Report No. 40405-MNA

Investing in Oil in the Middle East and North Africa

Institutions, Incentives and the National Oil Companies

August 2007

Sustainable Development Department
Middle East and North Africa Region

Energy Sector Management Assistance Programme

Document of the World Bank

Abbreviations and Acronyms

ADNOC	Abu Dhabi National Oil Corporation
Bbl	Barrel
Bcfd	Billion cubic feet per day
Bcm	Billion Cubic Meters
BP	British Petroleum
BTU	British Thermal Unit
CEO	Chief Executive Officer
CNG	Compressed Natural Gas
E&P	Exploration and Production
EGPC	Egypt Gas Production Company
EITI	Extractive Industry Transparency Initiative
FDI	Foreign Direct Investment
FSU	Former Soviet Union
GCC	Gulf Cooperation Council
GDP	Gross Domestic Product
GTL	Gas to Liquids
HFO	Heavy Fuel Oil
HSE	Health, Safety, Environment
IEA	International Energy Agency
ILSA	Iran-Libya Sanction Act, 1996
INOC	Iraq National Oil Company
IOC	International Oil Companies
KNPC	Kuwait National Petroleum Company
KOC	Kuwait Oil Company
KPC	Kuwait Petroleum Company
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
mb/d	Million Barrels per Day
mcmd	Million Cubic Meters per Day
MENA	Middle East and North Africa
MGS	Master Gas System
NAMA	Arabian Industrial Development Corporation
NGL	Natural Gas Liquids
NGO	Non-Governmental Organization
NIOC	National Iranian Oil Company
NIORDC	National Iranian Oil Refining and Distribution Company
NOC	National Oil Company
OAPEC	Organization of Arab Petroleum Exporting Countries
OECD	Organisation for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
PDV	Petróleos de Venezuela
PEDEC	Petroleum Engineering Development Company
PEL	Petroleum Economic Limited
PEPA	Petroleum Exploration and Production Authority
PIW	Petroleum Intelligence Weekly
PRSP	Poverty Reduction Strategy Paper
PSA	Production-Sharing Agreement
QP	Qatar Petroleum
R/P	Reserve to Production
RPLA	Resource-Poor, Labor-Abundant
RRLA	Resource-Rich, Labor-Abundant
RRLI	Resource-Rich, Labor-Importing
SABIC	Saudi Arabia Basic Industries Corporation
SAFER	Safer Oil Exploration and Production Company
SAMA	Saudi Arabian Monetary Agency
SAMAREC	Saudi Arabia Marketing and Refining Company
SPC	Supreme Petroleum Council
tcm	Thousand Cubic Meters
UAE	United Arab Emirates
UNDP	United Nations Development Programme
WEO	World Energy Outlook (IEA)
WTI	West Texas Intermediate
WTO	World Trade Organization
YGC	Yemen Gas Company
YICOM	Yemen Investment Company for Oil and Minerals
YLNG	Yemen LNG
YOGC	Yemen Oil and Gas Company

Vice President:	Daniela Gressani
Sector Director:	Inger Andersen
Sector Manager:	Jonathan D. Walters
Task Team Leader:	Pierre Audinet

Table of Contents

Contributors:

This report was written by a team comprising Pierre Audinet, Paul Stevens, and Shane Streifel.

The report also benefited from the helpful comments of Mustapha Nabli, Hossein Razavi, Jonathan Walters, Habib Fetini, Robert Bacon, Michael Levitsky, and Alex Kremer.

EXECUTIVE SUMMARY

This report asks the question: how can oil-producing countries maximize the contribution of the oil industry to their economic development goals? This is a complex process of ensuring that the right institutions and incentives govern petroleum companies' operations in a sector where the rents are high and the global markets imperfect. The issue is examined in four case studies: Iran, Kuwait, Saudi Arabia, and Yemen.

High oil prices can hide a number of inefficiencies in the ability of the petroleum sector to maximize hydrocarbon extraction efficiency and the spillover benefits to domestic economies. Yet, governments of oil-producing countries always seek to eliminate these inefficiencies and increase the value they can extract from their hydrocarbon resources. The reason why this report focuses on Middle East and North Africa (MENA) countries is twofold. MENA countries' experience in managing their petroleum sector has a number of useful lessons to offer to other oil-producing countries that seek to respond to similar questions. MENA countries often find themselves having to make difficult choices in order to maximize petroleum sector revenues, while at the same time maintaining sufficient levels of investment in the sector and finding efficient ways to redistribute the rent among their citizens. In addition, the importance of MENA to the global oil supply is such that inefficiencies in the management of the petroleum sector affect not only its economies, but also the rest of the world—in particular the poorer economies, which are most vulnerable to high-priced hydrocarbons.

WHY STRUCTURE MATTERS FOR PETROLEUM SUPPLY, REVENUES, AND DEVELOPMENT: LESSONS FROM FOUR CASE STUDIES

Sector governance should be conducive to investments and efficient oil and gas production—but is it? A closer examination of the structure of the petroleum sector points to deficiencies, suggesting ways to improve investment-allocation mechanisms in the sector, and increase development linkages.

In managing oil and gas resources, governments seek to respond to a number of important questions, such as:

- Who should set the objectives for the oil sector?
- Should the government set a production target or should this be left to the operator?
- How should the oil and gas sector be regulated?
- What is the role of private investment?
- If the country owns a national oil company (NOC), how should the financing of that NOC be organized?
- What decisions should be left to the NOC without government interference?
- Should the NOC be allowed to operate on a commercial basis and pay taxes?
- Should the NOC face domestic competition?
- Should the NOC be allowed to operate abroad?
- Should the minister of oil be the chairman of the NOC board?
- How much information about NOC operations should be made public?
- On what basis should the domestic oil product prices be set?
- Should there be a policy for developing domestic gas resources?
- Should the level of local inputs to the sector be subject to regulation?

Responses to these questions will shape the sector structure and its incentive to operate efficiently. Assessing sector structure can be done using the conventional theory of assessing the dynamics of firms trying to maximize profit (or market share, sales, and profit). Using such a model, however, is of limited policy relevance to the work, mainly because the oil sector has two specific features that need to be considered: (1) the international oil market is structured by a large group of players operating within the Organization of Petroleum Exporting Countries (OPEC), and (2) the size of the rents available to firms and governments is very large. As a result:

- There is a notable absence of numerical data (on production, costs, discount rates, and so on) that can be used to empirically test a model of the firm. This absence of data is at the heart of the strategy to increase the asymmetry of information about—and therefore control over—the rent from oil and gas extraction and sale. Asymmetry of information is found between oil-producing and importing countries, but also affects the relations between the industry and the governments of oil producing countries.
- Given the high rents, there is considerable competition within governments to achieve and increase control over part of those rents. This competition determines how the sector operates by gradually structuring the institutional framework, defining control and regulatory mechanisms, deciding whether private investors are allowed to invest or not, choosing rules to allocate revenues from oil and gas sales, and so on. Capturing the essence of the context in which the petroleum sector operates and how the sector's objectives are defined is therefore essential to understanding the dynamics of the operators themselves.

Given the importance of NOCs, which dominate the region's petroleum industry, efficiency of investment allocation in the petroleum sector is strongly linked to the role assigned to NOCs and the specific arrangements of their regulation. The four case studies presented in this report investigate how arrangements governing the petroleum sector affect the productive efficiency of the sector, as well as its ability to stimulate economic development through fiscal, backward, and forward linkages.

THE CASE STUDIES

Kuwait

Authority over the oil sector is dispersed, with an unclear division of responsibility. This means that the NOC lacks clear and stable objectives. Political influence sometimes leads to the hiring of relatively inexperienced managers. The NOC has limited financial incentive to reduce costs. A weak institutional framework and lack of incentives have prevented Kuwait from meeting its formal targets for capacity expansion.

Downstream, domestic supply matches demand, but the sector structure has clearly affected the efficiency of resource allocation (as in the case of natural gas use). The private sector was envisaged as playing a role both upstream (Project Kuwait) and downstream (in the privatization of refining activities). Decisions regarding private sector entry have, however, been limited to some technical assistance upstream and privatization of peripheral activities downstream.

Saudi Arabia

The oil sector has been protected from political interference and driven by a high degree of alignment among the various actors, resulting in a clear vision of the contribution expected from the sector in the use and allocation of investments. The operation of the NOC takes place within the government policy framework, which reflects Saudi Arabia's price-making role in global oil markets and the country pivotal role in the OPEC. The NOC is treated as a corporate entity with a financial system that creates incentives for low-cost operations, although lack of quantitative data makes it difficult to fully support this assertion.

Observers conclude that investments are made to maximize the recovery factor. This is in line with the choice of maximizing revenues from petroleum because of the dependence of economic development on government revenue from oil. In spite of some government efforts, private sector investment upstream has been restricted so far, not least by the incumbent NOC.

Day-to-day operations are left to professional decision making within the company. This has resulted in a sector that is self-regulated. While this presents a risk of excessive rent seeking, it appears that the corporate culture within the NOC has managed to constrain such tendencies. A result is that the sector seems to have developed high levels of competency, especially in technical fields.

In the provision of oil products and gas to the rest of the economy, the sector has a strong record of delivery, although domestic prices are well below international levels. The NOC has a long history of aiding local economic development by seeking to maximize backward linkages through a variety of ways, such as nurturing spillover investments.

Iran

The oil sector seems to suffer from significant political interference. This is due to the nature of the Iranian political system and its constitution's specific checks and balances, which, combined, tend to fragment the control and operations of the sector. In particular, there seems to be conflict over whether to involve the private sector more or less. Attempts to secure greater foreign direct investment (FDI) upstream by means of buy-back contracts have generally raised limited interest among investors (although this is also due to the existence of sanctions). The fragmentation of the sector itself also translates into gaps in the coherence and coordination of its operations. The main result is that the sector faces difficulties meeting its capacity expansion targets and serious problems in reducing the decline in crude export levels. These problems have been compounded because the hybrid budget model under which the NOC operates gives it limited access to investment revenues to offset the high, natural decline rate in the fields.

A decline in export capacity is also driven by downstream policy. Highly subsidized oil product prices have led to excessive growth in domestic consumption and smuggling, eroding the crude export surplus and challenging the delivery of products to the economy. Development of the natural gas potential has been delayed because of growing opposition within Iran to developing gas for export purposes, and the poor financial returns obtained from gas sales at subsidized prices to the domestic power sector. As for backward linkages, sanctions have encouraged more self-reliance within the sector, but a business climate that offers limited comfort to private investment has inhibited the local economy from realizing its full potential.

Yemen

The oil sector in Yemen shows that a lack of coordination among petroleum sector stakeholders can limit investment and reduce the possible growth of the extraction rate. Limited strategic direction—other than a general encouragement of private sector investment upstream to expand oil output—was sufficient to generate foreign direct investors' interest in exploration and production (E&P) in the past. But a renewed and clear expectation of petroleum resource expansion and use for domestic market and exports will need to emerge soon to boost investments, especially in natural gas E&P.

Given that Yemen has been experiencing significant oil production declines in recent years, the lack of a clear vision for the sector's contribution raises concerns about future government revenues, which remain highly dependent upon the oil sector. Downstream, the sector's performance is questionable, not least because of a lack of competition. Existing refinery capacity suffers from a lack of investment, and high price subsidies are leading to excessive domestic consumption and smuggling.

POLICY IMPLICATIONS OF THE CASE STUDIES

Sector Players, Regulations, and Objectives

Interactions between different players reflect national preferences. These differences relate to:

- The organization of institutional power and political dynamics
- The ministries and other agencies connected to petroleum supply
- The degree of dependency of the economy on petroleum and the size of reserves
- The level of national economic and educational development
- The structure and capacity of the NOC, and the presence or absence of an international oil company (IOC)
- International obligations (such as membership in OPEC or the World Trade Organization, WTO)
- The legal and fiscal framework that governs the petroleum sector

Governments may try to reduce the number of players to avoid the fragmented responsibility, lack of cohesion and strategic clarity, and rent seeking that affect the sector's supply. This is especially relevant where the state and its institutions dominate the operations (as in Iran, for example). If the private sector were the key operator, then the discipline of the market would likely improve clarity and coherence by focusing the players on finding a balance between maximizing revenues for the private sector and for the government. An absence of clarity and coherence leads to policy paralysis and an inability to mitigate the risks of state capture by the NOC (rent seeking) or the risks of underinvestment in the development of production and petroleum resources by the NOC (as rents are allocated outside the NOC to energy consumers through subsidized prices, for example).

In all four cases, there was growing government concern that the NOC was not performing but indulging in rent-seeking behavior, which raises questions about the quality of the regulatory framework. The Saudi system could be viewed as vulnerable to the information asymmetries that underlie rent-seeking behavior, given that Saudi production is largely self-regulated. A key area of debate in all four cases studies is where to locate the regulators, and what their role should be.

Governments need to avoid overlap in authority over sector regulation and operational decisions. Regulation upstream can range from technical inspection to overseeing financial transactions to monitoring licensing rounds to ensuring there is no corruption or anticompetitive practices. Downstream and midstream, in addition to technical and financial monitoring, there are also potential issues of competition and access to infrastructure that might require regulation. It is generally agreed that the optimal solution is to allow operators to operate and regulators to objectively determine compliance.

Governments need to avoid conflicts of interest with operators because these hamper operational decision making. Links between the regulator and the ministry can be controversial. Many examples in the case studies illustrate this, such as the debate between the Kuwait Petroleum Company (KPC) and the Ministry of Oil. Of special note is the frequent conflict of interest that emerges when the minister of oil is on the board of the NOC. The two hats worn are those of sovereign owner (on behalf of the citizens) and company shareholder seeking profit and value creation. This conflict was particularly noticeable in Iran and Kuwait, but could also emerge in Yemen.

Sorting out problems associated with oil sector control and monitoring raises two policy issues. The first relates to the legal and regulatory framework within which the sector operates. There are no clear lessons from the case studies. In Saudi Arabia, where the sector appears to work relatively well, there is no petroleum law and the sector is largely self-controlled and self-monitoring. In Yemen, where there is also no petroleum law, the sector performs less precisely because of a lack of control and centrally directed strategy. In Kuwait and Iran, the overarching legal framework is the constitution, which tends to act as a rather blunt instrument when it comes to the sector's operations. While there are also petroleum laws and regulations in Kuwait, they have yet to be agreed upon by the ministry and the NOC, a fact that has slowed down the decision-making process. The second policy issue is the transparency of financial and physical flows, which is essential for any meaningful level of sector monitoring, but appears weak in several case studies.

Governments have an interest in clarifying the sector's objectives and priorities in terms of a broad target for expanding supply capacity, the general role and long-term fiscal contribution of the private sector, domestic energy-pricing principles, and the share of production allocated to domestic energy markets. The four countries exhibited different policy objectives, all focusing on national interest, and—all else equal—often to reduce risks of revenue decline to the government. Upstream, Iran and Yemen were driven predominantly by the need to arrest and reverse declining crude export volumes. In Kuwait, the driver was anticipated production problems as the geology of the existing fields gets more complex. In Saudi Arabia, the driver was wider political interest, because excess capacity to produce crude oil gives the Kingdom a unique role in global oil markets and overall economic stability. In terms of downstream oil and gas developments, objectives also reflected differing circumstances. In Kuwait and Saudi Arabia, the main issue was to increase product exports over crude and the main debate was over the location of the new refinery capacity—that is, domestic or abroad. In both cases, supplying the domestic market with oil products is not a problem. In Yemen and Iran, on the other hand, the emphasis was on current problems supplying domestic markets, especially in Iran with its growing gasoline shortages. In both countries, there is also a lively debate over what constitutes the optimal function of gas reserves—export or domestic use.

The extent to which the sector objectives were linked to wider development objectives was often unclear, with the exception that, in all cases, a key objective was to maximize fiscal linkages in order to fund central government activities (which is a necessary but insufficient condition for maximizing government petroleum revenues on a sustainable basis). In this sense, **the overall objectives of the sector are set at the highest levels of government in order to maximize government revenue. To optimize sector performance, the translation of these high-level objectives into operational objectives should be left to the sector.**

Productive Efficiency

Although data are insufficient to assess the technical and financial performance of the NOCs in most MENA countries, case studies suggest there is scope for increasing the productive efficiency of the sector, which can often be hampered by inadequate provisions for government oversight of the NOCs, or conflicting objectives applied to the sector. **A key policy goal is to make sure that operators have the greatest incentive to reduce production costs and to invest in developing oil and gas reserves.**

Investment in reserve development, however, is rather specific to petroleum supply. More than any other underground natural resource, developing petroleum resources involves large and risky capital investments that require mitigating risks related to the appropriation of profits and long-term guarantees that part of the rent will be able to stay with the investing firm.

How much is reinvested will be influenced by three factors: (1) the need for government revenue, (2) the government's depletion policy based on the comparative rates of return on oil versus the rest of the economy, and (3) government confidence that the NOC will not use the cash for rent seeking or corruption. It is not at all clear from the case studies on Iran, Kuwait, and Yemen what this decision is based upon or, indeed, if there is any logical basis for the levels of reinvestment other than political compromises between opposing vested interests. In the case of Saudi Arabia, the situation is clearer since the capacity target is a given: 2 million barrels per day (mb/d) above current production—and whatever the sector needs to achieve this—is provided.

The case studies suggest that corporatizing the NOC is a good start to creating incentives to minimize production cost. The role of the private sector and competition—which, in theory, should promote greater efficiency—is unclear, not least because in all cases studied but Yemen, private sector involvement has been absent or severely constrained by barriers to effective entry. The private sector is, however, increasingly present in the supply of services to the upstream, and ought to be encouraged. Privatization of downstream activities also offers the potential to reduce both rent seeking and the burden of losses incurred downstream from selling oil products and natural gas to domestic markets at subsidized prices.

To assess sector performance, transparency of data—both operational and, most importantly, financial—between the government and the operator is key. **What is required is internal financial transparency between the oil ministry, the ministry of finance, and the NOC.** There is less agreement over what data should be divulged externally to the rest of society, but, at the very least, information access would increase public confidence in the sector.

What emerges from the case studies is the **need for the clear delegation of responsibility within the sector; the development of capable regulatory institutions; and, finally, the means to enforce regulations within the sector, leading to greater accountability.**

Fiscal Linkages

In all cases, maximizing fiscal linkages has been a key government objective. Over the years, governments have become extremely adept at using fiscal systems to maximize the size of revenue share they obtain, and there is little sign from the case studies that any improvement is required. Governments have been less successful in growing total revenue, most obviously in the cases of Iran and Yemen.

There are two relevant policy issues:

The first, already mentioned, is **how much of the revenue generated by the oil sector should be reinvested to expand the capacity to produce more oil and generate/earn more revenue. For the government, this may translate into defining a clear, long-term fiscal rule to appropriate revenues to be used for non-oil purposes.** The second is **what policies need to be developed to encourage additional investment (from NOCs or IOCs) to develop the upstream. In all cases, clearer fiscal expectations should be established for the sector.**

Forward Linkages

Forward linkages are a function of downstream operational efficiency, the pricing policies for domestic oil and gas products, and the optimized use of gas reserves. Policy can improve the situation by encouraging greater competition in the downstream sector, which by definition requires greater private sector involvement. In many cases, the downstream has suffered from underinvestment. As opposed to the situation upstream, **private sector involvement downstream tends to be much less politically sensitive. Improvement in efficiency also requires a regulatory system that is procompetition.**

As stated earlier, a major issue in all countries studied (and in many MENA countries) is the pricing of domestic oil products. Subsidy levels remain high in many MENA countries, although the levels of marginal production costs can be fairly low in the MENA region overall. A key policy issue is that **low domestic prices, even where costs are being covered, lead to excessive domestic consumption and the likelihood of high levels of smuggling.**

The presence of gas reserves tends to create a debate over whether to use them for domestic or export purposes, which again reflects a lack of strategic vision for the sector. In both Iran and Yemen, this has constrained gas development.

Backward Linkages

Backward linkages involve the employment of nationals, the development of local content, and the nature of the NOC's "national mission." In most MENA countries, the petroleum sector is seen as a major national employer. However appealing this may sound for governments trying to reduce unemployment, this obligation in what is a capital-intensive sector can burden overall functioning—as empirical evidence demonstrates. The policy solution to this problem is to **insulate the operators from excessive pressure to employ, while ensuring that education and training policies improve the pool of skilled labor from which the oil sector can draw.**

Regarding the obligation to increase local content in petroleum sector procurement, the case studies suggest that **decisions about local content are best left to the discretion of the NOC rather than to regulatory enforcement**. Regulatory enforcement can actually be counterproductive, as shown in some of the cases studied, not least because it simply encourages mechanisms to circumvent the regulations.

