cannot occur in isolation. Rather, it should be accompanied by other reforms in the energy sector designed to ensure, for example, the elimination of subsidies that SOCAR is currently forced to provide through either non payments or through the application of tariffs and prices that do not reflect the true economic value of the oil and gas being supplied. That having been said, specific reform and restructuring actions applicable to SOCAR's operations can be identified.

II-25. The restructuring of SOCAR's activities and associated reform efforts can be undertaken in a phased manner. The matrix table below summarizes these phases.

Table II-4
The Phased Restructuring of SOCAR's Operations

Phase	SOCAR's Operations	Holding Company Activities	The Regulatory Role
Current Situation	SOCAR manages vertically integrated oil operations and upstream gas operations but also operates a legacy of non oil and gas related businesses. Accounts are maintained in accordance with Azerbaijan accounting standards. There is no public reporting of SOCAR's financial and operating performance. SOCAR inherited a legacy of environmental problems but has yet to develop a program to address these.	SOCAR's interests in various joint venture activities have been incorporated in a series of joint stock companies that come under the SOCAR holding company umbrella. These companies do not have an operating role (that role is carried out by private sector partners). Revenues from these activities are accounted separately from SOCAR's other activities. These companies maintain their books of accounts in accordance with international financial reporting standards.	The Foreign Investment Department of SOCAR plays the role of "competent authority" in dealing with foreign investors in the upstream oil and gas sector. It issues licenses, negotiates PSAs and operates as the de facto regulator of upstream oil operations in Azerbaijan. Oil and gas prices in the domestic market are established by the government.

Phase 1	Initiate implementation of the key recommendations of the Ernst & Young study including the transition to IFRS throughout SOCAR. Initiate the USTDA funded study on restructuring. Commence public reporting of financial and operating performance. Establish a set of restructuring monitoring benchmarks. Ensure that all of SOCAR's operations fall within a corporatized structure (e.g. as part of a joint stock company) Identify all SOCAR's non core business activities. Initiate work on development of a program to address the legacy environmental problems in the sector.	Transfer the holding company activities to a new holding company not affiliated with SOCAR. Commence public reporting of the financial and operating performance of these companies.	Establish the regulatory functions now performed within SOCAR in an independent "competent authority". In order to preserve the independence of this unit it should be independently financed (e.g. through licensing fees) and should report directly to a high level within the government (not to a ministry) such as to the Prime Minister or to the President. Transfer price setting responsibilities to a new regulatory agency responsible for regulation of the energy sector.
Phase 2	Commence implementation of the key recommendations arising from the USTDA funded restructuring study. Initiate the restructuring benchmarking monitoring process and report on the results together with other public disclosures of financial and operating performance. Commence/continue divestment of non core business activities. Commence implementation of a program to address legacy environmental mitigation issues.	Maintain the holding company as a separate state owned operation.	

Phase 3	Complete the restructuring process. Assess the potential for privatization of part or all of SOCAR.	Maintain the holding company as a separate state owned operation.	

II-26. As has been noted, SOCAR at present combines (i) an operating role covering upstream oil and gas, refining, transportation and sales of crude oil and refined products with (ii) a holding company role associated with its ownership interest in ACG, BTC, Shah Deniz, SCP and other ventures and (iii) certain oil related regulatory functions including the role as "competent authority" to deal with international investors in the oil and gas sectors. Two overarching components are, therefore, envisaged in the restructuring process. The first is the separation of these three roles, allowing SOCAR to focus exclusively on its role as an operator. The second addresses the changes needed to enable SOCAR to evolve into a commercially focused organization that complies with best industry practice as an operator of oil and gas assets. The more detailed restructuring effort will be directed at this second component.

II-27. Within the context of this second component a few key themes are worth highlighting. The first is the need to couple a transition to improved financial management practices (including the adoption of international financial reporting standards) with the need for greater transparency. It would be highly desirable if SOCAR were to adopt the disclosure standards with regard to financial and operating performance that represent best practice among State owned oil and gas companies – Statoil of Norway and Petrobras of Brazil are examples of best practice among such companies. These requirements are summarized in the table above[17]:

II-28. The second theme relates to the legacy of environmental problems that SOCAR inherited. Increasing attention is being focused on these issues and it would be timely to initiate a process to address them. This process needs to assess the clean-up requirements, examine the options for addressing them and then establish an implementation plan. Activities can be broadly grouped into those that will require significant technology but are not particularly labor intensive (e.g. land reclamation) and those that are relatively labor intensive (e.g. dismantling abandoned rigs). Such a program will create jobs, particularly as regards the more labor intensive components. There will also be costs associated with such a program, although these may be partially, or even fully mitigated by (i) sales of land that has been cleaned up and (ii) reclamation programs (e.g. for the steel in the abandoned rigs and for oil recovered as part of the clean up) and initial budget provisions will have to be made to cover these costs[18]. This, in turn requires agreement on the assignment of responsibility and accountability for the clean-up effort.

[17] Not all the requirements would apply to SOCAR, but they are indicative of the types of information that should be disclosed.
[18] Given the appreciation in land values on the Apsheron Peninsula, a clean up program could well be financed through the sale of cleaned up land, thus budget funding may only be required to initiate the program.

Table II-5
Transparency Requirements for State Owned
Oil and Gas Companies

Disclosure Requirements to the General Public: Minimum requirements are those that pertain to a publicly quoted major oil and gas company: • Annual financial statements (which should be prepared in accordance with international financial reporting standards) for the consolidated operation and its major business units. • Quarterly interim financial statements. • Statistics on operating performance.
Disclosure to the Government: The Government has a valid basis for seeking disclosure of any information it requires to ensure that these State owned assets are being efficiently managed.
Disclosure to Lenders: • Detailed financial information (including, ideally, accounting statements audited in accordance with international financial reporting standards). • Project specifics (in the case of project financing).
Disclosure to the Regulatory Authority: Information required to allow the Regulator to make a determination of the appropriate course of action associated with any regulated activity such as transportation tariffs and compliance with service standards e.g.: • Detailed accounts • Operating costs • Actual and projected capital costs • Administrative and general costs • Borrowing costs • Customer data • Physical data • Quality of service indicators • Any other data deemed pertinent to the decision process* *Confidential information may be requested by the Regulator, but may not be disclosed by it.

II-29. The third theme is the importance of benchmarking performance and monitoring performance during the restructuring process. Performance should be monitored both internally, i.e. to track improvements over time, and externally against best practice performers both state owned (e.g. Statoil and Petrobras) and privately owned (e.g. BP, Shell, ExxonMobil etc.). These benchmarks should address key aspects of the business and should cover both revenues and costs.

The Introduction of International Financial Reporting Standards

II-30. The introduction of international financial reporting standards (IFRS) is an essential requirement if SOCAR is to make an effective transition into a commercially focused company capable of performing at a level defined by good international oil and gas industry practice. Financial reporting in accordance with IFRS will provide SOCAR's management and the government with critical tools to assess the performance of the company. Financial reporting in accordance with IFRS will also be essential if SOCAR is to secure access to commercial sources of financing in the future.

II-31. The process will, however, take some time and it could be as much as three years before SOCAR is able to effect the transition with some additional time possibly being required before SOCAR is able to secure unqualified audits of its operations. Key steps include developing the capacity to make the transition to IFRS and undertaking the analysis of activities and operations that will be required to effect the transition. In order to effect the transition, SOCAR will need access to expert advice and assistance. One measure that should prove particularly helpful would be to hire a senior adviser to guide the company through the process. Such an individual should have significant experience in dealing with the financial reporting of a major international integrated oil and gas corporation. Table II-6 below summarizes some of the key actions that will be required in making the transition to IFRS and the time frame in which such actions should be initiated/ undertaken.

Table II-6
The Introduction of International Financial Reporting Standards

Time Frame	Organizational Activities	Accounting Activities
Months 1 – 6	Hire a senior adviser Form an IFRS Steering Committee Prepare initial IFRS transition plan Commence IFRS management information training for all financial staff and for non financial managerial staff.	Prepare list of all business units, subsidiaries, joint ventures and other business arrangements and interests. Prepare list of all exploration and production wells with their history and details of their current status. Identify all bank accounts, cash deposits and loans to third parties. Identify all loans and other monetary liabilities and cash held for third parties. Identify current accounting policy for capitalization of expenditures and list all new capital expenditures by unit. Identify all material contracts.

Time Frame	Organizational Activities	Accounting Activities
Months 7 - 12		Prepare consolidated schedule of reserve estimates by field.[19] Conduct inventory count of all products in inventory (oil, gas liquids) by location including in transit product. Count to cover all locations at the same time and be completed at a reporting period end. The results should be reconciled to the accounting records. List fixed assets at a reporting period end with sufficient details to enable physical identification of assets. List the book value, the current status and condition and logical business unit owner in cases where the ownership is undetermined. Perform count of non product inventories and supplies.
Months 13 - 18		Prepare *Current Environment Assessment*. Report topics should include, but not be limited to: • Identification of primary operational accounting input data e.g. well production data, supplies usage, refinery outputs by product line. • Description and evaluation of major delivery processes which accounting relies on to receive accounting input data from operations. • Actual accounting procedures for primary balance sheet and expense items. • Accounting policies for Balance sheet items. • Accounting policies for Revenue and Expense recognition. • Identify and detail major related party transactions. Identify and detail inter/intra company transactions. Deliver initial high level internal accounting Policies and Procedures manual.
Months 19 - 30	Decide on future organizational structure. Deliver IFRS migration plan including a timetable. Develop criteria to determine which business units be IFRS transition pilots in the transition for the consolidated group.	For each implementation deliver detailed solutions for significant accounting issues.

[19] This will require the use of outside expertise.

II-32. Table II-6 contemplates a two and a half year period leading up to the initial switch to international financial reporting standards. The costs of this transition will not be insignificant. In addition to the requirement for expert assistance, training requirements will be extensive and there will be a need to transition to new accounting software. Provision should be made both in SOCAR's budget and, as needed, in the State budget to cover these costs.

Assuring SOCAR's Future Financial Viability

II-33. SOCAR was established in 1992 through the merger of Azneft and Kazpmorneftegas. The company continues to be responsible for more than half the country's oil production, although that will change as production from ACG increases (see Figure II-1 above). It operates the domestic oil pipeline system and Azerbaijan's two refineries. It supplies the domestic market with refined products and is responsible for oil product imports and exports and for the export of a portion of its own crude oil production together with the State's share of profit oil from ACG. In addition, it acts as the single buyer of gas for the domestic market, purchasing gas imported from or via Russia and handling the associated gas that is provided to the State, at no charge, under the terms of the ACG production sharing agreement.

II-34. There are clear opportunities to improve the financial performance of SOCAR's operations. Production costs are high as a result of equipment deterioration and declining reservoir pressures. The two refineries are in need of modernization and the pipeline network requires investment for rehabilitation. However, in theory, SOCAR should be able to generate adequate revenues to cover its costs. Financial performance, however, is compromised by the fact that SOCAR is effectively required to subsidize the overall energy sector within Azerbaijan.

II-35. SOCAR supplies the fuel required by Azerenergy (gas and mazut) and Azerigas (gas) to meet domestic requirements for electricity and gas. However, a number of subsidies are embedded in these transactions as a result of (i) non payment problems in the sector which translate into a shortfall in payments by these two State owned enterprises to SOCAR, and (ii) domestic prices that do not reflect the true value of these fuel supplies. In 2002, it is estimated that the shortfall in payments alone totaled $150 million, or about 2.5% of GDP[20] while the under recovery of the true economic value of the fuel exceeded $200 million[21].

II-36. In the last three years, the budget has made explicit transfers to SOCAR to cover the shortfall in payments on the part of Azerenergy and Azerigas. This, however, does not address the need for prices for these fuel supplies that reflect their true economic value.

II-37. The wholesale price of oil products in the domestic market is, at present, well below international price parity – this is largely a reflection of the significant increase in

[20] Source: the IMF.
[21] Source: World Bank analysis.

oil prices over the last few years. In November 2004, the government increased the prices of refined products as a step towards bringing them in line with international parity prices (see Attachment II-2).

II-38. There is also a need to increase the wholesale price for gas. On November 2nd, 2004, the wholesale gas price without VAT was increased from 64,000 AZM per thousand cubic meters (MCM) or about $13/MCM to 73,000 AZM for untreated gas and 82,000 AZM for treated gas for an average price of about 79,000 AZM/MCM or about $16/MCM. While this price is sufficient to allow SOCAR to recover the cost of domestic supply it is well below the price level necessary to allow SOCAR to cover the combined costs of domestic gas supply and imports[22] and is also well below the import parity price level of $52/MCM that would ultimately be the appropriate price.

II-39. As is indicated in Table II-7, on the basis of production and consumption in 2003, an average wholesale price of at least $32/MCM is required if SOCAR is to cover production and import costs.

Table II-7
Gas Supplies and Costs - 2003

Source of Gas Supply	Volume	Cost $/MCM
SOCAR Production	4.0	$20.0/MCM
AIOC Associated Gas	1.0	$ 2.0/MCM
Domestic Supply/Average Cost	5.0	$16.4/MCM
Imports	4.0	$52.0MCM
Total Volume/Average Cost	9.0	$32.2/MCM

Source: World Bank estimates.

II-40. SOCAR's financial performance will also be greatly aided through a rationalization of its work force. With over 60,000 employees, SOCAR is heavily overstaffed. To put this in perspective, ChevronTexaco, the second largest US oil company, which operates in more than 180 countries and has assets valued in excess of $80 billion employs 51,000 people.

II-41. A focused effort on improving operating performance (including a significant rationalization of the staff) coupled with a domestic tariff structure that reflects the true economic value of the oil and gas sold by SOCAR in the domestic market and an improvement in payments performance will greatly enhance SOCAR's financial health and should allow the company to enter into borrowings strictly on the strength of its balance sheet.

[22] SOCAR is compensated for the cost of imports for some of the gas supplied, for example for the gas supplied to Azerenergy. It would be more logical, however, to treat all gas as fungible and have a single wholesale price applicable to all wholesale customers.

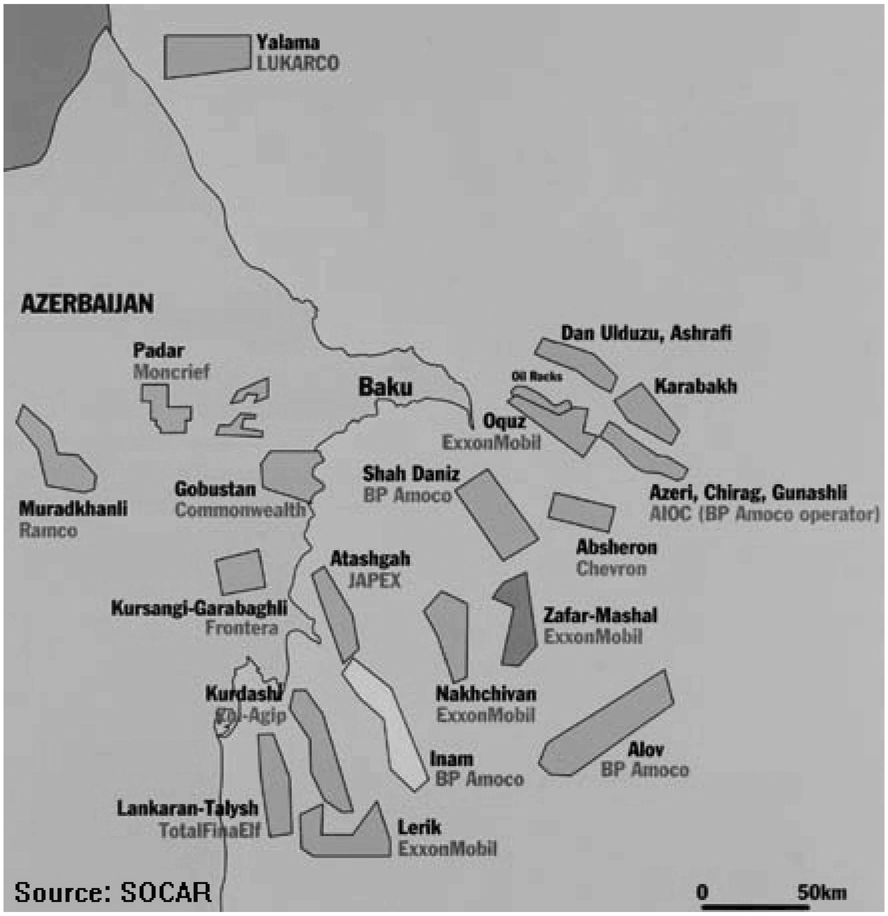
Attachment II-1

Production Sharing Agreements

Offshore Production Sharing Agreements				
Name of PSA	**Dates**	**Project Partners**	**%**	**Status as of 6/02**
Azeri, Chirag and Deepwater Guneshli (Azerbaijan International Operating Company AIOC)	Signed 9/20/94 Ratified Dec 94	BP (operator) Unocal Inpex SOCAR Statoil ExxonMobil TPAO Devon Energy Itochu Amerada Hess	34.1 10.3 10.0 10.0 8.6 8.0 6.8 5.6 3.9 2.7	Exports began 1997. Phase 1 under implementation.
Shah Deniz	Signed 6/4/96 Ratified 10/17/96	BP (operator) Statoil SOCAR LukAgip TotalFinaElf OIEC of Iran TPAO	25.5 25.5 10.0 10.0 10.0 10.0 9.0	Sanctioned, under implementation. Initial gas flows projected in 2006.
Lankaran-Talysh	Signed 1/13/97 Effective Jun 97	TotalFinaElf (operator) Wintershall SOCAR OIEC of Iran	35.0 30.0 25.0 10.0	First test well (2001) came up dry.
Yalama/D-222	Signed 7/4/97 Ratified Nov 97	LukArco (operator) SOCAR	60.0 40.0	Conducted 2-D and 3-D seismic work
Apsheron	Signed 8/1/97 Ratified Nov 97	SOCAR ChevronTexaco (operator) TotalFinaElf	50.0 30.0 20.0	First well drilled in 2001 with poor results.
Oguz	Signed 8/1/97 Ratified Nov 97	ExxonMobil (operator) SOCAR	50.0 50.0	Dry well April 2001. ExxonMobil withdrew
Nakhchivan	Signed 8/1/97 Ratified Nov 97	ExxonMobil (operator) SOCAR	50.0 50.0	One successful well. A second planned.
Kurdashi-Araz-Kirgan Deniz	Signed 7/7/98 Ratified Jul 98	SOCAR Agip (operator) Mitsui TPAO Repsol	50.0 25.0 15.0 5.0 5.0	First test well drilled with poor results
Inam	Signed 7/21/98 Ratified Dec 98	SOCAR BP (operator) Royal Dutch Shell	50.0 25.0 25.0	BP suspended drilling of its first appraisal well in Aug 2001
Araz, Alov, and Sharg	Signed 7/21/98 Ratified Dec 98	SOCAR BP (operator) Statoil ExxonMobil TPAO Alberta Energy	40.0 15.0 15.0 15.0 10.0 5.0	Exploration suspended Jul 2001 following confrontation with Iranian gunboat.
Atashgah	Signed 12/25/98 Ratified Jun 99	SOCAR JOAC Consortium: Japex (operator) Inpex Teikoku Itochu	50.0 50.0 22.5 12.5 7.5 7.5	Seismic work undertaken

Name of PSA	Dates	Project Partners	%	Status
Lerik, Jenab, Savalan, Dalga	Signed 4/27/99	SOCAR ExxonMobil (operator) Unassigned	50.0 30.0 20.0	
Zafar-Mashal	Signed 4/27/99 Ratified Apr 99	SOCAR ExxonMobil (operator) Conoco	50.0 30.0 20.0	
Onshore Production Sharing Agreements				
Name of PSA	**Dates**	**Project Partners**	**%**	**Status**
Kalamaddin-Mishovdagh (formerly AzPetoil JV)	JV signed 93 Converted to PSA 00	Moncrief Oil (operator) Pet Oil SOCAR	49.3 35.7 15.0	Produced 2.750 TBD oil in 2000
Anshad Petrol	JV signed in 93 Converted to PSA 2000	SOCAR Attila Dogan Land and General Berhard	51.0 31.5 17.5	Drilled 4 wells 98/99. Produced 0.9 TBD in 1999.
AzGeroil	JV signed in 95 Converted to PSA 2000	SOCAR Grunewald	51.0 49.0	Produced 1 TBD in 1999
Southwest Gobustan	Signed 6/2/98 Ratified Nov 98	Commonwealth Oil & Gas (operator) SOCAR Sooner International	67.25 20.00 12.75	Conducting 2-D seismic research
Zykh-Govsany	Signed 6/5/00	SOCAR Lukoil	50.0 50.0	Rehabilitating fields. Produced 1.83 TBD in 2000
Kursangi-Garabagli	Signed 12/15/98 Ratified Apr 99	SOCAR CNPC Amerada Delta-Hess JV	50.0 30.0 20.0	Producing 5.5 TBD
Muradkhanli-Jafarli-Zardab	Signed 7/21/98 Ratified Nov 98	Ramco SOCAR	50.0 50.0	First test well shut down in Apr 2001
Padar-Kharami	Signed 4/27/99	Moncrief (operator) SOCAR	80.0 20.0	Seismic work
Shirvanoil	JV signed in 97 Converted to PSA 2000	SOCAR Whitehall	60.0 40.0	Rehabilitating wells. Produced 4.35 TBD in 2001
West Apsheron (Karadag-Kergez-Umbaki fields)	Signed 8/10/94	BMB	100.0	SOCAR moved to take over in Dec 99, following BMB's request to suspend operations.

Location of the Existing Production Sharing Agreements



Attachment II-2

Azerbaijan: Oil Product Prices

in thousand of manats,	Intracompany prices *per ton*		Excise rate *in %*		Excise *per ton*		Trade expenses (including VAT), **per ton**		Wholesale price (inc.Excise and VAT)		Retail price, *per ton*		Retail price, *in manats per liter*	
	old	**new**	**old**	**new**	**old**	**new**	**old**	**new**	**old**	**new**	**old**	**new**	**old**	**new**
1. Gasoline AI-96	1000.0	1000.0	79.2	101.4	791.8	1,013.8	47.2	47.2	2161.5	2423.5	2358.0	2620.0	1800	2000
2. Gasoline AI-92	952.5	952.5	64.8	88.1	617.2	839.2	47.2	47.2	1899.5	2161.5	2096.0	2358.0	1600	1800
3. Gasoline AI-80	907.5	907.5	63.5	88.4	576.6	802.0	47.2	47.2	1798.5	2064.5	1995.0	2261.0	1500	1700
4. Diesel	644.7	644.7	0.0	15.0	0.0	96.8	36.6	41.3	797.3	916.3	952.0	1071.0	800	900
5. Furnace Fuel oil	318.7	318.7	3.1	18.6	10.0	59.2	41.3	41.3	429.2	487.2	580.0	638.0	500	550
6. Kerosene	538.5	538.5	2.8	22.3	15.0	120.1	41.3	41.3	694.4	818.4	868.0	992.0	700	800
7. Engine Lubricants	1390.3	1390.3	15.1	32.0	209.9	444.9	41.3	41.3	1929.7	2206.9	2051.7	2328.9	1850	2100
8. Industrial Lubricants	540.9	540.9	15.2	29.1	82.0	157.2	41.3	41.3	776.3	865.0	909.4	998.1	820	900
9. Turbine Lubricants	1368.4	1368.4	17.6	33.4	241.4	457.4	41.3	41.3	1940.8	2195.8	2073.8	2328.9	1870	2100
10. Transformer Lubricants	1150.7	1150.7	17.8	34.2	205.3	393.2	41.3	41.3	1641.3	1863.1	1774.4	1996.2	1600	1800
11. Other Lubricants	854.6	854.6	18.3	38.1	156.1	325.3	41.3	41.3	1234.0	1433.6	1353.0	1552.6	1220	1400
12. DT-OKPO2-5221-0101	401.2	401.2	14.5	39.6	58.0	158.9	41.3	41.3	583.1	702.1	714.0	833.0	600	700
13. Fuel Oil (Mazut)	300.0	300.0	0.0	0.0	0.0	-	35.4	35.4	389.4	389.4				
14. Engine Fuel DT	303.1	303.1	3.4	17.2	10.4	52.2	41.3	41.3	411.3	460.6				
15. Jet Fuel	621.8	621.8	0.0	12.6	0.0	78.2	35.4	35.4	769.1	861.4				
16. Naphtha (Primary Refining Gasoline)	660.9	660.9	0.0	8.0	0.0	52.9			779.8	842.2				
17. Coke K-8	254.8	254.8	1.7	13.9	4.4	35.4			305.8	342.5				
18. Coke K-0	131.4	131.4	1.7	13.9	2.2	18.3			157.7	176.7				
19. Coke K-0.25	168.5	168.5	1.7	13.9	2.9	23.5			202.2	226.5				
20. Coke Common	187.0	187.0	1.7	13.9	3.2	26.0			224.4	251.3				
21. Bitumen B/N 60/90	396.2	396.2	1.8	14.0	7.1	55.5			475.9	533.0				
22. Bitumen MQO	230.8	230.8	1.8	14.0	4.1	32.4			277.2	310.5				
23. Bitumen BNV, A-30, BNB-70/30	641.8	641.8	1.8	14.0	11.5	89.9			770.9	863.4				
24. Gas Gasoline	475.2	475.2	1.7	13.9	8.1	66.1			570.2	638.7				
25. Liquid Gas (Butane-Butylene frac.)	587.3	587.3	0.0	10.7	0.0	62.7			693.0	893.0	1000.0	1200.0	1000	1200

Source: the CoM's Resolution #165, dated November 1, 2004

III - The Gas Sector in Azerbaijan

Summary

III-i. At the time of independence, Azerbaijan inherited an extensive gas network. The sector's infrastructure, however, has suffered from lack of investment and limited maintenance. This has resulted in a significant deterioration in both the scope and quality of service. There is, however, evidence of substantial latent demand for gas and, given the country's underlying hydrocarbon resource base there are clear prospects that much of this latent demand can be met provided measures are put in place to ensure the effective functioning of the domestic gas sector.

III-ii. The government faces the challenges, therefore, of restoring and maintaining acceptable levels of service throughout the country that correspond to the latent demand and ensuring that the country secures the optimum benefit from its gas sector assets. These benefits include environmental gains that can be secured by substituting gas for more polluting fuels and by eliminating gas flaring and venting.

III-iii. The conclusions and recommendations of this section may briefly be summarized as follows:

- The increasing risk of systemic collapse resulting from the deterioration of the sector's infrastructure could be significantly reduced by rehabilitating key facilities. Investment is urgently required to rehabilitate the transmission system. Investment is also urgently required for the rehabilitation of some distribution facilities and for meter installation.

- Part of the deterioration in the transmission system results from the fact that over 3 BCM of domestic gas production – more than a third of supply - is not treated before it enters the system. The result is a gas mix of unacceptable quality with excessive liquids and water which causes corrosion and other problems. SOCAR has evaluated options to treat these volumes but has not developed a concrete plan to solve the problem. A failure to treat all the gas will negatively affect all storage and transmission operations. Consequently, priority should be given to developing a plan to deal with this issue.

- SOCAR operates as the "single buyer" of natural gas for delivery into the domestic market. In addition to its own production it receives associated gas produced under the Azeri, Chirag, Guneshli (ACG) production sharing agreement (PSA) and it purchases imported gas supplied by or though Russia. In the future the volumes of associated gas from ACG will increase significantly and SOCAR will begin buying gas from the Shah Deniz consortium under a supplier nomination arrangement. In order for SOCAR to be able to handle all these volumes, which could be subject to significant fluctuation, Azerbaijan will need to make a significant investment in rehabilitating its two underground gas storage facilities.

- SOCAR is likely to continue in the role of "single buyer" at least in the medium term. In undertaking this role, SOCAR will be faced with the challenge of balancing the domestic system with imports and, on occasion, dealing with potential supply surpluses. Consequently, it will be important for SOCAR to work closely with ACG, Shah Deniz and the domestic consumers to develop and maintain updated projections of the supply demand balance so as to allow maximum time to develop strategies to balance the market.

- It would be desirable to transfer the gas distribution activities to the private sector. This would leave Azerigaz as the operator of the gas transmission network and of the gas storage facilities[23]. The government plans to effect such a transfer of the distribution facilities. In preparation for this it would be helpful to consolidate the 68[24] distribution subsidiaries into a much smaller number – at least two (plus Nakhichevan) but not more than four or five – and corporatize them.

- In order to secure private sector involvement in storage and/or distribution, appropriate incentives will have to be provided, and should be supported by an independent and competitive regulatory regime. In conjunction with the privatization process, the government should establish quality standards. These should be monitored by the regulatory agency.

- Investment needs for the domestic gas sector are on the order of $1 billion, $450 million of which is urgently required. Transferring distribution activities to the private sector would reduce these overall requirements by about $100 to $150 million and would reduce the urgent funding requirements by about $30 to $50 million.

- Included in the $1 billion of investment needs is $60 million to eliminate gas flaring from shallow water Guneshli. While this is not classified as an urgent investment need it would result in the collection of an additional 0.3 BCM of gas. At current import prices the project would payout in under four years and, in view of the associated environmental benefits, the project might be able to access concessional financing.

- At present, the sector is not financially viable and is forced to rely on subsidies both explicit and implicit. There is a shortfall in both collections' levels and in tariff levels. At their present levels, tariffs are not adequate to cover the cash costs of gas supply, even with full collections. The government is committed to introducing a medium term tariff policy designed to bring tariffs up to full cost recovery levels. In designing this policy, attention must be paid to the need to rebalance tariffs between customer classes to avoid cross subsidies.

[23] The option also exists to have SOCAR manage the gas storage facilities.
[24] This includes 7 distribution companies in Nakhichevan.

The Gas Sector in Azerbaijan

III-1. At the time of independence, gas that conformed to acceptable quality standards was widely available in Azerbaijan and the country's gas network was integrated on a regional basis with connections into Russia, Iran, Georgia and Armenia. Azerbaijan also acted as a key transit route for gas supply to both Georgia and Armenia. Since then, however, lack of investment in the sector and limited maintenance have resulted in a significant deterioration in the sector's assets with the result that the system which is shown schematically in Figure III-1 below is no longer fully functional. Without adequate investment, further deterioration will occur increasing the risk of system failure.