Ideally, the oil and gas sector should be left to focus on issues related to the production and sale of oil and gas. As already mentioned, however, the national mission of the NOC often requires it to involve itself in a much wider agenda. Where this happens, **experience suggests that policy should be aimed at providing clear limits to the scope of this mission and ensuring a clear exit strategy once government capacity to manage such peripheral activities develops.**

1. Oil in the Middle East and North Africa: Why Sector Structure and National Oil Companies Matter

1.1 This report asks the question: how can oil-producing countries maximize the contribution of the oil industry to their economic development goals? This is a complex process of ensuring that the right institutions and incentives govern petroleum companies' operations in a sector where the rents are high and the global markets imperfect. The issue is examined in four case studies: Iran, Kuwait, Saudi Arabia, and Yemen.

1.2 High oil prices can hide a number of inefficiencies in the ability of the petroleum sector to maximize hydrocarbon extraction efficiency and the spillover benefits to domestic economies. Yet, governments of oil-producing countries always seek to eliminate these inefficiencies and increase the value they can extract from their hydrocarbon resources. The reason why this report focuses on Middle East and North Africa (MENA) countries is twofold. MENA countries' experience in managing their petroleum sector has a number of useful lessons to offer to other oil-producing countries that seek to respond to similar questions. MENA countries often find themselves having to make difficult choices in order to maximize petroleum sector revenues, while at the same time maintaining sufficient levels of investment in the sector and finding efficient ways to redistribute the rent among their citizens. In addition, the importance of MENA to the global oil supply is such that inefficiencies in the management of the petroleum sector affect not only its economies, but also the rest of the world—in particular the poorer economies, which are most vulnerable to high-priced hydrocarbons.

1.3 In managing oil and gas resources, governments can decide how they want to structure the petroleum sector, and, in this way, shape the nature of its contribution to the country's economic development. To do so, a minister of oil needs to respond to a number of important questions, such as:

- Who should set the objectives for the oil sector?
- Should the government set a production target or should this be left to the operator?
- How should private investment contribute to the development of the petroleum sector?
- How should the oil and gas sector be regulated?
- If the country owns a national oil company (NOC), how should the financing of that NOC be organized?
- Should the NOC be left to operate without interference?
- Should the NOC be allowed to operate on a commercial basis and pay taxes?
- Should the NOC face domestic competition?
- Should the NOC be allowed to operate abroad?
- Should the minister of oil be the chairman of the NOC board?
- How much information about the NOC operations should be made public?
- On what basis should the domestic oil product prices be set?
- Should there be a policy for developing domestic gas resources?
- Should the level of local inputs to the sector be subject to regulation?

1.4 This report analyzes these questions, focusing on two issues. The first is whether the oil sectors in MENA countries are capable of responding to the potential growth of market demand for oil and gas, given these countries' large oil and gas reserves. This is what we refer to as delivery on geology. The second question is whether the oil and gas sector can contribute to domestic economic development.

1.5 It is important to emphasize that this report is not intended to consider whether MENA countries should develop the capacity to produce sufficient oil or gas to meet consumer expectations. These are sovereign decisions left to individual governments, decisions that depend upon many factors including concerns about future generations and government exercise of market power.

1.6 Rather, the focus of the report is to highlight how, in various countries' experience, institutional structures influence whether investment levels are the product of design and successful strategies, or of political and economic constraints. In the management of oil and gas resources, MENA countries offer a unique source of experience that this report hopes to tap. MENA countries also offer a range of sector structures showing that, even if no size fits all, some arrangements will clearly be more efficient in ensuring that the sector performs well and benefits the country's economic development.

Delivery on Geology?

1.7 According to many forecasts, global oil consumption is projected to rise by more than one-third by 2030, or some 30 million barrels per day (mb/d) (see annexes 1 and 2). To meet this demand, substantial increases in MENA petroleum production are expected (see Figure 1). According to the International Energy Agency (IEA), MENA oil output (crude oil and natural gas liquids, NGL) is projected to rise by nearly two-thirds, or 17 mb/d, to about 44 mb/d in 2030. Its share of world oil supply could therefore increase from 32 percent to nearly 38 percent over the period. MENA has over 60 percent of the world's known oil reserves, mostly concentrated in the Middle East.

1.8 There is no question that the region has the oil reserves to meet current forecasts of oil demand.[1] In 2005, based upon data from the British Petroleum (BP) Statistical Review of World Energy 2006, the world outside the Middle East had a reserve production ratio of 22 years. Given the level of Middle East reserves, using the same reserve to production (R/P) ratio, the region could produce over 90 mb/d, compared to its actual production in 2005 of some 25 mb/d.

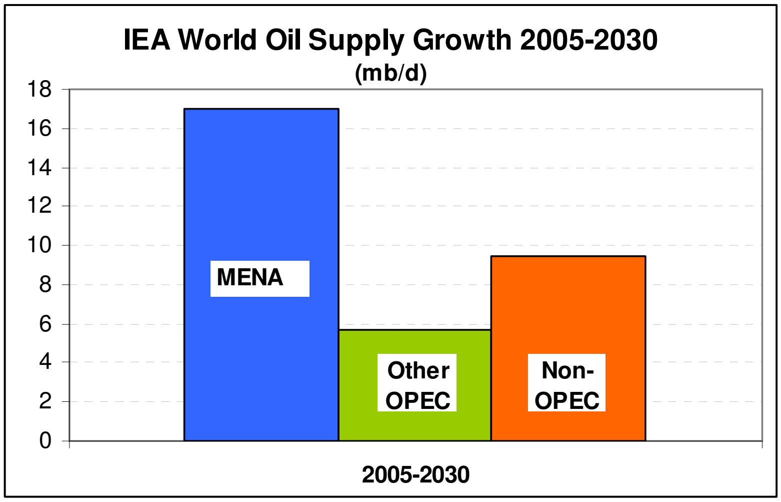
1.9 While the geological potential to produce more oil exists, the key question is whether the petroleum sector in MENA will be able to expand its production capacity, then export the oil and gas to international markets.

1.10 Oil prices and oil export revenues have experienced substantial fluctuation in the past 35 years (see figure 1.2), which in turn has impacted oil demand, oil supplies (both in and outside the Organization of Petroleum Exporting Countries, OPEC), and oil export revenues—most

[1] There are some (for example, see Simmons, 2005) who doubt the accuracy of OPEC reserve estimates. But, even allowing for overstatement, it is clear that, in the foreseeable future, there are sufficient reserves to carry much higher production levels from several countries.

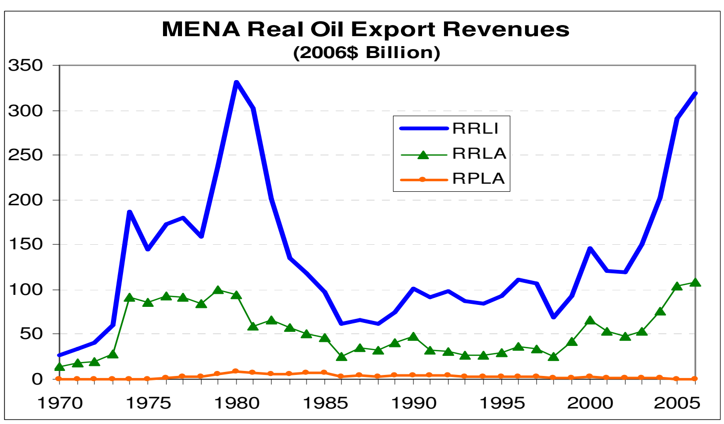
dramatically in the resource-rich, labor-importing (RRLI) countries (see Figure 1.3).[2] OPEC's policy decisions have had a significant impact on oil prices, and thus on oil revenues. MENA oil producers represent nearly 80 percent of OPEC, measured by oil-production volume, and thus play an important role in the global oil market, both with respect to volume and in determining average price (and, therefore, oil revenue).

Figure 1.1 IEA World Energy Supply Growth



Source: IEA.

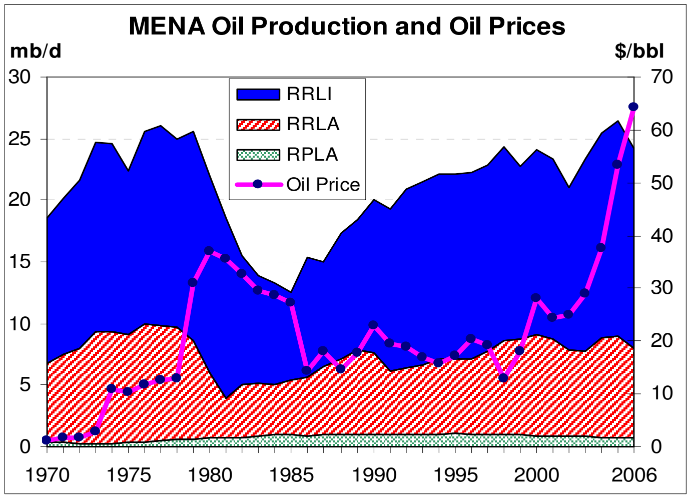
Figure 1.2 MENA Real Oil Export Revenues



Source: Energy Intelligence Group, *Petroleum Intelligence Weekly*, World Bank.

[2] Resource-rich, labor-importing countries are Bahrain, Kuwait, Libya, Oman, Qatar, Saudi Arabia, and the United Arab Emirates (UAE).

Figure 1.3 MENA Oil Production and Oil Prices



Source: Energy Intelligence Group, *Petroleum Intelligence Weekly*, and World Bank.

Delivery on Economic Development

1.11 The petroleum sector is also expected to help contribute to domestic development through (1) positive impacts on the non-oil economic sectors and (2) overall poverty reduction. Fiscal, forward, and backward linkages are the channels through which those contributions are mobilized.

1.12 *Fiscal linkages* refer to the sector's ability to provide the government with budgetary resources and foreign exchange from the export of petroleum—crude oil, gas, and oil products—to allow investment in infrastructure, education, health, and other key sectors. Fiscal linkages may appear as a one-way flow of revenues, but, obviously, the ability of the petroleum sector to provide revenues to the government is determined by sector incentives. In other words, the mechanisms that channel part of the revenues back to the sector and that determine operational decisions are a central element of fiscal linkages.

1.13 While broader economic development is strongly influenced by the sector's ability to provide revenue, foreign exchange, and other linkages (such as job creation), the government's overall development strategy in terms of how the revenues are deployed is crucial. In particular, the government's attitude toward the respective roles of the private and state sectors in the economy has considerable implications for (1) the ability of the hydrocarbon sector to generate sustainable sources of revenues for non-oil purposes, and (2) policies that affect the liberalization of trade and protectionism.[3]

[3] There is much literature on how oil revenues are used (and misused) for non-oil purposes in producing countries. See Auty, 2001; Davis and others, 2003; Hannesson, 2001; Isham and others, 2005; Rosser, 2006; Stevens, 2006; World Bank, 2005.

1.14 *Forward linkages* refer to the ability of the sector to provide energy and feedstock to fuel the non-oil economy. *Backward linkages* refer to the supply of factor inputs drawn into the sector from the rest of the economy, in particular, the employment of nationals and the development of local content in the supply chain.

THE ANALYTICAL FRAMEWORK

1.15 Neither delivery on geology nor delivery on economic development can be taken for granted. Independent of the decision to extract oil and gas resources (and set extraction goals), the government-structured framework must provide sufficient incentives to extract oil and gas efficiently, as well as to contribute to economic development via fiscal, forward, and backward linkages.

1.16 This discussion of incentives raises several questions. In terms of structure, what works and what does not in modifying the ability to deliver on geology and economic development?[4] What role can government policy play in improving sector performance? To answer these questions, we look to four case studies: Kuwait, Iran, Saudi Arabia, and Yemen. These countries were selected because of (1) their importance to the global oil supply, representing 42 percent of global oil reserves in 2005,[5] and (2) the variety of sector development styles and structures they represent. The role of the NOC is quite different in each. Yemen provides a contrast to the other three, where large monopoly NOCs dominate the upstream. In Yemen, the upstream has been dominated by international oil companies (IOCs).

1.17 As mentioned earlier, capacity investment plans and export levels can be significantly influenced by both OPEC decisions and domestic policy drivers not connected with the petroleum sector. The most obvious example is Saudi Arabia, where restoring a cushion of spare crude–production capacity was a deliberate government decision based on foreign policy considerations rather than sector performance. Another example is Iran's decision to heavily subsidize oil products for fear of a domestic political backlash if prices were raised, and as a means of redistributing some of the benefits of the nation's oil endowment to the population. The result is the serious erosion of Iran's capacity to export oil. A final example is Algeria's recent decision to suspend crude production capacity expansion plans because of growing problems of how to manage the inflow of oil revenues once the debt repayment option is exhausted. Geology is also a key factor constraining production capacity and export potential. Geology is exogenous to sector structure—although knowledge of the geology is not, since this is the result of exploration efforts.

1.18 Sector structure (the network of players and organizations that guide the sector) is amenable to change in a way that other drivers may not. OPEC policies are largely exogenous to the sector, and other decisions such as domestic oil product prices are constrained by domestic political considerations. Reforming sector structure, while not necessarily an easy task, involves far less constraints than other options.

[4] See Chatham House, 2005; Marcel, 2006; Davis and others, 2003; Stevens, 2004; Van der Linde, 2000.
[5] BP, 2006. Iraq has very significant reserves, but the current situation is extremely unclear in terms of both security and the way in which the petroleum sector may evolve. Therefore, Iraq has been omitted from this study.

1.19 In essence, this report is about how efficient sector structures are in making sure the hydrocarbon sector delivers on geology and economic development. Assessing sector structure can be done using the conventional theory of the firm, which considers that firms maximize profit (or market share, sales, and profit) under constraints. Monopolistic market structures are more prone than others to rent capture.

1.20 Assessing the sector using a production function approach would help us understand how output is driven by factor inputs (capital, technology, price of oil and gas).[6] Using such models is, however, of limited policy relevance to the work, mainly because the oil sector has two specific features that need to be considered: (1) the oil market is composed of a large group of players operating within OPEC, and (2) the size of the rents available to firms and governments is very large.[7] As a result:

- There is a notable absence of numerical data (on production, costs, discount rates, and so on) that can be used to empirically test the dynamics highlighted by such a model. This absence of data is at the heart of the strategy to increase the asymmetry of information—and therefore control—over the rent from oil and gas extraction and sale.[8]
- Given high rents, there is considerable competition within governments to achieve and increase control over part of those rents. This competition determines how the sector operates by gradually structuring the institutional framework, defining control and regulatory mechanisms, deciding whether private investors are allowed to invest or not, choosing rules to allocate revenues from oil and gas sales, and so on.

1.21 For these reasons, the report takes a qualitative empirical approach, looking back in time at how the sector was structured. This approach focuses on the broad context—the domestic political economy—in which the petroleum sector operates. This reveals the underlying dynamics that drive the sector's efficiency and its contribution to domestic economic development.

1.22 For each case study, the report begins with an analysis of who sets sector objectives, and how the players interact in setting up those objectives and in operating the sector. The authors then examine the control mechanisms influencing and monitoring the operations of the sector. Together, these set the political history and sociocultural dimensions of the sector.

1.23 Next, sector objectives are analyzed in terms of what they are, who sets them, and how far the objectives are characterized by conflict or cohesion. This identifies the political constituencies involved in the decision-making processes and the nature of the sector's "national mission."

[6] See Hartley and Medlock, 2007, for an example of such a model.

[7] In the oil price there are two elements of economic rent. The first is the difference between the supply price and the market price accruing to producers who face low costs—the so-called producers' surplus. This can arise from efficient production or favorable geology or both. The second is the supernormal profit accruing to all producers as a result of OPEC constraining supply.

[8] In addition, the oil and gas sector has gone through rapid technological change in the past 20 years, with innovations reducing the rate of decreasing returns and changing the cost structure.

1.24 Once this overall context has been established, sector performance is assessed, including (1) sector ability to deliver on geology in terms of sector investment; (2) productive efficiency; and (3) ability to deliver on development by considering fiscal, forward, and backward linkages. In each case, the performance is related to the sector structure and context. From this, various policy lessons are drawn that may inform governments of good and bad practices.

1.25 The analytical framework used for each case study is outlined below.

Context for the Petroleum Sector

The meaning of sector structure

The political economy of the sector structure
- Who sets the objectives?
- The players and their interactions
- Control operation and monitoring
- Main messages

The objectives of the sector
- What are the objectives?
- The objectives—conflict and cohesion
- Main messages

Sector Structure and Performance

Delivery on geology?
- Investment in the petroleum sector
- Productive efficiency
- Main messages

Delivery on development
- Fiscal linkages
- Forward linkages
- Backward linkages
- Main messages

1.26 The report also contains a detailed annex on trends in oil consumption, reserves, production, exports, and oil export revenues for individual MENA countries and the main groups—resource rich, poor and labor abundant, and importing. It presents MENA's role in OPEC, and the group's role in the world oil market. It also presents various long-term outlooks for oil and gas production both around the world and in MENA. Finally, it summarizes short-term oil development plans for OPEC oil producers in MENA, and ranks MENA's state oil companies among the world's top oil and gas oil companies.

MAIN LESSONS FROM PETROLEUM SECTOR CONTEXT

The meaning of Sector Structure

1.27 To understand how the context of a specific country situation emerges requires more careful definitions of terms such as *government-industry arrangements* and *sector structure*.

Government-industry arrangements refer to the relations between the petroleum sector and the rest of the country effectively represented by the government.

1.28 These relations refer to the ways decisions are made in a number of areas, and may concern the levels of capital spending in terms of access to domestic capital, foreign borrowing, and foreign direct investment (FDI). They may also relate to other factor inputs into the sector, ranging from labor to service industry access.

1.29 The players involved in government-industry relations obviously vary between countries, but, in general, can be categorized as citizens represented by parliament—elected or appointed—and the government, which may include a cabinet, ministries, central bank, regulators, and so on. The number and nature of the players that make up the "citizens represented by parliament" matter because each group will have its own interests and its own avenues of influence. The greater the number of players and the greater their diversity, the more difficult it may be to create and implement a coherent policy. There may be too many conflicting objectives that cannot be reconciled. As will be seen, a good example of problems arising from having too many influential players can be found in Kuwait.

Sector structure refers to the way in which the players in the petroleum sector interact.

1.30 Within the sector, players often include some form of overarching petroleum council, such as an oil or energy ministry; operators and investors represented by the NOC and its affiliates; and private sector players that may be local or may include the IOCs. Finally, there are the regulators, who may include the existing players or may be independent entities. Sector structure can also refer to the way in which individual players are organized. For example, the NOC may have upstream, midstream, or downstream assets, and these may be located domestically or abroad.

The Political Economy of the Sector

Who Sets the Objectives?

1.31 The overall objectives for the sector are set at the highest levels of government. What matters for sector performance, however, is who translates these high-level objectives into operational objectives. The case studies appear to confirm that the more this process is left to professional expertise within the operators, the better the outcome. Problems seem to emerge when political considerations begin to interfere with operational objectives.

1.32 The case studies show a wide spectrum of control over and coordination among sector objectives. At one extreme is Saudi Arabia, where, apart from the key decision on capacity levels, many sector objectives were set by Saudi Aramco (the NOC) and the Ministry of Oil. At the other extreme, in Yemen, the responsibility lies with the Ministry of Oil for setting sector objectives in terms of broad supply capacity expansion, plans for exploration and production (E&P), and anticipated long-term revenue contribution to the government budget. The decisions seem to be influenced by other interactions that affect the definition of actual priorities. In such a context, individual elements have latitude to create their own mini-constituencies within the structure, exploiting asymmetries of information. Kuwait and Iran were effectively in the middle of this range. Given their political context, the origin of sector objectives is unclear.

The Players and Their Interactions

1.33 The interactions between government-industry arrangements and the sector—and hence, the overall context—obviously vary among countries depending upon the political system and other factors. Normally, they are a function of formal relations embodied in laws, bylaws, and regulations. Players within and outside the petroleum sector all operate and interact within this legal and regulatory framework. This often—but not always—revolves around a specific petroleum law. In Yemen, for example, there is no overarching petroleum law, and each contract with an IOC is treated as an individual law. In addition to petroleum laws, there are also commonly a collection of bylaws and regulations that can sometimes contradict each other, as in Kuwait, for example, where there is an ongoing dispute between the Kuwait Petroleum Company (KPC) and the Ministry of Energy over the interpretation of such bylaws. This entire legal framework is expected to govern issues such as upstream contracts; domestic oil product prices; budget allocation and control; various mechanisms to manage the revenue flows; health, safety, environment (HSE) requirements; and many other dimensions of oil sector operations.

1.34 Informal networks based upon personal connections and the role of individuals often develop around this formal structure. For example, KPC's decision to initiate operations abroad both upstream and downstream was in large part due to the personality and driving ambition of one person, Ali Khalifah al-Sabah, who was oil minister between 1978 and 1990. These informal networks often complicate the understanding of how the sector operates in practice.

1.35 The precise nature of these operations and interactions will vary enormously among countries. Variations will stem from several factors.

1.36 ***The level of economic development*** plays a role by setting the broad economic objectives in which the petroleum sector operates. Economic development parameters include demographic growth, employment rates, poverty levels, the importance of oil revenues to the fiscal stance, the capacity of various government institutions to perform the tasks they are responsible for, and non-oil economy size and growth.

1.37 The categorization of RRLI; resource-rich, labor-abundant (RRLA); and resource-poor, labor-abundant (RPLA) countries indicates the relative importance of the oil and gas sector in the economy. In resource-rich economies such as those chosen for the case studies—Kuwait, Iran, Saudi Arabia, and even Yemen—the nature of the government-industry arrangements are subject to very close scrutiny given that they influence the largest source of government revenue and foreign exchange within the economies. The availability of labor can also often influence the competence of those scrutinizing the arrangements and their consequences.

1.38 As will be discussed below (see backward linkages), the level of economic development is also a key factor in determining the potential for the sector to influence backward linkages and promote non-oil economic growth. Thus, to use the language of Hirschman (1958), who first developed the concept of such linkages, the extent of backward linkages will often be determined by the degree of the "technological strangeness" of the oil sector vis-à-vis the rest of the economy.

1.39 ***The history of the petroleum sector*** matters since it influences public perception and expectations of the sector. It also informs the legal system governing the petroleum sector and its contractual and international obligations (such as membership in OPEC). For example, in both Iran and Kuwait, previous experience with the IOCs led to the constitution preventing foreigners from accessing legal rights over subsoil minerals. History also affects relations between sector players such as the government and the NOC.

1.40 A number of producers such as Algeria, Iran, and Iraq have a long and sometimes conflict-ridden history of dealings with IOCs, which are often perceived as mechanisms to export the petroleum rent out of the country. Others, such as Saudi Arabia, Bahrain, Qatar, Oman, and the United Arab Emirates (UAE) had more positive experiences and show less popular hostility toward IOCs. Countries such as Kuwait, Libya, Syria, and Yemen have experiences resulting in mixed perceptions of the way IOCs manage national petroleum resources, particularly oil fields.

1.41 ***Culture and politics*** affect the way in which authority and influence are employed, the extent to which decision making is centralized, and what role there is for the public debate of issues. They also determine the existence of checks and balances to executive power, and the allocation of power within the petroleum sector and between the sector and the rest of the political system. They may also affect the level of public trust in state institutions—which influences how much power is devolved within the sector—and the capacity of government to promote development and social welfare. A good example is the case of the KPC. Many in Kuwait, including members of the National Assembly, have raised concerns about the KPC's efficiency and competence. Whether such concerns are real or perceived, they have generated deep distrust in many of the KPC's initiatives. This is reinforced by the importance of the KPC in the Kuwaiti economy, and its potential to become a "state within a state."

Main Messages

1.42 *Clearly, no one system fits all circumstances.* Similarly, no single theory explains the complexity of a sector that controls such large shares of the economies examined. The greater the number of players and the more fragmented the system, however, the less likely it is to find cohesion and strategic clarity driving the sector. This is especially relevant where the state and its institutions dominate the operations. If the private sector were the key operator, then the discipline of the market would likely improve clarity and coherence by focusing the players on finding a balance between maximizing revenue for firms and for the government. The danger is that an absence of clarity and coherence leads to policy paralysis, and an inability to mitigate the risks of state capture by the NOC (rent seeking) or the risks of underinvestment in the development of production and resources by the NOC when the rent is diverted away and allocated to other rent seekers.

Control, operations, and monitoring

1.43 The relationship between government-industry arrangements and sector structure can be described in terms of control, operations, and monitoring.

1.44 ***Control***. There are controllers, such as petroleum councils and oil ministries, whose normal functions are to determine policy objectives. Control relates to a number of functions. It starts with setting sector objectives, a function that remains with the government because the objectives of the petroleum sector cannot be set in isolation from other more general government objectives (see below for a further discussion of what is meant by *objectives*). These strategic objectives must have some clarity, with potential conflicts resolved through a process of prioritization. Such strategic objectives relate to capacity-expansion plans, production levels, and downstream production plans and investments. But control relates to more than just objectives. It also extends to monitoring tasks (described below) and defining the shares of revenue available to the NOC, together with other decisions on industry strategy upstream, midstream, and downstream.

1.45 ***Operations***. The operators are the NOC and IOCs (if present). While overarching strategic objectives should be set outside the sector as part of a wider development strategy, translating them into tactical objectives (targets) and day-to-day operations is normally the responsibility of the operator. These operational decisions are technical issues that need to be determined by those competent to do so. For this reason, as will be developed later, experience suggests that the sector itself should be insulated from the outside interference of the various players representing society.

1.46 The two extreme examples in the case studies are Saudi Arabia and Kuwait. In Saudi Arabia, by order of the king over several decades, the sector is largely insulated from outside interference and allowed a free hand to operate. In Kuwait, by contrast, all elements of society—most noticeably the National Assembly and its individual members—feel entitled to interfere on a regular basis in issues such as hiring and investment allocations. In general, countries in the region are lumbering toward greater democracy, defined as greater public participation in the decision-making process. In an NOC-dominated petroleum sector, this presages greater interference in the way in which the petroleum sector is allowed to operate. The role of the Majlis (parliament) in Iran and the National Assembly in Kuwait illustrate this trend.

1.47 ***Monitoring***. Finally, there are the monitors, who may or may not be the controllers, often depending upon where regulation has been placed in the structure. Monitoring needs to be done within the sector, but there should also be outside monitoring to control rent seeking and corruption. The independence and competence of any regulatory authority is paramount to the quality of monitoring.

1.48 The contexts outlined above inevitably lead to wide differences in control and monitoring of the sector. In three of the cases—Kuwait, Iran, and Yemen—interactions among the various entities were confusing. Often this arose because of the way the political interactions in those countries developed. In effect, the organization of the sector was an organically grown phenomenon with little or no clear direction or strategy. By contrast, in Saudi Arabia the oil sector was protected from most sources of interference and therefore was able to behave much more like the IOC that it originally was. One may be tempted to say that an NOC may not be inherently problematic, provided control and monitoring effectively secure the performance of the sector.

1.49 In all four case studies, however, there was growing concern that the NOC was not performing but indulging in rent-seeking behavior. In Kuwait, Iran, and Yemen this concern came both from outside and from within the sector itself. For example, in Kuwait, it was the senior management of the KPC that wanted to encourage IOC involvement upstream to provide a benchmarking opportunity. By contrast, in Saudi Arabia, concern was generated outside the sector by both the foreign and finance ministries. This is particularly interesting because the existence of expertise in the oil industry outside of Saudi Aramco and the Saudi oil ministry is extremely limited. The Saudi system could be considered vulnerable to the information asymmetries that underlie rent-seeking behavior, given that control and monitoring are internal.

1.50 A key area of debate in all four cases studies is where to locate the regulators and what their role should be. Upstream regulation can range from technical inspection to overseeing financial transactions and monitoring licensing rounds to ensuring no corrupt and anticompetitive practices exist. In the down- and midstream, in addition to technical and financial monitoring, there are potential competition and infrastructure access issues that might require regulation. It is generally agreed that the optimal solution is to allow operators to operate and regulators to objectively determine compliance. But links between regulators and ministries can be controversial as many examples in the case studies illustrate, such as the debate between the KPC and the Kuwaiti Ministry of Oil. Of special note is the frequent conflict of interest that emerges when the minister of oil is on the board of the NOC. The two hats worn are those of sovereign owner (on behalf of the citizens) and company shareholder seeking profit and value creation. This conflict was particularly noticeable in Iran and Kuwait, but could also emerge in Yemen.

Main messages

1.51 The key is to allow the operators to manage technical targets without undue interference. Also important is that regulation should be independent and competent. Sorting out problems associated with oil sector control, operation, and monitoring raises policy issues. In terms of the need for a specific type of legal and regulatory framework within which the sector operates, there are no clear lessons from the case studies. The existence of a petroleum law or the presence of strong regulatory institutions does not guarantee sector's performances.

1.52 Policy can also play a key role in promoting transparency, which is essential for any meaningful level of sector monitoring. In all cases, while there is rhetoric in favor of greater transparency, there are no formal moves to sign up to various codes of practice such as the Extractive Industry Transparency Initiative (EITI), apart from the case of Yemen, who joined the EITI in November 2006.[9]

The objectives of the sector

What are the objectives?

1.53 The incentives and disincentives that emerge from the government-industry arrangements and the subsequent sector structure determine whether the sector achieves its objectives.

Objectives can be inspirational or binding.

1.54 ***Targets***, by contrast, relate to operational matters such as depletion rates, production volumes, and cost and productivity targets. Setting prioritized objectives is basically a political issue for the government to decide, while targets can often be set by the NOC. In MENA, petroleum sector objectives relate to the situation upstream, midstream, and downstream. Upstream plans are connected to capacity expansion plans for crude production. These are usually expressed in terms of exploration and development programs by the NOC. They can also relate to the expected role (if any) of the IOCs. For example, in the case of Iran, the expenditure plans for the sector explicitly identify a tranche of the investment expected from the IOCs. Upstream plans often include managing gas in terms of developing gathering systems and transporting gas to the market. In the midstream, plans may relate to investments in pipelines and, in many cases (most obviously Kuwait and Saudi Arabia), the size and deployment of a national tanker fleet. Downstream objectives relate to refinery capacity plans. They may also relate to domestic pricing objectives and product marketing arrangements.

1.55 **The prime objective should be the petroleum sector's sustainable development for the eventuality of oil or gas losing value.** This involves a number of dimensions. The first is to maximize the revenue accruing to the state to allow it to promote development. This concerns the state's strategy to exploit natural resources and the policy tools needed to capture the rent through taxes or revenue shares in fiscal regimes. As has already been discussed, this is a necessary but not sufficient condition to promote development. The use to which the revenues are put is also a key factor not covered in this report. The second dimension is to maximize the forward and backward linkages surrounding the petroleum sector. The third is to promote social welfare. Ideally, this last role should be the government's, but, in some cases, the government lacks capacity, and thus the role falls to the NOC. These objectives can be best understood by

[9] This may also simply reflect the unimportance of private oil companies in these three countries since the Extractive Industry Transparency Initiative (EITI) tends to be closely linked to the interest of the government to "publish what you pay" to private investors.

considering a common divide between commercial objectives and the objectives of the national mission. For example, as will be developed below, sector employment and procurement policies often raise concerns in terms of commercial efficiency, but make sense in terms of the national mission.

1.56 **The commercial objective can be defined as maximizing revenue.** But this may be more complicated than the profit-maximizing target normally associated with an IOC.[10] The NOC may indeed be obliged to consider optimizing revenue over time, which raises the issue of allocative efficiency upstream. This relates to not just the present value of the revenue flow, but the fact that the discount rate used to compute the present value can change over time. This simply reflects the changing preference of the government for present versus future revenues. For example, a country that is struggling to make good use of its revenue today arguably could have a negative discount rate reflecting a negative time value of money, that is, a preference for maximizing future revenue generated by the perception of the potential distorting effects of present revenues on the rest of the economy. For large oil-producing countries in a position to affect the global price, there is the additional possibility of a backward-bending supply curve, implying a preference to sell less oil or gas but at a much higher price. Commercial objectives are achieved by the implementation of projects upstream, midstream, and downstream. These projects can be located within the country or abroad, although the case studies show that NOC operations abroad attract considerable controversy. The extent to which sector objectives were linked to wider development objectives was often not clear with the exception that, in all cases, a key objective was to maximize the fiscal linkage in order to fund the activities of the central government.

1.57 **The national mission of the NOC has various interpretations.** The NOC is not just expected to produce oil and gas to generate revenue for the state; it is also expected to make other contributions to economic growth and social welfare. These could range from developing the non-oil economy to providing employment opportunities for nationals. In most MENA countries, unemployment is a major problem and the sector and its operating units are coming under increasing pressure to employ more nationals. Agreement between the government and the NOC over the goals of the national mission is essential. This involves defining what the potential contribution and limitations of the NOC might be. It also requires that the NOC has the appropriate resources and capacity to undertake its mission, and a realistic exit strategy for when the government or the private sector can take over (as it eventually should). For example, for many years Saudi Aramco has been involved in building hospitals and schools in the eastern province of the Kingdom. Once these have been built and staffed, the company hands control over to the government.

1.58 At the risk of overgeneralization, the trend in recent years has been to emphasize the commercial objectives of the NOC and downplay the national mission. The recent resurgence of resource nationalism in Latin America and Russia may well reverse that process.

[10] Modern corporations adopt a value-based management financial strategy that requires them to maximize return to shareholders. For the NOC, this approach could still be valid, with the qualification that there is only one shareholder—that is, the government.

1.59 All four case studies exhibited different policy objectives, but were clearly driven by national interest. In terms of the upstream, Iran and Yemen were driven predominantly by the need to arrest and reverse declining crude export volumes. In Kuwait, the driver was anticipated problems with production as the geology of the existing fields gets more complex and oil becomes more difficult to extract. In Saudi Arabia, the driver was wider political interests because excess capacity to produce crude oil gives the Kingdom a unique role in global oil markets and economic stability. In terms of downstream oil and gas developments, again the objectives reflected differing circumstances. In Kuwait and Saudi Arabia, the main issue was to increase product exports rather than crude, and the main debate was over the location of the new refinery capacity, that is, domestic or abroad. In both cases, supplying the domestic market with oil products was not a problem. By contrast, in Yemen and Iran, the emphasis was on current problems supplying domestic markets, especially in Iran with its growing gasoline shortages. Also, in both countries, there is a lively debate over what constitutes the optimal use of gas reserves—export versus domestic use.

1.60 Because any policy requires objectives, there is a clear policy dimension to this issue. Who should be responsible for setting these policy objectives?

Conflict and Cohesion in Objectives

1.61 Any lack of clarity in the objectives will create conflicting agendas, duplicated efforts, and eventually, policy paralysis. Where the setting of objectives and control is unclear, this leads to conflict of interest, and a lack of cohesion affecting the sector's performance. This is especially prevalent where an issue becomes a "political football," as was the case with Project Kuwait in Kuwait and buy-back contracts in Iran. A major problem emerges when this happens in the presence of private sector investment, since it increases the political and regulatory risks of the projects.

1.62 Frequently, even without a political dimension, sector objectives conflict. For example, objectives under the national mission will make it difficult for an NOC to be as low-cost as an IOC. The danger is that conflicting objectives will paralyze and delay policy decisions, slow sector operations, and lead to duplication and inefficient decision making. Therefore, as with any government policy area in the economy, it is essential that objectives are prioritized. The challenge is that the more entities are involved in such prioritization, the more difficult it is to get clear and consistent guidance. Each policy strategy or each operational decision requires clarity on the outcome of the decision, who will be involved in making it, and how. In particular, evidence suggests that any role for parliament or a national assembly is less than helpful in this respect. This creates a problem. The NOC is expected to primarily consider the interests of the nation, and the elected assembly is supposed to represent that nation. In addition, there is frequent confusion between the ministry of oil and the NOC over which is responsible for policy and strategy-making and, indeed, the difference between the two.

1.63 The speed of prioritizing objectives is also important. Excessive delay in setting priorities is as bad as having no priorities. Similarly, consistency of priorities matters because constantly revisiting priorities will slow the implementation of policy objectives and, hence, operations.

Kuwait provides a good example of this problem. Long-term policy volatility will also disrupt long-term strategies in a global petroleum industry with notoriously long lead times. This issue is of special relevance in the balance between the commercial and national missions of the NOC. Financial and decision-making authority can protect the NOC from policy volatility, but there is a danger its excessive control will increase rent seeking and corruption.

Main Messages

1.64 Clear and prioritized objectives appear to be the key to improving sector performance. The prioritization needs to be done by the government. The objectives for the oil sector need to be linked into the wider economy. It is also important to distinguish between commercial objectives and those relating to the national mission, if only to identify the actual cost of that mission.

1.65 The obvious policy response is to ensure that—through legislation and regulation—there is clarity of roles and responsibilities within the sector. If there is lack of clarity, this leads to conflicting agendas, duplicated efforts, and, ultimately, policy paralysis. Operators also need to be enabled to perform. In this context, it is important that the targets be set by those technically and professionally competent to do so. Finally, there needs to be transparency and accountability to ensure the operators do what they are expected to do within the strategic vision for the sector.

MAIN LESSONS ON SECTOR STRUCTURE AND PERFORMANCE

Delivery on Geology

Investment in the Petroleum Sector

1.66 A central issue affecting sector performance is how the revenues earned from crude oil, oil products, and gas sales are divided between the sector's own financial needs to maintain operations and government revenue. Investment levels in producing capacity and infrastructure, together with production levels in the sector, are a function of incentives within the sector. But they also depend upon the availability of budgetary resources for capital and operational expenditures. How the downstream sector is structured in terms of funding subsidies (if present) will also influence the division of revenue. In this context there is a conflict of interest between the allocation of expenditures required by the petroleum sector to deliver on geology, and the ones required by the government to deliver on non-oil development. This division is determined by how the sector's fiscal system is structured.

1.67 For NOCs, there are three commonly used models. A model common to Saudi Aramco (Saudi Arabia), Sonatrach (Algeria), Abu Dhabi National Oil Corporation (ADNOC, UAE), Petronas (Malaysia), Petrobras (Brazil), and Statoil (Norway) is the *corporatized model*. In accounting and financial terms, the NOC is treated as any IOC. While its investment plans require approval from the main shareholder, that is, the government,[11] the revenue inflow accrues to the NOC, which then decides its dispersal. The remaining profit is subject to royalty, taxation, and dividend.

1.68 At the other extreme is the *pure budget model*, which is found in Yemen, where the NOC is given a budget (often on an annual basis) and is then expected to follow already approved spending lines. All revenue then accrues directly to the central treasury. Between these two extremes there is the *hybrid model* found in Kuwait and Iran. In the hybrid model, some activities—usually crude oil production—are treated on a budget model basis, with other activities treated as if in a corporatized model.

1.69 If IOCs are present, a number of different fiscal systems are possible. The obvious division is between concession and contract. In the concession, the IOC is treated as a corporatized model where it spends funds, earns revenues, and then pays royalties and taxes to the government based on profits, and dividends to its own shareholders, who for the most part are outside the country of operations. In the situation of contracts there are a number of variations (see Table 1.1).

Table 1.1 Petroleum Fiscal Systems and Contracts

Contract **Types**	Exploration **Risk**	Commercial Discovery	Production
Joint **v**enture	Sole risk to IOC—no commercial discovery = IOC withdrawal	Joint company formed by government repays its share of exploration**; f**ield development jointly funded	Sales and proceeds are subject to royalty and taxation
Production Sharing Agreement **(PSA)**	Sole risk to IOC—no commercial discovery = IOC withdrawal	Development costs borne by IOC who operates the field	Cost oil accrues to IOC to allow cost recovery profit; oil split between IOC and government, with IOC share subject to royalty/tax
Service **c**ontract	Sole risk to IOC—no commercial discovery = IOC withdrawal	Development costs borne by IOC who operates the field	IOC recovers a "fixed" sum to cover its costs**; t**he remaining oil goes to the government*

Source: authors.
Note: In some cases the IOC is allowed a recovery above the agreed fixed sum to provide a degree of incentive.

[11] Interestingly, this is different from the IOC experience. NOC plans are approved before implementation, while in IOCs, plans are implemented and then results are subject to approval by shareholders. Another (perhaps more controversial) difference is that in the NOC case, less consideration is given to the results since there is only one shareholder and more attention is paid to the budget allocations and implementation plans than in the case of an IOC.

Productive Efficiency in the Sector

1.70 What is meant by efficient production in the context of oil and gas and how can the efficiency be measured? Three kinds of efficiency can be considered in the context of the petroleum sector: technical, allocative, and productive.

1.71 ***Technical Efficiency***. For upstream oil this can be measured by the recovery factor of fields, and, downstream, by how much of the mix of crude oil qualities that enter refining (crude slate) is lost to refinery fuel and losses. Assessing the recovery factor objectively is difficult. Benchmarking offers limited help since geology differs. Globally, there is a huge variation in recovery factors from as low as 10 percent in parts of Russia and Venezuela to as high as 65 percent in the North Sea.[12] Technical efficiency upstream can generally be identified by the term *good oil field practice*, which routinely appears as a requirement in concession and contract agreements. What this means is always open to interpretation, but while good oil field practice is difficult to identify, what constitutes bad oil field practice is well-known and understood among field engineers. Such practices can often be influenced by the sector structure and the nature of incentives. For example, as a contract with an IOC reaches the end of its life, there is little incentive for the IOC to maintain the fields and the infrastructure. Indeed, there is a positive incentive to accelerate depletion (maximize output), even if this negatively affects the recovery rate after the expiration of the contract. Given this, it is essential that whoever monitors field performance has the technical competency to do so.