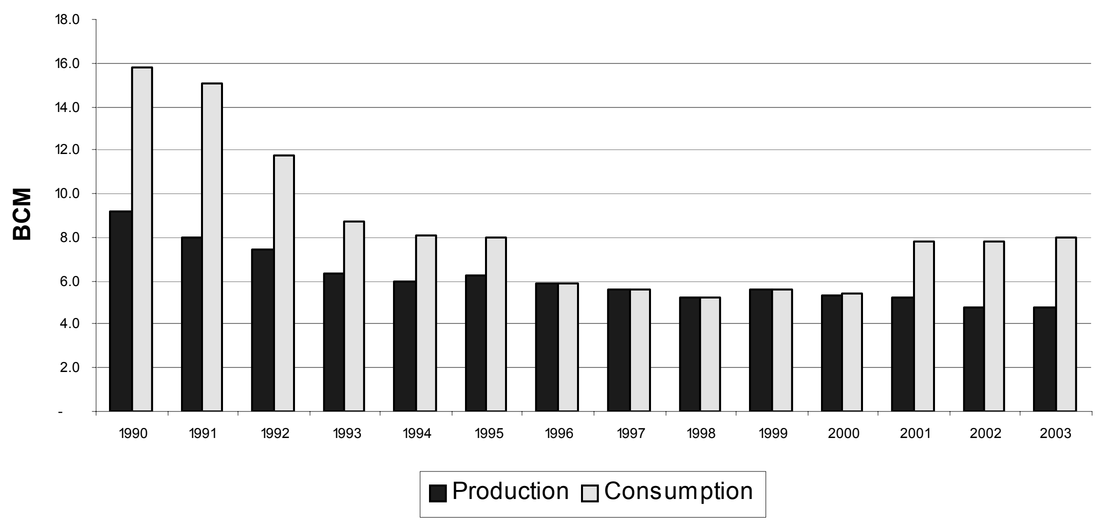
Figure III-1

III-2. As is shown in Figure III-2 below, a significant decline in domestic production during the 1990s was accompanied by a sharp decline in consumption. This, in turn led to a reduced scope of supply with large parts of the country losing access to gas supplies. At this time, gas supply is effectively limited to some larger urban and industrial areas most of which are located in the Greater Apsheron Peninsula or along the Western corridor that had originally played a major role in supplying gas to Georgia and Armenia.

III-3. When gas imports recommenced in 2001 consumption began to increase. There is immediate potential demand for gas to replace the mazut that is still being used for power generation and there is also evidence of significant latent demand in areas that have lost their access to gas supplies. This suggests that, with appropriate investment to rehabilitate and restore the gas transmission and distribution network, consumption could continue to increase, provided supplies are made available. The discovery of significant non associated gas reserves in Shah Deniz will not only allow Azerbaijan to become a gas exporter, but will enable the country to meet a significant portion of future domestic demand from its own resources. This, however, should be accompanied by reform of the domestic gas sector.

Figure III-2

Gas Production and Consumption



Source: BP Statistical Review of World Energy June 2004

III-4. To obtain a better understanding of the issues the government faces, it is instructive to look at an analysis of the sector's strengths and weaknesses and the associated opportunities and threats it faces.

Strengths	Weaknesses
• Significant associated and non associated gas reserves • Substantial FDI in the upstream gas sector • A well established competent authority (within SOCAR) to deal with the international oil and gas industry • Gas storage facilities • An established right of way transmission network throughout the country	• Aging and deteriorating physical infrastructure • Insufficient gas processing capacity • High losses in transmission and distribution • Poor payment performance • Low tariff levels and tariff imbalances • Quality problems • A weak legislative and regulatory framework with no regulatory agency • Inexperienced commercial management
Opportunities	**Threats**
• To support economic development through the restoration of consistent quality service • To secure environmental benefits by substituting gas for more polluting fuels and by eliminating gas flaring and venting • To secure foreign investment in the sector	• Further deterioration in service quality • Deterioration of the physical infrastructure • Inability to handle all available gas volumes • Increasing unmanaged demands on the fiscal revenue streams resulting from both explicit and implicit subsidies

III-5. The government faces two overarching challenges:

i. To restore and maintain acceptable levels of service throughout the country that correspond to latent demand; and
ii. To ensure the country secures optimum benefits from its gas sector assets.

III-6. These two challenges encompass a number of subsidiary issues, including:

- Establishing and sustaining financial viability in the sector
- Securing adequate funding for investment needs
- Introducing a commercial approach to management of the sector
- Minimizing the drain on public sector resources to support the sector

III-7. The government has already taken a number of steps to address these challenges including a commitment to strengthen financial discipline in the sector, to introduce an independent regulator, to establish a medium term tariff policy and to improve and strengthen the sector's infrastructure. However, strong commitment on the part of the government will be required together with the provision of sizable investment funds if these challenges are to be met. This section outlines issues and options to be considered as the government develops plans to address these challenges.

Overview of the Sector[25]

Gas Supply and Demand

III-8. SOCAR acts as the "single buyer" of natural gas for delivery into the domestic market. Gas supplies currently come from three sources: (i) SOCAR's own gas production (currently around 4 billion cubic meters (BCM), but declining); (ii) associated gas produced under the Azeri, Chirag, Guneshli (ACG) production sharing agreement (PSA) that, under the terms of the agreement, accrues to the State at no cost (currently around 1 BCM); and (iii) imports that are either sourced from Russia or transit from Central Asia through Russia (currently around 4 BCM). In the future, a fourth source of potential supply – gas from the Shah Deniz field, will join the mix. There is also the prospect that SOCAR will be able to increase its own production by gathering the associated gas it is currently flaring.

III-9. SOCAR is responsible for processing the gas currently produced in Azerbaijan whether from its own production or supplied from ACG. The gas is processed at the Garadag Gas Processing Plant. However, the gas treatment plant at Garadag is not fully operational and, as a result, only about 2 BCM out of a total domestic supply of 5 BCM is treated. The remainder is put into the domestic system untreated.

III-10. SOCAR sells directly, at a wholesale price, to three primary customers: AzerChemia, the country's petrochemical facility which also obtains naphtha from SOCAR, Azerenergy the power generator which also obtains mazut from SOCAR and

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[25] Information on the domestic network was provided by Dr. Vilayat Valiyev in a study commissioned by the World Bank in 2002.

Azerigaz. Azerigaz was established in 1992 and is responsible for domestic storage, transportation and distribution of natural gas.

Box III-1
Azerbaijan's Natural Gas Supply System

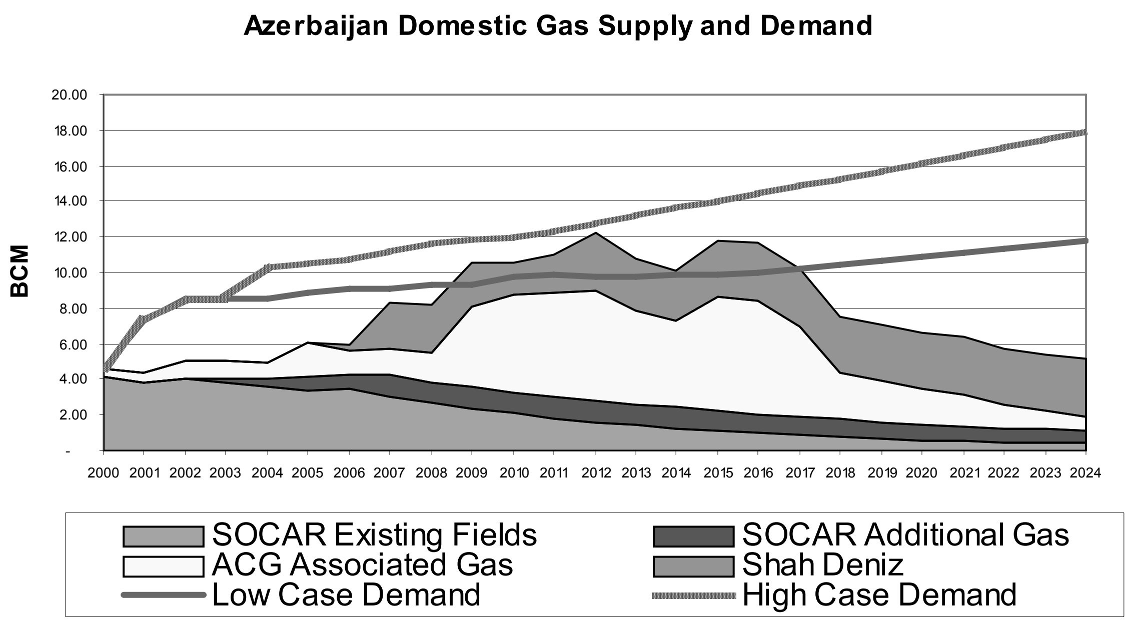
The gas supply system comprises:

- 4,000 km of main and branch gas pipelines of up to 1000-1200 mm in diameter, with working pressure of 55 atmospheres, a daily throughput capacity of 70 mcm and an annual throughput of 25 bcm;
- Over 36,000 km of medium and low pressure gas pipelines;
- 7 gas compressor stations with a total capacity of 200 mW;
- 150 gas distribution stations; and
- 2 underground gas storage facilities with a total active holding capacity of up to 3 bcm.

On average 8 bcm of gas is delivered each year through the gas transportation system, comprising equal proportions of domestically produced and imported gas. The gas distribution system supplies gas to all large cities and 32 regional centers in Azerbaijan. To date, 67,000 meters have been installed for residential consumers as part of an ongoing program to install meters for residential and other consumers.

Source: State Program for Development of the Fuel and Energy Sector in Azerbaijan (2005 – 2015)

Figure III-3



Source: World Bank analysis, NERA estimates and Shah Deniz

III-11. A projection of the outlook for supply and demand is shown in Figure III-3 above. This projection excludes those volumes that are produced to meet the export obligations of the Shah Deniz consortium, but assumes the purchase by SOCAR from Shah Deniz of all volumes available to the domestic market. The chart provides both a low demand and a high demand scenario. Under the low demand scenario, production targeted to the domestic market could exceed demand for a period of time. However, under the high demand scenario, Azerbaijan will remain a net importer.

III-12. Some comments are warranted on these projections:

- Gas production from SOCAR's existing facilities is now starting to decline. SOCAR, however, has the potential to recover about 0.3 BCM of associated gas that is currently being flared from its shallow water Guneshli field through implementation of a gas flaring reduction project. The investment costs for such a project are estimated at US$60 million, but with import gas prices of $60/MCM, such a project could show a payout in less than four years and could qualify for some concessional financing as a result of the associated environmental benefits.

- Under the terms of the ACG PSA, ACG is required to deliver associated gas produced in conjunction with oil operations to SOCAR free of charge[26]. At present, this gas is delivered to the gas processing plant at Garadag and amounts to about 1 BCM per year which is the maximum the pipeline to Garadag can handle. Given the transportation constraint, approximately 0.3 BCM of the associated gas produced by ACG is being flared.

  With the commissioning of ACG Phase 1, some associated gas will be re-injected to maintain reservoir pressure, with the balance being transported via a new 700 mm gas pipeline to Sangachal[27], where it will be treated to a marketable quality for delivery to SOCAR. Deliveries of associated gas from Sangachal are projected to begin the first quarter 2005. The completion of Phases 2 and 3 of ACG will provide further increments of associated gas, reaching a peak in total associated gas deliveries of about 6 BCM in 2012. From the first quarter 2006, all associated gas deliveries from ACG will be effected at Sangachal, although the line to Garadag will remain as an emergency back-up.

- The Shah Deniz field is being developed primarily to service export markets (initially Turkey but potentially further west). The gas delivered to Turkey will transit Georgia which will also purchase gas from the Shah Deniz consortium. In addition, gas will be sold to the government for use in the domestic market. Under the terms of the Shah Deniz–Azerbaijan Gas Sale and Purchase Agreement SOCAR, as the designated purchaser, will buy 1.5 BCM/year. This entire volume is subject to a seller nomination arrangement whereby Shah Deniz has the option of delivering between zero and 400 million standard cubic feet (SCF) on any given day. SOCAR will pay US$58/MCM[28] for gas delivered at the battery limit of the Shah Deniz Sangachal plant.

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[26] Article 15.1 of the Production Sharing Agreement
[27] Sangachal is also being constructed to process the non associated gas from Shah Deniz.
[28] The $58/MCM price is fixed for the duration of the contract. The Shah Deniz gas has a higher calorific content than the gas delivered from Russia and this price matches the 2004 price of $52/MCM for Russian imports in calorific terms. The import price was increased to $60/MCM at the beginning of 2005.

- Pending the receipt of the increments of gas from ACG phases 2 and 3 and from Shah Deniz, Azerbaijan will have to continue importing gas. Under a low demand scenario, imports could cease, although it is possible that imports would have to recommence as the associated production levels from ACG go into sharp decline. Under a high demand scenario, Azerbaijan will have to continue importing gas even with the additions from ACG phases 2 and 3 and from Shah Deniz. SOCAR should be able to balance supply and demand through a judicious use of imports, purchases from Shah Deniz and the use of the gas storage facilities. However, it will be important for SOCAR to work closely with ACG, Shah Deniz and the domestic consumers to develop and maintain updated projections of the supply demand balance so as to allow maximum time to develop strategies to balance the market. Given the possibility that supply surpluses could exist from time to time, SOCAR should also examine the potential to export surplus gas volumes.

The Domestic Transmission Network

III-13. Transmission within the domestic network was constructed around three corridors which meet at a hub location at Gazi-Mammad (see Figure III-1 above):

i. The Northern corridor connects to the Russian border and serves to bring in gas imported from or through Russia. The corridor includes (a) a 100 kilometer high pressure line, with a design capacity of 13 BCM/year, that carries the gas imports from the border to Siyazan and then continues a further 140 kilometers to Gazi-Mammad and (b) 60 kilometers of regional high pressure lines that branch off from the main line to service domestic customers in the northern part of the country. The corridor is served by a compressor station at Shirvanovka just inside the Azerbaijan border and a second compressor station at Siyazan.

ii. The Western corridor was designed both as a route to deliver gas to Georgia and Armenia and as a means of supplying domestic customers in the central and western parts of the country. The corridor includes (a) a main pipeline system totaling 930 kilometers of high pressure lines between Gazi-Mammad and the Georgian border, with a design capacity of 16 BCM/year, and (b) 500 kilometers of regional high pressure lines that branch off from the main pipeline system. The system is served by a compressor station at Gazi-Mammad. Compressor stations were also constructed at Agdash and Gazakh. However, the Agdash compressor station has not operated since 1993 and the Gazakh station which stopped operating in 1991 has been destroyed.

iii. The Southern corridor had been designed to import gas from Iran and service customers in the southern part of the country. The corridor includes (a) a 210 kilometer main pipeline between Astara and Gazi-Mammad, with a design capacity of 10 BCM/year, and (b) 85 kilometers of regional pipelines. The main pipeline has not operated since 1990.

Table III-1
The Status of the Transmission Network

Function	Route	Built	Km	Design Capacity	Pressure (Bar)		Operating
					Design	Avg.	
Import	Russia-Gazi-Mammad	1982	240	12.8 BCM	55	25	Yes
	Iran-Gazi-Mammad	1971	229	10.0 BCM	55	1	No
Transit To Georgia	Gazakh-Saguramo	1980	120	7.3 BCM	55	-	No
	Gazakh-Rustavi	1968		6.9 BCM	55	-	No
Transit To Armenia	Gazakh- Hiervan	1980	38	6.9 BCM	55	-	No
	Gazakh-Injeran	1986		7.3 BCM	55	-	No
Transmission	Garadag-Gazi-Mammad	1982	68	2.9 BCM		18	Yes
	Gazi-Mammad-Gazakh 1	1971	378	7.3 BCM		17	Yes
	Gazi-Mammad-Gazakh 2	1979	378	8.8 BCM		17	Yes
	Yevlakh-Nakhichevan	1978	350	4.6 BCM		-	No
	Altiagaj-Agsu	1986	76	9.9 BCM		20	Yes
	Galmaz UGS-Gazi-Mammad	1982	42	3.1 BCM		18	Yes

The status of the transmission network is summarized in Table III-1 (above)

Distribution

III-14. At the time of independence, almost all urban residents and 80% of residents in rural areas had access to the gas grid. As has been noted, this access has been substantially reduced, with access now generally limited to larger urban and industrial areas, primarily in the Greater Apsheron Peninsula area and along the Western corridor, although access has been expanding. The geographic distribution of gas consumption is summarized in Table III-2.

Table III-2
Geographic Distribution of Gas Consumption

Location	Consumption	Location	Consumption
Baku-Sumgayit-Apsheron	37 %	Central Azerbaijan	7 %
Ali-Bairamli and South	12 %	Western Azerbaijan	35 %
North-East Azerbaijan	5 %	North-West Azerbaijan	4 %

III-15. The distribution of consumption by class of consumer supplied by the Azerigaz transmission system is summarized in Table III-3.

Table III-3
Distribution of Gas Consumption by Consumer Category (2001)

Consumer Category	Consumption (BCM)	Percentage
Households	2.024	27.8 %
Budget/Public Services	0.527	7.2 %
Private Commercial	0.491	6.7 %
Power and Heat	4.215	57.9 %
Other	0.027	0.4 %
Total	7.284	100.0 %

Source: NERA: Azerbaijan Natural Gas Sector Strategy

III-16. As has been noted, significant latent demand for gas exists. However, major rehabilitation investments will be required if supply capacity is to be restored to its design levels. An indication of the challenges facing the sector in this regard is provided in the summary of technical problems and concerns given in Box III-2.

Box III-2
Technical Problems and Concerns in the Domestic Gas Sector

- Less than 40% of domestic gas production is treated
- Only 40% of gas entering the network is de-watered
- Cathodic protection is provided to only about 30% of the pipelines
- 25% of the pipelines are more than 20 years old; 38% are 10 to 20 years old; 5% have exceeded their operational lifespan
- More than 35% of the large diameter pipelines and 90% of the other high pressure pipelines have polymeric coatings that have exceeded their design life
- 13% of the lines have a wear rate of more than 75%; 26% have a wear rate of between 50% and 75% and 38% have a wear rate of between 25% and 50%;

Source: Dr. Vilayat Valiyev

III-17. In organizational terms, there are 68 distribution subsidiaries (including 7 in Nakhichevan). Looking to the future, distribution activities would benefit from being consolidated into a limited number of corporatized distribution companies. There should be at least two distribution companies (plus Nakhichevan), but probably not more than four or five. One option would be to match the consolidation that has taken place in the power sector which now has four distribution companies under private management in Baku, Sumgayit, Gandja and Ali-Bayramli. The government has made a commitment to transfer management control of distribution to the private sector.

Gas Storage

III-18. Azerbaijan has two underground gas storage facilities located at Galmaz and Garadag. While these facilities had a design capacity of 4.3 BCM, current capacity is limited to about 2 BCM and annual turnover is limited to about 0.5 BCM per year compared with a design capacity of 2.3 BCM per year. Azerbaijan is entitled to receive associated gas from ACG and has contracted to buy 1.5 BCM per year of gas from Shah Deniz under a seller's nomination arrangement. There will, therefore, likely be very large fluctuations in daily supply levels. In order to be able to handle these fluctuations, SOCAR will need access to significant gas storage capacity. Investments will be required to rehabilitate the gas facilities in order to provide the needed capacity. The full cost of rehabilitation is estimated at $272 million and would involve rehabilitation of both facilities with the rehabilitation of Garadag being effected in two stages. Table III-4 summarizes existing and projected capacity for the facilities as well as the projected capital investment requirements:

Table III-4
Underground Storage (UGS) Facilities

	Galmas UGS			Garadag UGS				
	Before Rehab		After Rehab	Before Rehab		After Rehab		
	Design	Current		Design	Current	Phase 1	Phase 2	Total
Initial operation	1976			1986				
Total storage capacity (BCM)	2.6	1.0	2.5	1.7	1.0	3.2	1.8	5.0
Annual turnover capacity (BCM)	1.3	0.3	1.5	1.0	0.2	1.3	1.7	3.0
Daily injection capacity (mmcm)	10.0	2.5	15.0	10.1	1.2	14.0	14.0	28.0
Daily withdrawal capacity (mmcm)	8.0	2.0	12.0	8.3	1.0	10.0	11.0	21.0
Investment needs (US$ million)			$81.0			$80.1	$111.3	$191.4

Source: Dr. Vilayat Valiyev

III-19. Azerigaz does not have the financial capacity to make these investments. However, while gas storage facilities are often associated with transmission activities there is no overarching reason for the facilities to be linked. Consequently, the gas storage facilities and the proposed rehabilitation projects could potentially be transferred to and funded by SOCAR.

III-20. Regardless of ownership, gas storage will operate as a monopoly activity and, as such, the terms and conditions for its use have to be regulated to ensure non-discriminatory access to all potential users. Users could include SOCAR, the Shah Deniz consortium[29] and customers both within Azerbaijan (such as the distribution companies) and outside Azerbaijan (for example, GIOC in Georgia[30]). The tariff for gas storage should be discretely identified and should allow a reasonable return on investment.

Investment Requirements

III-21. To ensure optimum exploitation of Azerbaijan's gas resource base, significant investments will be required to rehabilitate the domestic gas sector infrastructure. Investment requirements include the following: (i) rehabilitation of gas storage (described above); (ii) rehabilitation of transmission pipelines and compressor stations; (iii) installation of a SCADA system; (iv) rehabilitation of the distribution network and the installation of metering; (v) expansion of gas treatment facilities to ensure that all gas produced by SOCAR is treated before entering the domestic gas grid[31]; and (vi) gathering

[29] Shah Deniz is not anticipating a need for gas storage, but as a producer remains a potential future user.
[30] Georgia has no gas storage facilities but it has gas supply contracts involving supplies from and via Russia and from Azerbaijan. The only way it will be able to manage its gas arrangements effectively, without depending entirely on the Russians to balance the system, is by having access to some storage capacity. If Azerbaijan were to make some storage capacity available it would greatly enhance the probability of the supply arrangements involving gas from Azerbaijan functioning smoothly.
[31] Untreated gas causes serious corrosion problems in the transmission system.

of associated gas that is currently being flared. In all, these investment requirements are projected to total $1 billion, of which $450 million can be considered urgent.

Table III-5
Gas Sector Investment Needs 2004-2010

	Total Cost US$ millions	Urgent Needs US$ millions
Gas Storage	272	161
Gas Transmission and Distribution:		
New Pipeline from Sangachal	51	51
Rehabilitation in Nakhichevan	37	
Rehabilitation Outside Nakhichevan	259	59
Compressor Rehabilitation	60	
SCADA	18	18
Metering	90	10
Retrofitting Apartment Buildings	4	4
Sub-Total	519	142
Gas Treatment	150	150
Gas Flaring Reduction	60	
Total	**1,001**	**453**

Source: Azerigaz

III-22. Some observations are warranted on these investment requirements:

- As has already been noted, investment in gas storage is essential if Azerbaijan is to be able to handle future increments of associated gas as well as meet its purchase obligations related to Shah Deniz. The rehabilitation of Galmas UGS and the first phase of rehabilitation of Garadag are urgently required.

- Azerigaz has been making some investments in pipeline rehabilitation, but further investments will be required to ensure the integrity of the system and minimize venting and other transmission losses. Introduction of a SCADA system will enhance operational performance and safety.

- Distribution facilities are also in need of rehabilitation. In addition a comprehensive metering program is required. At present metering of households is limited to some customers in Baku and in Gandja. In order to effect 100% metering of existing customers an additional 750,000 meters will have to be installed. Expansion of the customer base, however, is expected to increase this requirement to between 1,000,000 and 1,100,000.

- Untreated gas is a source of corrosion of the transmission system. In order to ensure adequate quality, all gas input into the system should be treated. A 1996 study funded by the World Bank provided a cost estimate in 1997 dollars of $120 million to replace the Garadag treatment facility, the cost will have increased in the interim. Other options do exist but no firm investment program has been developed.

Funding Options for the Sector's Investment Needs

III-23. While there is considerable donor interest in providing financial support to the power sector, there has been only limited interest shown to date in providing financial support to the domestic gas sector[32]. The bulk of the sector's investment needs, therefore, will likely have to be met from sector cash flows, from the budget and/or from private investors.

III-24. The long term viability of the sector is ultimately predicated on its financial viability. Consequently, the sector needs to be capable of generating the funds to meet its investment needs along with its operational and maintenance requirements.

The Financial Outlook for the Sector

III-25. At present, the gas sector falls well short of covering its financial needs. In dealing with this problem, three factors will have to be addressed: (i) payment levels; (ii) the level of losses from the system[33] and (iii) tariffs. Table III-6 provides a comparison of the performance of the gas sectors in the CIS countries in 2002.

III-26. As Table III-6 indicates, only Armenia and the Kyrgyz Republic recovered the full cost of their gas supply. However, a number of the countries recovered sufficient revenues to cover their cash costs. The clear exceptions were Azerbaijan, Georgia, Russia and Uzbekistan.

III-27. The cost of gas supply in Azerbaijan is made up of both an upstream component, incurred by SOCAR as the "single buyer" providing gas to the market and a downstream component incurred by Azerigaz in managing transmission, storage and distribution. An estimate of SOCAR's cost of supply is shown in Table III-7.

III-28. With regard to the downstream components: in a study funded by the Public-Private Infrastructure Advisory Facility (PPIAF) that is administered by the World Bank, NERA estimated the tariff levels required to assure the financial viability of the various components of the gas sector. For the sector to be viable these tariffs have to be recovered from the consumers together with the cost of the gas being provided. The NERA analysis projects tariffs that vary over time and include a component to recover capital investment. The amounts shown in Table III-8, therefore, are intended as an indication of the order of magnitude of the unit tariffs required downstream from SOCAR.

Table III-6
Financial Performance of the Gas Sector – 2002

[32] EBRD is prepared to fund SOCAR's share of the Shah Deniz development but this is primarily an export project.
[33] Gas transmission and distribution losses in Azerbaijan average 7%.

Country	Collections %	Weighted Average Tariff US$/MCM	Average Receipt US$/MCM	Average Cost Recovery Price US$/MCM	% of Cost Recovery
Armenia	91	71.3	64.9	58.0	112
Azerbaijan	**47**	**19.0**	**8.9**	**30.0**[34]	**30**
Belarus	80	30.3	24.2	25.0	97
Georgia	25	93.2	23.3	65.0	36
Kazakhstan	95	53.2	50.5	62.0	81
Kyrgyz Republic	98	64.1	62.8	47.0	134
Moldova	78	72.0	56.2	65.0	86
Russia	79	14.0	11.1	35.0	32
Tajikistan	55	57.9	31.8	47.0	68
Ukraine	90	61.9	55.7	62.5	89
Uzbekistan	60	11.1	6.7	25.0	27

Source: World Bank analysis

Table III-7
Gas Supplies and Costs – 2003

Source of Gas Supply	Volume (BCM)	Cost US$/MCM
SOCAR Production	4.0	$20.0/MCM
ACG Associated Gas	1.0	$ 2.0/MCM
Domestic Supply/Average Cost	5.0	$16.4/MCM
Imports	4.0	$52.0/MCM
Total Volume/Average Cost	9.0	$32.2/MCM

Source: World Bank estimates

Table III-8
Projected Tariff Margin Requirements

	AZM/MCM	US$/MCM
Gas Transmission	28,000	5.71
Gas Storage	7,500	1.53
Gas Distribution (Average)	19,000	3.88
Total	54,500	11.12

Source: NERA

III-29. Azerigaz has also calculated the tariff amounts required downstream from SOCAR. The Azerigaz assessment is that before the application of VAT it requires a margin of AZM 42,000 to cover its costs and generate a small (5%) profit. In order to recover required investment costs this margin requirement would increase to AZM 88,000. Table III-9 summarizes the tariff levels that would need to be achieved to be able to recover SOCAR's and Azerigaz's costs (including the required investment costs). SOCAR's costs are shown both on average and on the basis of 2004 import costs[35]. Also shown are the tariff levels required to cover the average wholesale cost to Azerigaz.

Table III-9

[34] This does not include a component for full cost recovery of downstream investments.
[35] 2004 import costs also equate to the price that will be paid for gas purchased from Shah Deniz.

Projected Total Tariff Requirements

	AZM/MCM		
	Based on Wholesale Prices[36]	Based on SOCAR's Average Costs	Based on SOCAR's Import Costs
Wholesale Price/SOCAR's Costs	76,600	156,832	254,852
Azerigaz Operating Costs	42,000	42,000	42,000
Tariff Required to Cover Operating Costs	118,600	198,832	296,852
Tariff to Cover Investment Requirements	46,000	46,000	46,000
Total Required Tariff	164,600	244,832	342,852
VAT (18%)	29,628	44,070	61,713
Total Required Tariff with VAT	194,228	288,902	404,565

Source: Azerigaz and World Bank analysis

III-30. What these analyses suggest is that in order to recover the full cost of gas supply, including a component to recover downstream investments, and assuming full payment compliance, an average tariff level on the order of US$ 50/MCM, or 245,000 AZM/MCM before the application of VAT would be required. This would translate into a tariff level of 289,000 AZM/MCM with VAT. Covering only SOCAR's and Azerigaz' operating costs would require an average tariff of 199,000 AZM/MCM before the application of VAT and 235,000 AZM with VAT. The current tariff level is sufficient to cover the wholesale price and Azerigaz' operating costs (assuming collections in excess of 88%), but will not provide the funds to meet Azerigaz' investment needs.

III-31. Gas tariffs were increased as of November 2, 2004. However, as Table III-10 indicates, tariffs to the non residential consumers are sufficient to cover operating costs but are not sufficient to generate the funds needed for investment. It should also be noted that while the cost incurred by SOCAR in 2003 was estimated to average US$32/MCM, the import price in 2004 for gas, at the border, was US$52/MCM or 254,852 AZM/MCM. Tariffs should ultimately be brought up to levels that cover the import costs as well as domestic transmission, storage and distribution costs.

III-32. As Table III-10 indicates, only with the increases in November 2004 are all the non residential customers paying tariffs that are sufficient to cover operating costs and the tariffs are still not sufficient to cover the costs of required investment or the cost of gas imports. The tariffs paid by residential customers fall well short of even covering operating costs. This means that significant subsidies are being provided through the tariff structure to the consumers in the sector and this is compounded by the poor payments performance. In 2002, the overall subsidy amounted to about US$ 81 million, or about 1.3% of GDP, and was borne by the budget (87%) and by SOCAR (13%)[37].

Table III-10
Gas Tariffs – 2004

Customer Category	Prior to November 2nd		From November 2nd	
	AZM/MCM		AZM/MCM	
	w/o VAT	with VAT	w/o VAT	with VAT

[36] The wholesale price is based on domestic production only since that is the supply deemed to be provided to Azerigaz.
[37] Source: IMF estimates

Residential	30,135	35,560	68,644	81,000
Budget/Utilities/SOEs	89,918	106,103	200,000	236,000
Commercial	200,000	236,000	200,000	236,000
SOCAR	70,339	83,000	200,000	236,000
Azerenergy	165,000	194,700	200,000	236,000
Weighted Average	91,525	108,000	135,000[38]	159,300
Memo: Wholesale Price				
Untreated	64,000	75,520	73,000	86,140
Treated	64,000	75,520	82,000	96,760

III-33. Payment performance needs particular attention, but this should be accompanied by the introduction of a medium term tariff policy designed to bring tariffs up to full cost recovery levels. The government has made a commitment to introduce a medium term tariff policy. In designing a medium term tariff policy, the government also needs to avoid creating cross subsidies whereby certain categories of customers, e.g. the private commercial and industrial enterprises, subsidize the residential customers. As Table III-10 indicates, the customer that costs the most to supply, the residential customer pays the lowest tariff. There will, therefore, need to be a rebalancing of tariffs within the context of the increase in the overall average weighted tariff level required to achieve full cost recovery.