1.72 Downstream, benchmarking is more appropriate as the laws of physics and chemistry are universal and not subject to geographic variation, making refinery performance comparable irrespective of location. Technical efficiency is driven by engineering considerations. This generally requires no policy interference in daily operations to allow technical experts to decide on field developments or refinery operations. But this still requires transparency and ccountability to minimize rent seeking and eliminate corruption.

1.73 ***Allocative Efficiency***. Allocative efficiency requires that production levels match those desired by society.[13] Upstream, this implies the concept of an optimal depletion rate for the country. In turn, this has two dimensions. The first is a technical dimension related to the previously discussed concept of technical efficiency. Most fields are *rate sensitive*, which means the recovery factor is a function of the speed with which the reservoir is produced. Thus, the optimal depletion rate in technical terms is one that maximizes the recovery factor. But it is the second dimension that really matters—the desired revenue profile for the government, which will determine the speed with which the country's oil reserves are depleted.

[12] Data on recovery factors are notoriously difficult to come by. First, almost by definition they can only be computed at the end of the field's life. Second, they tend to be politically and commercially sensitive and while a number of sources gather the data, it is only available on a commercial basis.

[13] Economic theory argues this is achieved when price equals marginal cost. However, for the major oil exporters, marginal cost should be equal to the long-run marginal cost of producing the oil rather than the border price. This is because the large producers can influence the border price by increasing production. Thus, for example, in Saudi Arabia, where it is claimed the long run marginal cost is $2 per barrel, in economic theory this would be the correct level at which to set crude prices for domestic refineries.

1.74 How quickly should the oil be depleted? The government has the power to determine this by the extent to which it grants exploration licenses, the speed with which it approves development plans for fields, and the level at which it sets production. This is a country-specific choice. Rapid development means quick access to revenue, which is valid if revenue can be productively used today. Slower development means that the potential to waste revenue is reduced, and that there is more chance of developing a local service industry. The examples often quoted in this context are that of the U.K. and Norway at the start of North Sea developments. The British government was determined to produce as much as possible as rapidly as possible. By contrast, the Norwegian government chose a much slower pace of development.

1.75 In MENA, the speed of depletion has been a contentious issue. Following the first oil shock of 1973, a number of producers, most obviously Kuwait, Libya, and Iraq, decided to slow production and field development. This was justified based on motives ranging from trying to reduce the damage on the fields (Libya), retaining oil for future generations (Kuwait), and avoiding the accumulation of foreign assets vulnerable to sequestration for political motives (Libya and Iraq). Iran, the UAE, and Saudi Arabia, by contrast, decided to significantly increase the speed of their development and production plans.

1.76 More recently, the higher oil prices seen since 2003 have persuaded a number of countries in the region to postpone or slow their capacity expansion plans (as in Algeria). In others, the issue has been subject to heated debate (as in Kuwait, Iran, UAE for oil, and Qatar for gas). This has led to a revival of the discussions about backward-bending supply curves so influential in oil market analysis in the mid-1970s. The key determinant of the decision over the depletion rate should be the capacity of the country to productively invest the revenues either in developing the economy or in accumulating assets for future generations free from fear of corruption and theft. It is also influenced by the nature of the political system. A democracy might be expected to favor faster depletion to secure the benefits sooner rather than later compared to a "benevolent autocracy," which might favor slower depletion.

1.77 Allocative efficiency upstream should be determined outside of the sector by the government, since this relates directly to the speed of depletion in terms of how rapidly oil in place is discovered, how quickly the capacity is developed to convert oil in place into producing capacity, and how quickly the fields are depleted. This is a decision at the heart of petroleum policy.

1.78 In the downstream sector, allocative efficiency means providing oil products and gas for the domestic market. This is a contentious issue in terms of pricing for reasons already discussed. If the producer is a potential price maker in the international market, then oil products should not be priced at border prices but rather at their real long-term marginal costs. In some cases, low domestic prices can be justified. There is also the argument that low domestic prices are effectively an income redistribution mechanism. But this leads to excessive energy consumption and also smuggling, which erodes the export surplus. Iran provides a classic case of this problem.

1.79 ***Productive Efficiency***. This refers to producing at the lowest possible costs, that is, the minimum point on the average costs curve. In theory, such data is easily available, collectable, and—allowing for geology—comparable. All NOCs will keep such data. But, in practice, such data are very difficult to find for specific operations or indeed specific countries. They are usually not made public and there is much effort to keep such data secret as part of the general drive by many in the petroleum sector to deepen the information asymmetry between the NOC and the controlling principal in order to allow rent seeking.

1.80 Even if the data were available, interpretation would be difficult. In a cross-section comparison there is the obvious problem of differences in geology and geography. The cost of producing a barrel in the deep offshore is clearly going to be much higher than onshore in large, prolific fields. On a time-series basis, with the same geology and geography, there is the problem of changing costs as the cost of using the service industry changes. In recent years, for example, as the service industry faced growing capacity constraints following a long period of underinvestment, "drilling, material, and personnel costs in the industry have soared, so that in real terms investment in 2005 was barely higher than that in 2000" (IEA, 2006).

1.81 Incentives to encourage the productive efficiency of the NOC—that is, to pursue low-cost operations—are the same as would be relevant for an IOC. The incentives allow the NOC to keep a portion of the revenue saved by efficient operation and control of its day-to-day operations. Mechanisms for greater productive efficiency include rewarding those participating through some form of performance contract and a share of the benefits they have created for the development of the NOC. This is determined by the nature of the fiscal relationship between the NOC and the government. Of the models discussed earlier, the corporatized system creates, in theory, the greatest incentives to seek low-cost operations since the NOC can keep a portion of the costs saved.

1.82 The risk is the threat of introducing competition from IOCs, thereby forcing the NOC to keep costs low. Creating what in effect becomes a contestable market will force the NOC to behave as though it were in a competitive market. How realistic such threatened entry is depends upon the way in which the sector is structured and the terms upon which the IOC may enter. Often, a powerful NOC as incumbent is able to restrict IOC entry by virtue of controlling what acreage may be available and at the same time hindering IOC operations through a regulatory role. The classic example in recent times was the aborted attempt to open upstream oil development to IOCs in Saudi Arabia (see Box 1.1).

1.83 For the purpose of this report, the efficiency relates specifically to productive efficiency since this determines the surplus available to government from which the fiscal linkage is drawn. There are three areas that need to be considered under the heading of productive efficiency: achieving the national mission, minimizing rent seeking, and eliminating corruption.

1.84 ***National Mission***. When efficiency is considered in the context of an NOC, it must be remembered that the NOCs are perceived as vehicles to achieve some kind of national mission, and thus incentives will have an important role. Often, the incentives to create an effective national mission have to do with pride in the national role of the NOC. This involves issues related to corporate culture that are notoriously difficult to identify and influence. Ideally, there should be a balance between incentives to encourage effective and efficient commercial behavior and those to encourage a serious and effective national mission. The incentive to pursue the mission is the argument that the NOC can contribute to development—which the IOC, despite whatever may pass for "corporate social responsibility" spending—cannot. Pursuing the national mission often justifies, in the eyes of the government, an element of monopoly control enjoyed by the NOC.

1.85 ***Rent Seeking***. Many of the results from the case studies point to rent-seeking behaviors. There is nothing wrong in trying to seek rents from natural resources. Problems arise from poor rent allocation—that is, who captures the rents and the poor management of those rents. Mismanagement of rents means that NOC operations are often conducted with limited concerns for profitability. The NOC's national mission means it either maximizes the rent for the state (Saudi Arabia), or serves as a tool to redistribute rent to multiple political interests (Iran). The need to subsidize parts of its activity (as an employer or domestic supplier of cheap oil products, for example) necessarily ends up eroding the stock of petroleum resources to finance the subsidies.

1.86 Incentives to reduce rent seeking are complex. Reducing the information asymmetry between the principal (the government) and agent (the NOC) limits the ability to seek rent. Transparency is central to controlling rent-seeking behavior by the NOC. A commonly suggested solution to the information asymmetry at the heart of the principal-agent problem is privatization. The theory suggests that once the principal becomes a shareholder, it can assess the performance of the agent by observing the share price movements and dividend payments. The underlying logic of privatization, however, has its problems in the context of the national petroleum sector.[14] Privatizing an NOC can be politically sensitive, more so in a country where the NOC dominates the economy. Successful privatization (or partial privatization of NOCs such as Statoil in Norway, Petronas in Malaysia, and Petrobras in Brazil) has occurred in economies where the NOC was far from dominant in the overall economy. In addition, the extent of privatization is an open question. The above-ground assets of the company—that is, equipment and infrastructure—can be sold to the private sector, but it is far from clear that this could also be applied to the below-ground assets—that is, the reserves.[15]

1.87 ***Corruption***. Though necessary, direct incentives to minimize or control corruption are difficult to formulate and implement. As with rent seeking, transparency is clearly an important ingredient to control corrupt practices, although, while transparency is a necessary condition, it is not a sufficient condition. It must also be possible to act upon the outcome of exercises in transparency to hold decision makers accountable. One clear mechanism to eliminate corruption is provided by the control and reporting requirements prevailing in the sector in matters such as procurement, which might be expected to be found in any IOC. For example, Saudi Aramco has the same sort of processes for procurement that are used by Exxon, which actually set up the systems when it was a shareholder in Aramco prior to nationalization in 1976. Streamlining licensing procedures and developing an overarching petroleum law can also reduce the risk of corruption associated with the transaction costs involved in individual negotiations with private sector operators.

[14] The logic of the share price acting as a proxy for information assumes that the share price is based upon accurate and independently audited information provided in the company's accounts.

[15] This issue was very relevant in the negotiations leading to the General Agreement of Participation in October 1972 when a point of serious contention was the basis upon which the IOCs would be compensated for giving up equity to the host government.

1.88 *For productive efficiency, several key observations emerge.* First, there is a serious lack of publicly available quantitative data to properly assess the technical and financial performance of the NOCs in MENA. Furthermore, upstream at least, benchmarking is less than effective because of wide variations in geology. Casual observation suggests that, apart from Saudi Arabia, there are grounds for concern that the upstream will not be able to deliver on the geology. There are in fact two separate issues regarding delivery on geology. One is the willingness and ability of the sector to minimize production cost. The other is the willingness and ability to expand capacity, which relates to the country's depletion policy. As already explained, this latter issue is not discussed in this report.

1.89 In general, there is scope for increasing the productive efficiency of the sector. The policy dimensions are clear. What is required is the correct incentive structure so operators have the greatest incentive to reduce the costs of their operations and invest in reserve development. The need to minimize production cost is a feature found in all productive sectors. Investment in reserve development, however, is rather specific to petroleum supply. More than any other underground natural resource, developing petroleum resources involves large and risky capital investments, which require mitigating risks related to appropriation of profits and long-term guarantees that part of the rent will be able to stay with the investing firm (see also fiscal linkages below).

1.90 Corporatization of the NOC provides a good start to creating such incentives. Except in Yemen, the role of the private sector and competition, which in theory should promote greater efficiency, is ambivalent because private sector involvement has been absent or severely constrained by barriers to effective entry. The private sector is, however, increasingly present in the supply of services to the upstream and ought to be encouraged in this. The same holds true for downstream activities.

1.91 To determine effectiveness and efficiency requires transparency and accountability. Transparency has a number of requirements to assess sector performance. The first is transparency of all financial and operational data between the government and the operator. If published accounts are available, at least it is possible to compute company rates of return on capital employed, which provides some comparative basis for performance. There is a clear consensus that what is required is internal financial transparency among the oil ministry, the ministry of finance, and the NOC. To assess effectiveness requires information flows on the operations of the sector, auditing of those flows into a collection of comprehensible accounts, a criterion for assessment, and a feedback process to improve operational performance. It is important to remember that the NOC's pursuit of a national mission may make its performance indicators different from those associated with an IOC, where only commercial criteria rule.

1.92 While there is clear agreement on the need for transparency to allow the shareholder—that is, the government—to assess performance, there is less agreement over what data should be divulged to the rest of society. For example, as the case study indicates, detailed and audited information about Saudi Aramco's performance, as with any private company, is available to the shareholder. The only difference is the shareholder—that is, the government—chooses not to reveal this to the wider public. The incentives for government to divulge information are that it can create a sense of public ownership, social stability, and security. It can also earn international credit and credibility.

1.93 The second requirement to determine sector effectiveness is transparency in licensing and procurement within the sector—if the private sector is to play a role. This requires making the criteria upon which deals will be assessed more explicit, as is increasingly the case in Yemen. But, transparency often requires educating the public so that it can understand, for example, that investment in high-risk operations such as oil exploration and development requires an adequate return for the investor.

1.94 Transparency also requires accountability if it is to improve performance. Effective accountability requires clear delegation of responsibilities, capable institutions, and means of enforcing regulations. Mechanisms include "regulation, performance contracts, disciplinary processes, industry audits, and channels of communication with society and the law."[16] Benchmarking can often help clarify the comparative performance of the NOC within the limits mentioned earlier. In certain circumstances, parliament and NGOs can assist in the process of ensuring accountability by providing checks and balances in practice. An important issue is to consider who the NOC is actually accountable to. In theory there is a chain of accountability from the oil ministry to the government to the society. But, as the case studies make clear, it is not always obvious that each element of the hierarchy necessarily looks to the interests of the others. This makes NOC accountability more difficult.

Main Messages

1.95 This report is concerned with productive efficiency. Casual observation suggests that in the oil sector in MENA there is considerable scope for improvement although hard data is simply not available to support that assertion.[17] Even if data were available, comparison is difficult either on a time-series or cross-sectional basis because of different geology and different views on the NOC's national mission. The key is to create incentives to encourage the NOC to reduce costs by allowing it to benefit from lower costs. The case studies and other experience strongly suggest that corporatizing the NOC can create such incentives. Enablement of the NOC management is also an important factor allowing it to take advantage of incentives offered. Also control of rent-seeking behaviors and corruption is part of the solution. While in practice such control is far from easy or straightforward, transparency and accountability are an essential part of the story.

Delivery on Development

Fiscal Linkages: Government Revenues

1.96 The most obvious contribution to development is the *fiscal linkage* that concerns the provision of revenues and foreign exchange to the government. Of course, the ability to convert

[16] Chatham House, op. cit., p 12.
[17] The only available data is on employment—see below under backward linkages—and this confirms the assertion that costs are higher than they need to be based upon purely commercial considerations.

this revenue into development depends upon how the revenue is managed and allocated by the government.

1.97 The case studies indicate that maximizing fiscal linkages—that is, maximizing government rent collection—is at the center of the governments' objectives. Given the dominant importance of oil revenues in all four cases, this is hardly surprising. What emerges from the case studies is that there exists a conflict between two issues: the total size of the export revenues from which the government's share is taken, and the size of that share. The conflict is that private sector involvement may grow the total revenues but reduce the size of the government's share, while excluding the private sector will increase the size of the government's share while reducing revenue growth if insufficient investment in the sector occurs.

1.98 Over the years, governments have become adept at using fiscal systems to maximize their share and there is little sign from the case studies that any improvement is required. Even in Yemen, where the fiscal linkages appear weak compared to the other three case studies, this reflects a relatively hostile operating environment for IOCs, despite the country's challenges in terms of both geology and security, and the need for outside expertise. Given Yemen's urgent need to encourage IOC interest, terms have to be sufficiently attractive. This requires a smaller share in the hope of greater revenues. But the real problem relates to the size of the revenues from which the share is drawn.

1.99 The question is how much of the revenue generated should be reinvested to expand the capacity to produce more oil and earn more revenue? How much is reinvested will be influenced by three factors: the need for government revenue; the government's depletion policy based upon the comparative rates of return on oil versus the rest of the economy; and finally, government confidence that the NOC will not use the cash for rent seeking or corruption. It is not at all clear from the case studies on Iran, Kuwait, and Yemen what this decision is based upon or indeed if there is any logical basis for the levels of reinvestment rather than the outcome of some uncertain and unknown process. In the case of Saudi Arabia, the situation is clearer since the capacity target is a given—that is, 2 mb/d above current production and whatever the sector needs to achieve this—is provided. But, as already explained, such issues are a sovereign decision of the government and as such are not part of this report.

Forward Linkages: Products for the Domestic Market

1.100 The ability to deliver oil products is a function of the nature of the domestic refinery capacity and/or the ability of the infrastructure to import oil products. The willingness to deliver is strongly influenced by the domestic pricing policy. The key is who bears the cost of any subsidy and the consequence of that subsidy. If the subsidy has to be borne within the sector, this invariably reduces a willingness to supply domestic products, since it leads to financial losses. Given that the subsidy also increases domestic energy consumption, either directly or via smuggling, this puts pressure on the sector to deliver yet more refining capacity, adding to the sector's losses. This further inhibits a willingness to supply. By contrast, if the subsidy is borne by the central government this creates strong incentives for the sector to supply more products.

1.101 In both Saudi Arabia and Kuwait, significant investment by government means the refinery sector is modern and likely to have relatively low costs, although the lack of financial and technical data makes it difficult to prove this assertion. In Kuwait, efficiency is also likely to benefit as more of the downstream distribution networks are handed over to the private sector. This is providing the regulatory system can encourage competition and constrain the market power of the incumbent Kuwait National Petroleum Company (KNPC).

1.102 In Yemen and Iran, however, there are concerns about downstream efficiency and the ability to deliver sufficient oil products to feed the domestic market. The refineries are old, high cost, inefficient, and lack the necessary equipment upgrades to meet the growing demand for lighter products. In Iran there is a serious lack of competition downstream, and in Yemen private sector involvement has been limited.

1.103 Policy can improve the situation by encouraging greater competition downstream, which by definition requires greater private sector involvement. As opposed to the situation upstream, private sector involvement downstream tends to be less politically sensitive. Improvement also requires putting a pro-competition regulatory system in place.

1.104 A major issue in all four countries concerns the pricing of domestic oil products. This is a controversial area. In Kuwait and Saudi Arabia, while domestic prices are well below border prices, arguably they are efficient in the sense of reflecting the true long-run marginal costs of producing the products given the low cost of crude oil to the refineries. Low domestic prices are seen in both countries and elsewhere as a legitimate means to spread the benefits of the country's natural resource wealth to its citizens. Many in the countries concerned do see it as a legitimate use of oil revenues. But this means the government and the oil sectors are forgoing potential revenue. Such low prices also have serious consequences for the efficiency with which oil products are burnt. There is no incentive for fuel conservation.

1.105 In Yemen and Iran, however, the effects of domestic pricing policies are clear. The low price policy costs the economy dearly, not least through excessive consumption and widespread smuggling of products out of the countries. It is also a major contributor to the inability of the sector to provide sufficient products for domestic consumption since there is insufficient cash flow to allow greater investment in refinery and upgrading capacity. The policy implications to solve the problem are clear, although difficult. The governments need to move prices to border levels. But given the very low current price levels this will be a serious policy challenge, with likely political fall-out if prices are raised too rapidly.[18] Experience from elsewhere strongly suggests a gradual increasing of prices can create a money illusion that can help mute any political backlash. Charging realistic prices for oil products will both help to reduce oil consumption growth and also make private investor involvement in the sector a more realistic option.

1.106 Gas often presents specific problems. In many cases, its incentive structure is such that the development of gas finds is not encouraged. A good example is that of Yemen, where gas discovered by the IOC becomes the property of the government and any price relating to

[18] At the time of writing this report, Iran has just introduced gasoline rationing and what is a two-tiered pricing system in an effort to tackle the problem. The initial reaction appears to be violent and disruptive with a number of gasoline stations being attacked and destroyed.

defining commercial discovery is subject to negotiation. Since negotiation takes place after the discovery, the government is in a dominant bargaining situation. Unless the government modifies the terms of future contracts with operators, there is no incentive for the IOC to develop Yemen's gas capability.

1.107 In many other cases, this lack of incentive is reinforced if the domestic currency lacks convertibility since developing the gas for domestic use results in payment in nonconvertible currency. There is also the problem of competing use for the gas, which can range from an export option, reinjection, supplies to the power/desalination sector, and supplies to industry either as fuel or feedstock (in the case of petrochemicals). By contrast, if the sector is properly coordinated, developing the gas potential can become a viable option with a potentially positive contribution to development. The Saudi master gas system (MGS) provides a positive illustration.

1.108 Gas issues in terms of providing a supply to the domestic economy are relevant in all four cases. For Saudi Arabia and Kuwait the problem is how to secure sufficient supplies for domestic consumption. In Kuwait, which has in the past been gas poor, this requires considering import options, which the government has been doing for some time. For Yemen and Iran the situation is complicated because the option to export gas is realistic. There has long been a temptation for a government with access to gas to use it as the basis for an industrialization program. If this is to be undertaken by the private sector, then risks are reduced since it might be assumed the private sector will only invest in viable projects. The problem is when governments decide to institute an industrialization program themselves. Governments are notoriously bad at picking winners, and losers are very good at picking governments. Throughout oil-producing areas, large amounts of resources have been wasted in inappropriate industrial projects. These errors are often compounded by ill-advised protectionist policies. The policy solution is to ensure that any gas utilization projects carried out through public investment are subject to rigorous project appraisal, taking into account all feasible options for gas use, including reinjection into the oil fields.

Backward Linkages: Positive Impact for the National economy

1.109 Backward linkages have three specific dimensions influenced by the sector structure: development of local labor, development of local services, and the potential for positive spillover effects on the rest of the economy.

1.110 ***Use of Local Labor Force***. A key contribution is for the sector to provide training to workers, who then can take these skills into the rest of the economy. The classic example was Operation Bultiste undertaken by Aramco in the 1950s. A number of the brightest young Saudis working for the company were encouraged to leave, armed with contracts and access to capital to set up enterprises to supply Aramco's operational needs (Coon, 1955). The sector structure influences this process by virtue of how many nationals the sector employs and the nature of workforce turnover. It will also of course be influenced by factors outside the sector such as the education levels of the population and the scope for private sector enterprise.

1.111 In most cases, the petroleum sectors in MENA, even in the labor-importing countries, are under growing pressure to employ more nationals. Table 1.2 suggests that most of the NOCs in MENA tend to engage in overemployment and that resource rents are distributed away from the NOC. Results of the empirical investigation of the efficiency with which an NOC mobilizes production factors for a sample of 80 oil companies worldwide show that relative inefficiencies of various NOCs, observed when one considers only commercial objectives, are largely the result of governments exercising control over the distribution of rents (Eller and others, 2007).

Table 1.2 Petroleum Company Statistics and Comparators, MENA

Company	Revenue ($ / employee)	Revenue ($ / boe reserves)	State ownership (%)	Country
Saudi Aramco	2,261	0.40	100	Saudi Arabia
QP	1,800	0.10	100	Qatar
KPC	1,650	0.34	100	Kuwait
PDO	1,591	0.98	60	Oman
Sonatrach	688	0.93	100	Algeria
SPC	375	1.71	100	Syria
NIOC	283	0.11	100	Iran
Adnoc	205	0.20	100	UAE
NOC average	1,000	5.23	25–100	Sample of 33 companies worldwide
IOC average (majors)	2,865	21.67	0	British Petroleum (U.K.), Chevron / ConocoPhillips / ExxonMobil (U.S.), Shell (Netherlands)
IOC average (others)	1,629	11.24	0	–

Source: Eller and others, 2007.

1.112 Considering MENA countries and their importance to global energy supplies, Eller's results (Eller and others, 2007) add to the uncertainty mentioned earlier regarding the willingness of MENA countries to increase global petroleum supply. Indeed, inefficiencies in the production of revenues can manifest in lower levels of production and higher prices than would otherwise occur. In addition, dissipation of rents away from the petroleum sector puts the sector at risk in countries often highly dependent upon its revenues. Although diversifying their economies away from oil is a must for oil-dependent countries, making sure that they maximize revenues from the use of their natural resources is as important as the contribution of national petroleum resources to the economic development of MENA countries.

1.113 The problem of employing nationals presents a classic case of conflicting objectives within the sector. On the one hand, employing nationals may improve the quality of the pool of labor for the rest of the economy. On the other hand, employing unqualified nationals either inhibits the efficiency of sector operations or simply places a large financial burden on the

NOC.[19] The policy solutions to this problem are to insulate the operators from excessive pressure to employ, and at the same time to ensure that education and training policies improve the pool of skilled labor from which the oil sector can draw.

1.114 ***Development of Local Services***. There is a growing legal requirement in MENA to use a minimum of local content (products and services), such as in Iran[20] or Libya, where it is an important criterion in awarding licenses. Choosing to use local providers implies lower-cost provision and at the same time boosts the nonpetroleum economy.

1.115 The experience of the case studies suggests that decisions about local content are best left to the discretion of the NOC. It is clear that the Saudi model has been successful in developing and growing local suppliers. The situation in Iran is less clear cut, not least because the outcome has been clouded by sanctions. But it would appear there has developed in Iran a culture of self-sufficiency within the sector and its domestic supply chain that will create a sound basis for development in the rest of the economy. By contrast, in Kuwait and Yemen, local content remains small, reflecting the "technological strangeness" of the oil sector to the indigenous economy.[21] Generally, if the sector is forced to use local suppliers by virtue of regulation, this can actually increase costs and also lead to legal fictions to evade the regulations. This happens, for example, when "joint ventures" between foreign service companies and a "local company" are created only to appear to comply with regulations but with no actual local content.

1.116 ***Spillover Effect***. The petroleum sector has the potential to become an example of best-business practices for the rest of the economy. This is activated when IOCs operate within the sector and bring with them good practices of procurement and control of corruption, or when efficient practices of an NOC are transmitted to the private sector through joint ventures. A good example is Saudi Aramco, which creates joint ventures with the private sector, serving as an incubator and gradually reducing its shareholding, allowing the private sector partner to play a great role while benefiting from Saudi Aramco's business practices.

1.117 Finally, there is the question of how much of the NOC's national mission should devolve to governments. Ideally, the sector should focus on the production and sale of oil and gas. But, as mentioned earlier, the national mission of the NOC often requires involvement in a much wider agenda. This is reinforced when government capacity to provide services normally associated with development is restrained because of a lack of administrative competence. In such situations, the NOC, assuming it is the most competent arm of the government, often finds itself forced to take over such provision until government competencies increase. This was certainly the case both in Saudi Arabia and Iran in the early years of the industry.

---

[19] Marcel, 2006, cites the example of Saudi Aramco where it is believed there are certain sections of the corporation where nonperforming nationals are simply "dumped" to be kept away from serious operations.

[20] Recent legislation requires the buy back projects to use a minimum of 51 percent local content.

[21] Arguably the same "technological strangeness" existed in Saudi Arabia's eastern province in the 1950s, where it took a deliberate and explicit policy by Aramco to kick start the local supply chain.

Main Messages

1.118 In terms of fiscal linkages, there exists a clear conflict between enlarging the volume of oil revenues and the size of the share of the revenues. For the government, retaining too large a share now is likely to inhibit the growth of the revenue volume in the future if insufficient resources are left to invest in developing new capacity. This, of course, is the choice open to governments in terms of the trade-off represented by their depletion policy. But there is a strong sense that many in the MENA governments fail to understand the nature of this conflict, and the result is that the depletion policy is poorly thought out and simply emerges out of the fog of politics with little or no public debate.

1.119 That said, over the years, MENA governments have become very effective in maximizing the current share of the revenues that they capture. As indicated earlier, however, this does not necessarily translate into development since the impact depends upon how the revenues are managed and allocated—a subject deliberately avoided in this report to avoid duplication with the large number of other studies covering this issue (see References).

1.120 Regarding forward linkages, the key issue is the domestic pricing of oil products. Current practice in much of MENA is distributing the economic system, leading to unnecessarily large domestic consumption of oil products and extensive smuggling, putting the domestic refining and distribution systems under pressure, creating seriously distorting incentives, and in many cases reducing the availability of oil for export. A further problem in many cases is a lack of competition downstream, which creates an environment that inhibits productive efficiency in the sector. Finally, issues to do with gas are complex and controversial because, in many cases, there is no coherent and consistent policy. Policy has evolved with too little thought, analysis, and debate. This requires urgent policy attention.

1.121 Backward linkages raise a number of serious issues. Employment is a major concern, but it must be remembered that the oil and gas sector is a capital-intensive sector that uses relatively little labor. To solve unemployment problems in MENA by looking to the sector is a serious mistake and could lead to a dramatic reduction in the productive efficiency of the sector. A similar story relates to trying to maximize the local content of the supply chain feeding into the industry. An important debate concerning both employment and local content concerns whether it is good policy to impose levels by means of regulation. All the evidence from the case studies and other sources suggests that regulation is not the route to follow. At the very least, for local content, it simply encourages mechanisms to side-step the legislation.

1.122 It would appear that in many cases, the presence of IOCs can produce positive spillover effects in providing a demonstration effect for good business practice in the general economy.

1.123 Finally, it is clear that the content and extent of the national mission needs careful attention. Experience suggests that the more the government can take over the mission from the NOC, the more effective the outcome. But this is conditional upon the government having the necessary capacity to undertake such activities in an efficient and equitable manner.

2. Kuwait Case Study

POLITICAL ECONOMY OF THE PETROLEUM SECTOR STRUCTURE

Who Sets the Objectives?

2.1 As indicated in the previous chapter, it is essential that the objectives of any petroleum sector be aligned with a broader development agenda, which should itself take into consideration the long-term nature of the petroleum sector's investments. Kuwait's development agenda has suffered in past years because priorities were not clear. In 1987, a 26-member supreme planning council, including eight ministers, was set up. In 1989, it produced a document entitled the "Long-Term Strategic Development of Kuwait"; then, in 1992, it produced a "National Document for Reformation and Development" covering the period up to 1995. In February 1994, a five-year plan emerged covering the period 1995–2000, with the main objective of balancing the budget.

2.2 These documents offer limited clarity regarding priorities and specific targets or policy instruments. In March 2004, a new Higher Council for Planning and Development was launched. This last effort was intended to produce "goals and development programs" and to ensure "coherence and harmony" with cabinet decisions. The launching speech articulated the need to develop the oil sector by establishing oil industries that could compete globally and provide Kuwaiti nationals with "productive working opportunities." Little appears to have been done since the launch.

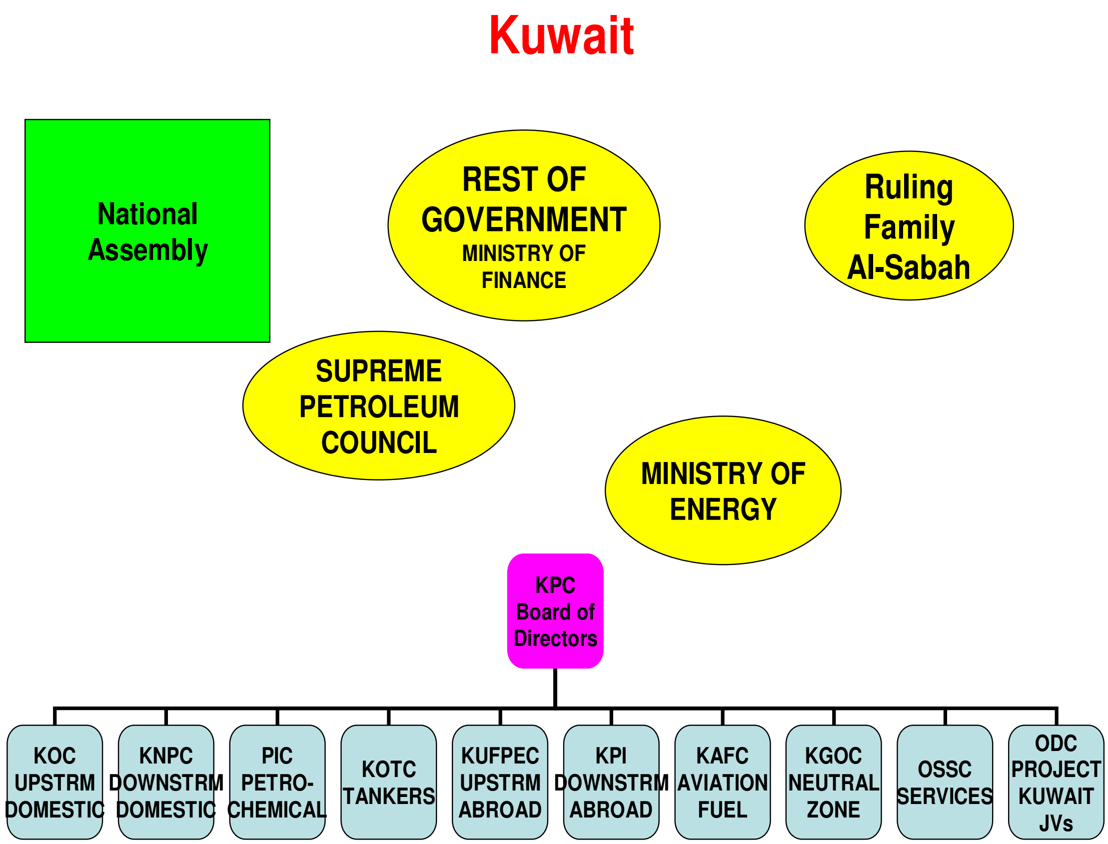
2.3 In terms of sector objectives, all plans and draft contracts of the Kuwait Petroleum Company (KPC) have to be approved by its board, the Ministry of Oil, the Supreme Petroleum Council (SPC), and the National Assembly. Policy directives come to the KPC and its subsidiaries from multiple and often conflicting sources. The situation is compounded by the limited trust between the National Assembly and the government, especially in matters related to oil. This has been further aggravated by a series of accidents at plants in recent years and by the uncertain nature of the regulatory function of the ministry vis-à-vis the KPC. While there are sector objectives, their nature is often imprecise,[22] prioritization is far from clear, and implementation is delayed by a slow and cumbersome decision-making process.

The players and their interactions

2.4 Figure 2.1 identifies players in the Kuwaiti petroleum sector, while Table 2.1 outlines the membership of the SPC and KPC boards.

[22] The web site of the KPC contains a large number of mission, vision, and value statements.

Figure 2.1 Organizational Structure of the Kuwaiti Petroleum Sector



Source: authors.

Table 2.1 Kuwait: Membership of Various Sector Institutions

SPC	Chair = prime minister Deputy chair = head of the KPC Governor, Central Bank Five ministers Nine nongovernmental members
KPC board	Chair = minister of energy Deputy chair = head of the KPC Minister of Finance Seven managing directors plus heads of KPC subsidiaries (except KUFPEC)

Source: authors.

Control Operation and Monitoring

2.5 How the various petroleum sector players in Kuwait interact is complex and confusing. At the start of the 1970s, the Ministry of Oil played a major role, with direct contact with privately owned operators. At the time, the Kuwait Oil Company (KOC) was owned by British Petroleum (BP) and Gulf. In 1973, Law 19 charged the ministries of finance and oil with the authority to inspect the operating companies. In 1974, the SPC was formed, chaired by the prime minister and including nine nongovernmental members. Its function was to draw up general petroleum policy for the sector. In 1975, the KOC was nationalized and the Ministry of Oil was created as a separate entity. The KPC was created in 1980 by a public law (Law 6 of 1980) to act as a holding company for the already-existing subsidiaries governed by commercial company law (including KOC, the company in charge of upstream). In 2000, the SPC formed three subcommittees to oversee strategic, technical, and financial aspects of the sector. These were intended to deal with major new initiatives including performance evaluation, the development of a strategic vision for 2020, and the restructuring and commercialization of the whole sector.

2.6 In October 1976, the KOC wrote a letter to the Ministry of Oil challenging the validity of Law 19 of 1973, which gave the ministry control over the KOC's operations. The KOC argued that this law had been designed to control the private international oil companies (IOCs), not the KOC as a state-owned entity. The reply, which came in November 1979, reasserted ministry control and demanded the KOC's compliance. In 1989, some of the bylaws associated with Law 19 were revised to account for technical advances in the industry. In October 2002, the KOC again challenged the ministry's position, and, in November 2002, the ministry again rejected the KOC's case.

2.7 Interestingly, the arguments used in 2002 were identical to those used in the earlier exchange of the 1970s. Most disputed were the ministry's supervisory and audit activities. In 2001, the Ministry of Oil developed a new strategy and action plan that was finally approved by the SPC in August 2002. The ministry tried to get the KPC's cooperation, but this was not forthcoming. At this point, the SPC stepped in to try and clarify the situation, and a series of meetings took place to reconcile the various positions. The outcome was the view that Law 19 was still applicable, but that the bylaws were effectively unworkable. The result was to dilute ministry control over operations, but to maintain its auditing responsibilities. Moreover, after 1991, the National Assembly had begun to take a growing interest in the sector's activities. This was driven by a fear of poor operating performance on the part of the KPC, dramatically lower oil revenues to the state (in part due to lower international prices), financial scandals, and growing incidents of pollution and accidents.

2.8 To clarify the situation, in March 2005, a draft law was proposed to try and align the future directions of the KPC and ministry. To date, this law is under discussion. Observers have identified three problems that need to be addressed (Al Atiqi, 2005). The legislation is tempted to use different regulatory rules for competing operators, which would likely result in legal conflicts and may not be aligned with constitutional provisions that provide ground for a level playing field. Restructuring the ministry—leaving duplicate or vacant functions in the KPC and its subsidiaries—would likely severely hamper existing and future operations. Finally, regulating operators may interrupt or delay approved projects.

2.9 The sector urgently needs restructuring and new regulations to clarify the roles and responsibilities of the various players—that is, who has control over whom and what. The problem is being addressed at the highest level of government and the sector, and efforts are underway to resolve the issues. While delivery on geology and development has been problematic in the past, the sheer size of the revenue vis-à-vis the size of the Kuwaiti population has kept this from being a key issue. Prospects for future delivery would improve if the regulatory environment were clarified.

2.10 A major problem is that the sector receives limited protection from outside interference—particularly from members of the National Assembly—in decisions affecting sector operations. This is particularly true of employment and promotion, in which "patrons" are seeking to promote the interests of their "clients." Interference is also common in project location, with National Assembly members attempting to promote the interests of their constituents.

2.11 As for monitoring and oversight, the KPC produces an annual report that, by the standards of many national oil companies (NOCs), is quite detailed. The KPC also produces an audited set of accounts. Furthermore, because of pressure from the National Assembly, considerable amounts of material are disclosed, generally not on a consistent or regular basis, but rather in response to specific requests from National Assembly members and their committees. The KPC's overseas operations are not as well-documented, raising the suspicion that investments outside of Kuwait are carried out to deepen the information asymmetries between the principal and the agent.[23]

The Objectives of the Sector

What Are the Objectives?

2.12 The official plans of the sector through 2020 are detailed in a strategic plan. Goals include increasing crude-producing capacity from 2.6 million barrels per day (mb/d) in 2005 to 4 mb/d by 2020.[24] Downstream, the strategy envisages increasing refinery capacity to 1 mb/d, including deep conversion by 2010 (a process of carbon extraction to increase the yield in lighter products), further increasing to 1.5 mb/d by 2020.[25] The rest of the KPC's subsidiaries have targets expressed as nonquantified aspirations.[26] Another official objective, driven by both the

[23] There is much casual evidence to support the idea that operations abroad can deepen the information asymmetry between the principal and the agent to allow greater rent seeking. Examples often cited include Venezuela (PDVSA), China (SINOPEC, CNOOC), and India (ONGC). Investments in the downstream (or upstream in the case of China and India) are based upon vertical integration, where one affiliate physically supplies crude or product to another affiliate provides opportunities to disguise activities exploiting gaps in transfer pricing regulation.

[24] In the 2005/6 KOC that annual report, actual capacity is 2.337 mb/d.

[25] The KPC report actually says 2010, but this appears to be a typographic error.

[26] The only exception is for the Kuwait Foreign Exploration Company (KUFPEC), where it is stated overseas production should reach 100,000 b/d by 2010 and 200,000 b/d by 2020.

KPC and the ministry, concerns the promotion of Project Kuwait to more directly involve IOCs in the development and production of the northern fields.[27]

2.13 Since the late 1990s, this project has progressed slowly because various parties use Project Kuwait as a tool to assert their power over broader issues in Kuwait. Initially, the government's position was that there was no role for the National Assembly and everything could be decided and managed within the sector by the KOC and the ministry. But both were forced to concede a role to the assembly, and for a number of years, legislation has been awaiting the assembly's final approval.

Box 2.1: Project Kuwait

The origins of Project Kuwait go back to the immediate aftermath of the liberation of Kuwait in 1991. The Kuwaiti oil sector was in a desperate state owing to war damage caused by the Iraqi invasion The Kuwait Petroleum Company (KPC) faced shortages of management following the evacuation of expatriate staff .

Kuwait sought technical assistance from international oil companies (IOCs). There was, however, an implicit understanding that when things had settled, the Kuwait upstream might be opened to those who had assisted. In 1993, a decision was taken to allow IOCs to invest in the upstream sector under the terms of Project Kuwait. This was driven by several factors.

- There was a need to secure military support from abroad. It was felt that military alliances would be more reliable if nationals from supporting countries were operating the front line of oil production.
- There was also a need to secure engineering and management expertise and technology to fill the gaps in the KPC's manpower.
- Finally, there was a growing belief in some quarters that the KPC had been engaged in rent-seeking behavior, raising doubts about its productive efficiency. The entry of the IOCs was to provide a benchmark to monitor the performance of the KPC.