The Future Structure of the Sector

III-34. At present, the gas sector is partially unbundled with SOCAR acting as the “single buyer” of natural gas for delivery into the market and Azerigaz managing the downstream portions of the sector: transmission, storage and distribution. A further unbundling within the sector, however, would be beneficial and would be consistent with the government’s stated objective of securing private sector involvement in the domestic gas sector.

III-35. In the medium term, there will likely be no realistic alternative to the “single buyer” model for supplying the market. While four separate sources of gas supply are projected to be available: (i) SOCAR’s own production; (ii) associated gas from ACG; (iii) gas from Shah Deniz; and (iv) imports, SOCAR has a role to play with all four sources and in balancing overall supply and demand.

III-36. Under the terms of the ACG PSA, SOCAR is designated to receive the associated gas from ACG free of charge. In receiving this gas, SOCAR is, in effect, acting as the beneficiary of a state owned resource. At a time when the wholesale price of gas is insufficient to cover SOCAR’s gas supply costs, the fact that SOCAR receives this gas free of charge serves to help reduce the level of subsidy the company bears. In the future, however, as prices increase ultimately to parity with import levels, SOCAR could receive significant benefits from the receipt of the associated gas whereas these benefits should rightly accrue directly to the State. Consideration should, therefore, be given to requiring

[38] World Bank estimate of Azerigaz’ weighted average tariff after November 2nd , 2004.

SOCAR to make a payment that reflects the value of the gas being received. Such a payment could, logically, be channeled through the State Oil Fund.

III-37. SOCAR is perceived by both the Shah Deniz consortium and by Russian suppliers as a creditworthy counter-part for gas sales transactions. SOCAR is, therefore, the designated buyer of gas that will be sold by the Shah Deniz consortium for consumption within Azerbaijan[39]. It will also likely be the preferred buyer of Russian gas, although there is no prohibition on suppliers of gas selling directly to consumers within Azerbaijan.

III-38. In the longer term, a more competitive gas market could develop with gas to gas competition, particularly if other gas discoveries are made. It may, therefore, be appropriate, at some point in the future, for the government to initiate actions to create such a market.

III-39. In the downstream portion of the sector it would be appropriate to separate transmission, storage and distribution. The government also plans to secure private sector involvement in gas distribution and the power sector provides a possible model for effecting this. The transfer of distribution to the private sector would leave the transmission grid, which functions as a natural monopoly, as a State owned and managed asset in the downstream portion of the sector, operated by Azerigaz, and would leave the gas storage facilities as State owned assets to be managed by either Azerigaz or SOCAR.

III-40. Involvement of the private sector in gas distribution would transfer the funding responsibility for needed investments away from the public sector. However, SOCAR and Azerigaz would remain responsible, as State owned enterprises for securing the funding for investment requirements associated with their operations. It should be noted that gas quality will be an issue of particular concern to private sector companies entering the distribution businesses. It is, therefore, important that SOCAR develop plans to ensure treatment of all the gas that enters the domestic network.

III-41. Appendix 2 to this report outlines the liberalization process and the regulatory models adopted for the gas sector in a number of locations.

[39] The sale and purchase contract is between Shah Deniz and the government.

IV - The Power Sector in Azerbaijan

Summary

IV-i. In the years since independence, Azerbaijan's power sector infrastructure has suffered an extended period of under-investment and limited maintenance. This has resulted in a significant deterioration in the infrastructure and the quality of service. It has also resulted in increased costs. The sector is now unable to meet domestic demand fully and faces an increasing risk of systemic collapse.

IV-ii. The government faces the twin challenges of restoring and maintaining acceptable levels of service throughout the country and ensuring the country secures optimum benefits from its power sector assets. Addressing these challenges will require efforts to establish and sustain financial viability in the sector, securing funding for investment needs and finding ways to minimize the drain on public sector resources to support the sector. This section addresses these challenges and outlines the issues and option to be considered as the government develops plans to support sector reform.

IV-iii. The conclusions and recommendations of this section may briefly be summarized as follows:

- The risk of system failure could be significantly reduced by rehabilitating and upgrading generation facilities and investing in a modern transmission management control system. The latter would support efforts to increase regional trade in future, thereby increasing the security of supply and reducing the needed domestic power reserve margin. Optimizing the operational and environmental performance of the system in tandem with measures to reduce demand would also help to reduce the overall vulnerability of the system. Long term competitive power import contracts could be considered, together with new generation proposals (possibly in the form of combined cycle gas turbines), to support the sector's least cost expansion plan.

- Rehabilitating and upgrading generation and transmission facilities would also yield environmental benefits through a reduction in emissions. Azerbaijan could capitalize on this through the sale of carbon credits.

- Investment needs in the sector for generation and transmission[40] are estimated at between $1,950 million and $3,600 million up to 2015, with about $910 million of investments needed in the next three to four years. There is considerable donor interest in providing financial support to the sector. However, donor loans and grants will not cover the entire investment requirement. The budget has the capacity to provide the needed funds. It is reasonable to retain the transmission and dispatch function under public ownership, but the balance of the sector would benefit from

[40] The State at present owns and manages the generation and transmission assets and is therefore responsible for these investments. Distribution investments will also be required but these are the responsibility of the private sector companies managing these assets.

private sector involvement. Public sector investment should, therefore, be somewhat limited and a focused effort should be directed to creating the climate to attract private investors to the sector.

- Appropriate incentives will have to be provided, and should be supported by an independent and competitive regulatory regime, to encourage private sector investment in generation. The process, however, should be appropriately sequenced. Azerenergy should be unbundled and the generation assets should be corporatized. Rehabilitation of the transmission network should be initiated and the introduction of a SCADA system should be followed by the establishment of a dispatch protocol. In addition the proposed structure of the future market, taking account of the dispatch protocol, should be established with the objective of ensuring energy costs overall are minimized. The government should avoid the temptation to enter into arrangements with individual generators that could result in contingent liabilities and a sub-optimal cost of electricity supply. The government also needs to ensure that appropriate incentives remain in place to support the distribution sector which is now under private sector management and that the contract obligations (on both sides) are honored.

- The sector is not currently financially viable and is forced to rely on subsidies both explicit and implicit. There is a shortfall in both collections' levels and tariff levels. Collections' performance is now in the hands of the distributing companies and payments for electricity supplies by these companies will be phased up to 100% by 2010. In the meantime, the budget should cover the payment shortfall to Azerenergy since the payment schedule was agreed by the government as part of the process of attracting the private sector.

- At their present level, tariffs would not cover operating and maintenance costs and provide funds for investment, even with full collections. The government is committed to introducing a medium term tariff policy designed to bring tariffs up to full cost recovery levels. In designing this policy, attention must be paid to the need to rebalance tariffs between customer classes to avoid cross subsidies. Correct tariff levels will promote appropriate consumption behavior – Azerbaijan's consumption levels relative to GDP are high. To support the planned transition to cost recovery tariffs, Azerenergy's assets should be re-evaluated to provide a correct basis for tariff setting.

- Appropriate social protection measures are needed to support tariff increases in order to improve targeting, to streamline and consolidate benefits, to reduce leakage and to apply means testing.

- Concurrent with the introduction of a medium term tariff policy, the government should establish quality standards. These should then be monitored by the regulatory agency.

The Power Sector in Azerbaijan

IV-1. At the time of independence, Azerbaijan inherited a power sector capable of providing almost universal service of acceptable quality. The network was integrated with neighboring countries that were part of the Soviet Union as well as with Iran, providing the opportunity to take advantage of regional synergies. However, an extended period of under-investment and limited maintenance has resulted in significant deterioration in the quality of the sector's infrastructure resulting in an inability to meet domestic demand on a consistent basis and an increasing risk of systemic collapse.

IV-2. Problems with the availability of electricity are consistently cited as the largest impediment to economic development in the non-oil sector in Azerbaijan. The government is aware of this concern and the power sector has received particular attention in its reform program. To obtain a better understanding of the issues the government faces, it is instructive to look at an analysis of the sector's strengths and weaknesses and the associated opportunities and threats it faces.

Strengths	Weaknesses
• Significant resources of primary energy (oil and gas). • A mixture of both hydro and thermal generation capacity. • Extensive network coverage. • Private sector participation in distribution. • Access to other electricity markets in the region.	• Aging and deteriorating physical infrastructure. • High generation cost (at the margin). • High losses in generation and transmission. • Regional disparities in quality of service. • Poor payment performance. • Low tariff levels and tariff imbalances. • Lack of an acceptable social safety net. • A weak legislative and regulatory framework with no regulatory agency. • Inexperienced commercial management.
Opportunities	**Threats**
• To support economic development through the restoration of consistent quality service. • To improve technical and economic efficiency of supply and consumption (including more economic dispatch). • To increase private sector participation. • To take advantage of opportunities for regional trade in electricity.	• Continuing deterioration in the quality of service. • Further deterioration of the physical infrastructure with an associated increased risk of systemic collapse. • A reduction or loss of private sector participation in the sector. • Increasing unmanaged demands on the fiscal revenue streams resulting from both explicit and implicit subsidies.

IV-3. The government faces two overarching challenges:

i. To restore and maintain acceptable levels of service throughout the country; and
ii. To ensure the country secures optimum benefits from its power sector assets.

IV-4. These two challenges encompass a number of subsidiary issues, including:

- Establishing and sustaining financial viability in the sector
- Securing adequate funding for investment needs
- Minimizing the drain on public sector resources to support the sector.

The government has already taken a number of steps to address these challenges. Notably, a fuel and energy development program has been prepared for the period 2005 – 2015 that addresses developments in the power sector (Appendix 3). The government's stated goals and objectives in this program are to:

- Identify key development targets;
- Meet power requirements using domestic resources;
- Overcome constraints affecting the power system;
- Provide quality power to established standards;
- Ensure the efficient use of energy resources;
- Expand the use of non traditional energy resources;
- Provide an enabling environment for increased investment and sound competition;
- Increase collection rates; and
- Ensure environmental safety.

IV-5. Realizing these goals, however, will take both time and a strong commitment on the part of the government. This section outlines issues and options to be considered as the government develops implementation plans to achieve these goals.

Overview of the Sector

IV-6. Azerbaijan's power generation capacity is comprised of a mixture of thermal and hydro generation facilities. The transmission and distribution networks were designed to provide almost universal access. Azerbaijan has transmission inter-connections and is able to trade power with Russia, Georgia, Iran, Turkey and Armenia. Table VI-1, below, summarizes the capacity in the sector

IV-7. Generation and transmission are both managed by Azerenergy, a state owned enterprise. Distribution activities are grouped in four regional distribution companies and the government has transferred management of these activities to two private companies under what is, in effect, a concession arrangement. The Baku and Sumgayit power distribution networks are managed by Barmek Holding AS and the Ali-Bayramli and Gandja networks are managed by the Baku High Voltage Electrical Equipment Company.

IV-8. The sector, however, has suffered from inadequate funding to perform essential maintenance functions and to introduce new technology. The result has been a distinct deterioration in the quality of the infrastructure and an associated deterioration in the quality of service. Rolling blackouts are now commonplace and the sector is becoming increasingly exposed to the risk of systemic collapse. The risk of system failure could be significantly reduced by rehabilitating and upgrading generation facilities and investing in a modern transmission management system.

IV-9. With the deterioration in the sector's infrastructure, the country is now no longer self sufficient in terms of electricity supplies. While it has the capability of providing the primary fuels for power generation from its natural resource base – in particular, its hydrocarbon resource base, significant investment in generation facilities will be required if self sufficiency in terms of electricity supply is to be re-established.

Table IV-1
Summary Description of Azerbaijan's Power Sector

Generation	Nameplate Capacity			Usable Capacity	
Hydro Power	1,040 MW			791.0 MW	
Thermal Power	4,695 MW			3498.0 MW	
Total	5,735 MW			4289.0 MW	
Transmission	500 kV	330 kV	220 kV	110 kV	Total
Line length – km.	450.8	1270.0	1,261.7	2,647.5	5,567.0
Number of substations	1	5	9	33	48
Distribution Network	110 kV	35 kV	20 kV	6-10 kV	0.4 kV
Line length km.					
Baku	0	727	72	1,271	6,490
Gandja	0	1,925	0	12,519	20,659
Ali-Bayramli	934	1,951	0	11,534	20,529
Sumgayit	0	527	0	3,672	6,807
Total	934	5,130	72	28,996	54,485
Cable line length km.					
Baku	0	111	9	1,653	1,330
Gandja	0	171	0	0	280
Ali-Bayramli	0	0	0	15	132
Sumgayit	0	6	0	297	535
Total	0	288	9	1,965	2,277
Substations					
Baku	11	217	57	3,674	
Gandja	87	192	0	6,129	
Ali-Bayramli	66	272	0	6,290	
Sumgayit	29	60	0	2,087	
Total	193	741	57	18,180	

Source: Report prepared for the World Bank by Dr. Vilayat Valiyev; and, State Program om Development of Azerbaijan Republic Fuel Energy Complex within 2004 – 2015 (Draft), Baku 2004.

Investment Requirements

IV-10. As Table IV-1 indicates, available generation capacity is substantially less than installed capacity, representing a little less than 75% of installed capacity. Available capacity is not sufficient to meet peak winter domestic demand when there is extensive use of electricity for heating and, at current consumption rates[41], the reserve margin which would be expected to be around 20% to 25% is non existent.

IV-11. Options to meet peak demand include (i) expanding and upgrading existing generation facilities; (ii) increasing regional trade; (iii) improving the performance of existing facilities; and (iv) demand side management.

IV-12. State forecasts for the period 2004 – 2015 predict a 4.7 % growth in electricity demand per annum, based on the projected trend of GDP in the non oil sector. To meet projected demand, new generation capacity would be needed from 2005, with required additions exceeding 2750 MW by 2015.

Table IV-2
Installed Capacity Forecast

New capacity to be launched in the power system	Installed capacity (MW)	Years											
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total on capacities to be launched with State Guarantee, including:	**1920 - 2020**		**60**	**120**	**480 - 580**	**460**	**400**		**400**				
Sumgayit SGF	400÷500				400÷ 500								
Shimal SRPP-2	400					400							
AzDRES	300		60	120	60	60							
Mingechavir Water Reservoir	20				20								
Ali-Bayramli SRPP	800						400		400				
Independent power plants - no state guarantee	500			60	70	70	100	100	100				
Wind power plants (private)	260		5	10	10	25	30	30	30	30	30	30	30
Small HPPs (private)	30			3	5	10	12						
Total capacity of power system		**4100**	**4165**	**4378**	**4923**	**5428**	**5970**	**6100**	**6630**	**6660**	**6690**	**6720**	**6750**

Source: State Program on Development of Azerbaijan Republic Fuel Energy Complex within 2004 – 2015 (draft)

IV-13. Significant investments would be required in the power sector to address generation and transmission needs up to 2015. Investment estimates range from $1,950 million to $3,600 million, depending upon the development profile chosen for the sector. $680 million would be required to meet new generation needs (state-owned) up to 2008. The investment requirements are briefly summarized in Table IV-3. With these investments Azerbaijan would be on track to meet the generation profile required to cover its projected demand through 2015.

IV-14. Priority investments are required to upgrade and rehabilitate existing generation facilities to meet the near term demand and to allow time for the financing and construction of new capacity. At a minimum, emergency facilities should be enhanced to

[41] In 2002, billed consumption was 18,031 MWh.

reduce the risk of large-scale failure. EBRD is preparing a loan[42] to support emergency and capacity enhancing investments in generation.

Table IV-3
Power Sector Investment Needs (2004 – 2015)

	Total Cost US$ millions	2005 – 2008 Needs US$ millions
Construction and refurbishment of power plants, including:	1,720 – 3,370	680
Shimal SRPP Phase 2	270	270
Sumgayit SGF	300	300
AzDRES units 1 – 9	70 - 270	70
Mingechavir water reservoir	40	40
Ordubad HPP	90	-
Ali Bayramli SRPP	650	-
Tovuz HPP	0 – 450	-
Sangachal TPP	300	-
Shamkir HPP	0 – 1,000	-
Navahi NPP	0 – 1,200	-
Construction of key transmission lines and substations	230	230
Total	1,950 – 3,600	910

Source: State Program on Development of Azerbaijan Republic Fuel Energy Complex within 2004 – 2015 (draft); World Bank

IV-15. The transmission grid represents the largest risk of systemic, catastrophic failure. Overloading and protective relay operations have been major contributors to winter blackouts[43]. There is a high risk that availability could be further reduced due to the sub-optimal location of generation compared to demand and the consequent reliance on long transmission lines. Investment in a modern transmission control system, such as SCADA[44], could reduce the risk of failure and improve economic dispatch. The World Bank, in cooperation with Azerenergy, is preparing a power transmission project[45] to improve system control and complete some upgrades. KfW is also supporting the upgrade of substations[46].

IV-16. With the transfer of the distribution facilities to the private sector, responsibility for investment in distribution has also been transferred. These arrangements have been established on a contract basis essentially equivalent to a concession arrangement (although described as a "management contract"). While the terms of the contractual arrangements need to be respected, careful monitoring will be required to ensure that

[42] The loan is expected to amount to at least 70 million Euros.
[43] This was clearly demonstrated in July 2002, when a combination of fire on the ground and poor transmission line maintenance caused short-circuits of both the 500 kV and the parallel 330 kV power lines. between the Azgres thermal power station at Mingechevir and Baku, ultimately causing the whole power system to trip and blackout the entire country.
[44] Including an Energy Management System, metering and telecommunication upgrades.
[45] Up to $50 million is contemplated as an IBRD loan.
[46] KfW has provided a 15 million Euros credit.

appropriate investments are made in the distribution companies. The contracts do include an obligation on the part of the private sector enterprises to generate and submit an investment plan (see the box below). Since availability of funding to meet future investment requirements will be very much dependent on the margins available to the distribution companies, the government will need to work closely with these companies to ensure that appropriate incentives exist to allow adequate investment in distribution. Within this context, investment plans should be reviewed to ensure that there are sufficient funds to support working capital and investment needs.

Box IV - 1
Management Contract Terms

The management contracts for the four regional distribution and retail companies include the following requirements:

- To make at least certain annual minimum levels of investment in specified areas
- To install metering for defined customer groups
- To meet the technical and operational standards proposed by the operator and agreed with the MED
- To meet or exceed specified performance targets for technical losses (or suffer reduced profit levels)
- To propose within one year a new detailed investment program and feasibility study which will set out a forward looking business plan for the company
- Restrict operations to “constant margin” for the first three years of the contract

Regional Trade

IV-17. Supply demand projections assume some continuing level of imports. This reflects the fact that power exchange takes place regularly among some of the countries of the region, although on a rather limited scale. Increased regional trade could improve the security of supply and, at the same time, reduce the required domestic capacity reserve. Diversifying sources of supply increases competition and has the potential to reduce the cost of power.

IV-18. The government is considering increased private sector involvement in generation, predicting private ownership of generation of about 12 % by 2015. It is important, however, that any such arrangements not preclude the opportunity to take advantage of attractively priced imports (the issue of privatization of generation is discussed further below).

IV-19. In order to take full advantage of potential import opportunities, the transmission system will first need to be rehabilitated. The degree of reliance that can be placed on imports as a long term source of supply will have to be based on an assessment of the security and reliability of such imports. However, long term competitively priced power import contracts could increase system availability and form part of a least cost supply plan in the longer term.

Energy Efficiency

IV-20. The fuel input to electrical output is high and has risen over 12% in the past decade from 364 grams per kWh in 1991 to 407 grams per kWh in 2002. As Table IV-4 below indicates, this level of fuel input compares relatively unfavorably to a number of other FSU countries. Gas-fueled combined-cycle thermal power plants can reach thermal efficiencies of 55% to 60% and, thus, produce considerably more electricity per unit of natural gas fuel input than Azerbaijan's aging stock of power plants. Given Azerbaijan's substantial gas resource base, it would be logical to consider gas fired combined-cycle plants as an option for new increments of capacity.

Table IV-4
Fuel Input to Electrical Output

Country	grams/kWh
Azerbaijan	407[47]
Armenia	375
Kazakhstan	466
Latvia	233
Tajikistan	365
Ukraine	373
Uzbekistan	383

Source: World Bank analysis

IV-21. The State's program for development of the sector predicts that with the modernization of thermal generation facilities and the increased use of natural gas as a fuel source there will be a corresponding decline in conventional fuel use to a level of 250 grams per kWh by 2015.

Demand Side Management

IV-22. As in all the FSU countries, electricity consumption in Azerbaijan is high relative to GDP. Azerbaijan, however, is one of the higher consumers of electricity suggesting there are opportunities for consumption savings. Table IV-5 provides details of total electricity consumption relative to GDP for all of the FSU countries in 2001. The demand profile for the period 2004 – 2015 (Table IV-6) shows an increasing trend in per capita consumption, although there is a decline in the overall ratio of consumption relative to GDP.

[47] State Program on Development of Azerbaijan Fuel Energy Complex within 2004 – 2015, Baku 2004 (draft)

Table IV-5
Annual Electricity Consumption Per Capita Relative to GDP Per Capita - 2002

Country	kWh	US $	Ratio	Country	kWh	US $	Ratio
Middle Income	1,422	1,770	0.80	Kyrgyz Republic	1,269	290	4.38
USA	12,183	35,430	0.34	Latvia	2,088	3,780	0.55
Total World	2,225	5,130	0.43	Lithuania	1,938	3,730	0.52
Armenia	1,113	800	1.39	Moldova	909	400	2.27
Azerbaijan	**1,878**	**720**	**2.61**	Russia	4,291	2,120	2.02
Belarus	2,657	1,380	1.93	Tajikistan	2,236	180	12.42
Estonia	3,882	4,540	0.86	Turkmenistán	1,371	860	1.59
Georgia	1,033	650	1.59	Ukraine	2,229	780	2.86
Kazakhstan	2,911	1,520	1.92	Uzbekistan	1,670	460	3.63

Source: World Bank Group Data and Statistics

Table IV-6
Demand Profile 2004 - 2015

Indicators	**Unit**	**Years**											
		2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Electricity Demand	Billion kWh	22.9	23.6	24.4	25.3	26.1	27.9	29.2	30.7	32.2	33.9	36.1	37.9
Electricity Generation	kWh per capita	2735	2784	2851	2928	2993	3142	3281	3404	3531	3677	3882	4032
Demand per Unit of GDP	kwh per AZM	0.81	0.75	0.68	0.63	0.55	0.52	0.48	0.45	0.42	0.40	0.37	0.36

Source: State Program on Development of Azerbaijan Republic Fuel Energy Complex Within 2004 – 2015 (draft), Baku 2004.

IV-23. The key factors influencing electricity consumption levels are (i) the incentives to conserve and (ii) the availability of alternative more attractive energy sources. As is discussed further below, Azerbaijan's current tariff structure does not cover the cost of electricity supply. Consequently, appropriate incentives are not in place to ensure that electricity is consumed with full regard to the economic consequences. In addition, Azerbaijan uses a substantial amount of electricity for heating in the winter. This is, in part, a result of the deterioration in the domestic gas transmission and distribution network. Azerbaijan is endowed with significant gas resources and should, therefore, establish a longer term objective of transitioning from electricity to gas for heating purposes where this makes economic sense.

Funding Options for the Sector's Investment Needs

IV-24. As has been noted above, there is considerable donor interest in providing financial support to the power sector. Donor loans and grants, however, will not be sufficient to meet all the investment requirements of the sector. The balance of the funding will have to come from sector cash flows, from the budget or from private investors.

IV-25. The long term viability of the sector is ultimately predicated on its financial viability. Consequently the sector needs to be capable of generating the funds to meet its investment needs along with its operational and maintenance requirements.

The Financial Outlook for the Sector

IV-26. At present, the power sector falls well short of covering its financial needs. In dealing with this problem, three factors will have to be addressed: (i) payment levels; (ii) the level of losses from the system; and (iii) tariffs. Table IV-7 provides a comparison of the financial performance of the power sectors in the CIS countries in 2002.

Table IV-7
Financial Performance of the Power Sector - 2002

Country	Excess Losses %[48]	Collections %	Weighted Average Tariff USc/kWh	Average Receipt USc/kWh	Average Cost Recovery Price USc/kWh	% of Cost Recovery
Armenia	11.95	90.0	3.08	2.77	3.70	74.9
Azerbaijan	**2.03**	**34.0**	**1.90**	**0.65**	**3.80**	**17.1**
Belarus	-	97.8	3.31	3.24	3.57	90.8
Georgia	1.23	47.0	4.30	2.02	4.07	49.6
Kazakhstan	8.07	62.0	2.60	1.61	3.00	53.7
Kyrgyz Republic	28.72	84.0	1.13	0.94	2.30	40.9
Moldova	11.70	107.9	5.00	5.40	5.00	108.0
Russia	2.05	92.1	1.50	1.38	3.00	46.0
Tajikistan	3.73	70.0	0.50	0.35	2.10	16.7
Turkmenistan	4.49	n/a	n/a	n/a	n/a	n/a
Ukraine	8.04	89.8	2.62	2.35	4.00	58.8
Uzbekistan	-	50.0	0.85	0.43	3.50	12.3

Source: World Bank analysis

IV-27. As Table IV-7 indicates, among the CIS countries, only Moldova recovered the full cost of its electricity supply in 2002. However, most of the countries collected sufficient revenues to cover cash costs. The clear exceptions were Azerbaijan, Tajikistan and Uzbekistan. Since 2002, however, Uzbekistan has increased its tariffs substantially, thereby reducing the shortfall in cost recovery.

IV-28. The situation on collections in Azerbaijan is somewhat distorted by the contractual arrangements that were agreed for the management contracts for the distribution companies. These arrangements allow the management contractors to defer amounts payable for electricity purchased from Azerenergy. The projected payments' percentages are summarized in Table IV-8.

[48] Excess losses are technical and commercial losses in the system that are in excess of expected system norms.

Table IV-8
Projected Payment Levels of the Distributing Companies (Percentage)

Distributor	Purchases in 2002 - GWh	2002	2003	2004	2005	2006	2007	2008	2009	2010
Baku	6,487	50	55	60	75	100	100	100	100	100
Sumgayit	2,096	30	30	35	40	45	50	65	80	100
Ganja	4,708	30	30	35	40	45	50	65	80	100
Ali-Bayramli	3,083	30	30	35	40	45	50	65	80	100

Source Azerenergy Financial Model (April 2004)

IV-29. In 2002, the overall collection rate from the distribution networks was 34%, but the amount paid to Azerenegy was only 27.6%[49]. The holders of the four distribution contracts are committed to increasing collections from their customers to 100% by 2006 although they are not obliged to exceed the percentage payment levels to Azerenergy that are shown in Table IV-8.

IV-30. The phasing up of payment levels to Azerenergy provides an improving outlook for the sector. However, since the agreement to defer payment obligations was a government decision, the government should ensure that Azerenergy is compensated for the shortfall in payments via the State Budget[50]. The budget did provide explicit subsidies of $307 million in 2002 and $388 million in 2003 to Azerenergy to cover the majority of fuel costs for thermal power generation. A decision was taken in 2003, to formalize these payments within the State budget and offset SOCAR's debts to the budget with receivables from Azerenergy. Such support needs to be continued with provision being made to include funds to support investment.

IV-31. Even with 100% collections, however, Azerbaijan will fall short of covering the full cost of its electricity. Tariff increases will be required and the government has committed to the establishment of a medium term tariff policy designed to bring tariffs up to full cost recovery levels. In order to minimize the impact of higher tariff levels on the poor, a targeted and effective social safety net must be developed and introduced and the government is working on the implementation of an appropriate social safety net. Tariff increases need to take into account the ability of the population to pay for the electricity. However, the increases in income levels, pensions and the minimum wage over the past one to two years have been sufficient to make a higher tariff level more affordable. Thus, even absent the implementation of an effective social safety net, phased increases in electricity prices can be implemented.

IV-32. In designing a medium tariff policy the government also needs to avoid creating cross subsidies whereby certain customer classes, e.g. the commercial and industrial customers, subsidize the residential customers. In the first quarter of 2004, the tariffs to residential, industrial and commercial customers equated to 2.0 US cents/kWh, 2.7 US

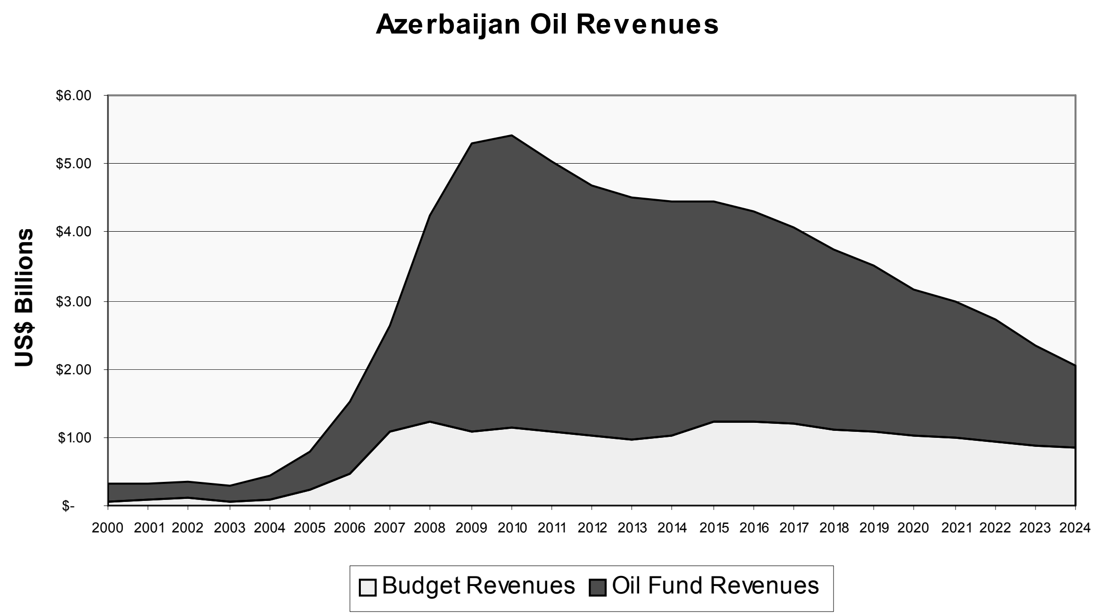
[49] The shortfall is attributed to non payment, corruption by low level employees and selective under reporting by the companies themselves. Theft is also high due in part to a lack of metering and under reporting as well as to widespread meter tampering.
[50] The government should also ensure that Azerenergy is compensated for the shortfall in tariff levels that reflects a government decision to phase in tariff increases to full cost recovery levels.

cents/kWh and 5.1 cents/kWh respectively. Consequently, the class of customer that cost most to supply – the residential customer – paid the lowest tariff. There will, therefore, need to be a rebalancing of tariffs within the context of the increase in the overall average weighted tariff level required to achieve full cost recovery.

Public Sector Funding

IV-33. Azerbaijan is blessed with significant hydrocarbon resources and enjoys the prospect of significant fiscal revenues over the upcoming two plus decades. Figure IV-1 below summarizes a projection of fiscal revenues flowing both to the State Oil Fund and to the State Budget. This projection is based on the World Bank's 2004 price forecast which projected oil prices of $39/barrel in 2004, $36/barrel in 2005, $32/barrel in 2006, declining to a floor price of $26/barrel in the 2009 to 2010 timeframe.

Figure IV-1



Source: World Bank analysis

IV-34. This projection suggests that Azerbaijan should have the financial capacity to meet the critical investment requirements of the power sector from the budget. This, however, represents a potential drain on public sector resources which should be avoided if possible.

Private Sector Participation

IV-35. While overall tariff levels remain below cost recovery levels, the margins provided to the distribution companies coupled with the deferred payment mechanism for the purchase of electricity resulted in attracting private sector participation in electricity distribution. The government has stated an interest in securing further private sector involvement in the sector and has specifically identified generation as an area for increased private sector involvement (predicting around a 12% private share in the ownership of generation facilities by 2015, Table IV-9). Such involvement could take a number of forms; for example: (i) outright sale of Azerenergy's generating assets; (ii) a concession arrangement similar to that put in place for the distribution companies; (iii) a standard management contract whereby management responsibility is transferred to a private sector contractor on a fee basis; and (iv) the creation of incentives to encourage the development of new capacity by independent power producers (IPPs). Care must be taken, however, with the timing and the sequencing of such additional private sector involvement.

Table IV-9
Projected Ownership of Generation

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total capacity	4100	4165	4378	4923	5428	5970	6100	6630	6660	6690	6720	6750
State owned (%)	100	99.9	98.2	96.7	95	93.3	91.2	90	89.5	89.1	88.7	88.3
Privately owned (%)	0	0.1	1.8	3.3	5	6.7	8.8	10	10.5	10.9	11.3	11.7

Source: State Program on Development of Azerbaijan Republic Fuel Energy Complex Within 2004 – 2015 (draft), Baku 2004.

IV-36. Absent appropriate incentives, private sector interest will be very muted. Incentives, however, need to be introduced on a basis that is consistent with the overall reform objectives of the sector. Other countries have experienced significant problems by introducing specific incentives for individual private sector generators that create long term market distortions. Such incentives often take the form of attractive power purchase arrangement terms that have the effect of transferring all commercial risk from the private sector generator to a state owned purchaser of power[51]. As a precursor to involving the private sector in power generation several actions are required:

i. The sector will need to be restructured and a first step is to unbundle Azerenergy, separating the transmission and dispatch roles from the generation role.
ii. Generation activities should then be corporatized in several companies, possibly with each generation facility being a company.
iii. Rehabilitation of the transmission system is also required and the introduction of a SCADA system will permit the development of a dispatch protocol which should govern future dispatch arrangements.

[51] The case of Turkey provides a number of examples of problems associated with specific power purchase arrangements (PPAs). To cite one example, the PPA negotiated by Enron assured the company of a rate of 11 cents/kWh for electricity supplied to the transmission company which, in turn was only able to resell it to the distribution companies at a price of less than 5 cents/kWh. Turkey's subsequent decision not to provide a state guarantee on such arrangements slowed down the pace of private sector involvement but substantially reduced the State's contingent liabilities and ensured that over the longer term a more competitive power market will emerge.

iv. A market structure will have to be developed which, coupled with the dispatch protocol, should optimize the overall cost of power supply within Azerbaijan. The government has already established the principle of bi-lateral contracting between Azerenergy and the distribution companies. It should be possible to build on this principle and avoid the introduction of a single buyer model to the sector. In particular, Azerbaijan should avoid a situation whereby the transmission company takes on a single buyer role.

v. A clearly articulated medium term tariff policy and the establishment of an independent regulator will also be important in promoting private sector investment interest.

vi. An important adjunct to the development of a medium term tariff policy is the development of monitorable quality standards. Tariff increases will be much more palatable if accompanied by a demonstrated commitment to improve the quality of service. Quality standards should be developed and monitored at the distribution level and should be incorporated into any agreement for private sector involvement in generation. Establishing and monitoring quality standards will be an important role for the regulator

IV-37. The government has outlined a program[52] for developing a new regulatory regime by mid 2006 that will include a Utility Regulatory Agency with responsibility for the regulation of prices and tariffs, technical performance and customer service. The government has also issued a decree emphasizing its commitment to enhance the financial discipline in the sector.

IV-38. The measures outlined above can be implemented within the next two to three years. There is then the potential for the sector to continue to evolve towards becoming a fully competitive market; in particular it will be possible to establish competition in generation. One barrier at this time is the size of the market in Azerbaijan which is probably too small to support the creation of a fully competitive wholesale market. As the market grows such an option will become more feasible and will need to be evaluated. In the meantime efforts should be made to develop an understanding of the market structure options in order to ensure that the ultimate market design for the power sector in Azerbaijan is optimal for the specific circumstances of the country.

[52] In April 2003, the government provided a letter of intent to the World Bank on the "Development of the Regulatory Framework for the Utility Sector and Creation of New Institutional Arrangements for Regulation". This letter of intent covers the electricity; natural gas transmission, storage and distribution; heating; water supply; and sewerage sub-sectors.

V - The Regulatory Environment in Azerbaijan

Summary

V-i. There is, at present, no independent regulator for the energy industry in Azerbaijan. Responsibilities for regulation of the utility service sectors are fragmented and laws overlap in a number of areas, for example licensing and tariffs. The Ministry of Economic Development (MED), the Ministry of Industry and Energy (MoIE)[53] and the Ministry of Finance (MoF) share responsibilities for policy development and regulatory oversight and both the President's office and the state owned enterprises in each sub-sector also play a role in policy making. This introduces potential conflicts between political and economic decision making.

V-ii. There is a well established "competent authority" within SOCAR that deals with the international oil and gas industry on a day to day basis. However, SOCAR's role as government representative represents a potential conflict of interest with its other commercial and investor roles.

V-iii. A solid legislative framework and an effective regulatory function are essential to the long term viability of the utility service sectors. Absent a good legislative and regulatory framework it will be difficult to attract adequate private investment to the sectors and to promote the needed improvements in efficiency. This section addresses the actions needed to introduce an acceptable regulatory environment to Azerbaijan and highlights the respective roles and responsibilities of various stakeholders in this regard[54].

V-iv. The conclusions and recommendations of this section may briefly be summarized as follows:

- There is a need to establish greater clarity with regard to responsibilities for policy making for the energy sector. In particular, there is overlap and the potential for confusion regarding the respective roles of MED and MoIE. In order to address this, the respective roles and responsibilities could be redefined and incorporated in a new decree. Alternatively, the policy making functions of MED and MoIE could be consolidated in a single ministry.

- SOCAR is very effective in performing the role of "competent authority" in dealing with the international oil and gas industry. However, this represents a potential conflict of interest given SOCAR's other commercial and investor roles. To remove this potential conflict of interest, this role should be transferred to an independent agency with financing and reporting structures that are separate from SOCAR. Given

[53] The responsibilities of the Ministry of Industry and Energy were previously assigned to the Ministry of Fuel and Energy. The charter for the Ministry of Industry and Energy has not yet been finalized but it is anticipated that it would include the roles and responsibilities of the former Ministry of Fuel and Energy.
[54] While tariff setting is identified as one of the roles of the regulator, this section does not address the methodology of establishing tariffs. This is addressed in other work that has been undertaken with the government.

the importance of the role the agency should report directly to top levels of government.

- The government has made a commitment to establish a regulatory agency for the energy sector. It is essential that the regulatory agency be solidly supported by legislation and that the structure and functions of the agency conform to good international practice. Within this context several factors require particular attention:

  ◊ The agency should be and should be seen to be independent. This will require an assured source of funding that should, ideally, not come from budget sources. The agency should be empowered to establish its own hiring and human resource policies. The agency should operate without direct orders, advice or interference from the government and the Commissioners should have tenure and should only be removable as the result of egregious acts or gross incompetence.

  ◊ The agency should be mandated to promote improved transparency and accountability. This will necessitate a transparent approach towards decision making and information disclosure.

  ◊ A key role for the agency will be the establishment and monitoring of service quality standards. The agency will be responsible for tariff setting. Service quality is as important for consumers as prices; yet this fact is frequently ignored by newly established regulatory agencies.

  ◊ The agency should also have powers to promote competition and prevent anti-competitive behavior.

- The government's plans contemplate full implementation of the new regulatory regime by mid-2006. In the meantime, however, a transition plan should be developed for the period prior to full implementation of the new regulatory regime proposed in the government's Letter of Intent to the Bank. The transition plan should conform to the good international practices that should ultimately be incorporated in the new regime. Key issues to be addressed are the need to: (i) concentrate regulatory functions in a single location; (ii) change Decrees and Regulations pertaining to the MED, MoF, MoIE and the Tariff Council; (iii) rapidly build capacity to regulate the sector; (iv) establish clear coordination across institutions with overlapping regulatory roles and responsibilities; (v) document regulatory roles, responsibilities and procedures; and (vi) promote increased transparency around the regulatory processes.

- At present, there are a number of perceived risks embodied within the current regulatory framework that act as disincentives for external investors in the energy sector. These need to be reviewed and clarified as part of the transition to an independent regulatory regime. A more liberal policy regime that addresses market rules and the opening of the domestic market would also support external involvement in the sector.

V-v. A step that is urgently required is passage of legislation establishing the regulatory agency. However, in order to craft this legislation a number of government decisions are required. The key decisions relate primarily to the autonomy and the authority of the agency. However, the issue of accountability of the agency is also important. The specific issues to be addressed are as follows:

- *In which branch (executive, legislative or judicial) should the agency be located?*

  Regulatory agencies are generally placed in either the legislative or executive branch. If placed in the legislative branch, the agency would report to the Milli Majlis. Such an approach, in theory, provides the greatest degree of independence to the agency by placing some distance between the regulator and the government, the utility companies and the public. However, a considerable degree of autonomy can still be retained with an executive-branch agency. Many of the regulatory authorities established in southeastern Europe and in other former Soviet Union countries have been structured as executive-branch agencies.

  In the event the agency is located in the executive branch the question arises as to where, specifically, it should report. The preferred option would be to have it report at the highest levels of government to the President, the Prime Minister or to the Cabinet of Ministers. This would minimize the risk of interference with the agency's role. There are examples, however, where a regulatory agency reports through a ministry. In such event, however, it remains important that the agency's autonomy be preserved to the extent possible. In the case of Azerbaijan, were the decision made to have the agency report through a ministry it is likely that only assignment to the Ministry of Economic Development would be seen as preserving sufficient autonomy to the agency to allow such an arrangement to function.

- *How should the Commissioners be appointed?*

  If the agency were to be established in the legislative branch, the normal practice would be to have the Milli Majlis appoint the Commissioners, although the appointment could be based on nominations submitted by the President and approved by the Milli Majlis. If the agency were to be established in the executive branch the appointments could be made by the President. It would still be desirable, however, to have the appointments ratified by the Milli Majlis.

  Regardless of the specifics of the method of appointment, the autonomy of the agency will be predicated on assurances that the Commissioners will be allowed to exercise their role without undue interference. This means that the Commissioners should be assured that they can only be removed for clearly defined reasons such as being convicted of a criminal offense or becoming permanently incapacitated. It is also important that the institutional memory of the agency be preserved and this can be effected by appointing Commissioners to staggered terms. The total number of Commissioners will be dictated in part by the available capacity to perform the function. It would be desirable, however, to have a minimum of three Commissioners appointed to the agency. The Chairmanship could either rotate among the Commissioners or be subject to the same rules of appointment as apply for the appointment of the Commissioners.

- *How will the agency be funded?*

  In order to preserve its autonomy, it is important that the agency be independently funded to the maximum extent possible. In the event a regulatory agency is entirely dependent on the government for its funding it becomes more susceptible to government interference. The normal forms of independent funding are license fees and/or tariff surcharges levied on consumption. Dedicated taxes are also sometimes used as a source of independent funding. The government will need to decide on the preferred sources of independent funding for the agency. To the extent tariff surcharges are used this will impact the form of the tariff policy the government will need to adopt (see the discussion below). It may also be necessary, at least for an interim period, to fund a part of the agency's costs from the State budget – this is particularly likely during the start up phase. Ideally, however, the period for such budget funding should have a sunset provision.

  The regulatory agency should prepare its own budget, although the government should have the opportunity to review and approve the budget. The government will need to decide who should have the authority to approve the budget; options include the Milli Majlis or an appropriate authority in the executive branch, for example the President.

  The regulatory agency should also be authorized to establish its own hiring and human resources policies and practices. This should include the authority to establish compensation packages for its employees that will enable it to compete with private sector and regulated companies in securing high quality professionals for the agency. This would mean, in effect, that the agency would have a separate salary scale from the civil service.

- *Who should be responsible for issuing licenses?*

  It is fairly common for the responsibility for issuing licenses to regulated enterprises to be assigned to the regulatory agency along with full responsibility to monitor and enforce the provisions of the license. In certain circumstances these responsibilities may be shared with a government agency that would be charged with issuing the license while the regulatory agency would be responsible for monitoring and enforcing the implementation of the provisions of the license. In the case of Azerbaijan such a split responsibility could apply in the case of licenses issued by the Ministry of Economic Development. However, all licensing responsibility currently assigned to the Ministry of Industry and Energy should be transferred to the regulatory agency.

- *What level of tariff setting responsibility will be assigned to the regulatory agency?*

    A principal function of the independent regulator is to regulate tariffs, taking into consideration the interests of sector participants, consumers and other interested parties. Ultimately, therefore, the regulator should have comprehensive authority to establish a tariff methodology and to calculate tariffs on the basis of that methodology. This authority must be administered in an open and transparent manner through such processes as the use of public hearings and publication of records of decisions with all supporting documentation.

    Tariffs at present, however, are well below full cost recovery levels and a medium term tariff policy is required to establish a road map to move tariffs to the appropriate levels. Development and implementation of this medium term tariff policy is a government responsibility and actions of the regulator with regard to tariff setting will have to be undertaken within the constraints imposed by this policy. The government should, therefore, establish and make public its medium term tariff policy and this should, ideally, be done before the regulatory agency is established.

- *What form of appeal process should be instituted?*

    It is important that a process be in place to allow an appeal against tariff and license decisions. Ideally, an appeal of tariff and license decisions should only be to the courts and should be limited to cases based on errors of fact or procedure. The courts should not take on, or be assigned, the role of providing de facto approval of regulatory decisions. For international investors it may be appropriate to incorporate provisions allowing some issues to be made subject to international arbitration.

The Regulatory Environment in Azerbaijan

Background

Current Policy Making and Regulatory Responsibilities

V-1. The Ministry of Economic Development (MED) and the Ministry of Industry and Energy (MoIE) [55] were established in 2001 and 2005 respectively and are the primary agencies responsible for energy sector policy making. The MED has broad functions and responsibilities including policy making, regulation, pricing and tariffs, licensing, and management of fixed assets. The MoIE is responsible for formulating and implementing State policy for oil and natural gas production, transport and processing, electricity generation and transmission, district heating, and gas transmission and distribution. However, many functions of the MoIE overlap with those of the MED. The respective functions are summarized in Boxes V-1 and V-2 below.

Box V-1
Key Functions of the MED

Regulation[56] Article No.	Key Provisions
3	Formulate and implement State Policy to prevent monopolies and promote competition.
5	Work with other central and local Executive Authorities, local government bodies and public organizations.
5	Regulate socio-economic activities.
9.10	Prevent monopoly activities and protect consumer interests.
10.1	Work out the general principles of price and tariff policy (with other bodies).
10.18	Develop mechanisms to efficiently use natural resources including energy (with other bodies).
10.27	Draft international treaties regarding legal, tariff and other actions in transport, transit of goods and foreign trade shipments. Participate in the negotiation and implementation of these treaties.
10.83	Provide consent to transfer State owned facilities from one balance sheet to another and provide opinions to justify writing off fixed assets.
10.109	Determine the regulatory instruments to be applied to each natural monopoly. Issue binding instructions regarding payment of profits to the State budget as a result of legal violations in signing contracts with consumers, the provision of compulsory services and making changes to contracts.
11.5	Issue and revoke licenses.

Source: Nexant (2003)

[55] The responsibilities of the Ministry of Industry and Energy were previously assigned to the Ministry of Fuel and Energy. The charter for the Ministry of Industry and Energy has not yet been finalized but it is anticipated that it would include the roles and responsibilities of the former Ministry of Fuel and Energy.
[56] Approval of MED Regulations was through Presidential Decree No. 495 (June 11, 2001).

Box V-2
Key Functions of the MoIE

Regulation[57] Article No.	Key Provisions
7.5	Participate in the preparation of capital investment programs for the development of various parts of the fuel and energy complex.
7.6	Represent State interests regarding the change of ownership and management of State property.
7.7	Submit proposals to improve the economic regulation of the fuel and energy sectors.
7.8	Regulate State enterprises in the fuel and energy sectors.
7.12	Participate in the regulation of natural monopolies.
7.13	Draft normative legal acts to regulate economic relations in the fuel and energy sectors and participate in the approval process.
7.22	Issue licenses for fuel and energy, oversee compliance, and decide on revocation / termination.
7.40	Participate in the regulation of transportation systems of energy carriers.
7.27	Set guidelines for labor protection and improve working conditions in the fuel/ energy field and ensure licenses comply with regulations.

Source: Nexant (2003)

V-2. The President's Office and the state owned enterprises operating in each sub-sector also play a role in policy making.

V-3. The Tariff Council addresses monopoly services for the electricity, natural gas and water sectors and its Secretariat has authority[58] to restructure tariffs, define customer categories and adopt cost reflective tariff designs. The MED has a pricing and tariff policy function[59] that provides technical and administrative support to the Council. The Council is also supported by Working Groups that include industry representation[60]. Rules and procedures[61] have been adopted by the Council that outline the principles and process for tariff determination. However, they do not address sector specific issues. Tariffs for the utility sectors include heavy subsidies to residential consumers and public authorities[62]. The tariff review procedure lacks clarity and public disclosure of decision processes is limited. There is no appeal process for tariff decisions and for penalties for violations and there is no mechanism to challenge details of investigations.

[57] Regulations for the former Ministry of Fuel and Energy (since replaced by the MoIE) were established through Presidential Decree No. 602 (September 6, 2001). These are the regulations referred to in this table and it is anticipated that they will also form part of the charter for the MoIE. This charter has yet to be finalized.
[58] Cabinet of Ministers Decision No. 17
[59] The Economic and Forecasting Department (EPFD)
[60] Azerenergy, Azerigaz, SOCAR, Azerbaijan Airlines, the four distribution companies, Industrial Unit Bakukanalizasiya.
[61] Rules for Formation and State Regulation of Prices (Tariffs) of the Products (Works, Services) of Natural Monopoly Subjects, MED Order No. 67, September 20, 2002. These rules are registered with the Ministry of Justice.
[62] the latter for the gas sector only

V-4. There is a well established "competent authority" within SOCAR that deals with the international oil and gas industry on a day to day basis. SOCAR's Foreign Investment Department issues licenses, negotiates PSAs and operates as the de facto regulator of upstream oil operations. This, however, represents a potential conflict of interest with SOCAR's other commercial and investor roles.

V-5. There is, at present, no independent regulator for the energy industry. Responsibilities for regulation of the utility sector are fragmented, introducing potential conflicts between political and economic decision making[63]. There are no provisions that allow regulatory review of investment plans to screen for economic efficiency, tariff impacts and system prioritization.

The Legislative Framework

V-6. The key legal provisions affecting the energy sector are embodied in the following laws and in the Production Sharing Agreements signed with major international companies.

Box V-3
The Legislative Framework

Law on the Protection of Foreign Investments (1992) – This includes a number of safeguards for foreign investors and allows the acquisition of exploration and development rights. Revisions to this Law are planned.

Law on Use of Energy Resources (1996) – This provides the legal, economic and social policy basis for the efficient use of energy resources. The State has the power to control the use of energy resources by State enterprises and organizations, to set policy for efficient energy resource use, and to use a range of mechanisms to promote energy saving technology and equipment. Registration of plans for energy resource use is also addressed.

Law on Gas Supply (1998) – This regulates the exploration, production, refining, transportation, storage, marketing and use of gas including gas liquids. It includes requirements for gas facilities, gas connections, licensing, energy agreements, land use, health, safety and environment provisions, and enforcement. Under this law, only approved contractors can use the transportation and distribution system or the underground gas storage facilities. In addition, consumers can only connect to gas systems following testing and certification by a 'gas expert'.

Law on Power Engineering (1998) – This provides the legal basis for electrical and thermal power generation, transmission, distribution, purchase, sales and consumption. It governs the activities of State power engineering companies, power supply companies, independent power producers and consumers. The relevant State authorities are responsible for licensing, transmission and distribution contracts, pricing, de-monopolization, performance criteria, rules and standards.

[63] Concession agreements for electricity distribution granted by the MED (also the asset owner) combine both regulatory and commercial terms but do not adequately address economic regulation or consumer protection

Law on Energy (1999) – This covers energy policy objectives; ownership of resources; control of exploration, development of fields and the construction and maintenance of transport systems. The law includes a strong commitment to energy efficiency and contains significant licensing provisions.

Oil Law – This has been under preparation and is currently with the Parliamentary Commission. A date has not yet been confirmed for the first reading of this law.

Production Sharing Agreements (PSAs) - At this point, Azerbaijan has signed over 20 major international field agreements. Most PSAs have been developed on an individual basis and have the status of law. While various ministries handle the exploration and production agreements with foreign companies, SOCAR is a party to all international consortia developing new oil and gas projects.

V-7. A critically required addition to this legislative framework is a law establishing the regulatory agency, outlining its roles and responsibilities and assuring its independence.

Establishing an Effective Regulatory Function

V-8. Regulation normally has two important purposes, namely:

i. Protecting consumers from monopoly practices in those parts of the sector that are not subject to competition. The regulator establishes prices and quality of service standards and tries to stimulate a competitive market. To the extent that the regulator succeeds, new investments will be undertaken by the utilities and consumers will be satisfied with the quality of service. If the regulator fails to set prices at a level that provides a fair, reasonable and acceptable rate of return to investors, new investments will not be forthcoming and the quality of service will deteriorate.

ii. Monitoring proper competitive behavior. Whenever the regulator determines that there is not enough competition, or that there are anti-competitive practices, it should take action to prevent these practices from adversely affecting consumer prices or the quality of service.

V-9. The range of specific functions assigned to the regulator may vary, but in general, the following key functions are assigned throughout the world:

- Approve and set tariffs;
- Issue licenses;
- Review/approve system expansion, upgrade and rehabilitation plans by all regulated licensees;
- Require implementation of a system of accounts consistent with international accounting standards (e.g. international financial reporting standards);
- Require the filing of annual and other periodic reports containing all information necessary to the discharge of regulatory responsibilities;

- Specify quality of service and reliability standards as well as customer service standards;
- Carry out inspections and enforcement of license conditions and other regulatory requirements;
- Oversee creation of programs and incentives for maximum efficiency in the use of utility services;
- Cooperate with other government agencies in a transparent manner in implementing national priorities in such areas as national security, regional development, environmental protection and social welfare;
- Adjudicate disputes involving licensees and the government, between and among licensees, and between licensees and consumers;
- Carry out a continuous and thorough program of public interaction and information on matters relating to the regulator's mandate.

V-10. The government has made a commitment to introduce an effective regulatory function for the utility sectors. In April 2003, the government provided a Letter of Intent (LoI) to the World Bank on the "*Development of the Regulatory Framework for the Utility Sector and the Creation of New Institutional Arrangements for Regulation*". The LoI covers utility services including electricity, natural gas, water, wastewater and heating. It outlines a program for developing institutional arrangements and draft legislation to regulate these sub-sectors. The government's primary objectives are to:

- Ensure efficient and equitable service delivery to consumers at prices that reflect the cost of delivery;
- Protect low income consumers;
- Increase investment in these sectors; and
- Accelerate reforms for sector development while minimizing their environmental and social impacts.

V-11. In order to achieve these objectives, the government plans to establish a Utility Regulatory Agency (URA) that will be responsible for technical and customer service regulation in the utility sector as well as for the regulation of prices and tariffs. The URA will be independent in its decision making, organizationally separate and directed by a Commission of full-time regulators. Commission members will be appointed for a fixed term based on objective criteria and will not be removed without just cause. The regulatory agency will be responsible for communicating with the public. The Ministry of Economic Development (MED), supported by line ministries and sector entities, will be responsible for developing the regulatory framework and actions required to establish the URA. Key targets dates include:

- mid 2005 – passage of appropriate enabling legislation;
- end 2005 – establishment of the Utility Regulatory Agency;
- mid 2006 – provision of social protection for vulnerable households; and
- mid 2006 - full implementation of the new regulatory regime.

V-12. In developing the structure and governance provisions for the regulatory agency, the government should remain cognizant of good international practice. In this regard, there are four well-documented and accepted fundamental requirements for effective regulation. These are summarized in Box V-4

Box V-4
Fundamental Requirements for Effective Regulation

1. The regulator must be assigned the requisite authority in its enabling legislation for conducting basic regulatory functions. The regulator should be unambiguously assigned its responsibilities by statute and the statute should include clear, substantive and procedural guidelines for conducting the tasks.

2. The regulator must be afforded the requisite capacity for performing its assigned functions. This means that the regulatory body should be adequately staffed with personnel that have sufficient knowledge of utility sector operations, as well as highly developed skills along both functional (e.g. rate design, safety and reliability assessment etc.) and disciplinary (e.g. economics, finance, engineering, etc.) lines. This also requires that regulatory staff be organized in a manner that allows their knowledge and skills to be effectively employed.

3. The regulator must maintain sufficient independence from political interference in its day-to-day affairs. This sort of autonomy from the political process is necessary to facilitate difficult and politically unpopular decisions. Investors have consistently displayed a strong preference for an agency that is sufficiently shielded from the inevitable shifting tides of political concerns and calculations. They will demand that the regulator operate under a statutory mandate that protects its autonomy and provides for appeal of regulatory decisions to a court system that is also independent of political influence. In practice, the notion of independence can be effectively accomplished by the establishment of several structural and procedural safeguards.

4. The regulator should establish and consistently apply a set of procedures for conducting its responsibilities. There are a few basic principles that should guide the development of these procedures. Interference with management of regulated companies, and the procedural requirements placed on the companies, should be minimized to the greatest extent possible. Standards for decision making should be clearly stated and publicly disclosed; and the process of applying standards should be transparent. In particular, specific mechanisms are needed to give consumers a voice in major decisions. Public participation is important because it is a key component in any regulatory agency's mandate to protect and respond to consumers' interests.

Source: Nexant

Addressing the Key Challenges

V-13. In order to establish an effective regulatory function, the government will need to address a number of key challenges:

i. To separate clearly policy making and regulatory functions
ii. To ensure regulatory independence
iii. To improve transparency and accountability

iv. To ensure service quality
v. To promote competition

To Separate Clearly Policy Making and Regulatory Functions

V-14. Policy making and regulatory functions should be clearly separated. Insofar as the government is concerned, policy making responsibility should be vested in the appropriate ministries while regulatory functions should be assigned to an independent agency. The utilities themselves should not play a direct role in either policy making or regulatory oversight; their responsibilities should be focused on the technical and financial management of their operations.

V-15. Most policy making functions for the energy sector are presently embodied in MED and the MoIE, with many functions overlapping. The President's Office and the state owned utility enterprises have also played a role in policy development. However, there needs to be greater clarity with regard to the responsibility for policy making with regard to the energy sector.

V-16. In order to provide greater clarity with regard to the responsibility for policy making in the energy sector, the government could redefine the relative roles and responsibilities of the two ministries in the area of energy policy making and incorporate the revised definition in a new decree. Alternatively, the government could consolidate the entire responsibility within a single ministry (for example, MED).

V-17. In the oil sector, SOCAR's role as "competent authority" should be transferred to an independent agency with financing and reporting structures that are separate from SOCAR[64]. Given the importance of the role, and the high economic profile of oil and gas development in Azerbaijan, the agency should report directly to top levels of Government.

To Ensure Regulatory Independence

V-18. Independent regulation ensures that key regulatory decisions are not distorted by political drivers, and provides third parties with confidence that they will be treated without political bias. In the utility sectors, the Government's commitment to establish an independent, non political, specialized regulatory agency is of crucial importance for conveying a sense of stability and continuity and encouraging foreign and domestic investment in the sectors.

V-19. The issues of financial and organizational independence of the proposed URA are crucial. On the financial side, the URA should develop a budget on an annual basis for approval by the government and/or Parliament. This will help to ensure that the URA

[64] SOCAR's roles currently include: Government representative for oil and gas, investor in a number of joint ventures and PSAs, operator and manager of peripheral activities.

does not spend more than is strictly necessary to manage its affairs in an efficient manner. The URA should, however, have discretion to manage its budget and resources.

V-20. There are several mechanisms that could be applied to finance the URA's budget. These include: (i) State budget funding; (ii) earmarking taxes; (iii) the introduction of license fees for utilities; (iv) the introduction of a tariff surcharge on units of energy (each kWh of electricity and/or MCM of gas) purchased by consumers; or (v) making legislative provisions to exempt the URA from generally applicable constraints. In general it is preferable to fund regulatory agencies from fees rather than from budget sources since this promotes a greater degree of independence. As is indicated in Box V-5 such a practice is consistent with the actions of European countries that have recently decided to establish regulatory agencies.

Box V-5
Resources of Electricity Regulators in Southeastern Europe

	Budget Amount	**Budget Source**	**Budget Approval**	**Budget Schedule**
Albania	0.2 mil EURO	License fees, services and penalties	Under existing Law, the Government approves the annual budget; under the draft Law, Parliament approves the budget	Annual; under draft Law, ERE submits budget for approval to Council of Ministers no later than three months prior to the beginning of the next fiscal year.
Bosnia and Herzegovina	For SERC, the budget is estimated to be from approximately 613,000 to 701,000 Euro, depending on whether government facilities are provided or not. No amounts for the Entity regulators have been disclosed.	Fees; also, in the case of Entity regulators, grants.	Parliament	In the case of SERC, must be submitted by Dec. 1. In the case of the Entities, start of the budget year.
Bulgaria	1 mil Euro	EEEA: Council of Ministers approves SERC budget and receives budgetary reports by SERC (Art. 5 and 20). Draft law: SERC has: self-administered budget (Art. 10(1)); financed by fees and by the state budget (Art. 26(1)); and Council of Ministers approves level of fees (Art. 27(1)). Under EEEA version.	EEEA: National Assembly Draft law: Parliament, based upon proposal from the Council of Ministers.	Annual

	Budget Amount	Budget Source	Budget Approval	Budget Schedule
Croatia	For 2002: 2 million Euro allocated; 1.2 received for April-December term (term of CERC in office); the budget for 2003 has not yet been approved. The proposed figure is comparable, but may be significantly reduced.	.07% of the annual income of energy undertakings, fees imposed by CERC.	Government; CERC prepares its budget and plan of activities, then submits to Government.	Submit request to Government in November for following calendar year.
FYROM[65]	0.3 mil Euro	For 2003, from the government; thereafter from income fees and license fees of energy undertakings.	Parliament	Draft budget shall be proposed by ERC to Parliament no later than October 1st of each year. Budget must contain all expenditures of ERC, including salaries of the commissioners and staff.
Greece	4.4 mil Euro	RAE's budget is annexed to the budget of the Ministry of Development. The budget of RAE is collected through levies on electricity, gas and oil undertakings. The levies are determined by a common decision of the Minister of Development and the Minister of Economics.	RAE's budget is annexed to the budget of the Ministry of Development.	Annual
Romania	1.6 mil Euro	Tariffs and contributions from sector undertakings; in addition, ANRE may collect money for its budget from donors, legal and natural persons. ANRE is funded entirely from outside the state budget.	Ministry of Industry and Resources	"During the year" provide more information
Serbia and Montenegro	Serbia: For 2003 and 2004, 1 mil. Euro; for 2005, 1.2 mil. Euro. Montenegro: Not yet determined.	Serbia: For 2003 and 2004, from the European Agency for Reconstruction; for 2005, fees. Montenegro: Initially, from Government; thereafter from fees.	Serbia: National Assembly Montenegro: Regulator approves its own budget, but subject to annual reports to the Government, which must also be made available to the public.	Serbia: Not yet defined Montenegro: Regulator shall create a detailed budget by September 30th for the subsequent year and must submit the budget to the Government and make it available to the public in accordance to rules established by the regulator.