Initial proposals from the KPC to create Project Kuwait were rejected in 1995 by both the National Assembly and the Supreme Petroleum Council. Over 1998–99, new details emerged for the terms of the "operating service agreements." In November 1999, a major international conference was held to launch the process, without significant results. Interestingly, many National Assembly opponents did not, in principle, object to IOC involvement. It was the process that caused a problem. The proposal triggered more fundamental concerns such as the respective roles of the Kuwaiti leadership. There was also a subset of concern over the potential for corruption if the authority over awarding contracts was concentrated in too few hands. The debate was over whether a specific law was required.

The government initially rejected the need for such legislation but relented after the conference. In February 2000, a law was put before the assembly, but was rejected. A new law was presented in April but failed to even get on the agenda as the crisis between the assembly and the government deepened. In January 2001, despairing of progress and wishing to speed negotiation, KPC sent out initial protocols describing the process to IOCs. It also announced that the "data room" needed to formulate bids would be open in February 2001. Without supporting legislation, however, the process was effectively frozen.

Since then, despite several changes of government, the situation remains unresolved and variations on the legislation have been presented to the National Assembly and relevant committees without success. A growing opposition to IOC involvement upstream is now emerging. In November 2006, the Minister of Oil publicly stated that he would not be submitting Project Kuwait to the National Assembly unless "appropriate measures" for preserving Kuwait's oil wealth could be agreed on. Meanwhile, much of the original IOC interest has disappeared.

[27] Since the liberation of Kuwait in 1991, IOCs have been involved in the upstream in the role of providing technical assistance.

The Objectives: Conflict and Cohesion

2.14 A good example of conflicting objectives and lack of coordination is illustrated by the decision to raise crude oil production capacity, which appeared “to go back and forth between institutions with a degree of confusion for all” (Marcel, 2006). The KPC’s corporate planning department projected a possible call on Kuwaiti crude (within the OPEC quota context) of 7 mb/d by 2020. The KOC indicated that 4 mb/d was the maximum sustainable capacity under prevailing conditions. The KPC presented this as the target, but was overruled by the SPC, which wanted a target of 5 mb/d—although the analytical basis for such a number is not clear. The SPC backed down and reverted to a goal of 4 mb/d for 2020.

2.15 In general, the KPC’s senior management is frustrated by a lack of implementation, attributable to government interference and political wrangling. It is claimed that this process is aggravated by the KPC’s culture of open debate and self-examination. The Diwaniya-Wasta culture common in Kuwait[28] feeds criticism and intervention from outside the sector, creating a self-destructive, vicious cycle. There is also a view that the KPC does not have a clear corporate culture. This weakness in part reflects the dominance of expatriates within the KPC prior to 1990.

2.16 A major problem facing the sector relates to the role of the minister. As chair of the KPC, the minister has veto power over all KPC decisions. Once something has been decided and agreed on by the KPC board, which is chaired by the minister, the minister can unilaterally reverse the decision. Because the minister’s office is a political appointment, and senior managers of the KPC are technocrats, there is significant tension especially in cases when the minister has limited knowledge of the oil industry. Since 1991, there have been 11 different ministers appointed, submitting the KPC to the risks of inconsistent strategy.

2.17 Beyond the views mentioned above, there is agreement within the sector on the importance of maximizing field recovery and developing downstream opportunities. There is also a strong lobby group within Kuwait that favors greater private sector involvement in petroleum activities. The process of privatizing certain elements downstream has already begun, but is currently stalled because the regulations governing the newly privatized elements are under debate, and members of Parliament and the Ministry of Oil have reservations about the project.

STRUCTURE AND SECTOR PERFORMANCE

2.18 The KPC and its affiliates, in comparison with many NOCs, do produce fairly comprehensive information on a regular basis. Annual reports include audited accounts. Any assessment of sector efficiency, whether qualitative or quantitative, must take into account the massive physical destruction suffered in the Iraqi invasion of 1990.

[28] The Diwaniya-Wasta culture refers to the practice of organized public debates (Diwaniya) common in Kuwait, and existing personal connections (Wasta).

Productive Efficiency

2.19 The production costs per barrel (bbl) are given in the table below.

Table 2.2 Production Costs in Kuwait ($ per bbl)

	2001/2	2002/3	2003/4	2004/5	2005/6
Costs	1.29	1.83	2.23	2.90	1.47

Source: Kuwait Oil Company (KOC) Annual Report 2005–2006.
Note: 0.426 KD = $1.47

2.20 As explained in the previous chapter, productions costs in Kuwait indicate relatively little, although the 2005/6 reversal of the rising trend occurred in the context of significantly higher costs from various service companies. Higher levels of global demand trigger a scarcity of service industry capacity in the short run. Many senior officials in the sector have stated that one of the reasons for Project Kuwait and the entry of IOCs was to try and reverse the rising costs attributed to declining efficiency in the sector, not least as the recovery became more dependent upon more complex geology, especially in the northern fields. This is particularly relevant in the context of a growing need for water management in the fields.

2.21 The managerial capacity of the sector was diminished by the loss of the KPC's expatriate managers in 1990. While efforts have been made to replace the losses, the political and personal pressure to employ and promote locally—linked to the Diwaniya-Wasta culture (Marcel, 2006)—is considered to have a negative effect on sector capacity.

2.22 It is reasonable to assume, at least on the basis of qualitative analysis, that Kuwaiti oil sector production is not particularly efficient. Nor is such efficiency high on the list of sectoral priorities—although, to be fair, the low upstream costs attributable to the geology allow for some space. The low priority is also reinforced by the relatively high world prices experienced since 2002.

2.23 At the core of Kuwait's sector structure is the incentive system. The way the sector is structured does not create an incentive for the KOC to minimize production costs.

Linkages

Fiscal Linkages

2.24 The Kuwaiti fiscal system is based upon a hybrid budget system.

- The KOC receives its capital expenditure in a budget set by the government.
- The KPC then buys its crude oil from the government at a price fixed annually by the pricing committee (on the basis of international prices). From the purchase price are

deducted the KOC's operating expenses plus 10 percent for a legal reserve—a requirement for all Kuwaiti companies to cover possible claims against the company.

- The marketing division of the KPC then sells the oil at a price set by the international market and returns the sales revenue to the state, less 10 percent for the reserve fund for future generations, and in return takes a 50 cents marketing fee per barrel.
- Any differential between the price paid by the KPC and the market sales price is carried by the KPC, whether positive or negative.

2.25 Alternatively, the KPC can refine the crude through its refinery subsidiary, the Kuwait National Petroleum Company (KNPC), and sell the products. Thus the KOC is treated as a cost center in which there is no incentive whatever to reduce operating costs. Since it has access to sufficient capital funding, this inevitably encourages "gold plating" and significant rent seeking by the KOC. The KPC's other subsidiaries are allowed to earn a profit. The KPC can earn profits by refining and selling products. One obvious consequence of this system is a strong incentive for the KPC to maximize its downstream operations, especially those selling into the international market, since domestic product prices in Kuwait remain subject to control to keep them below border prices.

2.26 Obviously, refinery operations abroad pay taxes to their host governments rather than the government of Kuwait. Another consequence of this system is that it is very much in the KPC's interest for the pricing committee to set the oil price at a low level relative to the market. This gives the KPC the advantage of being able to sell more crude to its subsidiaries, thereby increasing its sales commissions. It also reduces the cost of the refinery slate, increasing refinery margins and allowing the KPC to profit from the difference in a rising market. Given the clear weaknesses in this system of financing the KPC, there is talk of reform, including the suggestion that price targets should be replaced with revenue targets to reduce gold plating and rent seeking.

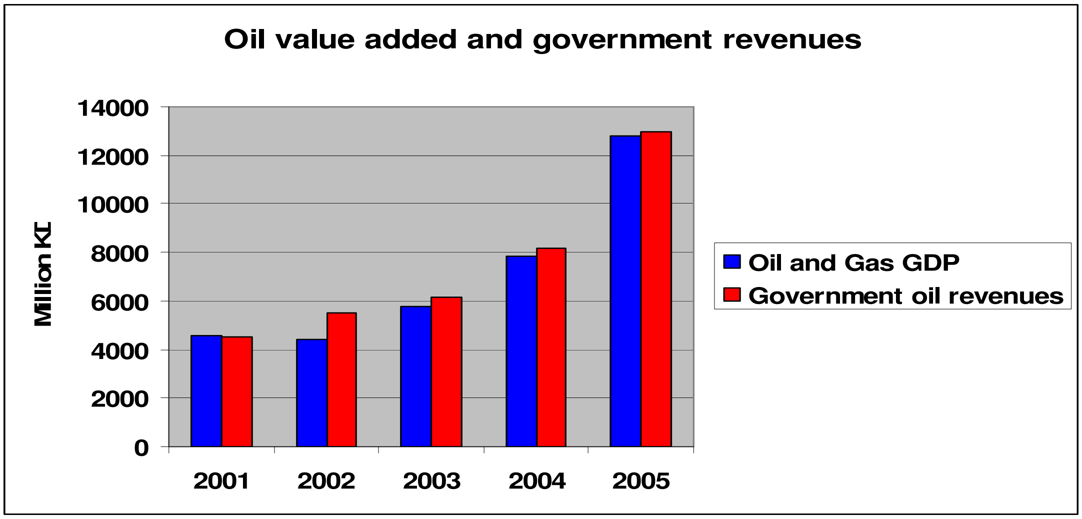
2.27 There is very little detail given in the central government's budget accounts other than the heading *oil revenues*. Thus, the exact composition of these revenues is unknown. But they are substantial, and, in 2005/6, accounted for over 94 percent of total government revenue.[29] Domestic oil product prices, which are regulated and have been fixed for many years, are below international prices.[30] The KNPC must pay the KPC the market price for its crude, implying losses on domestic sales. Domestic consumption in Kuwait is relatively small; in the current world of high crude prices, the KNPC's losses on domestic sales are small relative to its profits on sales of export products. To cover this, the government grants a subsidy to the KPC.

2.28 Figure 2.2 illustrates the fiscal linkages for the period 2001–05. Certainly, the size of the revenue slice appears to be very high, but, as discussed in chapter 1, gives us little or no indication of the size of the total revenues that could be generated from the sector.

[29] In 2005, oil exports accounted for 94 percent of total merchandise exports.

[30] In 2005, domestic prices for ultra-unleaded were 30.8 cents per liter and for gas oil/diesel 18.8 cents per liter (OAPEC). This compared to the Rotterdam spot price at the end of 2005 of $1.59 and $1.47 per liter (IEA).

Figure 2.2 Kuwait: Government Oil Revenues



Source: Central Bank of Kuwait.
Note: While the gross domestic product (GDP) data is for the calendar year, the revenue data is for the budget year. Thus 2001 is 2001/2, which effectively creates a lag in the GDP, explaining why revenue appears to exceed value added.

2.29 Given the Kuwaiti government's large accumulations of currency reserves,[31] any lack of development cannot be attributed to problems arising from a lack of revenue resulting from any weakness in the fiscal linkages.

2.30 Although the KPC's revenue and asset growth appear good based upon annual reports, casual observation of the sector shows that there is a lack of investment upstream and improvement projects are subject to extensive delays, leading to chronic problems in the sector. This raises serious doubts about the ability of the sector to meet crude oil production capacity targets, and hence its ability to deliver on geology. In this context it is interesting to quote Nader Sultan, former chief executive officer of the KPC:

> . . . we abide by performance indices that we monitor every three months with international companies, and we have clear strategic plans. But the difference between us and commercial companies is the existence of many obstacles as exemplified by external supervisory measures imposed by bureaucracies outside KPC. In the end, we find it difficult working as a commercial establishment in the true sense of the word because of these outside restraints. For example, in approving the KPC budget we have to go through several stages. We begin the budgetary procedures in September and we end in July the following year. We start by presenting a draft budget to the KPC board, then it goes to the specialized

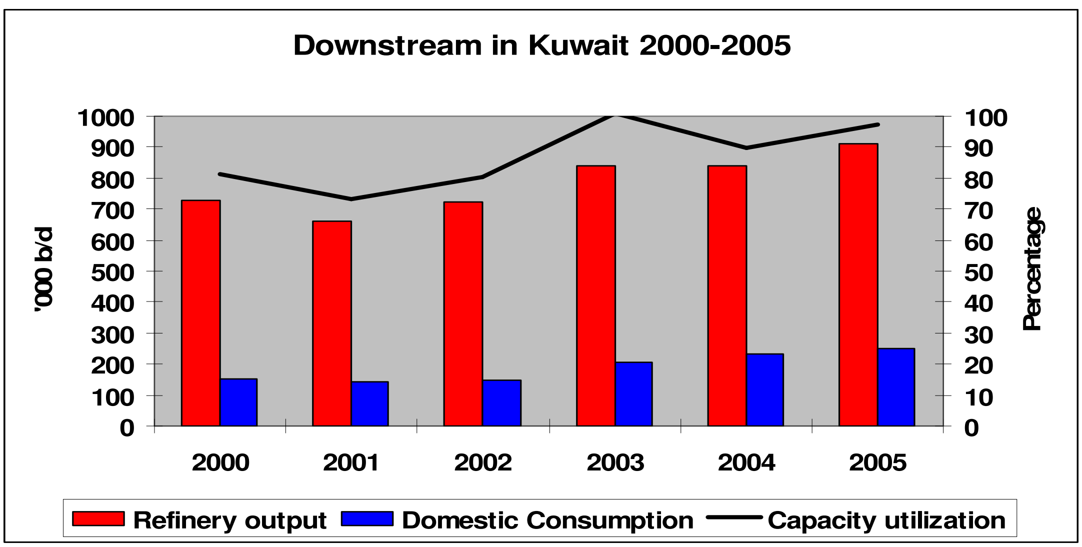
[31] It is not known how much is in the reserve fund for future generations, and it is actually a criminal offence in Kuwait to reveal the magnitude of the fund. Whatever the precise number, it is likely to be extremely large relative to the size of Kuwait's economy.

committee of the Supreme Petroleum Council, to the Ministry of Oil, to the Ministry of Finance, then to the Budgetary Committee of the National Assembly, and then to parliament itself. Whereas approving the budget of a commercial company requires nothing more than the draft budget being presented to the board, that is, one stage only, our budget takes nine months to get approval. Frankly, it takes KPC executives a long time to carry out a task which other institutions can complete in a much shorter time. We tell those who monitor our work: if you want KPC to act as a commercial organization, then give it the flexibility and authority it needs. When we compare ourselves with Gulf and international companies we find that their rules are different from ours. (Middle East Economic Survey, 45/16, 2002)

Forward Linkages

2.31 In terms of forward linkages, the sector does appear to be delivering. Figure 2.3 indicates that the sector is well able to supply the continually growing demand for oil products in a context where demand growth is strong. As with other countries in the region, the issue is what this costs the economy given the level of domestic prices for oil products.

Figure 2.3 The Downstream in Kuwait, 2000–05



Source: Organization of Petroleum Exporting Countries (OPEC) Statistical Bulletin, 2005.

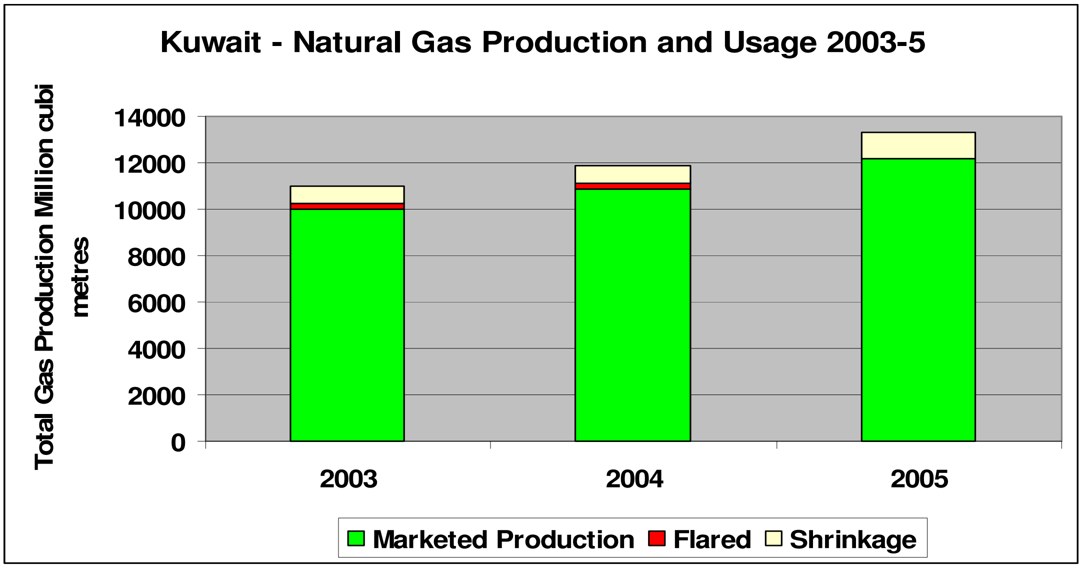
2.32 Refinery capacity utilization is sound, although the figures for 2003 were distorted by a loss of refinery capacity following a serious fire. There are no signs whatever of shortages, however, and, according to the KNPC's annual reports, the sector appears to be financially sound.[32]

2.33 The picture is not so attractive for natural gas, largely because Kuwait produces no non-associated gas. Only associated gas is produced, although, as can be seen from figure 2.4, utilization has improved. But Kuwait has suffered from gas shortages over the years. Prior to 1990, Kuwait was becoming increasingly dependent upon gas imports from Iraq. The invasion in 1990 and subsequent events have caused this source of gas to disappear. Other plans for importation from a variety of sources, including Qatar and Iran, have periodically emerged since 1990. But given the availability of cheap fuel oil for energy and naphtha for petrochemical feedstock, this cannot be construed as a problem or indeed a failure of the sector. If the geology is not conducive to finding and producing nonassociated gas, then the gas supply is a function of crude production.

2.34 A large gas field was recently discovered in Kuwait, but as yet the plans for its development are unclear. In the case of Kuwait, forward linkages are affected by a conflict of interest. One of the areas where the KPC has a costly conflict of interest is in the allocation and pricing of scarce natural gas, since the KPC's subsidiaries compete with other users for a limited amount of gas. The tendency, and indeed the practice in this case, is for the KPC to allocate the gas to its subsidiaries first and to provide only the bare minimum to the Ministry of Energy, even though the market value of the gas in power generation is considerably higher than its value among the KPC's subsidiaries. In the case of the Ministry of Energy, the opportunity cost of gas is 10–15 percent higher than the Light Sulfur Fuel Oil equivalent (about $5.5/ per million British thermal units, Btu, at about $45–50/bbl of oil) whereas the opportunity cost of gas in urea production at the same oil price is at most $2.5–3.0 per million Btu (the netback value of gas as derived from the sales revenue of the urea). As such, it would make economic sense to allocate all the gas to the Ministry of Energy first, and then to the next highest value (as fuel in refineries), and finally as feedstock. In this context, and provided the capacity to undertake the complex modeling for gas allocation and pricing is available, it would be more sensible to have the Ministry of Energy, and not the KPC, be responsible for the evaluation of gas supply and its allocation and pricing, as these are central to energy policy.

[32] In 2005 KNPC posted a gross profit of 653.2 million KD compared to 128.0 million KD in 2004. The dip in capacity utilization in 2001 reflected a small fall in domestic consumption.

Figure 2.4 Kuwait: Natural Gas Production and Usage, 2003–05



Source: OPEC Statistical Bulletin, 2005.

Backward Linkages

2.35 Other than issues to do with employment, the KPC website and related sites are very reticent to disclose information on the issue of local content in the Kuwaiti oil sector. There is no data regarding how much of the supply chain comes from Kuwaiti companies. This suggests that local content is fairly limited. But it can hardly be argued that this lack of backward linkages in the supply chain is in any way related to the way in which the sector is structured. Given the relatively limited scope of the rest of the Kuwaiti economy,[33] limited linkages are hardly surprising. It is significant that the KPC subsidiary the Oil Services Sector Company—aimed at providing construction and security services for the sector—was only created in 2005. It might be argued that the development of the petrochemical sector is a form of backward linkage, although its sustainability in the absence of cheap feedstock might be questioned.

2.36 The situation is different with respect to employment, although it should be remembered that in Kuwait, while the oil sector accounts for some 50 percent of gross domestic product (GDP), it accounts for less than 3 percent of direct employment. Following the departure of expatriate staff in 1990–91, the sector found itself under pressure from the government to provide more jobs for Kuwaitis. Quality of staff has, however, been a concern given the deficit of the Kuwaiti labor force supply when compared to demand from the oil sector. This process has been compounded as various interested parties within Kuwait have been putting pressure on the KPC to treat certain individuals preferentially. In 2003/4, the KPC introduced a five-year "Kuwaitization" plan. At the end of 2002/3, the KPC and its subsidiaries employed 12,963, of

[33] In Hirschman's terms, the *technological strangeness* of the oil sector.

which 75.4 percent were Kuwaiti nationals.[34] In addition, the KPC introduced a requirement that its contractors employ at least 25 percent Kuwaiti nationals.