[65] Former Yugoslav Republic of Macedonia

	Budget Amount	Budget Source	Budget Approval	Budget Schedule
Turkey	4.3 mil Euro	Budget from license fees; publications and other revenues; grants from international organizations; 25% of administrative fines imposed; and transmission surcharges equal to 1% of the transmission tariff at most. Art. 10	The Energy Market Regulatory Board (EMRB) approves EMRA's budget. EMRA sends its annual report to the Ministry of Energy and is audited by a group of three inspectors, one from the Prime Minister's Inspection Board, one from the Prime Ministry's Higher Board of Audit and one from the Finance Ministry.	Regulator shall send by April 30, annual report for past financial year and shall be audited annually by Prime Minister's Higher Audit Board.
UNMIK[66]	Through the EU arm of UNMIK; not a separate budget. Budget for future regulator, not yet defined.	Not yet defined.	Not yet defined	Not yet defined

Source: "Regulatory Benchmarking Report" dated May 30, 2003, prepared for USAID by Pierce Atwood.

V-21. From an organizational perspective, the URA should be provided, by law, with the authority to establish its own hiring and human resources policies and practices. In addition, the URA should establish adequate compensation packages for its employees. Salaries should be comparable with the top salaries paid to staff of privately owned utilities that perform roughly equivalent work and/or have similar academic and experience requirements for their jobs. This is necessary since the URA would be in direct competition with utilities for competent staff and needs to attract better than average professionals.

V-22. URA decisions should be made in accordance with rules defined in the enabling legislation or in other normative acts and guidance set by official policy measures. The URA should operate without direct orders, advice or interference from the government. However, to ensure an appropriate balance between political concerns and discipline in the sector, the government could play a role in setting criteria and guidance within which the URA could operate. This could include: defining social objectives; participating in the formulation of technical and performance standards; permitting the use of technology and resources; recommending standards to the URA; and, laying down the principles and policy requirements for service production, transmission and distribution.

V-23. Procedures need to be developed for URA operations and their interaction with utility operators. Procedures should address enforcement mechanisms, dispute resolution and tariff review procedures, reporting requirements and the transparent application and public disclosure of decision making standards.

V-24. To ensure the effective functioning of the URA, it should be empowered to:

- Issue mandatory requirements for periodic reports to be submitted by the regulated companies on financial, statistical, accounting, technical and commercial information;

[66] United Nations Administration in Kosovo

- Request and receive any information that it considers necessary for regulatory purposes in a reasonable timeframe;

- Establish, for regulatory purposes, standard accounts to be used by regulated enterprises;

- Investigate any complaints or abuse, and potential changes to the industry structure;

- Impose penalties on utilities, up to a limit set by law, for non-compliance with applicable laws, decrees, resolutions or service standards;

- Order interconnections and access to transmission and distribution systems;

- Approve or disapprove mergers and acquisitions in the utility sector; and

- Preserve confidentiality of individual customer's financial data and of commercially sensitive information pertaining to the regulated entities.

V-25. A clear description of the process for application and issue of licenses for each utility function should be outlined. Typically, the URA would be responsible for the issue, modification, suspension, revocation and termination of licenses for utility services. In some cases these responsibilities are shared with a government agency that would be responsible for issuing licenses while the URA would be responsible for monitoring and enforcing their implementation.

To Improve Transparency and Accountability

V-26. To promote public acceptance of the URA, a transparent approach should be taken towards decision making and information disclosure which includes:

- The use of public hearings to elicit opinions from stakeholders on key issues such as proposed changes to rules and standards;

- Publication of records of decisions including supporting documentation, analysis and explanation;

- Public access to communications on pending matters;

- Public meetings where decisions are taken by a vote of the Commission members, with each Commission member having the opportunity to express their opinion. Commission members should also have the right to submit a written opinion, either concurring with the majority or dissenting from it;

- Public disclosure of information received or developed by the regulatory body at the request of any member of the public.

V-27. To ensure accountability, annual or biannual public reviews should be conducted of the URA's activities by legislative and executive authorities designated by law. The reviews should cover both external actions, such as tariff setting or establishing service standards, and internal actions such as staffing policies and the audit of the use of funds.

To Ensure Service Quality

V-28. Service quality is as important for consumers as prices. If standards of service fall but prices remain the same, customers are effectively suffering an increase in prices. In competitive industries, dissatisfied customers will then either demand lower prices or change suppliers. Customers of regulated monopolies, however, do not have the choice of seeking other suppliers. Regulators must, therefore, act to protect customers and set quality standards, monitor them and provide incentives for the regulated enterprises to comply with these standards through fines, discounts or rebates in billings to their customers in cases of non-compliance with the minimum quality standards. This is particularly important as the sector moves towards more market oriented practices and tariffs are set on the basis of efficiency incentives. Under these conditions, utilities could attempt to increase their profits by reducing operation and maintenance costs without due consideration of the possible effects on service quality.

V-29. At present, in Azerbaijan, documented performance standards for utility technical quality and customer service are not linked to a penalty regime[67]. While consumers may elect any supplier and force a supplier to assist with transmission costs[68] there is little consumer protection if services are poor; the only alternative, in theory, is to select a new supplier[69] although this is not, at present, a practical option.

Box V-6
Defining Service Quality in the Power sector

Service quality is grouped under three major categories: technical quality, commercial quality and reliability:

- Technical quality includes, but is not limited to, voltage and frequency levels.
- Commercial quality refers to transactions between the distribution company and its customers, for example, time to connect new customers, adequacy of billings and meter readings, and time to answer and provide solutions to complaints.
- Reliability is a measure of the ability of the distribution company to meet customer requirements for continuous electricity service, both in the short and long term, and is characterized by the number and duration of interruptions experienced by consumers. The most common measures are SAIFI, SAIDI, CAIDI and ASAI – see Box V-7.

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[67] Currently Azerenergy and Azerigaz apply and monitor their own standards. In the power sector some concession agreements contain some service quality provisions.
[68] The Law on Electrical Energy (Article 15)
[69] The Law on Electrical Energy (Article 8) and the Law on Energy (Article 17(3))

Box V-7
Reliability Indicators

SAIFI stands for System Average Interruption Frequency Index and measures the number of outages experienced by users. It is calculated by dividing the number of interrupted customers by the total number of customers served.

SAIDI stands for System Average Interruption Duration Index and provides a measure for the average time that customers are interrupted. It is calculated by dividing aggregated time that all customers were interrupted by the total number of customers.

CAIDI stands for Customer Average Interruption Duration Index and is a measure for the average time required to restore service to the average customer per interruption. It is calculated by dividing the total interruption duration by the total number of interruptions.

ASAI stands for Average System Availability Index. It is derived from the ***SAIDI*** according to the formula:

$$\frac{1\text{-SAIDI}}{8760}$$

V-30. Target service quality indicators should be established both for the system as a whole and for individual customers. The program should distinguish between rural areas, small towns and large cities and should provide a reasonable timeframe for compliance. Compliance would be the responsibility of the distributors. However, to protect the distributors, the URA should also establish standards of service quality for transmission operators, with rebates or fines being provided to their customers (generators and distributors). Bi-lateral contracts between distributors and generators could be employed to compensate distributors for rebates or fines for which they may be liable due to the failure of generators to perform in line with contractual agreements.

V-31. The URA should also develop targets to regulate losses and to allocate the benefits of loss reductions amongst the distributors and their consumers. This could be done through benchmarking or other means. Distribution companies should be allowed to meet or exceed those targets through optimizing operational, maintenance and investment expenditures. Utilities should be able to capture efficiency gains derived from exceeding the targets. If the targets are not met, consumers should not bear the cost of inadequate management.

To promote competition

V-32. The URA should have powers to encourage competition and prevent anti-competitive behavior. To achieve this, a number of basic principles apply:

- *Full legal separation of monopoly activities* **-** With full legal separation, competitors know that monopolies do not gain from treating any one company differently from any other company. Full legal separation could be achieved in two stages, starting with separation within the company and extensive powers for the URA, followed by the full de-merger of shareholder interests. Many of the provisions to protect third parties could be dismantled once full separation is achieved – and this is one of the reasons companies may decide to de-merge of their own accord (e.g. British Gas in the UK).

- *Separate monopoly activities from all other activities* **-** If full legal separation does not exist there would need to be strong institutional separation including a compliance team with full powers to investigate complaints that is appointed by the URA and reports to the URA and to third parties. There would also need to be full and accurate published accounts on all the activities of the monopoly services allocated in fine detail to cover all the activities of the company. Third parties would need protection, backed up by regulatory powers, to police and punish any discrimination exhibited by the monopolist.

- *Pricing* **-** The URA is required to provide the same kind of impetus that in other industries is provided by competition. The URA would need to set overall price controls to ensure that too much money is not raised from customers and to provide incentives for productivity improvements and appropriate investment. Having set the overall level of prices/revenues, the URA would need to have a clear strategy for ensuring prices are fair between consumers. This can be done in a number of ways, and would normally be a result of extensive consultation with the industry, consumers and other interested organizations. Access to good quality information would be essential.

- *Investment* **-** Third parties should be able to request access to any service they need to supply their customers. The URA should be able to ensure that access would be provided within a reasonable time frame and at a reasonable cost. Only when there is competition in potential provision of a service can the requirement for reasonable access be dropped.

Conclusion

V-33. Establishment of a solid legislative framework and an effective regulatory function is essential to the long term viability of the utility service sectors in Azerbaijan. The government's decision to establish a regulatory agency is very positive, but it is important that the structure of the agency and its assigned roles and responsibilities conform to good international practice and that its function is rooted in solid legislation.

VI - Energy and the Environment in Azerbaijan

Summary

VI-i. While Azerbaijan is endowed with a significant hydrocarbon resource base that offers substantial wealth generation potential, it also inherited a legacy of extensive environmental problems related to more than 100 years of oil production. In addition to the problems associated with oil contamination, increasing concerns are emerging related to emissions and to air quality that relate to the consumption of polluting fuels and to flaring and venting of natural gas.

VI-ii. At the time the proposals for IFC and EBRD financing of the Baku Tbilisi Ceyhan (BTC) pipeline and the Azeri Chirag Guneshli (ACG) Phase 1 field development were being taken to the two institutions' respective Boards, a number of questions were raised by shareholders of these institutions concerning the need for a program to address the legacy environmental problems. This underscores the perception outside Azerbaijan that the country should give considerable priority to dealing with energy related environmental issues. A proactive and aggressive stance on the part of the government to deal with these issues will enhance perceptions internationally that Azerbaijan is a responsible global citizen and will likely translate into an improvement in the overall climate for foreign investment.

VI-iii. The immediate challenges facing Azerbaijan are (i) to ensure that environmental standards that conform to best international practice are implemented and monitored throughout the energy sector; (ii) to develop and implement a mitigation plan to address the legacy of oil related contamination; (iii) to reduce the incidence of indoor air pollution related to consumption of polluting fuels; and (iv) to reduce and ultimately eliminate flaring and venting of natural gas.

VI-iv. The conclusions and recommendations of this section may briefly be summarized as follows:

- Azerbaijan has demonstrated a commitment, in principle, to environmental protection by ratifying a wide range of international environmental conventions. However, the country has yet to implement the programs required to conform to these conventions. A comprehensive environmental strategy that prioritizes environmental mitigation and investment needs for the energy sector should be developed as a matter of urgency and should be accompanied by the provision of budget funds to support implementation.

- The framework of environmental legislation is a mixture of new and old approaches and important components are missing. A gap analysis of Azerbaijan's environmental legislation and standards is underway. Once complete, a time bound action plan should be prepared to develop and implement measures to deal with the identified gaps.

- Onshore oil contamination affects a region of about 100 square kilometers and is one of the most serious examples of environmental degradation in the country. There is an urgent need to address these legacy environmental problems. Development and implementation of a program to address these problems should, therefore, be accorded high priority. Land prices have been rapidly increasing, particularly around Baku where almost 7,000 hectares of land are contaminated. As a result, there is potential to generate significant funds from the clean up and redeployment of this land and the funds generated could well be more than sufficient to finance the entire clean up program. The proceeds from land sales and redeployment could be supplemented by the reclamation of oil and steel as part of the clean up process. In this regard, the government should be cognizant of the fact that the current high oil price environment, together with the appreciation in land values, has created a window of opportunity to attract private sector participants to assist with remediation measures, thereby reducing the net cost of the clean up. Such a program, which could extend over a ten year timeframe, also has the potential to create new job opportunities, some of which could be used to mitigate the impact of rationalizing SOCAR's heavily over-staffed workforce.

- Deterioration of the gas sector infrastructure over the last 12 years has led to a significant reduction in the availability of gas to households, particularly in rural areas. As a result many households have switched to more polluting fuels. In mountainous areas households near forests have typically switched to fuel wood creating a problem of de-forestation as well as significantly increasing indoor pollution with its consequent health risks. In order to address this problem, a review is required of potential energy options for areas at high risk of de-forestation or loss of vegetation as a result of their use as fuel. This should be accompanied by the establishment and implementation of sustainable wood cultivation and forest management practices and consideration should be given to the introduction of participatory forest management programs.

- Approximately 1 billion cubic meters (BCM) of natural gas is being flared and an unknown quantity of gas is being vented as a result of leaks in the gas transmission and distribution systems. Flaring and venting of natural gas not only constitutes a waste of a valuable resource, it also has negative environmental connotations in terms of air quality and emissions. A portion of the existing gas flaring (about 0.3 BCM) will be eliminated once the Phase 1 development of ACG comes on stream. A further 0.3 BCM could be eliminated through an investment of about US$ 60 million to gather associated gas in shallow water Guneshli. Given the current price level associated with gas imports such an investment could pay out in less than four years and could also be eligible for concessional financing. In order to address the venting problem, investment for the rehabilitation of the transmission and distribution pipeline systems will be required.

Energy and the Environment in Azerbaijan

VI-1. While Azerbaijan inherited a significant hydrocarbon resource base and an extensive energy infrastructure, it also inherited a legacy of environmental problems related to more than 100 years of oil production. This environmental degradation affects more than one percent of the total land area.

VI-2. The contamination associated with oil operations is the most visible evidence of Azerbaijan's hydrocarbon related environmental problems. There are, however, increasing concerns related to emissions and to air quality that are related to gas operations both directly and indirectly and to the growing inefficiencies in the energy sector overall.

VI-3. Azerbaijan, therefore, faces several immediate challenges in addressing energy related environmental issues:

i. To ensure that environmental standards that conform to best international practice are implemented and monitored throughout the energy sector;
ii. To develop and implement a mitigation plan to address the legacy of oil related contamination;
iii. To reduce the incidence of indoor air pollution related to consumption of polluting fuels; and
iv. To reduce and ultimately eliminate flaring and venting of natural gas.

Ensuring the Implementation and Monitoring of Appropriate Environmental Standards

VI-4. The overarching law providing the basis for environmental legislation in Azerbaijan is the Law on the Protection of the Environment (adopted August 1999). Under this law responsibility rests with the State to set, monitor and control environmental standards. Consistent with other economies in transition, the legal framework is presently a mixture of new and old approaches and many regulations and by-laws that are important for implementation of environmental legislation are lacking. A gap analysis of Azerbaijan's environmental legislation and standards has therefore been initiated through the World Bank's Urgent Environmental Investment Project (with support from a PHRD grant) to support the Government's efforts to align national laws and standards with international best practice and to identify gaps in the implementation of existing legislation. Once completed, a time bound action plan will need to be developed to prioritize actions identified through the gap analysis and to identify and allocate resources and responsibilities for their implementation.

VI-5. Environmental protection is recognized as being important and actions to improve Azerbaijan's environmental performance have been identified through: (i) the National Environmental Action Plan developed in 1998; and (ii) the National Program on Environmentally Sustainable Socio-economic Development developed in 2003.

Amongst other items these plans include actions to mitigate the impact of the energy sector on the environment.

Box VI-1
Actions Required to Mitigate the Impact of the Energy Sector on the Environment

National Program on Environmentally Sustainable Socio-Economic Development

This program covers the period 2003 to 2010 and includes actions to mitigate the impact of the energy sector on the environment, including:

i. The introduction of highly efficient technologies at thermal power plants;
ii. The promotion of modern energy saving technologies in both the production and non-production sectors;
iii. The development and implementation of national and regional programs aimed at demand management; and
iv. The better use of renewable energy sources (hydro, wind and solar energy, biogas) in rural areas.

VI-6. In parallel, Azerbaijan has ratified a number of international conventions (see Attachment VI-1) and has been harmonizing environmental legislation with international laws and conventions, an example being the new Law on Air Protection under which ambient standards will be aligned with WHO Guidelines.

VI-7. That being said, funding for implementation of these programs remains an issue. For example, the 1998 NEAP listed 46 items that required action, 33 of which were classified as top priority, requiring attention within a 1 to 2 year timeframe. Direct implementation costs for the NEAP were estimated as US$ 42.5 million over the planned timeframe of 1998 to 2003, or approximately 1% of State budget expenditure. However, by the end of 2003 only about 20% of activities had been completed due to a lack of financing and prioritization of actions[70]. A similar issue has the potential to arise for the National Program on Environmentally Sustainable Socio-economic Development. While this Program outlines a strategy covering 2003 to 2010 for the initial resolution of environmental concerns it lacks cost estimates or details of financing measures. Its implementation is therefore dependent on the ability to obtain financing from external sources.

VI-8. To minimize the risks and impacts of energy sector activities on the environment, a comprehensive environmental management strategy is needed for the sector that prioritizes environmental mitigation and investment needs. The strategy should take into account issues identified in the NEAP and the National Program on Environmentally Sustainable Socio-economic Development, as well as pollution (and liabilities) related to past practices and current sector operations. In the latter case, a program of environmental audit and monitoring would enable a better understanding to be gained of

[70] Completed items included the implementation of new legislation and most significantly the establishment of the Ministry of Ecology and Natural Resources (2001). At this point there has been insufficient progress on the clean up and prevention of pollution and the introduction of lower level normative acts for implementation of the general provisions of laws.

how well sector operations comply with existing legislation and apply environmental practices that are consistent with good international practice. Regular reporting and disclosure of environmental data and information related to the strategy and audit program would be essential to ensure transparency and to improve the investment climate.

VI-9. Funding has been, and is, an important issue and budget provisions would need to be made in relation to this strategy, as well as the allocation of accountability for its timely implementation. Consideration should be given as to how best to leverage external funds including those of the private sector to support investment needs. This could include the promotion of environmental investments in concession contracts, or the identification of projects for co-financing.

Establishing and Implementing a Program to Address Legacy Environmental Problems

VI-10. Azerbaijan's history as an oil producer stretches back into the late 19th century. Unfortunately, much of the development and production activity over this extended period paid little regard to consequential environmental damage. As a result, Azerbaijan has a legacy of oil related environmental problems characterized by extensive onshore oil contamination and the visual pollution associated with abandoned rigs.

VI-11. Onshore oil contamination affects a region of about 100 square kilometers (more than one percent of the land area) and is one of the most serious examples, and certainly the most visible, of environmental degradation in the country. Many oil field sites have also been used as unofficial waste disposal sites creating a secondary problem. The situation is most acute on the Apsheron Peninsula and in areas around Baku where almost 7,000 hectares of land are contaminated.

VI-12. Onshore oil contamination has been occurring since oil was first extracted on a commercial basis. Early oil field practices, such as the use of unlined storage ponds or occasionally free flowing wells, had high contamination potential. As has been noted, lack of investment for maintenance and technology upgrades have resulted in the level of contamination continuing to grow.

VI-13. Clearly an immediate priority is to bring all current operating practices in line with good international practice. However, there is an increasingly urgent need to develop and implement a program to address the legacy of environmental problems.

VI-14. At the time the proposals for IFC and EBRD financing of the Baku Tbilisi Ceyhan (BTC) pipeline and the Azeri Chirag Guneshli (ACG) Phase 1 field development were being taken to the two institutions' respective Boards, a number of questions were raised by shareholders of these institutions concerning the need for a program to address the legacy environmental problems. The level of interest in this issue underscores the increasing concern about this legacy on the part of both donors and potential investors.

Consequently, it will be very much in Azerbaijan's interest to develop and implement a program to address these problems.

VI-15. Three other factors are also of immediate relevance. First, land values in Azerbaijan and, in particular on the Apsheron Peninsula have been rapidly increasing creating the potential to generate significant funds as a result of clean up and redeployment of contaminated land[71]. Second, funds can also be generated from the reclamation of oil and steel as part of the clean up process. The current high oil price environment makes the prospect of oil reclamation particularly attractive and this, coupled with the appreciation in land values, provides a possible window of opportunity to attract private sector participants to assist with remediation measures and there is the associated potential to reduce and potentially eliminate the net cost of clean up. Third, Azerbaijan is faced with a need both to rationalize the work force in its heavily over-staffed state oil and gas company SOCAR and to create new job opportunities. Elements of the environmental clean up will be relatively labor intensive and will, therefore, provide an opportunity both to re-deploy some of SOCAR's existing workforce as well as provide some new job opportunities.

VI-16. Some work has been undertaken to address the issue of onshore oil contamination. In 1999-2000, an EU TACIS funded project tested local clean up technologies. The project included the establishment of a small laboratory to test contaminated soil samples. Also, an ongoing World Bank funded project is designed to demonstrate the clean up of lands contaminated by mercury and oil.

VI-17. In 1988-1989, a detailed study was conducted of the nature and extent of oil contamination. A map of oil contamination was developed and an inventory of contaminated lakes was completed. While this provides an analytical base, further work will be required to update the study and to classify the nature of contamination. This, in turn, will allow the government to assess the extent of the clean up requirements and prioritize areas for clean up. This additional work, therefore, represents a priority action item.

VI-18. Another issue that requires early resolution is the assignment of both liability for past contamination and responsibilities for effecting the cleanup. Although SOCAR has legal responsibility for the land, the land pollution in many of these sites was generated as a result of practices that occurred prior to SOCAR assuming this legal responsibility. Land for oil production is currently assigned to SOCAR and is handed back to local authorities when operations cease and clean up is complete. In the interim, SOCAR pays compensation for land which is not used for oil production but is unavailable for other uses such as agriculture or construction as a result of its condition.

VI-19. SOCAR is the logical choice to oversee the clean up since it has knowledge and understanding of the sites, technologies and oil field chemistry. Consistent with normal

[71] The clean up program should, of course, not be limited to areas where significant additional value can be attained (such as on the Apsheron Peninsula) but should be designed to address the legacy of environmental problems throughout the country.

industry practice when assets are transferred, however, SOCAR should not be required to assume the full financial responsibility for cleaning up land that was polluted when assigned to SOCAR. (Conversely, of course, SOCAR should assume the financial responsibility to clean up any pollution it caused). Budget provisions will, therefore, likely be required to cover the costs associated with this exercise

VI-20. Cost assessments for the clean up of polluted land are still very preliminary, although some estimates suggest a cost level on the order of $100 million, assuming a clean up program that extends over ten years. It should be cautioned, however, that these estimates are very rough, reflecting experience elsewhere. A more refined estimate will require verification on the basis of site specific information. As has been noted, it should be possible to mitigate a portion, and perhaps all of these costs through the sale of cleaned up land and through reclamation programs involving the sale of scrap steel from abandoned rigs and the sale of oil recovered from polluted soils and ponds. If the budget takes on the responsibility to cover the cost of the cleanup, the budget should also be the beneficiary of any reclamation proceeds.

VI-21. A number of private firms in the US and elsewhere have made a successful business of managing the environmental clean up of polluted oil facilities, covering the costs and securing a profit through reclamation programs. In the current high oil price environment, it is possible that private sector interests may be prepared to manage the clean up of certain sites with no cost to the budget. Contaminated land is conservatively estimated to include 2 million tons of crude oil components. Even though a large proportion of this oil could be unrecoverable or unusable, at today's oil prices this represents a significant financial resource. The government, either directly or through SOCAR, would benefit from soliciting expressions of interest to manage environmental clean up activities. This would serve as input into development of a program, but final decisions on the inclusion of any such enterprises would have to await an overall assessment of the best way to implement the entire program.

VI-22. Clean up activities can be broadly grouped into those that will require significant technology but are not particularly labor intensive (e.g. some forms of land reclamation) and those that are relatively labor intensive (e.g. dismantling abandoned rigs). The more labor intensive activities represent an opportunity for SOCAR to re-deploy a portion of its workforce and reduce the overall workforce rationalization requirement.

VI-23. Development and implementation of a program to mitigate the legacy of environmental problems will have to move forward in phases. The key actions are briefly outlined in Table VI-1 below.

VI-24. The first two phases of the program are likely to take up to two years. It would, therefore, be desirable to initiate work as soon as possible.

Table VI-1
The Phased Development of an Environmental Mitigation Program

Phase	Analysis	Implementation	Financing
Current Status	A 1988/89 map of oil contamination was developed and an inventory of contaminated lakes was completed.	Pilot projects funded by EU TACIS (1999/2000) and the World Bank (ongoing) have been implemented.	No serious discussion has taken place regarding financing for an environmental mitigation program.
Phase	**Analysis**	**Implementation**	**Financing**
Phase 1	Update the 1988/89 study. Establish clean up priorities and refine clean up cost estimates.	Solicit expressions of interest from private contractors in participating in the clean up	Clarify relative liabilities and responsibilities for the clean up and identify potential sources of funding.
Phase 2		Establish and make public a specific time bound program for the clean up. Initiate contractor hiring.	Make specific financing provisions including provisions in the budget. Initiate a program to recover clean up costs through land sales and reclamation of oil and steel.
Phase 3		Implement the clean up program. Monitor performance against the established program and make the results public.	

Reducing Indoor Air Pollution

VI-25. Since independence, Azerbaijan's extensive gas transmission and distribution network has suffered significant deterioration and this, in turn, has led to a significant decrease in gas supplies to rural areas. Prior to 1991, approximately 80% of rural households were connected to the gas grid. It is currently estimated that less than 50% of rural households still have access to gas through the grid and availability of gas to these households is not consistently reliable. Faced with a reduced access or no access to gas, many households have switched to more polluting fuels.

VI-26. In mountainous areas, households near forests have typically switched to fuel wood and this is often associated with illegal wood cutting. These households generally burn the wood in low efficiency stoves. This, in turn, has resulted in a significant increase in indoor pollution. Indoor pollution associated with wood burning is linked to a number of health concerns, particularly of a respiratory nature.

VI-27. The current demand for fuel wood is also estimated to exceed sustainable annual yields for Azerbaijan's forests. As a result, mountain valleys are suffering the effects of deforestation and erosion, a drastic reduction in forest areas and fauna and the eradication of some plant species[72].

VI-28. Tariffs for power and gas need to be increased if they are to cover the economic cost of these energy supplies. However, such increases also raise the prospect of a further increase in the use of wood for heating with a consequent adverse impact on both health and the environment. Areas most at risk from increased wood usage related to increases in power and gas tariffs have been assessed in the recent Poverty and Social Impact Analysis (PSIA) undertaken by the Bank and include Gusar and Khachmaz in the north and Yardymly and Jalilabad in the south (see Attachment VI-2).

VI-29. In order to address these concerns, a series of parallel measures are required:

i. A review should be conducted of potential energy options for areas at high risk of deforestation or loss of vegetation as a result of utility price increases. Energy solutions could vary from place to place and could include improvements in existing energy services or the promotion of other alternate energy resources. In all cases they would need to be cost effective and sustainable and take into account the level of poverty, climatic conditions and the availability of resources and facilities to deliver energy supplies. Solutions could deal with both the issue of supply (considering both existing and potential supply options) and demand (for example, the provision of high efficiency stoves and other energy efficiency measures).

ii. Sustainable wood cultivation and forest management practices should be established and implemented, with priority of implementation given to those areas at highest risk of increased deforestation due to proposed utility tariff reforms (see Attachment 1).

iii. The introduction of participatory forest management programs should be considered. With the development of local level forest management plans, the transparency of transactions related to resource use and pricing could be improved and measures could be introduced to manage cutting and reforestation, as well as supervision, monitoring and enforcement of good forest management practices.

Reducing and Ultimately Eliminating Venting and Flaring of Natural Gas

VI-30. Flaring and venting of natural gas not only constitutes a waste of a valuable resource, it also has negative environmental connotations in terms of air quality and emissions. Approximately 1 billion cubic meters (BCM) of gas is currently being flared annually in Azerbaijan. SOCAR contributes about 0.7 BCM of this amount with about half being associated with operations in shallow water Guneshli and the remainder associated with operations in several smaller onshore locations. The balance of the flaring, approximately 0.3 BCM, is attributable to the Early Oil phase of the AIOC Consortium's development of Azeri, Chirag, Guneshli (ACG). In addition, an

[72] The Ministry of Ecology has estimated that 41,110 cubic meters of forest was damaged in 2003.

indeterminate amount of gas is vented as a result of problems with the integrity of the gas transmission and distribution systems.

VI-31. The ACG Consortium anticipates eliminating flaring from its existing facilities in the 2005/2006 timeframe concurrent with the implementation of Phase 1 development of ACG. However, full field development will ultimately produce about 6.2 BCM per year (at the peak) of additional associated gas. The ACG Consortium plans to install compression facilities so that this gas can be piped onshore where, under the terms of the PSA, it accrues to the benefit of the State. However, investments will also be required for the pipeline to transport the gas onshore, to expand the gas processing facilities and to upgrade and rehabilitate the gas storage facilities in order to handle these increments of associated gas. Preliminary estimates suggest a capital investment requirement on the order of $200 million. Given the cost of alternative gas supplies which are currently priced at the border at $60 per thousand cubic meters, the required investments can clearly be justified.

V-32. SOCAR has also developed a preliminary plan to eliminate the gas flaring associated with operations in shallow water Guneshli. This would result in a reduction of about 0.3 BCM per year of flared gas at an investment cost estimated at $60 million. Again, given the substitution of this gathered gas for imported gas, the project would offer a reasonably quick payout. A project designed to reduce gas flaring such as this could also be eligible for some grant and/or concessionary funding from such sources as the Prototype Carbon Fund administered by the World Bank.

Attachment VI-1
Status of Ratification of Selected Multilateral Environmental Agreements

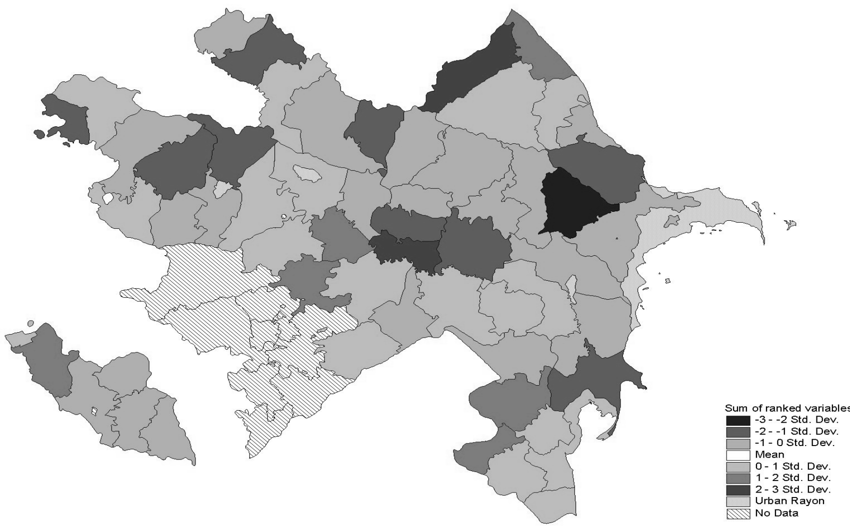
Agreement	Azerbaijan	Armenia	Georgia	Kazakhstan	Russia	Tajikistan	Turkmenistan	Uzbekistan
Framework Convention on Climate Change (1992)	Y	Y	Y	Y	Y	Y	Y	Y
Kyoto Protocol (1997)	Y	Y	Y	S	S	-	Y	Y
Paris Convention to Combat Desertification (1994)	Y	Y	Y	Y	Y	Y	Y	Y
Vienna Convention for the Protection of the Ozone Layer (1985)	Y	Y	Y	Y	Y	Y	Y	Y
Montreal Protocol on Substances that Deplete the Ozone Layer (1987)	Y	Y	Y	Y	Y	Y	Y	Y
Basel Convention on the Control of Transboundary Movements of Hazardous Waste and their Disposal (1989)	Y	Y	Y	Y	Y	-	Y	Y
Rotterdam Convention on the Prior Informed Consent Procedure for Hazardous Chemicals and Pesticides in International Trade (1998)	-	Y	-	-	-	S	-	-
Rio Convention on Biological Diversity (1992)	Y	Y	Y	Y	Y	Y	Y	Y
Cartagena Protocol on Biosafety (2000)	-	Y	-	-	-	Y	-	-
Ramsar Convention on Wetlands of International Importance Especially as Waterfowl Habitat (1971)	P	P	P	-	P	P	-	P
Paris Convention on the Protection of World Cultural and Natural Heritage (1972)	Y	S	S	Y	Y	S	S	S
Espoo Convention on EIA in a Transboundary Context (1991)	Y	Y	-	Y	S	-	-	-
Aarhus Convention on Access to Information, Public Participation in Decision Making and Access to Justice in Environmental Matters (1998)	Y	Y	Y	Y	-	-	Y	-
Stockholm Convention on Persistent Organic Pollutants (2004)	Y	Y	S	S	S	S	-	-

Y = Accession/Acceptance/Approval/Ratification; P = Party; S = Signed

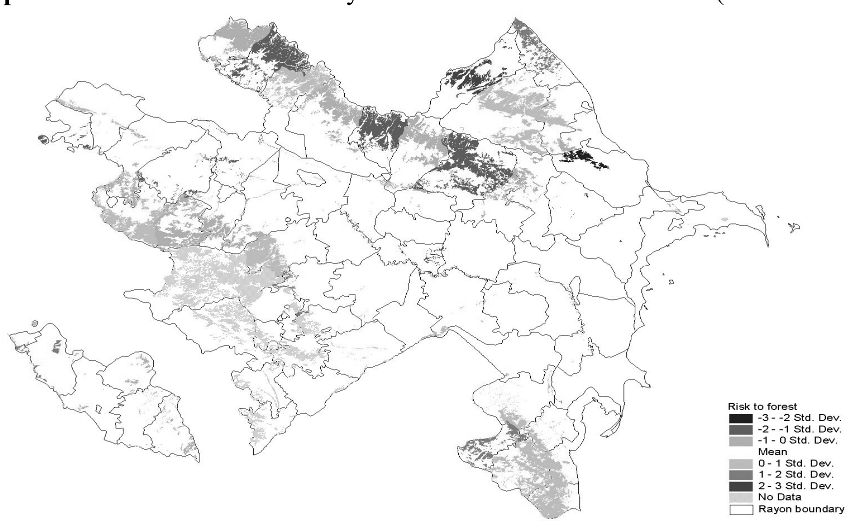
Attachment VI-2
Areas at Risk of Deforestation as a Result of Utility Tariff Increases

The risk of deforestation as a result of tariff increases in the power sector has been assessed in the recent PSIA for Azerbaijan. The analysis has been based on: (i) residential wood consumption; (ii) poverty; (iii) access to gas; (iv) access to forests; (v) proximity of population to forests. The study concludes that Gusar in the Northeast and Zardab in the center of Azerbaijan are at greatest risk of increased residential wood use when tariff levels rise (Map 1). They are also potentially at greatest risk from indoor air pollution associated with wood burning. Where there is no forest cover, such as Zardab, Map 1 demonstrates where total vegetation cover (including peri-urban trees, tree lined alleys, tree-lined rivers and hedgerows) is threatened by increased wood use. When Map 1 is overlaid with the country's forest resources this shows the forest areas at greatest risk (Map 2), i.e. Gusar and Khachmaz in the North and Yardymly and Jalilabad in the South.

Map 1: Risk of Increased Residential Wood Use is Likely to be Highest in Gusar and Zardab (dark red zones)



Map 2: Deforestation is Most Likely to Occur in the North and South (dark red zones)



Source: Poverty and Social Impact Analysis, Ex-Ante Evaluation of Residential Electricity Tariff Reform, Decision Draft, June 22, 2004, Europe and Central Asia Region.

Ref: Ex-Ante Evaluation of Residential Electricity Tariff Reform, June 22, 2004, The World Bank

VII - Social Issues in the Energy Sector in Azerbaijan

Summary

VII-i. The long term financial viability of the domestic power and gas sectors is predicated on improvements in collections levels and on an increase in tariffs to levels that are sufficient to recover costs in the sector. At present, residential customers, who are the most costly to supply, benefit from the lowest tariff levels. Consequently, they will ultimately have to be subject to a greater level of tariff increases than other customer categories.

VII-ii. Under ideal circumstances, a targeted, fully functioning social safety net should be in place before utility tariffs to residential customers should be increased. However, in the absence of such a safety net, tariffs can still be increased with only limited adverse social consequences if the population is able to afford the increases.

VII-iii. This section discusses the issue of the affordability of energy utility services. It also discusses the need to establish an effective social safety net along with some of the options that need to be addressed. The conclusions and recommendations of this section may briefly be summarized as follows:

- There has been a significant growth in economic activity and in incomes of the population over the last few years. Old age pensions were raised by 41,000 AZM/month (approximately $8) in 2003; public sector employees received an average 30% wage increase in 2003 and an additional 30% increase in January, 2004; and the minimum wage was increased by 40,000 AZM/month (approximately $8) in July, 2004. Estimates of the potential impact of electricity tariff increases suggest that the average income loss from a 50% tariff increase in Baku is just under AZM 10,000/month (approximately $2). Since the increase in the minimum wage that took place in July, 2004 and the increase in old age pensions that took place in 2003 were both about four times the size of the likely impact of a 50% increase in electricity tariffs, such an increase should be affordable.

- Within the context of the discussion on the affordability of utility services, it is worth noting that, based on data from the 2002 household survey it appears that, on average, households spent only 5.8% of their consumption expenditures on housing and utilities. This ranks among the lowest percentage rates in the region.

- Electricity supply to residents in Baku is metered. In much of the country, however, there is no metering and norms are used to calculate billings for electricity use. A comparison, however, of these norms with consumption levels in areas which are metered (Baku and Sumgayit) suggests that these norms may be disproportionately high. Consequently, in conjunction with tariff increases to households it would be appropriate to revise some (and possibly all) of the norms downwards to provide a more accurate reflection of what is actually being consumed. Such revisions should be preceded by some pilot programs using meters to obtain validating data on

consumption levels in each region. A downward revision in the norms would help mitigate the impact of higher unit tariffs.

- In the case of gas, norms are more widely used and an analysis of their accuracy should also be undertaken.

- While it appears the population should be able to afford some increases in utility tariff levels, it is important that work continue on refining and improving the social protection system. The first priority should be to strengthen the current social safety system. The draft Law on Targeted Social Assistance anticipates the introduction of a means tested family poverty benefit which could be supported in the short term by selective adjustments to the existing network of social assistance payments (or categorical benefits) to support some of the more vulnerable groups.

- In the longer term, the upgraded social safety system should be reviewed for adequacy and an assessment made of the benefit or need for a parallel scheme to focus specifically on addressing the impact of utility tariffs. An integrated approach should be taken to ensure that tariff adjustments do not collectively overburden vulnerable households.

- Regardless of the chosen tariff scheme, non payments represent a significant hurdle to sustainable cost recovery. A mechanism should, therefore, be established to track and evaluate non payments as an integral component of the regulation of the sector.

VII - Social Issues in the Energy Sector in Azerbaijan

VII-1. At present, both the domestic power sector and the domestic gas sector fall well short of covering their financial needs. As is indicated in Table VII-1, in 2002 the combination of non payments, tariffs below full cost recovery levels and excess losses resulted in the power sector recovering only 17% of its costs and the gas sector recovering only 30%.

Table VII-1
Financial Performance of the Power and Gas Sectors – 2002

Commodity	Excess Losses %	Collections %	Weighted Average Tariff	Average Receipt	Average Cost Recovery Price	% of Cost Recovery
Electricity (Usc/kWh)	2.03	34.0	1.90	0.65	3.80	17.1
Gas (US$/MCM)	2.00	47.0	19.00	8.93	30.00	29.8

Source: World Bank analysis

VII-2. The government is cognizant of these problems and has, appropriately, placed priority emphasis on addressing the non payments problem. However, the longer term financial viability of the domestic power and gas sectors will be dependent on both an improvement in collections performance and an increase in tariffs to full cost recovery levels. In considering tariff increases, the issue of an appropriate balance of tariff levels will have to be addressed. At present, residential customers, who are the most costly to supply, benefit from the lowest tariff levels (see Table VII-2 below). This means that residential customers will ultimately be subject to a greater level of tariff increases than other customer categories. This, in turn, raises the issues of the affordability of these services and the need for a social safety net.

Table VII-2
Electricity and Gas Tariffs – 2004[73]

Customer Category	Electricity AZM/kWh		Gas AZM/MCM	
	w/o VAT	with VAT	w/o VAT	with VAT
Residential	96	96	68,644	81,000
Budget/Utilities/SOEs	130	153	200,000	236,000
Commercial	250	295	200,000	236,000
Weighted Average		110		
Memo: Wholesale Price	71	84	73,000 82,000	82,000 96,760
Average Cost Recovery Price	186	219	198,832[74]	234,622

[73] Gas tariffs were increased on November 2nd 2004. The prices shown are the post November 2nd prices. The wholesale gas prices apply to treated (73,000) and untreated (82,000) gas.

[74] This price covers operating costs only (SOCAR's costs for supplying gas are assumed to average 156,832 AZM/MCM ($32/MCM)), it does not provide funds to cover investment requirements (estimated as a 46,000 AZM/MCM increment). It should also be noted that the import price for gas, at the border is $52/MCM or 254,852 AZM. The tariff should ultimately be brought up to a level that covers import costs and domestic transmission and distribution costs.

The Affordability of Higher Priced Electricity and Gas

VII-3. Under ideal circumstances, a targeted fully functioning social safety net should be in place before tariffs to residential customers are increased. However, in the absence of such a safety net tariffs can still be increased with only limited adverse social consequences if the population is able to afford the increases. The high rates of economic growth in Azerbaijan coupled with the increases in the incomes of the population suggest that some fairly substantial tariff increases would be affordable.

VII-4. By all macroeconomic indicators, the country enjoys one of the highest rates of economic growth in the region and perhaps even the world. Economic recovery started in 1996 and, in the past six years, GDP growth rates have been close to, or in excess of, double-digit figures. However, growth is concentrated in only a few sectors of the economy, particularly the oil and gas sector, and, in recent years, also in agriculture[75]. The mono-structural nature of the economy is readily evident when considering the GDP. For example, in 2002, the oil sector accounted for about 30 percent of GDP, but only one percent of employment.

Table VII-3
Azerbaijan: Real GDP and Consumer Prices (Annual percentage change)

	1998	1999	2000	2001	2002	2003	2004*
Real GDP	10.0	7.4	11.1	9.0	10.6	11.2	9.1
CPI	-1	-9	1.8	1.5	2.8	2.7	2.5

* - estimate
Source: IMF World Economic Outlook, relevant years; National Bank of Azerbaijan (www.nba.az).

Table VII-4
Azerbaijan: Macroeconomic Indicators

	2001	2002	2003
GDP, % of increase	9.9	10.2	11.2
Volume of industry production, % of increase	5.1	3.6	6.1
Volume of agriculture production, % of increase	11.1	6.4	5.6
Population money income, % of increase	10.4	11.4	11.4
Nominal average monthly wage (1000' manat)	260.0	312.9	383.1
Wage increase, compared with the same period of previous year	26.7	21.2	21.4
CPI, %, December to December	101.3	103.3	103.6

Source: National Bank of Azerbaijan (www.nba.az).

VII-5. Average monthly wage increases have outpaced GDP and labor productivity growth. In each of 2001, 2002 and 2003 reported average nominal wages increased more than 20% annually. Over the past three years the monetary income of the population has increased by between 10% and 11% per annum.

VII-6. In 2003 and 2004, the Government took measures to increase significantly the incomes of members of the population financed through the State budget. In particular, old age pensions were raised on average from AZM 92,200 in 2002 to AZM 133,000 in

[75] This is directly related to land reform which resulted in the allocation of small land plots to most of the rural population who are considered, under the Law on Employment, to be employed.

2003. The long-awaited reform of the public pay system resulted in a 30% average wage increase for public sector employees in autumn 2003 and an additional 30% rise in January, 2004. The minimum wage also increased from AZM 60,000 to AZM 100,000 in July, 2004. Following the recommendations of the European Social Charter, the Government aims to bring the minimum salary in line with the minimum per capita poverty level (AZM 125,100 per capita per month).

VII-7. Between 1998 and 2002, the number of employed people of working age increased by 0.7%[76]. This was predominantly in the agricultural sector where employment increased by 35%. In contrast, employment in the industrial sector declined 20%. The informal economy is widespread[77] and about 34% of the employed workforce[78] is self employed. Earnings from employment represent about 40% of total household income, with the share being higher in urban areas (55%). The unemployment rate was estimated at 10.7% in 2003 (Labor Force Survey) which is considered to be around average for an economy in transition.

VII-8. Taking into account measures undertaken by the Government, as well as the rapid increase in real wages and other incomes, the number of people living in poverty has reduced. The number of Azeris below the poverty threshold of AZM 175,000[79] per capita per month was estimated at 46.7% in 2002[80]. During the same period approximately 10% of these were in extreme poverty, i.e. below the threshold of AZM 125,100 per capita per month[81]. Those below the poverty line are predominantly urban dwellers, with the largest concentration found in Baku. However, those in the extreme poverty category are almost exclusively urban dwellers in centers other than Baku.

Table VII-5
Azerbaijan: Consumer Price Index
(Compared with December of previous year, %)

Year	CPI, total	Food, beverages and tobacco	Non-food products, services	Non-food products	Food and non-food products	Services
1998	-7.6	-9.0	-2.1	-3.0	-8.2	-0.6
1999	-0.5	-2.0	2.5	0.0	-1.6	6.1
2000	2.2	4.0	-0.9	1.7	3.4	-4.4
2001	1.3	1.8	0.5	1.3	1.7	-0.6
2002	3.3	4.8	1.0	1.7	4.0	-0.1
2003	3.6	5.4	0.5	1.0	4.1	-0.3

Source: National Bank of Azerbaijan (www.nba.az).

VII-9. The CPI has remained relatively stable in recent years (see Table VII-5 above), increasing by two to three percentage points annually mostly due to rising food prices.

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[76] From 3.701 million to 3.727 million people
[77] Statistics register more than 3.7 million employed persons in the country but the State Social Protection Fund receives pension contributions from less than 1 million people in 2002.
[78] Based on the last census in 1999.
[79] Consumption expenditures per capita
[80] Based on the revised 2002 Household Budget Survey
[81] 70% of median per capita consumption expenditure

However prices and tariffs for services[82] have declined slightly. The latest information from the 2002 household survey shows that, on average, households spent 5.8% of their consumption expenditures on housing and utilities. This ranks among the lowest in the region[83].

VII-10.Estimates of the potential impact of electricity tariff increases suggest that the average income loss resulting from a 50% tariff increase in Baku is close to two dollars per household per month. Assuming a pre-tariff consumption level of 200 kWh, a price elasticity of demand of – 0.20, and 100 percent collection, then the upper bound on the income loss from a 50 percent tariff rise is US$ 1.95 (AZM 9,600) per month and the lower bound is US$ 1.76 (AZM 8,640)[84]. This is the amount of money that would have to be given to a household to make it no worse off than it was before the tariff increase. To reach cost recovery levels (for the residential customer) of 5 US cents per kWh or AZM 240, the income loss would be between US$ 4.1 and US$ 5.9 per month. Table VII-6 below summarizes the projected household income losses under alternative electricity tariff scenarios.

Table VII-6
Household Income Losses Under Alternative Electricity Tariff Scenarios

Elasticity 0.2

Increase in Tariffs	Tariff		Consumption	Income Loss (per month)			
(%)	(Manat)	(US$)	(kWh)	Max (US$)	Min (US$)	% of Min. Wage	% of Avg. Wage
0%	96	0.02	200	0	0	0	0
50%	144	0.03	180	2.0	1.8	15 - 16	2 - 3
100%	192	0.04	160	3.9	3.1	25 - 32	4 - 5
150%	240	0.05	140	5.9	4.1	34 - 48	5 - 8
200%	288	0.06	120	7.8	4.7	39 - 64	6 - 10

Source: World Bank (2004). Ex-Ante Evaluation of Residential Electricity Tariff Reform. Mimeo.
Note: Min. wage of 60,000 AZM per capita per month (January 2004); Average wage 383,100 AZM per capita per month (2003).

VII-11.This analysis suggests that an immediate increase in tariff levels of 50% would be affordable. However, as is discussed below, some other adjustments would also be appropriate in the case of households whose tariffs are calculated on the basis of norms which would mitigate the impact of higher unit tariff levels.

Quality of Service

VII-12.In an environment where infrastructure is deteriorating and quality of service is becoming increasingly problematic, non payment problems tend to increase and there is

[82] This includes housing and utility costs.
[83] This analysis was undertaken by the PRSP Strategy Working Group under the Ministry of Economic Development.
[84] Lower bound = manat 8,640 = (manat 144 - manat 96) x 180 kWh per month
Upper bound = manat 9,600= (manat 144 – manat 96) x 200 kWh per month

resistance to tariff increases. In effect, if standards of service fall but prices remain the same, customers are suffering an increase in prices. Such a deemed increase is compounded if tariffs rise while service declines.

VII-13.In Azerbaijan, while a large percentage of households are connected to the power and gas networks, the availability of services has not been continuous or consistent across regions and consumer satisfaction is low (see Table VII-7 below).

Table VII-7
Satisfaction with Municipal Energy Services

Type of service	% Households connected or using	% of using households who report permanent or near permanent supply	% of using households who believe strongly or very strongly that maintenance of the service is needed	% of using households who are dissatisfied or very dissatisfied with the service
Network electricity	100.0	48.6	39.6	48.6[1] / 53.2[2]
Network gas	87.9	81.5	10.6	42.0

[1] % of connected households who are dissatisfied or very dissatisfied with the duration of power supply;
[2] % of connected households who are dissatisfied or very dissatisfied with the power intensity;
Source: Azerbaijan Municipal Services Survey (AMSS)

VII-14.There are also distinct disparities in the quality of service depending on the location. Table VII-8 summarizes these disparities.

Table VII-8
Electricity Consumption and Service Quality Varies Widely by Location

Location	Billing method	Mean Household consumption (kWh per month)	Winter Supply (hours per day)	Summer Supply (hours per day)	Collection Rate (Payments/ Billing)
Ali-Bairamly	Norms	628	17	22	25%
Baku	Meters	265	24	24	63%
Ganja	Norms	n/a	10	22	n/a
Gosar	Norms	503	15	18	42%
Guba	Norms	n/a	9	15	n/a
Imishly	Norms	960	8	20	7%
Ismailly	Norms	n/a	18	21	n/a
Mingechevir	Norms	260	9	21	28%
Sabirabad	Norms	447	8	20	35%
Sumgayit	Meters	374	24	24	24%

Source: 2003 Household Energy Survey, (non-random), 2003 Barmek Records, 2003 Bayva records. In: World Bank (2004). Ex-Ante Evaluation of Residential Electricity Tariff Reform. Mimeo.

VII-15.One other feature in Table VII-8 that is interesting is the discrepancy between consumption levels where power is metered (in Baku and Sumgayit) and the deemed consumption associated with the use of norms which is considerably higher. While the use of meters creates incentives to conserve energy and thereby reduce consumption levels, certain of the norms appear disproportionately high. Consequently, in conjunction with tariff increases to households it would be appropriate to revise some (and possibly all) of the norms downwards to provide a more accurate reflection of what is actually being consumed. Such revisions should be preceded by some pilot programs using meters to obtain validating data on consumption levels in each region. A downward revision of norms would ensure that households are not charged for amounts of electricity significantly in excess of their consumption levels and would help mitigate the impact of higher unit tariffs.

VII-16. In the case of gas, norms are more widely used and an analysis of their accuracy should also be undertaken.

The Social Protection System

VII-17. While it would appear that the population should be able to afford some increases in utility tariff levels, it is important that work continue on refining and improving the social protection system so that the impact of tariff increases on the most vulnerable groups[85] can be fully mitigated in the future.

Table VII-9
The Efficiency of Selected Social Assistance Programs

	Coverage of the Poor[86]	**Leakage Towards the Non-poor**	
		Individuals	Benefits
	(%)	(%)	(%)
Social assistance,	44	47	39
Of which:			
Child allowances	39	47	44
Scholarships	6	31	31
Social Pension	4	44	43

Source: World Bank estimations based on the HBS 2002.

VII-18. The current social protection system is built on two components: (i) a mandatory social insurance system for old age, illness, disability and unemployment; and, (ii) non-contributory social assistance for categories of persons considered at risk or poor. A substantial amount - (between 5% and 6% of GDP) - has been redistributed through these programs every year from 1995 to 2002. According to SPPRED[87] documents, it is expected that over the coming three years, social protection expenditures will increase as a proportion of budgetary expenditures from 16% in 2002 to 18.6% in 2005; in other words, more resources will be spent on social protection. The 2002 Household Budget Survey shows that social benefits[88] are distributed almost equally across the expenditure

[85] Such as households with many children, single parent households, old people who live alone and have no support from relatives, and households with disabled and unemployed members.
[86] Coverage of the poor is the percentage of poor individuals that receive benefits from the program. Leakage toward the non-poor represents the share of funds that are captured by the non-poor.
[87] State Program on Poverty Reduction and Economic Development
[88] Excluding pensions

deciles. However, there is wide recognition that these programs are not adequately focused on those most in need (see Table VII-9). Most programs are based on flat rate allowances that are unrelated to the economic status of the recipient and, therefore, do not make a major contribution to poverty reduction. As such, the Government is pursuing an overall reform of its social assistance program.

VII-19. The fragmentation of assistance funds into multiple programs greatly reduces the efficacy of the overall safety net. Out of 35 benefits[89], only nine are higher than one tenth of the average monthly wage (more than AZM 35,000, or US$ 7 per month). For the vast majority of recipients, benefits are between 2% and 10% of the monthly average wage. Thus, in terms of adequacy (ratio of benefits to average household consumption, or to the monthly wage), most benefits fail to provide the needed assistance. In fact, administrative costs may hardly be justified for some of these benefits; such costs may outweigh the value of the benefit, reducing considerably the efficiency of the transfer. On the demand side, the take-up rate may possibly be low due to the private costs[90] associated with cashing in the benefits acting as a barrier for many households.

VII-20. To address these issues the government has outlined its social reform strategy in the State Program on Poverty Reduction and Economic Development (SPPRED). The SPPRED defines the Government's main task as "*to define an effective safety net strategy that will enhance the targeting efficiency, support the poorest and most vulnerable groups and will mitigate the impact of new public utility policies in the short-run*." The Government, with the help of the World Bank and other international donors (EU TACIS), is currently involved in the design of a new means tested and targeted family poverty benefit.

VII-21. To this end, in January 2004, a new draft Law on Targeted Social Assistance was submitted by the Inter-ministerial Working Group under the Ministry of Labor and Social Protection to the Cabinet of Ministers. Under this new law, social assistance would be rendered in the following ways: (i) cash payments (social benefits, compensations for utility services and other payments); and (ii) in kind assistance (food, fuel, clothes, medicine and other types of assistance). The draft law anticipates the introduction of an employment test[91] and an asset test[92].

VII-22. Other measures taken to reform the social assistance program include:

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[89] Nine can be classified as family and child benefits; eight benefits are pension and disability supplements, and sick leave payments; fourteen benefits are merit based; and four benefits support households in other occasions (funeral allowance; food allowance for IDPs, etc.).

[90] Such as the time spent queuing to get the benefit

[91] e.g., Able-bodied but unemployed citizens who are not registered with relevant executive authorities and who refuse suitable vacancies offered more than twice by these agency two times will not be entitled to targeted social assistance.

[92] e.g., an assessment of family property, however, the rules need to be developed.

- In 2002, the abolition of social privileges (discounts in prices and tariffs, mostly on housing and utilities) provided to 25 categories of citizens and their replacement with cash compensation to nine groups. [93]

- A commitment to raise utility tariffs to cover marginal costs by 2005 and to strengthen financial discipline in the energy sector, including the unconditional disconnection of households that fail to pay for services.

- The proposal to develop an employment program, supported by budgetary resources and institutional reforms, to create 600,000 new jobs between 2004 and 2008 (November 2003 Presidential Decree).

VII-23. The government's priority now should be to strengthen the current social safety system, particularly given the existing and significant institutional constraints. This would allow benefit targeting and coverage to be improved and expenditures to be rationalized while raising institutional capacity.

VII-24. The basic safety net is currently a fragmentation of programs offering low benefit levels spread among a large number of recipients. There is general consensus that most of these benefits need to be streamlined and consolidated, with benefits based on targeting and means testing principles. The draft Law on Targeted Social Assistance anticipates the introduction of a means tested family poverty benefit that would improve the efficiency of use of public funds and provide more equitable compensation for economic hardships that would accompany energy sector reforms. The government, with the help of the World Bank, is working on the improvement of current social assistance schemes to incorporate also the mitigation of the potential impact of utility tariff increases on living standards of the population. The government also proposes to adjust further its pension, wage and minimum wage policies in relation to necessary future price increases on utility services.

VII-25. The rapid growth in population incomes, together with the expected reduction in explicit and implicit subsidies to the energy and housing sectors, will enable selectivity to be increased in the application of social benefits financed by the State Social Protection Fund (SSPF) and the budget[94]. As an additional supporting short term and relatively easy intervention, the Government could use the existing network of social assistance payments (or categorical benefits) and selectively adjust them to support some of the more vulnerable groups from tariff increases. A review would need to be conducted to identify those groups most at risk.

VII-26. In the longer term, the upgraded social safety system should be reviewed for adequacy and an assessment should be made of the benefit or need for a parallel scheme

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[93] A few remaining social privileges cover public transport and pharmaceuticals for a very few categories of the population.

[94] Of 35 benefits (except pensions), 29 benefit payments are financed from the state budget. The State Social Protection Fund is heavily dependent on budgetary transfers. In 2003, 42.5 percent of the SSPF's budget came from the state budget.

to focus specifically on addressing the impact of utility tariffs. The design of a parallel scheme would be based, in part, upon the characteristics of the upgraded social safety system. It would also need to take into consideration the use of other specially designed policies and measures to mitigate the impact of tariff increases, such as life-line tariffs, subsidies to limit the burden placed by utility expenditures on household budgets (so-called notional burden approach), or earmarked cash transfers.

Table VII-10
Benefits and Shortcomings of Various Housing Subsidy Mechanisms

Mechanism	Benefits	Shortcomings
Notional burden approach	Benefits can be predicted with reasonable certainty; relatively low administration costs	Coverage and targeting of the poor is usually relatively low; there are heavy administrative burdens on the poor associated with its application; it is one of the most distortionary mechanisms of all utility subsidy mechanisms on the demand side; costly for the budget; a network of offices needed to administer the scheme.
Life-line tariffs	High coverage of the poor; targeting ratio improves as the size of the initial block decreases; the benefits received are highly predictable, especially through a two-block life-line tariff; the scheme is simple to administer.	Since the poor tend to be under-represented among those with utility connections, many would not benefit; it requires reliable (tamper-proof) metering or a reasonable proxy (such as apartment size for heating) to estimate consumption; disciplined meter readers/controllers are needed; there is a significant burden on the budget, on the finances of the utility, or on other (industrial) consumers (if the cost is recovered through a higher industrial tariff).
Other earmarked cash transfer	The targeting ratio is relatively high; the net financial burden on utilities is low.	Coverage of the poor as achieved by earmarked cash transfer schemes is highly uncertain, and in most surveyed countries was low; it is administratively demanding.
Non-earmarked cash transfers (Current Scheme in Azerbaijan)	Coverage depends on the ability and willingness of the poor to meet the eligibility criteria; it is the least distortionary of the utility subsidy mechanisms; there are no additional administrative requirements if a social assistance system is already in place; there is no financial burden for utilities or other (non-household) consumers.	The targeting ratio of the poor is usually at a medium or low level; there is a significant fiscal cost.