Box 2.2 Key Observations – Kuwait

Authority over the oil sector is dispersed, with an unclear division of responsibilities. This means that the national oil company (NOC) lacks clear and stable objectives. Political influence sometimes leads to the hiring of relatively inexperienced managers. The fiscal system provides limited financial incentive to the NOC to reduce costs. These weak institutions and incentives have prevented Kuwait from meeting its formal targets for capacity expansion.

Objective-setting processes would benefit from clear and streamlined rules to avoid delays and undue interferences. Clarity of supervision responsibilities could reduce possibilities for interference in operational decisions leading to inefficiencies.

Downstream, domestic supply matched demand, but the sector structure has clearly affected the optimization of resource allocation (as experienced in the case of natural gas use). The private sector was envisaged to play a role both upstream (Project Kuwait) and downstream (privatization of refining activities). Decisions regarding private sector entry have, however, been limited to some technical assistance upstream and privatization of peripheral activities downstream, and would require the NOC to adopt corporate governance methods to take a possible shareholder role in the privatized entities. The government would also need to take the burden of remaining price subsidies instead of leaving it to the Kuwait Petroleum Company (KPC), so that the company focuses on implementing commercial and technical decisions and the government focuses on policy implementation.

[34] Interestingly, Petroleum Intelligence Weekly's Supplement (PIW, December 18, 2006) gives the total KPC employment at 20,340.

3. Saudi Arabia Case Study

POLITICAL ECONOMY OF THE PETROLEUM SECTOR STRUCTURE

Who Sets the Objectives?

3.1 Within the petroleum sector, apart from capacity levels and a few other decisions, Saudi Aramco is left to determine its own objectives and their prioritization. Setting the capacity level is, of course, extremely important. Once it is set, Saudi Aramco seeks to maximize the recovery factor on the fields within its constraint. The objectives are set out in a five-year rolling strategic plan. While this must be approved by the Supreme Petroleum Council (SPC), in practice approval is a formality. The ministry, by contrast, is left to deal with the Organization of Petroleum Exporting Countries (OPEC), global supply and demand estimates that feed into decisions on capacity, the opening of the sector to foreign investment, and the consumer-producer dialogue.

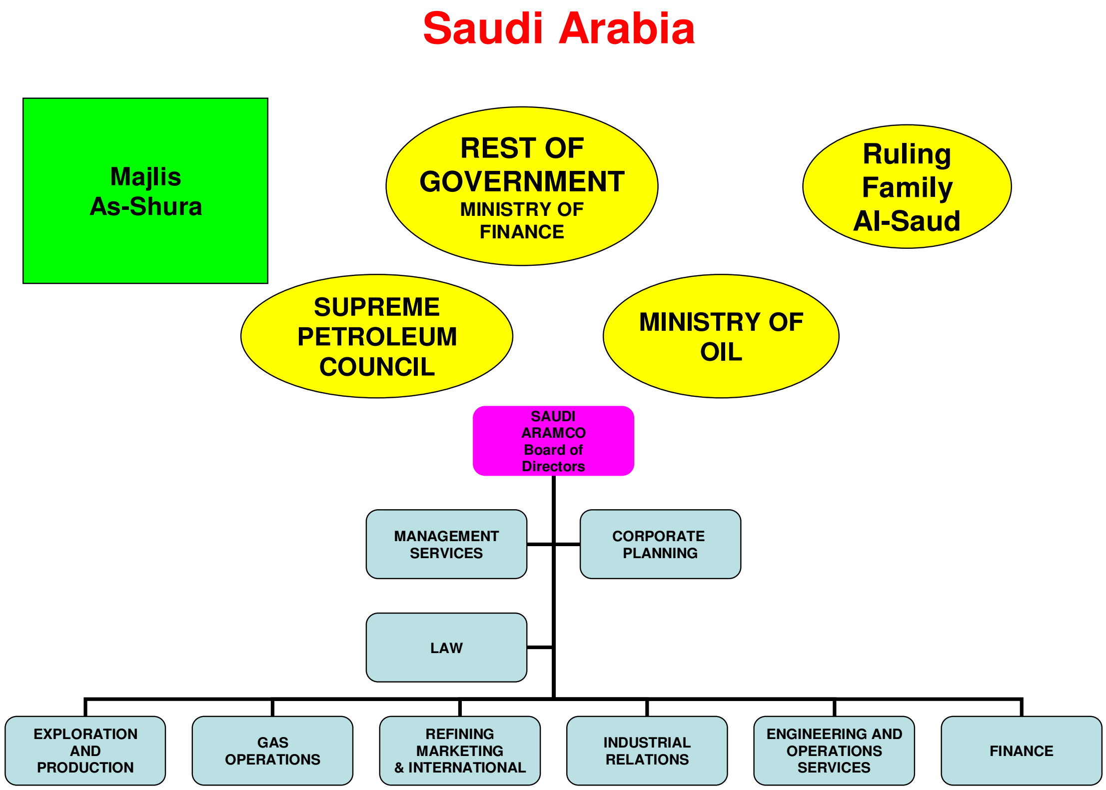
The Players and Their Interactions

The main players in the petroleum sector are shown in figure 3.1.

3.2 Although the structure of Saudi Arabia's sector appears similar to that of Kuwait, in reality the two structures are different in how they operate. A key difference is that in the Saudi case there is effectively a protective wall around Saudi Aramco and the only entry route to influence what the company does is via the SPC and the Ministry of Petroleum and Natural Resources. Unlike Kuwait, by strict order of successive kings, Saudi Aramco has been protected from political interference.

3.3 The membership of the SPC and the Saudi Aramco board are shown in table 3.3. The SPC's membership is relatively predictable, but the board membership is unusual in terms of national oil company (NOC) boards, as there are a number of outsiders who are board members by virtue of their expertise rather than any official position. In other words, the Saudi Aramco board is not unlike a typical international oil company (IOC) board containing nonexecutive directors.

Figure 3.1 Saudi Arabia: Petroleum Sector Structure



Source: authors.
Note: The Ministry of Oil's full name is the Ministry of Petroleum and Natural Resources.

Table 3.1 Saudi Arabia: Membership of Various Sector Institutions

SPC	Chair = prime minister (king) Deputy Chair = deputy prime minister (crown prince) Eight ministers Chief executive officer of Saudi Aramco
Saudi Aramco board	Chair = Minister of Petroleum and Natural Resources Secretary general, Supreme Economic Council Minister of Finance and National Economy Minister of State and chair of the Saudi Seaports Authority Head of Saudi Aramco, plus three vice presidents Governor, Saudi Communications and International Technology Community Retired presidents, Marathon and Texaco; former vice chairman of JP Morgan

Source: authors.

Control of Operations and Monitoring

3.4 In theory, the activities of Saudi Aramco are monitored by the SPC. In practice, Saudi Aramco is virtually self-regulating and the SPC only provides light supervision, mainly endorsing decisions made by Saudi Aramco. There has long been a culture of performance self-assessment within Saudi Aramco, with clear lines of reporting and responsibility that create accountability within the company. But it is precisely these internal processes, with no independent assessment, that make external observers in the country raise concerns about the company's performance. The system is an open invitation to pursue rent seeking based upon information asymmetries. These concerns are unlikely to go away, and it will be interesting to see whether they will eventually lead to changes within the sector.

3.5 As part of its performance assessment, Saudi Aramco places great emphasis on benchmarking. But while benchmarking can be quite effective downstream—since the laws of physics and chemistry are the same the world over—upstream, for reasons already discussed, significant differences in geology raise doubts about its usefulness. Geology in Saudi Arabia provides for very low costs of exploration and production (E&P).

3.6 There is effective transparency between Saudi Aramco and the government through the oversight of the SPC. This information, which includes detailed operating reports and independently audited financial accounts, is not available outside of the SPC to the rest of the society or indeed many other parts of the government—although eight ministers are members of the SPC. This raises an interesting question: is public disclosure a necessary requirement for effective operation? Disclosure of more information would hopefully improve general public trust in the sector in the eventuality that this trust is challenged.

The Objectives of the Sector

3.7 The objectives of the petroleum sector have always been closely aligned with the broader development policy objectives of the Saudi government. Saudi Arabia has a long history of five-year plans. The eighth plan was launched in December 2005, covering 2005–10. Its 12 objectives were broadly similar to those of previous plans, and ranged from diversification of the economy (partly by developing a manufacturing sector), to increasing employment for nationals, to the efficient management of Saudi Arabia's share of international markets. To achieve these objectives, 21 strategies were enumerated to explain how all this would be done. The plan claimed to be different from its seven predecessors in that it was based upon a long-term development strategy to 2024. The plans have, however, tended to be inspirational, with limited resort to measurable goals and methods to achieve their goals.

What Are the Objectives?

3.8 ***Upstream***. As of September 2006, the objective was to increase crude-production capacity from 11.3 million barrels per day (mb/d) to 12.5 mb/d by 2009 with the possibility of a further 0.9 mb/d of Arab Heavy from the Manifa field by 2011. Up to 2009, the increment would be 2.35 mb/d from seven fields, of which 1.5 mb/d would be net additions, predominantly of lighter crude. The stated objective is to maintain a cushion of spare capacity, amounting to 1.5 to 2 mb/d, to act as a stabilizing force for the global oil market. Underlying these targets, there is an explicit objective to protect the fields and maximize recovery rates.

3.9 ***Downstream***. In November 2006, it was announced that Saudi Arabia's domestic refinery capacity would be increased from 1.9 mb/d to 3 mb/d by 2010. While some of this expansion would come from Saudi Aramco's refineries, there was also a stated intention to involve private sector investment. It has been announced that the Arabian Industrial Development Corporation (NAMA) will build a privately owned 400,000 b/d refinery at Jubail in partnership with Petronas. Created to invest in petrochemicals, NAMA is a private consortium of some 300 Saudis and other Gulf Cooperation Council (GCC) nationals, in which the Saudi Arabia Basic Industries Corporation (SABIC) has a 10 percent stake. SABIC was created in 1976 to promote petrochemicals and metals in Saudi Arabia; 70 percent is currently owned by the Saudi government and 30 percent by the private sector. Its broad plans are to expand by moving further down the value chain. In January 2006, it was announced that VELA, a tanker company and wholly owned subsidiary of Saudi Aramco, had ordered six 318,000 deadweight tonnage (dwt) tankers to add to its existing fleet of 23 tankers.

Saudi Aramco's broader objectives are encapsulated in its corporate values and resemble the corporate culture of an IOC.[35]

The Objectives: Conflict and Cohesion

3.10 There seems to be a clear vision in Saudi Arabia that helps align sector actors. There is a clear desire to maximize crude recovery from the reserves. But there are some areas of contention. In particular, the Ministry of Finance and some of the senior members of the government wish to see Saudi Aramco's monopoly broken. This concern was evident in the government's attempt to open the sector to IOC investment in the late 1990s (see box 3.1). Given how Saudi Aramco is carefully insulated from such debates, at present it is unlikely that this lack of alignment affects the daily operations of the company in any negative way.

3.11 In Saudi Aramco, as with the National Iranian Oil Company (NIOC) in Iran, there is a strong sense of a "national mission" within the corporate culture, and a strong corporate culture maintained by employees. There is obvious pride in being an "Aramcan," a view that is explicitly cultivated by the company. The corporation is seen as the guardian of a national resource, and maximizing recovery factors is a central tenet of Saudi Aramco's objectives. Aramco has a strong sense of responsibility to the rest of Saudi society, which should be met by maximizing the positive social impact of its operations. But there is a downside to such a strong sense of corporate culture. As Marcel (2006) has pointed out, there is the danger that Saudi Aramco is developing a "fortress culture," especially as it comes under greater pressure from the government to do more to reduce unemployment among Saudi nationals. This could create rigidity in thinking that makes the company resistant to change.

[35] An illustrative list is as follows: "We pursue excellence in everything we do. We encourage continuous learning and strive to develop our people to their highest potential. We strive for fairness and adhere to the highest ethical standards. We support each other and work together to achieve our business objectives successfully. We strive to maintain the highest levels of safety, security, health and environmental standards. We are responsive to the expectations of the government and our customers. We place authority where responsibility lies. We are accountable for our actions. We support our communities and serve as a role model for others."

SECTOR STRUCTURE AND PERFORMANCE

Productive Efficiency

3.12 There is almost no publicly available financial information about Saudi Aramco, although a widely quoted number is that fully built-up average production costs are around $2 per barrel. This number obviously depends upon the speed with which the capacity is developed and the cost of services. For example, in 1995, the company hurriedly developed the Shaybah fields with a capacity of 0.5 mb/d. The speed of this development, it was rumored, led to much higher costs than normal. Similarly, the recent drive to restore surplus capacity has been apparently done at a relatively high cost because of the global shortage of drilling rigs and pipeline steel.

3.13 As a result of the pervasive influence of Exxon on the development of Saudi Aramco over many decades, there is a view widely held in the industry that, in its engineering projects and technical competencies, the company shares the kind of efficiency levels found in IOCs. In the past, its published plans, on a project-by-project basis, have certainly been realized in a timely manner, although a lack of financial transparency in whether cost estimates were met complicates the situation.

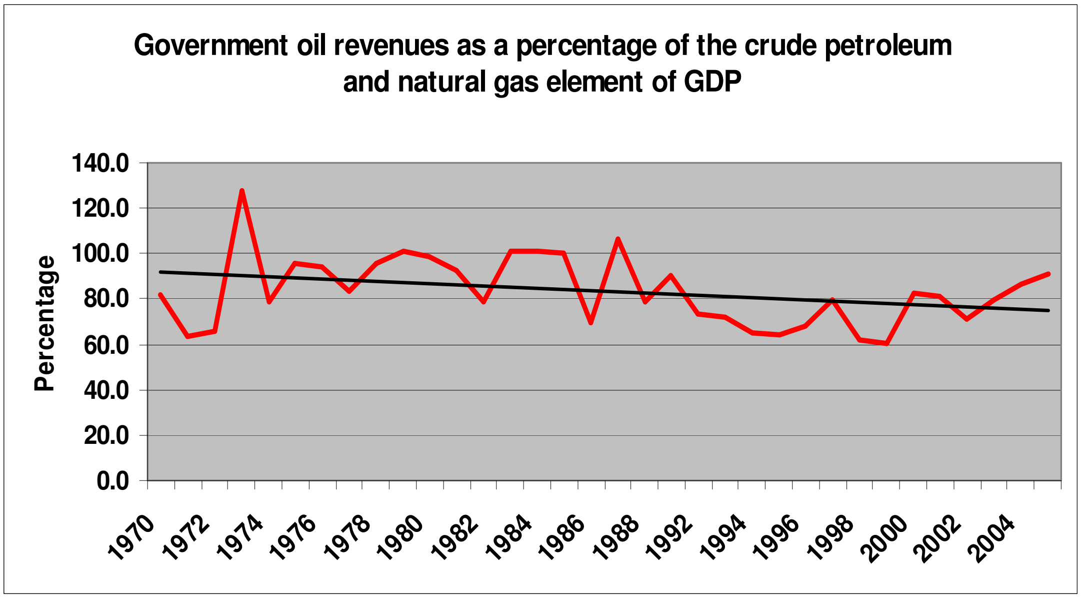
3.14 Saudi Aramco has so far been able to resist pressure to dilute its management capacity as a result of growing requirements to employ more Saudi nationals. It is in a position to employ the best and brightest Saudi graduates, and, over many years, has done precisely that. In addition, it has extensively developed not only its own training programs but also provided extensive scholarship for personnel to study abroad. There is little doubt that, among IOCs, Saudi Aramco is regarded as the best-run NOC in terms of the technical ability of its management and engineers. Lack of capacity in the sector is not an issue.

Linkages

Fiscal Linkages

3.15 There is a distinct lack of transparency in the nature of the oil revenues accruing to the central government. The Saudi Arabian Monetary Agency (SAMA) report simply refers to *oil revenues* with no further detail. Figure 3.2 illustrates the apparent government revenue from the value added generated by the sector.

Figure 3.2 Saudi Arabia: Government Oil Revenues as a Percentage of Oil and gas GDP



Source: Saudi Arabian Monetary Agency (SAMA) annual reports.

3.16 The importance of oil revenue is crucial to the government's finances. In 2005, for example, oil revenues accounted for 89.4 percent of total government revenues.

3.17 Saudi Aramco operates on a corporatized basis.[36] It is allowed to keep its revenue from crude and product sales, and then pays royalties and dividends equivalent to 93 percent of its profits. Its sales of crude oil to its own domestic refineries are charged at the long-run marginal cost of crude production ($2 per barrel), which is not regarded as a subsidized price by the government. This, therefore, ensures that the company has sufficient capital funds to meet whatever is required to fulfill its objectives. But there is a weakness in the system. The company pays out its operating costs after paying royalties, and before paying dividends. This reduces the incentive to cut operating costs.

3.18 The argument has been made (Marcel, 2006) that the management wants to minimize costs because it feels this helps retain government trust.[37] This relationship can be seen when the government effectively leaves Saudi Aramco to its day-to-day operations without any attempts at micromanagement or interference. Also, financial accounts are based upon best-practice auditing procedures supervised by an internal auditing committee that is overseen by independent foreign auditors. In this respect, Saudi Aramco is, in financial terms, like any IOC. The only difference—and it is key—is that there is only one shareholder (the government), who chooses not to reveal the accounts. Unlike a great many other NOCs, rumors of corruption in Saudi

[36] It is helpful to remember that Saudi Aramco was never the NOC of Saudi Arabia—that role was filled by Petromin, whose functions were eventually absorbed into Saudi Aramco. Thus, the fiscal system and structure was effectively inherited from Aramco based upon the system devised by the four owning majors: Exxon, Mobil, Chevron, and Texaco.

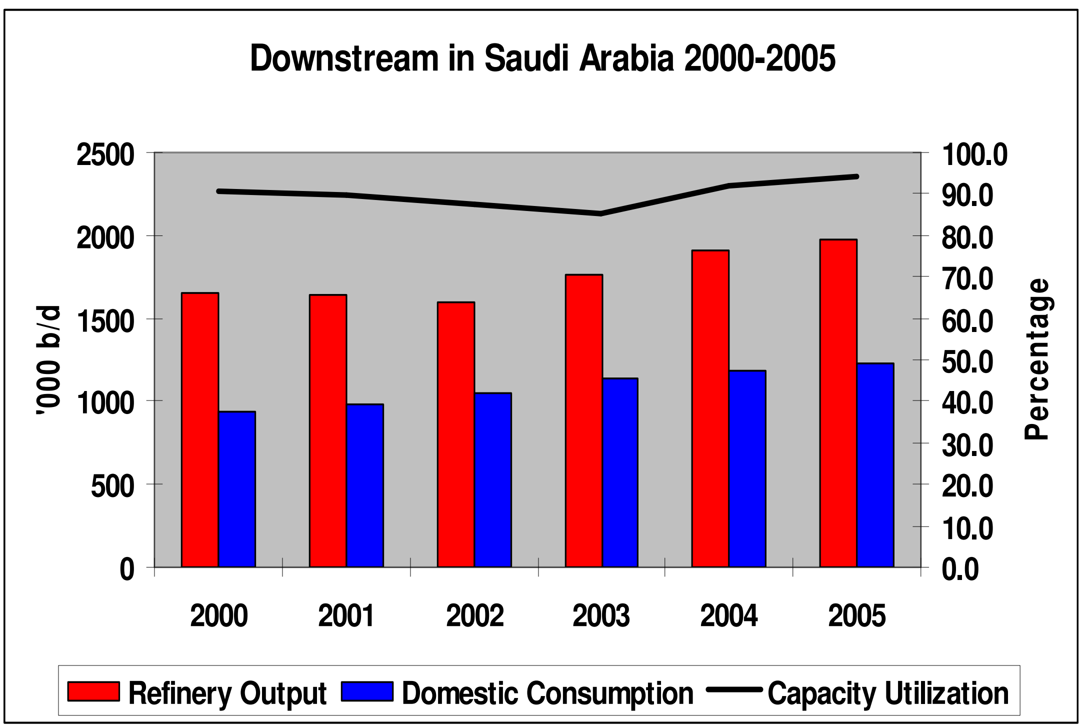
[37] It is interesting to observe that the attempted opening of the Kingdom's upstream to IOCs in 1998 caused huge resentment within Saudi Aramco precisely because Aramco felt this was effectively a vote of no confidence in its management.