VII-27. There is significant debate on the validity of these individual assistance measures (see Table VII-10 above). Instruments that perform well against some criteria frequently perform poorly according to others. Further, not all mechanisms are expected to perform equally across countries or over all utility services. While each approach has its own pros and cons, selected measures should recognize the low institutional capacity of the existing social protection system and the already extremely high work load of social assistance officers. The selection of one of these options would be driven to some extent by the availability and reliability of metering, Baku being one example where there is a higher level of household metering. For example, if electricity tariff increases were considered in isolation, life-line tariffs could be appropriate due to the relative ease of metering. Disciplined meter readers/controllers would be needed to underpin this approach to ensure its effectiveness. If, however, a more comprehensive package of utility tariff increases is considered, ear-marked cash transfers or the application of the notional burden approach may be more promising.

VII-28.In all scenarios, an integrated approach needs to be taken towards social assistance to ensure that energy sector tariff adjustments do not collectively overburden vulnerable households. This is particularly important given the likelihood that privatization or letting of concession contracts for power and gas distribution would be spread across multiple entities.

VII-29.Incentives could be provided to promote the use of more efficient energy sources to mitigate the effect of tariff increases on the poor. A variety of instruments could be effectively used but explicit compensation should be considered by the Government for the “losing” utility provider. Examples could include the award of subsidies to encourage the extension of natural gas into rural areas or purchase assistance programs for high cost items such as gas furnaces for poorer households.

VII-30.Utility tariff increases could also raise the prospect of further increases in the use of wood for heating particularly for households in forested mountainous areas. This is often associated with illegal wood cutting and the demand for fuel wood is estimated to exceed sustainable annual yields. A review should therefore be conducted of potential alternative energy options for areas at high risk of deforestation or loss of vegetation as a result of utility price increases.

VII-31.It should also be emphasized that, while social assistance can ameliorate poverty, the escape from poverty has to come from economic growth and better employment opportunities for the poor.

Restructuring of Energy Sector State Operated Enterprises

VII-32.Restructuring the utilities sector, and SOCAR, to eliminate operational and financial inefficiencies could lead to an increase in unemployment, and hence to poverty. The Government wishes to develop a Social Support Program (SSP) to cushion the impact of restructuring. The SSP would address the social protection and employment of persons displaced as a result of the privatization of state owned enterprises. The recently completed IBTA-I labor redeployment program focused on the design of the labor redeployment program itself. The Bank is supporting a Poverty and Social Impact Analysis (PSIA)[95] that will address other aspects of labor retrenchment including an analysis of employment opportunities and social mitigation measures. The PSIA will be linked to the PRSP and the upcoming CAS that anticipate the development of a strategy

[95] PSIA, Azerbaijan: a Framework for Labor Redeployment Program, Concept Note. Draft outputs are expected at the end of 2004.

to cushion the effects of mass redundancies, together with analysis of labor markets and the institutional capacity of relevant agencies.

VII-33.In the specific case of SOCAR, where studies are ongoing regarding the restructuring of the organization, a transition strategy should be developed for workers at risk. Potential job opportunities linked to the clean up and decommissioning of past extraction activities could be linked to the transition strategy to help relieve pressures from staff reductions associated with restructuring.

Appendix 1
The Outlook for Crude Oil Prices[96]

1. For much of the past year, crude oil prices have been above OPEC's target range of $22 to $28 per barrel and, in recent months, have climbed well above the top of the range and have reached a series of all time highs (in current dollar terms). This has generated expectations that prices may remain well above their historic norms (in constant dollar terms) for the indefinite future. However, an analysis of price trends going back to the inception of the industry in the middle of the 19th century would not support that assessment.

2. Oil prices have always been managed[97] to some degree, although the entities effectively doing the "managing" have changed over time. Price levels are driven by perceptions and these, in turn, are colored by assumptions about the effectiveness of the management process. The current high price environment has been created by a number of factors, including the following:

i. The initial upturn in prices following the very low levels prevalent in 1998, as well as the more sustained upturn that began early in 2002, were both driven by perceptions that OPEC was reasserting a level of control over the market.

ii. The global economic recovery has created a surge in demand for oil, led by surging demand in China and significant demand increases in the United States. The IEA estimates that current demand growth levels are higher than any year since 1988, when demand grew 2.8%[98], and this, coupled with low stock levels and assessments that spare capacity is limited, have created the perception that oil is and will be in short supply.

iii. The U.S. refining sector is currently operating at about 96% of capacity in contrast with historic norms of just under 90% utilization. This has supported the perception of a tight supply situation.

iv. There is a widespread view that only limited spare capacity currently exists – mainly in Saudi Arabia - and that even if all this capacity is made available, it may not be sufficient to meet potential demand.

v. Uncertainties in the Middle East have created a premium component in the market.

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[96] This Appendix was prepared in October 2004, but the analysis and conclusions remain relevant in March 2005.

[97] In other words, market efficiency alone has not been allowed to dictate the price of oil.

[98] To put this in perspective a 2.8% increase in demand translates into an additional requirement of about 2.1 million barrels per day or 105 million tons per year. Between 1998 and 1999 global demand grew 2.3%. In the three year period from the end of 1999 through 2002, however, demand growth averaged less than 0.6% per year.

vi. The Yukos situation in Russia has raised questions about future levels of Russian production.

vii. Speculative activity involving hedge funds and other derivatives traders have also pushed prices up. Some industry estimates suggest that the speculative activity associated with oil trading has added as much as $10/barrel to the price.

3. While prices may not stay at levels above $40/barrel for an extended period, there is widespread expectation that prices will remain well above their historic norms for some time. Historic patterns, however, suggest that perceptions could well be reversed completely within the next two to thee years and there are some underlying fundamentals that also support this.

The "Management" of Oil Markets

4. The process of "managing" the oil markets is effected through manipulation of oil supplies. Effective management, therefore, is predicated on (i) the ability to manipulate supplies which means having both adequate spare producing capacity and the capability to adjust production volumes and (ii) willingness to exploit this ability fully. The perception of the "market manager's" ability and willingness to manage the market determines the effectiveness of the management process. The effectiveness of the process, in turn, affects the degree of pricing volatility in the market place.

The Evolution of "Market Management"

5. The industry began in the United States in 1859 in a laissez-faire economic environment. The business climate was characterized by a short-term perspective in which oil fields were found, produced at "flush" production and rapidly depleted. The result was a total mismatch of supply and demand, chaotic markets and volatile prices. Out of this chaos Standard Oil emerged as a dominant force, reaching the peak of its power at the turn of the century (1885-1910). Standard's tremendous purchasing power and its transportation and storage facilities resulted in the achievement of relative market stability in areas in which it operated. However the "boom and bust" oil field practices of the time prevented market stabilization in absolute terms. After the break-up of Standard Oil in 1911 markets remained turbulent until 1935 when the Texas Railroad Commission took steps to control production.

6. The long period of market stability that extended from 1935 to 1973 was essentially the result of a series of actions and sanctions by the U.S. and British governments to establish a system that would regulate supply and demand and stabilize markets and prices. The most important of these was to give individual states in the U.S. the power to regulate the production of oil. Two states, Texas and Oklahoma, thus assumed the role of swing producers. Internationally, the victorious powers of the First World War allocated the then known oil resources of the Middle East to consortia consisting of a few international oil companies. The "Red Line Agreement" of 1928 had the effect of limiting competition for Middle East oil which, in turn, put the international

oil companies in the position of individually matching their oil production with system demands.

7. This system was remarkably successful in maintaining market stability for 38 years, including the years of the Second World War. However, in the early 1970s, OPEC took control of a significant portion of the world's hydrocarbon resources and production and, in doing so, effectively took over the role of managing the market. The role has remained with OPEC since then. (Or, to be more specific, with those OPEC members with the capacity and willingness to manipulate supply). This transition, however, was accompanied by an abiding perception that OPEC cannot consistently manage the market effectively. The result has been a marked upsurge in pricing volatility since 1973.

8. The first evidence of this loss of market stability came in the form of the two major price shocks of the 1970s (1973/74 and 1979/80). These were the result of strong perceptions of supply shortages and geopolitical uncertainty together with concerns that OPEC would be unable or unwilling to make adequate volumes of crude oil available to stabilize the market. In the subsequent period, OPEC's attempts to maintain price levels through the imposition of production quotas were adversely impacted by a perception of supply surpluses resulting from (i) the sharp decline in demand brought about by the two price shocks, (ii) increased competition from non-OPEC oil and (iii) quota cheating on the part of member states.

9. This period of perceived supply surplus continued through 1998, albeit in an environment of considerable price volatility. Perceptions again began to change in 1999 as key countries within OPEC (Saudi Arabia, Venezuela and Kuwait) took more effective action to control supply availability. The price rise that began in 1999 has been fueled by the various events cited on the first page of this appendix, underscored by OPEC's apparent commitment to control access to oil at the margin. However, with the recent surge in prices, the perception has now emerged that, while OPEC has the ability to keep oil off the market, it does not have the capacity to provide the additional supplies that would be required to dampen availability concerns. While OPEC's announcements that it would increase quotas created initial drops in spot market prices these were short-lived and prices moved on to achieve all time high levels (in current dollar terms).

Historic Market Cycles

10. The attached chart details oil prices in 2003 dollar terms from 1861 through 2002[99]. This chart demonstrates the relative levels of volatility associated with the way management of the market has evolved.

11. It is interesting to note that in 2003 dollar terms the median price for the entire period has been about $17.51/barrel and the average price about $23.15/barrel and that prices have shown a tendency to revert to this historic band. Since OPEC took over de facto management of the market, prices have been higher. For the 1974 – 2003 period, the median price (in 2003 dollars) was $29.33/barrel and the average price was

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[99] Source: BP Statistical Review of World Energy 2004

$36.15/barrel. However, these price levels were inordinately influenced by the high prices that prevailed from 1974 through 1985 that were associated with the two oil price shocks. For the period 1986 through 2002, both the average and the median prices have been just under $25/barrel, only slightly above the top end of the historic band.

12. An analysis of the chart points to a series of cycles comprising periods of perceived tight supply (when the tendency was for prices to rise) and periods of perceived surplus (when the tendency was for prices to fall). The length of these cycles has been remarkably consistent over the last 100 plus years with a period of perceived tight supply in the range of 7 to 10 years being followed by a period of perceived glut lasting almost twice as long. The chart highlights the turning points in the cycles.

13. These cycles were identified in the mid 1980s in the midst of a perceived supply glut. At the time it was predicted that the glut would continue until about the 1997/1998 timeframe at which point, it was projected, a period of perceived tight supply would ensue. The turn, in fact, took place at the beginning of 1999 having been presaged by an extended period of relative price softness. It is perhaps worth noting that in periods of perceived glut, prices tend to soften but are not necessarily consistently low. When Iraq invaded Kuwait, followed by Desert Storm, prices spiked upwards but the higher levels were not sustained[100]. Similarly, in periods of perceived tight supply, prices will not remain consistently high. Rather, the tendency will be for volatility to spike upwards rather than downwards.

14. The timing of the cycles suggest that, while we are now in a “tight” cycle, the situation will likely turn in the 2006 – 2008 timeframe and be followed by a 15 to 20 year period of perceived “glut” with associated price softness.

The Underlying Fundamentals

15. There are a number of underlying fundamentals that would tend to support this assessment:

i. The upstream oil industry requires significant capital and fairly long lead times in order to bring on new capacity. Lead times for the development of major new increments of capacity can be in the 7 to 10 year range[101] which may well explain the timing of the historic cycles. When oil prices are high, capital budgets tend to be increased. In general, therefore, producers commit more capital than average in periods of tight supply creating the potential for future supply surpluses. Producers also, however, discount sunk costs (consistent with a zero base budgeting approach). Consequently, when perceptions change and a perceived tight market becomes a perceived glut, capital spending does not drop off right

[100] Prices initially surged in mid August 1990, peaked in mid October 1990 but then dropped back to pre-August 1990 levels by mid January 1991, notwithstanding the fact that Kuwait production was not resumed until several months later.

[101] Projects onshore can typically be brought on stream in a four to five year time frame. However, the time required for offshore projects can extend to ten years or more.

away. Rather, commitments are fulfilled, sustaining the potential supply surplus. However, when these capital commitments have been met, new commitments tend to be much lower, presaging a reduction in future increments of supply which, coupled with a boost in demand growth fueled by lower prices, ultimately translates into a perception of supply shortages and a new cycle of perceived "tight" supply.

ii. One of the clearest examples of the impact that higher prices can have on production is provided by Russia. Table 1 below details crude oil production, consumption and available export levels for Russia for the period 1998 (when prices bottomed out) through 2003, and reflects the major upswing in investment in the Russian oil sector that began in 2000.

Table 1
Russian Crude Oil (Million Tons)

	1998	1999	2000	2001	2002	2003
Production	304.3	304.8	323.3	348.1	379.6	421.4
Consumption	123.7	126.2	123.5	122.3	122.9	123.0
Available for Export	180.6	178.6	199.8	226.3	256.7	298.4

Source: BP Statistical Review of World Energy and Interfax

There is every indication that Russian production levels will continue to increase. The main near term constraint is export capacity. Over the last few years Russia has been effective in increasing the availability of crude oil export capacity (something the World Bank had strongly encouraged the government to do). Statements from the President of Transneft early in 2004, however, suggest that a near term ceiling has been reached (a further factor in fueling the current perception of supply shortages). There is, however, extensive discussion of new export projects including a pipeline to the East and it is very likely that implementation of these projects will get underway within the next one to two years creating the perception that substantial additional supplies will become available from Russia within a few years.

There is some question about how much Russia's production can increase without initiating major new plays. This constraint, however, may not come into play until sometime after 2010 and a number of analysts believe that by 2010 Russia's production capacity could exceed 600 million tons per year which could translate into an additional 180 million tons per year of exports.

iii. Both Azerbaijan and Kazakhstan have major investment programs underway that will result in significantly higher export levels in the 2008 – 2010 timeframe. Table 2 summarizes the production projections through 2010 for these two countries.

Table 2
Crude Oil Production Outlook – Azerbaijan and Kazakhstan (Million Tons)

	2003	2004	2005	2006	2007	2008	2009	2010
Azerbaijan	15.2	15.1	19.6	29.8	47.3	62.3	69.5	71.2
Kazakhstan	51.4	56.4	61.6	74.6	82.8	83.4	91.9	97.5

Source: World Bank estimates

In 2008 exports from these two countries could increase by as much million tons versus 2004 and could increase by over 90 million tons by 2010. These increases will serve to ease supply concern perceptions.

iv. While the OPEC countries have very little spare production capacity at present, the underlying reserve base is sufficient to support capacity increases and there is a distinct possibility that investments will be directed towards increasing capacity. Significant additions may not materialize for several years but the expectation that such capacity will come on stream could help fuel a perception of supply surpluses[102]. Iraq, of course, is one producing country that offers significant upside potential as and when the political situation stabilizes. It is also worth noting that Libya has sizable reserves with a current reserves–to-production ratio of 59 years. Libya's willingness to invite in weapons inspectors and other measures to develop more positive relations with the West may well result in additional investment in the development of its oil resources.

v. Several non OPEC countries in Africa – Angola, Equatorial Guinea and Chad - are also expected to increase production capacity over the next few years.

vi. Current high price levels will have an effect on demand. The first oil price shock in 1973 led to a 2.75% reduction in global demand by 1975, at which point demand again began to grow. However, the second price shock had a more dramatic impact reducing demand by 11% between 1979 and 1983. While demand began to grow again in 1984 it did not reach the 1979 level until 1990. The relative impact of the current price levels is not as dramatic as the impact that was felt by the two oil price shocks. The current price levels will, however, dampen economic growth and with it the growth in demand for oil. At some point a slowing in demand growth will play into perceptions concerning oil supply availability and help trigger the perception that the next "glut" has arrived.

Product Pricing Considerations

16. A few comments on the issue of product pricing may be appropriate. Unlike the crude oil market, the refined product market is not "managed" although it is significantly impacted by crude oil prices. There are three factors that impact product prices; (i) refinery economics, (ii) the price of alternative fuels such as gas and coal that compete with residual fuel oil, and (iii) the price of crude oil.

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[102] Some industry analysts have estimated that OPEC capacity could be increased by 1.0 to 1.5 million barrels per day within a year.

17. Refinery economics are influenced by three principal closely inter-related factors: the mode of incremental operation in a particular refining enclave; the cost and types of feedstock available; and which product is the swing component of the refined product barrel.

18. Incremental refining economics play a significant role in defining spot product prices. In Europe, for example, incremental topping/reforming economics based on spot product prices and spot crude in major refining enclaves, such as Rotterdam, have consistently been close to break-even. This is true despite the fluctuations in the price spread between residual fuel and gasoline and distillates. This black/white product spread defines the additional economic contribution, or upgrading margin, made by conversion capacity.

19. The price of crude oil dictates the overall price level of the mix of product prices. Higher crude prices tend to increase the black/white product spread since, in general, residual fuel is the swing product. Residual fuel competes with coal and natural gas in the industrial boiler market, which effectively defines the residual fuel price. However, this is not always the case. In 1984 and 1985, in part because of the UK coal miners strike, crude was run specifically to meet residual fuel demand. The result was a surplus in white products that had no ready alternative outlet. The market narrowed the black/white product price spread, residual fuel prices increased and white product prices declined. This sharply reduced and, in some cases eliminated, the economic contribution made by conversion hardware.

20. The two factors therefore that most influence upgrading margins are the price of crude oil and the demand for residual fuel. In the current environment, availability of coal and gas supplies acts as a damper on demand for residual fuel and hence the price (although a tightening gas supply outlook and increasing demand for coal could push up both residual fuel demand and prices). The current high crude oil prices, therefore, provide extremely attractive upgrading margins and the refining sector, as a whole, is generating significant profits. It should be kept in mind, however, that refineries that operate in essentially the same mode as an enclave's incremental refining mode (e.g. simple topping reforming refineries in both the Europe North Africa and the Asia Pacific enclaves) will not benefit from a high oil price environment. It is also worth noting that, while the US refining sector is operating at close to full capacity, there is still quite a bit of spare capacity in both the Europe North Africa and Asia Pacific refining enclaves.

The Impact of High Oil Prices

21. While it is not clear exactly what effect the current level of oil prices will have on the global economy higher prices do tend to impact the poorer countries disproportionately. The impact of a \$10/barrel price increase on the US results in a higher cost for consumption of about \$72 billion on an annualized basis. This is a little less than 0.7% of GDP. In the five poorest countries in the former Soviet Union (the CIS 7 excluding Azerbaijan and Uzbekistan) the impact of a \$10/barrel price increase is

equivalent to about 2.8% of GDP – or about four times the impact on the US in relative terms. Resource rich countries, of course, benefit in absolute terms but there is strong evidence that the "resource curse" (the inability of these economies to deploy these revenues effectively) minimizes the value of these benefits such that, in global welfare terms, high oil prices have a negative impact.

22. High volatility for a commodity as critical as oil (and, more broadly, energy) also tends to constrain economic development. Again the impact falls disproportionately on the poorer countries since they have less capacity within their economies to manage commodity price volatility.

23. The history of the industry demonstrates that periods of greatest price stability also offer lower prices on average – in effect prices remain at levels sufficient to encourage the exploration and development activity necessary to maintain a stable market without providing windfall profits.

Conclusions

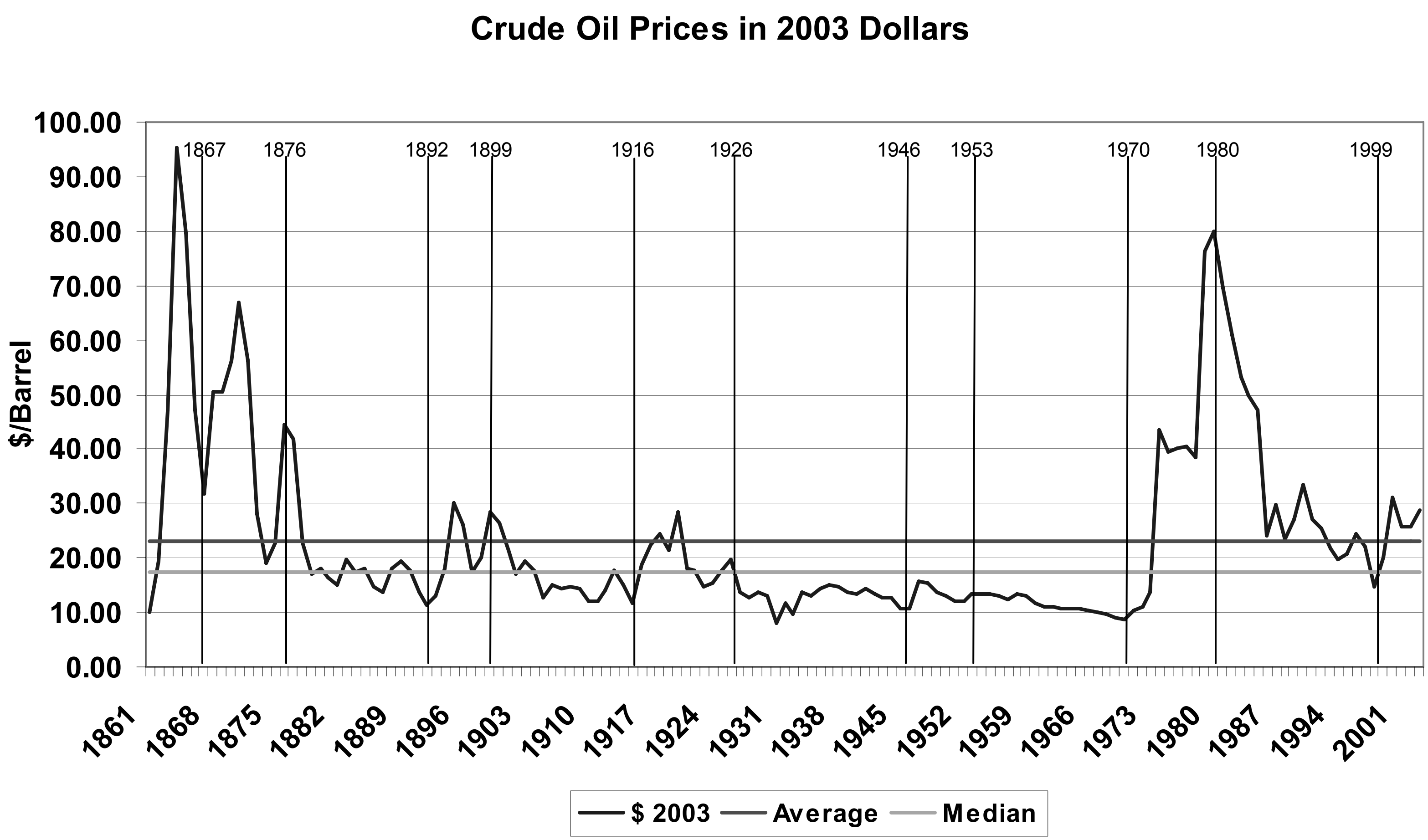
24. In brief, the following are key conclusions that can be drawn from the analysis of historic pricing:

i. Unmanaged markets are liable to be highly volatile (as was evidenced in the earliest years of the industry). However, OPEC (or more specifically the few countries within OPEC with the capacity to manage supply levels), has been relatively ineffective in the role of "managing" the market. It has demonstrated that it can, from time to time, apply upward pressure to the market, but that it does not have the capacity to establish and maintain a high degree of market stability.

ii. The period of extended market stability that ran from 1935 to 1973 owed a great deal to the direct support of the US and British governments – both countries were major oil consumers. This was also a period of significant economic growth driven, in part, by stability in the oil market and moderate pricing levels.

iii. A more stable oil market with a moderate level of oil pricing will deliver optimum benefits to the global economy. There will always be debate about what level of pricing is appropriately "moderate", but there seems to be some consensus to the view that a stable price in the low to mid $20s/barrel in real terms (i.e. increasing with inflation) could meet this definition.

iv. Given the uncertainty about the crude oil price outlook and the questions about OPEC's ability to manage the market effectively, it would be prudent for the government of Azerbaijan to take a fairly conservative view in making pricing projections for budget purposes.



Crude Oil Prices in 2003 Dollars
$/Barrel
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
1867
1876
1892
1899
1916
1926
1946
1953
1970
1980
1999
1861
1868
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1896
1903
1910
1917
1924
1931
1938
1945
1952
1959
1966
1973
1980
1987
1994
2001
$ 2003
Average
Median

Appendix 2

The Gas Sector Regulator[103]

1. This appendix lists the key functions needed by the regulator to further the development of competition in the market. It examines the liberalization process and the regulatory models that have been adopted in the UK, USA, California, Romania and Germany. It explains how these models have promoted or hindered competition and the functioning of the market.

Key Features of Regulatory Function to Promote Competition

2. The regulator has to have powers to encourage competition and prevent anti-monopoly behavior. If these powers are backed up by a strong national law on competition and the prevention of monopoly abuse of power, the regulator does not need additional strong legal powers. However if this law is weak, strong laws and powers need to be provided expressly for the gas industry (and the remainder of the energy industries). Specifically, the regulator needs to able to police and punish anti-competitive behavior. The first step is to provide some basic principles:

- ***Separate Natural Monopoly Activities from all other activities***
    - This does not necessitate full legal separation, but if full legal separation does not exist, there needs to be strong institutional separation including a compliance team appointed by the regulator and reporting to the regulator and third parties to whistle blow abuses, and with full powers to investigate complaints.
    - There also needs to be full and accurate published accounts on all the activities of the monopoly services allocated in fine detail to cover all the activities of the company.
    - Non-Discrimination provision. Third parties need protection, backed up by regulatory powers, to police and punish any discrimination exhibited by the monopolist.
- ***Separate monopoly activities from all other activities***
    - The same issues apply as for a natural monopoly, but these activities should be presumed to be open to competition over time, preferably to a defined timetable.
    - The power of separation is difficult to exaggerate – effectively done it provides confidence to the industry that it will be treated fairly.
- ***Full legal separation is the best option***
    - With full legal separation competitors know that the monopoly does not gain from treating any one company differently from any other company.
    - As long as the company is one legal entity there is advantage for it to discriminate in favor of its other parts. The only way to provide confidence is to ensure the regulator has enough powers to investigate, police, and enforce with punitive damages.

[103] This appendix was prepared for the World Bank by Gas Strategies Consulting Ltd.

  - The first choice is therefore full separation. This can be done in two stages, starting with separation within the company and extensive powers for the regulator, followed by full demerger of shareholder interests. Many of the provisions to protect third parties can be dismantled once full separation is achieved – and this is one of the reasons companies may decide to demerge of their own accord (e.g. British Gas in the UK)

- ***Monopolies act as Monopolists***
  - Uncontrolled monopoly behavior results in too high prices, too little investment, and moribund managerial and worker behavior. A regulator is required to provide the same kind of impetus that in other industries is provided by competition.
  - The regulator needs to set overall price controls to ensure that too much money is not raised from customers and to provide incentives for productivity improvements and appropriate investment
  - Having set the overall level of prices / revenues, the regulator needs to have a clear strategy for ensuring prices are fair between consumers. This can be done in a number of ways, and would normally be a result of extensive consultation with the industry, consumers and other interested organizations. Access to good quality information is essential.

- ***Investment***
  - Third parties need to be able to request access to any service they need to provide gas to their customers. The regulator has to have powers to ensure that this access will be provided within a reasonable time frame and at a reasonable cost. Only when there is competition in potential provision of a service can this requirement for reasonable access be dropped.

- ***Information***
  - The regulator needs access to any information requested in a reasonable time frame. Ideally the regulator should have full access to all the internal accounts systems, staff, IT systems, etc to ensure that information is provided and is accurate. Where there is no information internally the regulator needs to be able to insist it is provided.

- ***Political Independence***
  - The best systems work by government providing the policy framework, and taking the tax and spend decisions, while the regulator implements the policy and works out how most effectively to deliver that policy, and works closely with government to provide the analytical framework and data to help the government make better decisions.
  - Independent regulation ensures that key regulatory decisions are not distorted by political drivers, and provides third parties with confidence that they will be treated without political bias.

- ***Powers to investigate and remedy transgressions***
    - The regulator needs full powers to investigate any complaints, abuse, and to investigate potential changes to the industry structure. It needs enough powers to dissuade the company from misbehaving in the first place, and a system of penalties if misbehavior is identified.

Regulatory Models in Developed and Transition Economies

UK

3. The UK was the first country to introduce gas market liberalization all the way to the retail customer. Gas market liberalization was promoted as part of a political and economic agenda intended to introduce competition into the downstream gas business. Competition would promote choice for customers, increased efficiency of operations, and price reductions for consumers. The process has largely been successful, and there are now 93 licensed gas-marketing companies, and prices paid by end users are among the lowest in Europe, all customers can choice their supplier, and barriers to switching are small.

4. The process of liberalization took 16 years to complete, beginning in 1982 and finishing in 1998. The process can be defined in four phases, as shown in Table 1.

5. In the initial phase of liberalization between 1982 and 1988 there was very little material progress made toward the introduction of competition despite the legislative and regulatory changes introduced. Although the Oil and Gas Enterprise Act 1982 granted firms other than British Gas Corporation the right to use the existing pipeline network and to supply customers whose annual consumption exceeded 25,000 therms (732.7 MWh), by 1985, three years after the act, no alternate supplier had entered the market. There were a number of reasons that explain the failure of competition in the early days of liberalization. Chief among which were first, the difficulty any potential new suppliers had accessing the transmission and distribution grid which was through negotiation with British Gas and secondly, the difficulty of actually obtaining gas supplies.

6. However, with the introduction of measures to create a more competitive environment in the early 1990s, large numbers of marketers began to enter the market. The release gas programs introduced in 1992, the relatively undemanding financial credentials required for new marketers and the fact that British Gas was forced to stick to its published price schedules meant that it was relatively easy for companies to enter the market and sell gas at a profit. Furthermore, in 1992 Ofgas lowered the eligibility threshold for consumers from 25,000 therms per annum (732.7 MWh) to 2,500 therms per annum (73.3 MWh) which effectively made all but commercial and residential customers eligible to buy from suppliers other than British Gas. At the same time Ofgas put an upper limit of British Gas's allowed share of the eligible market of 55% effectively forcing them to release market share to new entrants.

Phases of UK Gas Market Deregulation

	Measures	Effects
1982-1988	From 1982, companies other than British Gas Corporation has the right to use the existing pipeline network and supply customers with an annual consumption over 25,000 therms (732.7 MWh)	By 1985, no new suppliers had entered the market, mainly for two reasons: difficulty in accessing the transmission and distribution grid which was through negotiation with British Gas and difficulty in obtaining supplies
1988-1994	In 1988 British Gas was made to publish a price schedule and stick to it, giving new suppliers a target price to beat. British Gas was allowed to buy only 90% of new gas production In 1992 British Gas was forced to release some gas purchased under long term contracts Eligibility threshold to choose supplier 2.500 therms (73.3 MWh) – effectively all industrial customers	First third party transportation deal signed in 1990. By the end of 1990, British Gas had lost 10% of its market share. By 1995, British Gas' share of the eligible market had fallen to 50% and over 65% of industrial customers had switched suppliers
1994-1996	Prices fell due to new entrants securing supplies. British Gas starts renegotiating long term contracts which are at higher prices British Gas share of eligible market limited to 55% The Network Code introduced setting out rules for regulated third party access to the transmission network British Gas to de-merge into Centrica (trading) and BG (transportation, exploration and international)	
1996-1998	Opening of residential market started in 1996 and was complete by June 1998	

Source: Gas Strategies

7. In 1996 the network code setting out the rules and allowing for regulated third party access to the UK transmission network was established and then in 1997 British Gas de-merged into two companies, one a trading business to be named Centrica and the second a transportation, exploration and international business to be named BG plc. Both these moves were regarded as essential by the regulator to ensure the continued development of competition. It was believed that without formal separation of the

transmission and supply business and a clear transparent third party access regime competition would certainly be hindered.

8. The final phase of the process was the gradual opening of the residential market to competition. This market was opened in stages from 1996 with competition gradually introduced over a period of two years in a series of trial areas; by June 1998 this process was completed.

USA

9. The US gas industry started to be transformed to its current shape with FERC Order 436 in 1985 which encourage pipeline companies to separate their sales and transportation functions. Prior to FERC order 436, pipeline companies bought gas from producers, transported it through their pipelines, and sold it to distribution companies which then sold it to end users. A series of FERC orders, starting with 436 and culminating in FERC order 636 in 1992, unbundled these services, so pipeline companies provided services for third parties and did not own the gas they transported. Purchasers of natural gas are now able to negotiate with many different suppliers and contract separately with pipeline companies for transportation and storage. This has led to the emergence of independent gas marketers, which arrange transportation and market gas for producers. The availability of information about commodity and transportation prices via commodity markets and electronic bulletin boards mean that price signals are quickly transmitted between consumers and producers.

10. Between 1988 and 1994, the market changed considerably.

- Gas production increased by 10%, wellhead prices declined by 11% and reserves declined by 2%.
- Gas delivered to consumers increased by 16%.
- Prices to consumers dropped significantly as consumers benefited from lower wellhead prices and transportation costs.

US Gas Market Development

1938	The National Gas Act created the Federal Power Commission (FPC) to regulate natural gas pipelines but not wellhead prices. Demand growth in the 1940s and 1950s outpaced pipeline expansion, leading to price volatility and supply shortages. Producers wanted price caps, but the FPC said it did not have the authority to introduce them.
1954	The Supreme Court decides that the National Gas Act should provide for the regulation of both pipelines and wellhead prices. This led to an industry structure where regulated gas producers sold to regulated pipeline companies, who sold gas to local distribution companies, who then sold the gas to end users. Local distribution companies were regulated by state or local agencies. This reduced price volatility but caused supply shortages, as it did not provide any incentive for producers to replace reserves.

1978	The Natural Gas Policy acted created the Federal Energy Regulatory Commission (FERC) to replace the FPC. Wellhead prices were deregulated and production increased rapidly. This led to a gas surplus. However, as pipeline companies charged enough to cover the cost they paid to purchase gas, there was no incentive for them to select the most competitively priced gas.
1985	FERC Order 436 required pipelines to provide open access, allowing consumers to negotiate prices directly with producers and contract separately with pipelines for transportation.
1987	FERC order 500 clarified some open access issues remaining after Order 436 and created a mechanism for pipeline companies to recover from their customers the costs of modifying or terminating their long term take or pay contracts with producers.
1992	FERC Order 636 required pipeline companies to provide open access transportation and storage and to separate sales completely from transportation.
1994	FERC retained the right to disregard the separate corporate structures of a pipeline company and its affiliates in the event that they abuse their interrelationship.

Source: Gas Strategies

Californian Energy Crisis

Introduction

11. The California Energy Crisis hit California in summer 2000 and ran on for the first quarter of 2001. The whole state was affected with rotating black outs and frequent brown outs hitting homes and businesses across the state. The crisis has cost the state billions both directly as a result of electricity purchases that it has had to make and indirectly in terms of damage to businesses. The crisis has led to a worldwide reappraisal of the way in which energy markets are liberalized and has caused many to call into question the wisdom of breaking up the old monopoly systems. Much of the response and lasting impression both locally and internationally is based on myth and emotion but it is a very forceful impression. Thus, whilst it is important to try to understand the real facts, it is equally important to note that most people identify the cause as “deregulation” and the liberalization agenda worldwide has been impacted by the various perceptions of California. The causes that lay behind the crisis can be summarized as:

- Fundamental electricity supply demand imbalance (supply shortage)
- Flawed electricity market structure
- Regulatory uncertainty, political interference
- Unexpectedly hot weather in summer of 2000
- Coincidence of high gas prices which further pushed up electricity prices

Legislation and Regulation

12. Although it was the fundamental supply situation which lay at the heart of the crisis the problem was exacerbated by the legislative and regulatory framework that was in place. An ever increasing spread of responsibility amongst too many regulatory and supervisory bodies, the inadequate structure of those bodies and a degree of political interference (primarily from the legislature) caused regulatory uncertainty at best, chaos at worst.

13. The supervisory bodies that were set up to oversee the CalPX (California Power Exchange) and the Independent System Operator (ISO) were too unwieldy and poorly structured to make decisions. For example, the ISO board had 28 members representing different interest groups who made decision-making practically impossible and it was one of many bodies involved. These inadequacies became particularly apparent as the crisis unfolded and quick decisions were needed. Political interference in the design of the market structure and failure to implement timely remedies made things worse not better. The frequent insistence of politicians on setting consumer prices to meet political rather than economic ends seems to have fuelled the crisis.

Pricing Systems and Market Structures

14. In 1996, the state law AB 1890 changed the structure of California's electricity industry which was intended to create a market based system from a tightly regulated monopoly system. It relied exclusively on spot, day ahead price and supply. For the first two years of the transition, market prices tracked expectations with wholesale electricity prices averaging $33 per MWh which was very close to the marginal cost of power production. However, from the summer of 2000 and through early 2001 market trends were extremely volatile with the market producing a series of problems; including very high electricity prices, decreased system reliability, very high profits for generators and wholesale power sellers and large debts for utility distributors who were forced to buy their power at inflated prices but unable to pass any of this price increase on to their retail consumers.

15. There were a number of reasons that explain the problems outlined above. Firstly the politicians were initially unwilling to allow consumers to face any price increases regardless of the cost of power, which in turn, undermined a proper demand response to higher prices, eroded supplier confidence and thus fuelled the crisis. This was manifest in the fact that retail prices were capped while the wholesale price was governed entirely by the daily spot market. In order for liberalization to work successfully, wholesale markets need realistic contracted revenue from the retail market or a free retail market. However, politicians are often very unwilling to leave control of retail energy prices to the market. As the problems unfolded in California and the crisis deepened the governor's office categorically refused to put up retail electricity prices when only minor action was required. It was argued that a simple 2% rise in retail prices early on in the crisis could have significantly reduced its impact.

16. In addition, the decision to force all electricity sales through the CalPX (California Power Exchange) and the refusal to allow long term bilateral contracts between power producers and consumers meant that the system was structurally unstable and extremely vulnerable to massive short term price hikes. This problem was exacerbated by the fact that no realistic hedging in the forward markets was allowed (the rules were set so tight as to make permissible hedging useless). Furthermore, California did not develop a capacity market or other mechanism, which would trigger the building of generating capacity and transmission, an extremely dangerous omission, given the supply shortage that has already been described. Indeed this weakness in the market structure was noticed as early as 1997 in a CERA report on Californian electricity market deregulation in which it was pointed out that:

> "There is no reliable mechanism [in California] to pay for the fixed and operating costs of new generating facilities, … That is likely to lead to extended periods of low prices followed by periods of very high prices, as supply shortages and surpluses develop. Price volatility will not be conducive to a smooth transition to competition."

17. The structure of the market combined with the system supply shortages allowed generators to "play" the system and take advantage of, and artificially inflate, prices on the CalPX. By carrying out "maintenance" or choosing to export power out of California at times of peak demand generators were able to push prices on the CalPX even higher. A further flaw in the market relates to the relatively low numbers of players involved in both supplying and generating power. Insufficient incentives were provided to IPP's to build capacity and, as explained above, tight siting and environmental regulations also made it difficult to get capacity built in California. Equally, on the supply side, the state legislature in dismantling the monopoly system was very keen to protect consumers, particularly retail consumers, under the new market structure. As such extremely tight regulations were imposed on potential new Energy Service Providers (ESPs) which negated all the incentives designed to encourage new entrants into the market.

Supply – Demand

18. The fundamental problem that lay behind the energy crisis in California was the existence of an imbalance between supply and demand, an imbalance that was improperly handled and made worse by the actions and reactions of the authorities. Over the preceding decade the state failed to approve (and developers to build) adequate capacity to meet rising demand; between 1990 and 1999 electricity demand rose by 11.3% but supply capacity actually fell by 1.7% as some older power plants were retired. After 1990 no new major power plants were constructed, relatively few were planned and a significant number were shut down.

19. Incumbents and new entrants alike were unwilling to invest in capacity and transmission due to the uncertainty and difficulty of the regulatory situation. Furthermore, strict planning laws supported by a strong environmental lobby meant that it was extremely difficult to gain permission to build new capacity. On average, it took seven years to get a project from application to completion. This was in sharp contrast to

other states where power projects could be fast-tracked if deemed necessary by the regulator and local authorities.

20. California also faced the problem that it relied heavily on hydro generation for its electricity (much of it from outside the state). In an average year hydro accounts for more than 30% of supply. This was reduced to only 20% in 2000 as a result of poor rainfall. It must be noted that similar low rainfall in the summer of 2001 did not spark another crisis that year.

21. The supply side problem was exacerbated by California's reliance on imports of electricity from neighboring states particularly in the peak summer period. This was sustainable for many years because the region was generally oversupplied with generating capacity. Power surpluses in the southwest were caused by overbuilding of generation capacity in 1970s and 1980s which had been driven by demand forecasts which turned out to overoptimistic. Similarly, the Pacific Northwest (PNW), a major source of imports to California, had substantial supply available to export. Its supply is also ideal for California in that seasonal demand within the region is complementary with that of California; that is to say, peak demand in PNW is in winter whereas peak demand in California is in summer. However, surplus capacity built in both PNW and the southwest has been steadily absorbed by growing local demand thereby reducing that available for export to California. Clearly, California came to take out of state electricity for granted.

22. By the time of the crisis, the robustness of California's electricity supply system was compromised, peak reserve margins (i.e. the capacity available in reserve at peak periods) had fallen from a high of 18% in 1993 to around 5% in 1999 making the system dangerously vulnerable. It is clear, therefore, that the supply shortfall in California was fundamental to the energy crisis of 2000 and 2001 and was not a one off brought on by exceptional conditions but a result of a long running failure to invest or to encourage investment in sufficient new generating capacity both within and outside California. In addition there was a failure to build capacity close to the major centers of demand which in part was a result of the difficulty of gaining planning consent for power projects close to centers of population.

Gas Prices

23. The price of gas also played its part in exacerbating the effect of the California energy crisis. Close to 50% of California's instate generation capacity is driven by gas, such that the extremely high gas prices at the California border which were seen in November 2000 and February and March 2001 had a serious effect on electricity prices. At the same time the whole US was seeing a rise in gas prices with Henry Hub[104] floating around $10/MMBtu throughout late November, December and early January. These prices were small in comparison with the $50/MMBtu on the Californian border in November 2000 and the $30+ price seen in February and March 2001.

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[104] Henry Hub is the physical delivery location for gas traded under regulated futures contracts in the United States.

24. These high prices can be explained by a number of factors; the long running low gas prices in the US prior to the rises at the end of 2000 had meant a reduction in drilling activity over the preceding years which in turn led to the supply surplus being eroded. A further reason was the lack of an economic alternative fuel supply with the prices of competing fuels rising in parallel with gas. For power generators fuel switching was also not really an option with heavy environmental restrictions on burning fuel oil. In addition an explosion in August 2000 on one of the pipelines delivering southwestern gas to California meant reduced capacity at a time when supplies were already tight. The pipelines feeding into California have also been running at close to capacity, as have pipelines within the state. As such, stiff competition to gain access to capacity had an inflationary effect on prices. Furthermore, price spikes at the Californian border have also been blamed on suppliers withholding gas in order to take advantage of high prices and on “round-trip” trades conducted by Enron and others that intensified price spikes.

Developments Since the Crisis

25. After the first quarter of 2001 the situation in California stabilized, the last brown or black outs being in March 2001. Similarly electricity spot prices fell back into line with long-term expectations. The explanation for this is manifold but there were several key reasons

i. FERC imposed temporary price caps to spot market price spikes
ii. Department of Water Resources signed long term power purchase contracts with generators (for above current electricity prices)
iii. Electricity consumption fell due to both more moderate temperatures in summer 2001 and major consumer conservation initiatives
iv. Fast tracking of new build generating capacity

26. By June 2001, natural gas prices in California fell back into line with Henry Hub and as drilling increased across the US and Canada it brought new supplies to market alleviating the supply shortages. Equally the constraints on infrastructure have been addressed, with the expansion of delivery capacity to California from 6630 MMcf/d in 2001 to 8310 MMcf/d in 2003, and additional expansion being considered. The CalPX has been disbanded and the state legislature has, through the Department of Water Resources, entered into a number of long term power purchase contracts with generators to ensure security of electricity supply to consumers within the state. The price cap imposed on spot electricity had the effect of curbing excessive prices for electricity within the state and helped to bring the situation under control. The weather intervened with temperatures that summer being moderate compared with 2000. In addition the state legislature also launched a major energy conservation program which included an energy efficiency rebate system which has had a significant effect on suppressing demand. Finally the state has radically overhauled the planning process for getting new generation capacity built, three major and six minor (under 150 MW) power plants , with a combined capacity of 1864.5 MW came on line in 2001. In 2002, a total on 2502.5 MW came on line, and in 2003, 3944 MW. In 2003, there was 4051 MW of generating capacity under construction, and 6007 MW under review.

Implications of the Crisis

27. The measures taken since the crisis brought the situation under control and many of the measures that have been taken will help prevent a recurrence of the crisis. New generating and gas pipeline infrastructure will address the long running supply shortfalls which were fundamentally behind the crisis. Equally the conservation program has also had a very positive effect. The cause of market liberalization has been damaged by the crisis but it is unlikely that there will be a return to the old monopoly based structures of the past; the uncertainty over the future will inevitably cause potential generators, suppliers and infrastructure developers to think twice before embarking on expensive projects. Similarly, one of the most important questions that has to be addressed is the way in which generating capacity and infrastructure are built in time to avoid the kind of supply shortfalls that lay at the heart of this crisis. Would a capacity market be able to read price signals in time to develop capacity as it is needed or do the lead times involved in building generation make this impractical?

28. It is essential to make the point that the Californian energy crisis does not represent a failure of market liberalization, but rather a failure to liberalize correctly. The market structure was fundamentally flawed and no one agency with enough authority had regulatory oversight for the development of the market as a whole. Since the crisis, measures have been taken to allow the Californian market to function effectively. CalPX stopped operating in January 2001. In February 2001 California's Department of Water Resources was permitted to purchase power under long-term contracts for sale to PG&E and SCE. In April 2001, FERC introduced a price mitigation plan for the spot market, and in May 2001, it was announced that prices would be raised by 19% for all except the most vulnerable customers. Also in May 2001, Senate Bill 28X was signed to shorten the time needed to review plans for building new capacity. It may well be that to produce an effective market more not less regulation is required and this is one of the key lessons that can be drawn from the crisis, liberalization does not mean deregulation, indeed the transition from a monopoly market to a free market requires heavy handed regulation to force the market open but that regulation needs to be focused and free from day-to-day interference from political bodies.

29. California's electricity crisis remains an example of how not to organize energy markets. Ironically, it is not and was not a flawed gas market. The message to be learnt from it is not to avoid liberalization, but to ensure that new market reforms are structured on a practical basis, taking care to avoid the obvious mistakes of curtailed supply, total exposure to price risk and a multiplicity of regulatory bodies.

Romania

30. Romania is a country with a highly developed gas industry with a long tradition of upstream industry and the liberalization of the gas industry is also highly politicized. Romania is one of the highest consumers and producers of energy in Central and Eastern Europe. By the early 1980s natural gas accounted for 55% of Romania's total energy

supply - the highest penetration any Central and Eastern European country has achieved. This unusually large market share was due to former President Ceaucescu's policy of self-sufficiency at all costs, which led to short-term maximization of domestic gas production without heed to optimizing recoverability of reserves. The high inefficiency of the industry and falling gas production prompted the Romanian authorities to reform and liberalize the industry in order to reverse the negative development. Romania is in the process of reforming its energy industries but the reluctance of the government to introduce politically controversial and economically challenging reforms means Romania is moving slower than originally planned and progress in implementing key structural reforms and improving administrative capacity has been limited. Nevertheless, a number of changes have been implemented and liberalization is an objective.

31. The Romanian government has committed itself to increasing domestic production of oil and gas in order to reduce the country's reliance on imports. Restructuring of the gas industry has commenced with the "unbundling" of Romgaz into divisions for storage, production and transmission. A regulatory authority, the National Agency for Natural Gas Reserves, (ANRGN) has been created and continues to oversee the industry and introduce legislation, often with one eye on EU requirements with the intention of aiding Romania's accession process to the EU. Liberalization of the gas market has commenced with the creation of a free market to Eligible Customers, typically the largest gas consumers. However, Romania has been inconsistent in how it has applied the energy reform. A timeline of the main events in the Romanian legislation is shown below:

Main Events in Romanian Legislation

1990	Passed first energy reform
1996	Introduction of the Petroleum Law
2000	ANRGN was established
2001	Romanian Energy Legislative was updated
2001	ANRGN re-opened the gas market
2002	New list of Eligible Customers

Source: Gas Strategies

32. As part of the Romanian energy reform passed in 1990, the sector was reorganized by separating policy and regulation from operation and function. On the production side, regional divisions were created to better manage output and supply, aided by commercial companies providing more centralized support. The intention was to break up the large, cumbersome companies inherited from the centrally planned economy of the Soviet era. In fact, little alteration was seen in practice as the inertia and, in some cases, hostility of existing bureaucracies proved resistant to change. As regards liberalization of the gas industry hardly any progress was made and the industry remained in the hands of the gas monopoly, Romgaz.

33. A second major change was introduced in the Petroleum Law passed in February 1996, which provided the legal framework for the operation of both Romanian and foreign companies. The law introduced third party access (TPA) to gas pipelines. The

TPA was granted to other parties and the market was opened to a limited number of largest industrial gas consumers. In 2000, Romania established a National Agency for Natural Gas Reserves (ANRGN). The Agency is responsible for issuing licenses, drafting operational legislation, establishing gas tariffs, and monitoring the observance of competition rules. All cross-subsidies have been reportedly removed in these sectors though in practice this is not easy to verify. The establishment of ANRGN as the national gas regulator is intended to be the main step towards creating a tool that, in the context of a free market, will: increase the security of supplying natural gas; facilitate free market transactions between licensed suppliers and eligible consumers; improve the dispatching and distribution system; optimize the delivery parameters for natural gas by specifying the precise quantities and pressures to be delivered by a direct contractual relationship between client and supplier. The Prime Minister appoints the president of ANRGN. The energy sector is under the supervision of the Ministry of Industries and Resources, which formulates policy and strategy.

34. However, the gas sector has been subject to considerable shifts in policy over the last three years. Whereas 15% of the market used to be open through licensed suppliers and eligible customers, the government suspended all bilateral contracts in October 2000 as winter supply shortages threatened domestic supplies. In July 2001 it re-opened 10% of the market to competition and the regulatory authority selected 18 new eligible customers, who were free to switch suppliers and operate in a "liberalized" market. In 2002 the regulator ANRGN selected 45 eligible customers with a minimum consumption of 5 MMcm in the previous year, with the intention of opening more than 25% of the national gas market to competitive pressure. As more eligible customers qualify for this status it is planned to have 33% of the market for gas in competition by 2006. Eligible customers are natural gas consumers that have the right to select their own supplier and to contract directly, having access to the transport/distribution network. They have the right to connect to and use the transport/distribution network. To qualify as an eligible customer the entity has to meet fairly strict criteria in different areas of activity. New eligible consumers have to re-apply for accreditation on an annual basis. Re-qualification as eligible is not automatic. Eligibility commences on 31st January. The consumer loses the status of eligible customer if it does not fulfill its obligations under the contract concluded with the chosen supplier. In the event of contract breach the supplier can ask ANRGN for the suspension or cancellation of accreditation for the eligible customer. An independent producer can sell gas directly to an eligible customer if it is a licensed supplier.

35. Captive Customers are all customers that are not defined and qualified as eligible. One exception is Termoelectrica, the national electricity producer, (a de facto captive customer), a company that is not qualified as eligible but may be allowed to directly negotiate imported gas supply under contracts. As it is also the largest gas consumer in Romania, the reform of the electricity sector will undoubtedly affect the gas demand of Termoelectrica. As Termoelectrica restructures it may privatize a number of power plants, which may become Eligible Customers in their own right. The captive customers may only buy from the distribution companies at the ANRGN regulated price. Gas prices have been adjusted to reflect production costs and they are now indexed with the US

dollar. The eligible customers may choose to buy either from distribution companies or from licensed traders/suppliers. They can also buy from importers but only if the selling party holds a license to sell/distribute gas. There are a number of independent suppliers and importers who successfully supply gas directly to industrial customers. Romania has thus managed to open its gas market to large industrial consumers since it introduced non-discriminatory TPA. Apart from the Baltic republics, Romania is the only country in Central and Eastern Europe where liberalization has been successfully introduced. Although legislation was already introduced in 1990 the process only started once the transparent TPA was introduced in 1996. Nevertheless, there are some problems with the gas liberalization, because the complexity of the legislation and strict criteria mean that many industrial consumers are unaware that they could qualify, and thereby acquire access to the gas transit system and contract for new supplies. However, these are bureaucratic difficulties rather than real obstructions to the liberalization.

Germany

36. The liberalization process in Germany is largely driven by EU directives. Germany has been one of the slowest to adopt the EU directive, and it only became law in 11 April 2003, when the federal government passed the amendment to the 1998 German Energy Law. Germany is virtually alone in attempting to implement the EU third party access agreement by means of a negotiated rather than a regulated mechanism. The system of negotiated TPA to pipelines as it has developed in Germany since 1998 is based on private, voluntary industry agreements, the so-called Verbandevereinbarungen. These agreements set common pricing guidelines for industry participants, but are negotiated on a case-by-case basis by the parties involved.

37. The chronology of liberalization process in Germany is outlined below:

Chronology of the German Gas Market Liberalization Process

1998	April - German Energy Law passed, June - EU Directive passed
2000	July - German VVI for gas agreed
2001	March – First amendment to VVI for gas agreed
2002	March – at Barcelona summit Germany succeeds opt out from EU requirement to set up regulator, May – German VVII for gas signed
2003	February – EU amendments to original energy directive passed, April – industry talks on German VVIII for gas break down, German government passes amendment to Energy Law, September – German gas code VVII expires
2004	Q1 – German government to finalize regulatory framework, July – German regulatory framework comes into force

Source: Gas Strategies

38. At present Germany still has no independent regulator. Instead it has a system of self-regulation based on voluntary agreements between industry participants. Germany's

Federal Cartel Office (FCO) carries out the supervision on an ex-post basis, which is a government-funded but independent entity responsible for ensuring that German business adheres to national and EU competition law. FCO has the power to investigate network access charges when it has grounds for suspecting that prices are excessive, both in response to customers' complaints and on its own initiative. It has the power to reduce the price. However, German transmission and storage charges are well above the relevant EU average. Although the EU's legal requirement that all member states establish an energy regulator by July 1, 2004 is that it still leaves a lot of discretion to the governments of each member state in deciding on the nature and scope of the regulatory framework.

39. The German gas industry is concentrated at the transmission level but extremely fragmented at the distribution level. The distribution level is very politicized because it is dominated by municipal-utility companies that generate much needed finances to the municipal authorities, which are currently experiencing severe budgetary difficulties. The financing of municipalities is a major concern to the federal government and thus government decision on the regulator will be influenced by this factor.

40. German gas market is currently theoretically free and 100% open to competition but this is only theory. In practice change has been limited and very slow. However, court cases under domestic and European competition law have opened up volumes under old long-term contracts to competition. But little has changed at the customer end because Germany has opted for negotiated third-party access, which has not so far brought down network charges sufficiently for competitors to make real inroads into the market. Storage is still a particularly difficult area. The vagueness of the EU Gas Directive originally gave incumbents hope that, although they had been obliged to concede the principal of third party access to pipes, they might be able to eviscerate the overall impact of that measure by denying access to storage. In Germany access to storage is particularly important for new suppliers looking to use Interconnector gas because the Interconnector is a sub-sea pipeline, which closes for maintenance for about two weeks per year (and has recently suffered unplanned downtime as a result of liquid incursion). Therefore without storage somewhere it cannot be a source of firm gas. Without storage facilities in Germany, close to customers, a supplier has no hope of offering seasonally structured gas on competitive terms.

41. In July 2003 the German gas industry group, the BGW, published a survey of 700 grid operators, as well as TPA contracts which had been agreed since July 2000 when the Verbändevereinbarung Gas agreement became effective. Around 469 TPA contracts had been made since July 2000, with approximately 180 of these agreements being signed between the beginning of the current gas year and April 2003. The survey indicated that, since July 2000, there had been a tripling of the cumulated gas volumes, reaching a total of around 77.5 billion kWh in April, which had been transported via TPA contracts. However, the consumer lobby group, VIK, was critical of the methodology used by the BGW. The group suggested that the number of TPA contracts was small in relation to the 700 active grid operators, but more significantly, the number of contracts was unimpressive when compared to the number of transportation cases underlying the TPA

contracts, which had not been included in the BGW statistics. The VIK explained that if a gas supplier transports gas across Germany, the supplier may require several TPA contracts in order to ship the gas through various grid systems. The BGW had, for the purposes of the survey, simply added up all contracts which represented a distortion of actual competition. On the grid operator's side, a large number of contracts have involved major gas distributors.

42. The EU Directives impose obligations on Germany in two specific areas: one is legal unbundling which is to be introduced to prevent cross-subsidization among company divisions; and the other is stricter ex-ante regulation in relation to conditions for network access and fees for network use. The structure of the German gas market, with several providers across the municipalities, may yet prove to be a favorable landscape for the emergence of competition. The lack of transparency of TPA and regulatory framework resulted in the slow process of gas liberalization in Germany. As regards gas liberalization within the EU Germany has become the laggard among the member's countries. As a result no customer group in Germany has enjoyed falling end-user prices since the process of liberalization started. Other EU members on the other hand have achieved falling end-user prices over the same period despite the rise in gas border price since 2000. Moreover, not only are German prices high compared to the EU average; they have actually risen for small commercial customers and for households.

Appendix 3

The State Program for the Development of the Fuel and Energy Sector of the Azerbaijan Republic (2005 – 2015)

Summary Description

The State Program for the Development of the Fuel and Energy Sector of the Azerbaijan Republic (2005 – 2015) was approved by Presidential Decree on February 14, 2005. The Ministry of Industry and Energy has been designated as the coordinating agency for this program.

The overall goal of this program is to fully meet demand for power, gas and other energy resources through the continued development of the fuel and energy sector. The program also focuses on sector restructuring, the installation of modern equipment and the introduction of management systems suitable for operating in a market economy. Specific aims of the program include:

- the identification of priority areas for development;
- improvements in the production, processing, transport, storage, accounting and consumption of energy resources;
- the enhancement of operational effectiveness and compliance with best practice;
- an improvement in utility collection rates;
- an increase in sector investment;
- the provision of an enabling environment for competition; and
- ensuring environmental safety.

Between 2005 and 2015, the State's upstream oil and gas program will focus on development of the oil and gas industry and modernization of the processing and refining sector. Specific activities will focus on new field exploration; full scale development of discovered fields; drilling programs and the modernization of facilities in operated fields; and the construction, rehabilitation and modernization of production, transport, refining and processing facilities.

In the upstream oil and gas sector, Azerbaijan has been successful in attracting foreign investment (to the tune of US$13 billion) and 23 exploration and development contracts have been entered into with foreign investors[105]. Over the period 2006 to 2008 further foreign investments totaling US$ 10 – 12 billion are expected for the Phase 2 development of the ACG (Western and Southern Azeri) field. Other activities associated with the development of the Azeri, Chirag and Gunashli fields, the BTC and South Caucasus pipelines and the Sangachal facilities are also expected to continue.

[105] This includes 4 significant and ongoing projects: full field development of the ACG field; the first stage development of the Shah Deniz gas condensate field; construction of the BTC main export pipeline; and construction of the BTE South Caucasus pipeline.

The gas sector serves all large cities and 32 regional centers in Azerbaijan. Approximately 8 bcm of natural gas are transported (50% from imports) and 67,000 meters have been installed for residential consumers to date. The State's development program will continue with and accelerate the metering program and expand coverage to other consumer groups. Emphasis will be placed on improving financial discipline in the gas sector including the resolution of collection, payment and mutual debt issues; excess loss reduction; and an improvement in gas quality and sales. Technical capacity will be developed in Azerigaz JSC.

Domestic demand for natural gas is expected to increase to a level of about 5.4 – 5.9 bcm per year with natural gas being the primary fuel source for the power sector[106]. Domestic supplies will only be able to meet this need from 2009 due to other competing demands within the economy. Gas imports will fill the gap in the interim.

There has been a sharp decline in power generation capacity (4289 MW available compared to 5735 MW installed capacity) due to aging and under-maintained equipment. At the same time demand has increased. Residential consumers account for 70 – 75% of power demand[107] using power largely for heating purposes. Around 50% of consumption takes place in the Absheron Peninsula while the main generation facilities are located to the west of Azerbaijan increasing technical losses and fuel transportation costs and affecting system stability. There are sharp disparities in power supply between regions, with Lenkaran, Shaki-Zagatala and Guba-Khachmaz being most affected due to technical constraints in the system.

To meet the expected growth in demand (4.7% per annum to 2015)[108], the State's program will develop generation capacity up to 6500 – 7000 MW by 2015, with new capacity being located closer to consumers. This will be achieved through the modernization of existing generation facilities[109], the construction of new thermal power facilities and the use of renewable energy resources. These measures will also serve to improve fuel efficiency[110]. Generation capacity is expected to be increased through a combination of State owned (88.3%) and private facilities (11.7%).

To ensure reliable and continuous power supply, system forming transmission lines will be reconstructed together with relevant sub-stations. Similar works will be conducted in the distribution sector. System losses and theft will be reduced; and energy efficiency and accounting will also be focal points for the development program.

[106] Mazut (fuel oil) will cover 15- 20% of fuel supply and consumption needs
[107] In contrast with developed countries were residential demand is typically in the range 25 – 30%
[108] Based on the projected GDP trend in the non oil sector from 2004 – 2015.
[109] Mostly at Azerbaijan DRES and Mingchevir SES
[110] Conventional fuel use at thermal power facilities is predicted to decline from 407 gr/kWh in 2002 to 250 gr/ kWh in 2015