Aramco's operations are extremely few and far between. In theory, Saudi Aramco is free to borrow from international capital markets if it feels it needs to supplement its access to capital. It has only done this once, in 1996, in order to increase the capacity of its tanker fleet. But even then it effectively prepaid the loan to avoid the necessity of financial disclosure normal in such transactions.

Forward Linkages

3.19 The oil sector has been extremely active in Saudi Arabia in order to supply oil products and gas. Figure 3.3 illustrates the results for oil products. There is no evidence of any product shortages at the ruling prices. The sector actually produces a significant export surplus. While domestic product prices, as set by the government, are well below border prices,[38] the downstream sector argues that it still makes a profit because it is charged the long-run marginal cost of producing the crude oil mentioned above. The logic is that, as the world's oil price maker, the correct price is the cost rather than the border price since if the crude were to be actually exported this would cause the border price to be much lower. Thus, the argument is that there is no subsidy in the downstream sector. But the argument is not robust. Raising domestic prices would not increase exports enough to significantly affect border prices. The reality is that the central government is forgoing a revenue-earning opportunity in favor of distributing income to domestic oil-product consumers.

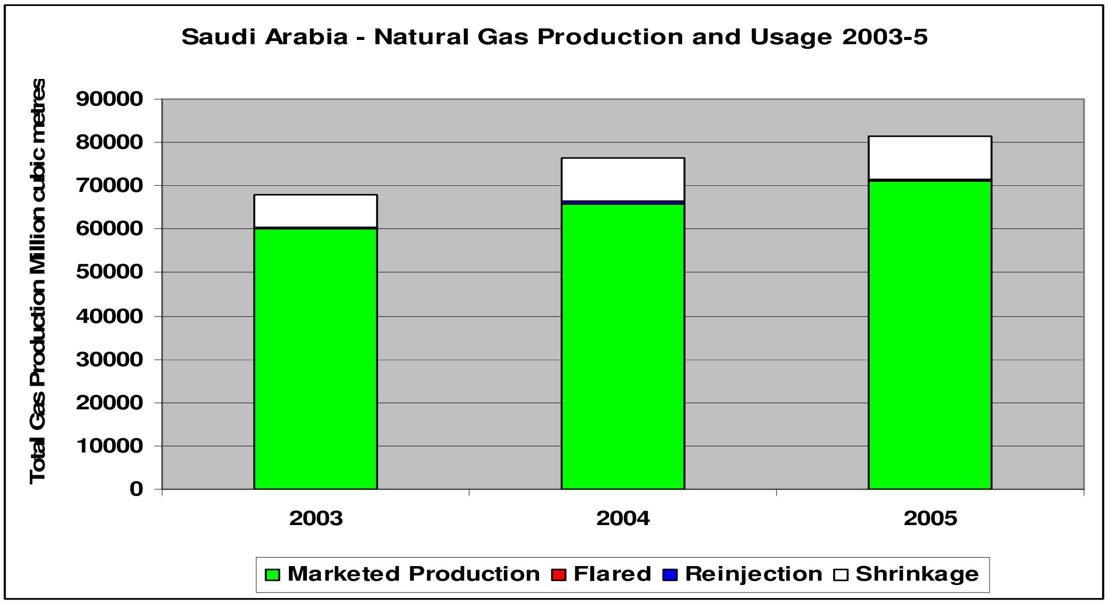
Figure 3.3 The Downstream in Saudi Arabia, 2000–05



Source: Organization of Petroleum Exporting Countries (OPEC) Statistical Bulletin 2005.

[38] In 2006, OAPEC reported Saudi domestic prices at 16 to 20 cents per liter for premium gasoline, 9.9 cents per liter for gas oil and diesel, and 9.3 cents per liter for jet fuel. These are significantly below the domestic prices charged in Kuwait.

Figure 3.4 Saudi Arabia: Natural Gas Production and Usage, 2003–05



Source: OPEC Statistical Bulletin 2005.

3.20 Forward linkages in natural gas are quite complex. Figure 3.4 illustrates recent developments. In 1975, the Saudi government decided that the extensive flaring of associated gas should cease. To that end, Aramco (subsequently Saudi Aramco) planned and constructed the master gas system (MGS). This was intended to gather the associated wet gas, strip out the natural gas liquids (NGLs), and then deliver the dry gas to consumers. The MGS began full-scale operations in 1980. In 1984, the plants were revamped to allow them to process nonassociated gas. In 1996, the MGS capacity was increased, and, in 2000, gas supplies were provided to Riyadh for the first time. At this point, the system had the capacity to process 7.5 billion cubic feet per day (bcfd), producing 5.8 bcfd of sales gas and processing 1.1 mb/d of NGLs.

3.21 The system is undergoing further expansion to manage 9.3 bcfd of gas and produce 7 bcfd of sales gas. There can be little doubt that this willingness and ability to deliver natural gas is a major part of the development story in Saudi Arabia. As well as supplying gas for Saudi Aramco's own operations, the MGS supplies 54 other companies—including power and desalination plants, plus 21 large petrochemical plants (18 owned by SABIC and three owned by private sector interests). Currently, a gas initiative is underway whereby consortia of IOCs are allowed upstream access to explore for nonassociated gas to supplement the Kingdom's gas supplies. Arguably, this forward linkage of gas provision, so crucial to the Kingdom's development, has been the result of sector project and engineering management, and the national mission that has dominated the Saudi Aramco culture. Staff quality, Saudi Aramco's autonomy over investment decisions, and an interest in promoting economic development to mobilize staff facilitated such a development.

Box 3.1:The Oil and Gas Upstream Opening in Saudi Arabia

In principle, the decision to open upstream access was made in the summer of 1998, when the government (independently of Saudi Aramco) considered a new position paper prepared by the Ministry of Foreign Affairs. This paper was intended to map a series of major economic reforms to develop the Saudi economy to meet the challenge of growing unemployment (especially among the younger population). The opening was intended to achieve several objectives. First, it was seen as a way to secure support from industrialized countries at a time of an oil price collapse (1998), when it was thought the Kingdom's purchase of large amounts of military hardware would be increasingly restricted. Second, the resulting investment was to be oriented to provide large numbers of jobs for young Saudis. Third, there were increasing questions within the government about the efficiency of Saudi Aramco. Allowing some foreign investment in the petroleum sector was perceived as a mechanism to provide benchmarking and, eventually, competition.

The government of Saudi Arabia then invited the heads of the major international oil companies (IOCs) to submit bids to the Kingdom. The nature of the bids was deliberately left imprecise, but they were supposed to present mutually beneficial opportunities for the IOCs and the Kingdom. But there seems to have been limited consultation with Saudi Aramco and the Ministry of Oil on the details of the process. There was a serious absence of detail provided to the IOCs, preventing them from making sensible bids. Also, Saudi Aramco was the only source of expertise competent to assess the IOC proposals. It was noticeable that the committee responsible for assessing the projects (dominated by Saudi Aramco and created in September 1999) did little while its chairman was absent because of illness. Only on his return in early 2000 did things begin to move, but even so negotiations were painfully slow. Eventually it became clear to the IOCs that upstream oil was not to be on the agenda, and attention turned to gas. In December 2000, three core ventures in the Natural Gas Initiative were identified, and ten IOCs were invited to bid. But another source of delay was that the downstream gas projects being suggested were not highly attractive to the IOCs, which were mainly seeking involvement in the hope that the oil upstream would be opened at some point in the future.

These events represented a major departure from the way in which the sector had been managed. Previously, it was Saudi Aramco and the Ministry of Oil that laid out plans and strategies for approval by the government. The opening initiative came from the government**,** and was perceived by the oil sector as being imposed upon the oil technocrats**,** much to their dismay. It took some time for the sector to reassert its dominance, but it did so simply by virtue of natural information asymmetries.

Source: authors.

Backward Linkages

3.22 In the past, Aramco has been central to the economic development of the eastern province, and has always gone to considerable lengths to try and maximize the backward linkages to the rest of the economy to encourage the availability of local factor inputs. This reflects the very strong sense of national mission that has characterized the company even before it was the NOC, as witnessed in Operation Bultiste.[39] But attempts to maximize local input have always been done on a commercial basis with no regulatory requirements. Thus, within Saudi Aramco there is talk of the need to locate projects within the so-called "Golden Quadrant," where projects have both high commercial returns and high social returns for the Kingdom.

[39] There has always been much debate in academic literature over why the Aramco partners went to such lengths in the 1950s to make a positive contribution to the Kingdom. One obvious explanation is that it made commercial sense. In the early 1950s, they realized that for every dollar spent producing oil, two dollars had to be spent upon service support. Since the eastern province of Saudi Arabia had limited resources, everything had to be flown in. But another explanation (not mutually exclusive) is that the Aramco management was encouraged to facilitate such linkage as a reaction to the real hatred observed against the expatriate management of the Anglo-Iranian oil company after the 1951 nationalization.

Saudi Aramco has long created joint ventures with the private sector, providing training and selling shares. Saudi Aramco claims that, in 2000, 86 percent of its purchases were from "Saudi factories or Saudi imports" and that the factories supplied more than $330 million of its purchases. Otherwise, data from the company on local content and how it is defined are extremely sparse.

3.23 More recently, the company has been devising strategies to encourage local firms too small to bid on some of the megaprojects to form a consortia. In 2005, two contracts for project management were awarded to two such consortia of local engineering companies. Clearly, the key principle is that Saudi Aramco makes use of local content on an economic basis. There is a trade-off between low cost provision and encouraging local content, and getting the balance right is important if efficiency is to be protected. This is a major problem if local content is forced by means of regulation.

3.24 A backward linkage causing growing concern is that of employing Saudi nationals. For many years the government of Saudi Arabia has pursued a Saudization program in a desperate effort to find employment for its growing labor force.[40] Saudi Aramco employs predominantly Saudis and, over the years, the number of expatriates has significantly reduced. In 2005, Saudi Aramco employed 51,843 workers, of which 87 percent were Saudis. This compares with 57,500 in 1995, of which nearly 80 percent were Saudis. Furthermore, Saudi Aramco has developed extensive training programs for nationals. But the government increasingly sees the petroleum sector as a source of new jobs.

3.25 While Saudi Aramco has remarkable freedom to determine its objectives, in recent years there has been growing pressure to play a greater role in employing Saudi nationals, both directly and through possible investments in downstream activities. This has not been entirely unwelcome within the company, since there is a strong sense of national mission, part of which is seen to be the provision of employment to provide highly skilled workers to benefit the rest of the economy. But there is also concern that if too many nationals are employed, this could dilute the managerial competence of the company. This is a serious problem for the sector, since its capital-intensive nature severely restricts its job-creating ability if real, genuinely productive jobs are to be created.[41] There is concern that pressure to increase the employment of Saudis could undermine the effectiveness of the sector if pushed too hard, too quickly. But Saudi Aramco has indicated that it is stipulating employment quotas for Saudis for the IOCs involved in the gas initiative.

[40] In 2005, 37 percent of the population was under 14 years old (World Bank, Development Indicators).

[41] For example, MEES has reported that the PetroRabigh joint venture conversion of the refinery into a fully integrated petrochemical complex will generate only 1,400 direct jobs, although it was claimed that three times this number would also be created indirectly in related "industrial, maintenance and support activities." The total cost of the project is estimated at $9.8 billion, reflecting the high capital intensity of the petroleum sector.

Box 3.2 Key Observations – Saudi Arabia

The oil sector seems to be protected from political interference, and is driven by a high degree of alignment among its various actors, resulting in a clear vision of the contribution expected from the sector, its role, and its degree of liberty in the use and allocation of investments.

The national oil company (NOC) is treated as a corporatized entity with a financial system that creates incentives for low-cost operations, although lack of data makes it difficult to support this assertion. Observers converge in concluding that investments are made to maximize the recovery factor. This is in line with the choice of maximizing revenues from petroleum, in a situation of strong dependency of economic development on government revenue from oil. In spite of some government efforts, private sector investment upstream has been restricted so far, not the least by the incumbent NOC.

Day-to-day operations are left to professional decision making within the company. This has resulted in a sector that is self-regulated. While this presents a risk of excessive rent seeking, it appears that the corporate culture within this NOC has managed to constrain such tendencies. A result is that the sector seems to have developed high levels of competency especially in technical fields.

The main lesson is that simple and ring-fenced lines of control around the NOC facilitate efficient operations. Similarly, freedom of the NOC to operate, including in matters of human resources and financial management, encourages efficiency.

In terms of the provision of oil products and gas to the rest of the economy, the sector has a strong record of delivery, although domestic prices are well below international levels. The NOC has a long record of helping the development of the local economy by seeking to maximize backward linkages through promotion of local content in NOC procurement, and by nurturing spillover investments transferred to the private sector. Indigenization of employment can work if it is a commercial strategy, and when skill evaluations are based on need, not nepotism.

4. Iran Case Study

POLITICAL ECONOMY OF THE PETROLEUM SECTOR

Who Sets the Objectives?

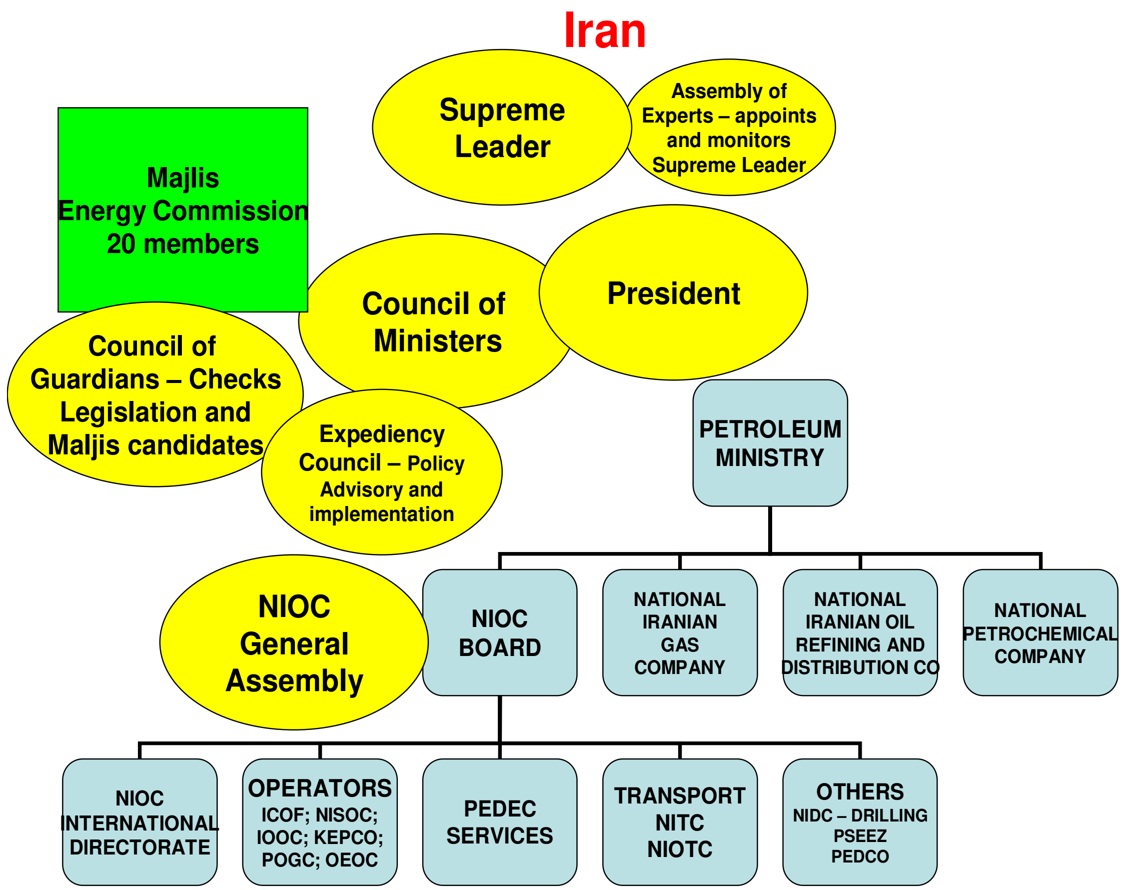
4.1 The objectives for Iran's oil sector have been set in the context of wider development goals reflected in a series of five-year plans. The current plan is the fourth, running from 2005 to 2010. It main objectives include gross domestic product (GDP) growth (8 percent per annum, 6.6 percent per annum and per capita) and a reduction in the size of the government. This was to be in a context of greater economic liberalization and privatization, with public and private monopolies removed. In effect, it was a reformists' agenda based on oil revenues of $120 billion, although the actual account was still expected to be in deficit by $25 billion, to be covered by borrowing. The plan was finally approved in August 2004. In August 2005, the new government of President Mahmoud Ahmadinezhad produced its own plan, which consisted of 10 objectives, among them greater self-reliance, employment creation, and nonhydrocarbon export promotion. These were to be achieved through 58 strategies and policies that included rationalizing energy consumption, reducing dependence on oil revenues, and fighting corruption. A central tenet of the policy was that the country's natural resources should be owned and managed by the people, not by growing state enterprises.

4.2 The objectives described above reflect the complex nature of the Iranian political system, with its intricate checks and balances. The seventh Majlis (parliament) reviewed a bill to alter the relationship between the government and the National Iranian Oil Company (NIOC). In particular, it moved the NIOC to a tax and royalty system, and gave the Majlis greater supervisory powers over buy-back contracts and other relations with foreign companies. A version had actually been passed by the sixth Majlis, but was subsequently blocked by the Guardian Council. Even the new bill may be overtaken by events, since it appears that the higher political level of the government has sought greater central control over the petroleum sector and the NIOC's activities. Certainly the politicization of the sector's objectives is having negative effects on its ability to provide funds to the central government, although recent high petroleum prices have masked this problem.

The players and their interactions

Figure 4.1 outlines the main players who control and operate the petroleum sector.

Figure 4.1 Iran: Petroleum Sector Structure



Source: authors.

4.3 The multiplicity of sector players is larger in Iran than in either Kuwait or Saudi Arabia. The NIOC's general assembly is the highest decision-making body for the sector. Its membership, together with that of the NIOC board, is outlined in Table 4.1.

Table 4.1 Members of General Assembly and Board of Directors of National Iranian Oil Company

General assembly	President and vice president Ministers of Petroleum, Energy, Industry and Mines; Labor and Social Affairs; Economy and Finance. DG [[define?]] of the Management and Planning Organization
Board of directors	Chairman = Minister of Petroleum Nine executive directors, including the managing director

Source: authors.

4.4 The foregoing figure does not reflect the full complexity of the sector, as it shows only the NIOC's subsidiaries. The National Iranian Oil Refining and Distribution Company (NIORDC) also has five subsidiaries: the National Iranian Oil Products Distribution Co., Management of Construction & Development of "CNG" Stations Co., National Iranian Oil Engineering and Construction Co., Oil Pipeline and Telecommunication Co., and Oil Refining Co.

4.5 The function of the NIOC's general assembly is to determine the NIOC's general policy guidelines, agree on its annual budget, and approve operational plans and financial accounts. The board of the NIOC approves operational schemes within the framework set by the general assembly, and can also propose projects and budgets to the assembly. The relationship between the Ministry of Petroleum and the NIOC is difficult to define since there is considerable overlap, with shared personnel and offices.

Control Operation and Monitoring

4.6 In Iran, the workings of the sector are extremely opaque to the external observer. In part, this reflects the nature of the Iranian political system. Once it has been approved by the Ministry of Petroleum, the NIOC's budget must also be approved by the Ministry of Planning and the Majlis. Once the Majlis gets involved, many of the other elements of the Iranian polity can intervene. For example, the Guardian Council has the right to question the budget—as legislation within the Majlis—to check its consistency with the constitution and Islamic law.

4.7 At a project level, sector operations are subject to constant interference from political individuals and institutions. This gives rise to considerable problems.

4.8 Because the nature of the objectives and targets are uncertain and there is no formal mechanism for monitoring, it is not clear that there is any formal, consistent, and regular means of evaluating the performance of the NIOC. None of the companies in the sector publish financial statements that are publicly available. Information on operations—as published in the various company websites—is sparse and restricted to the most basic of operational data. The lack of monitoring is further compounded by constant restructuring of the sector, which has taken place with little or no thought to the interconnections of its various elements.

The Objectives of the Sector

What are the objectives?

4.9 Since the end of the Iran-Iraq war, the key objective has been to expand crude-production capacity. A major change in policy came in 1990 when a key strategic decision was made to open the sector to international oil company (IOC) investment.

4.10 Several factors explain this dramatic change.

- First, there was a drive from within the government (the Foreign Ministry in particular) to try to end Iran's international isolation. In particular, it was hoped that a European presence would help mitigate the effects of U.S. hostility toward Iran, which had arisen as a consequence of the embassy hostage crisis in the immediate aftermath of the Iranian Revolution.
- Second, there was a shift in some quarters in favor of greater private sector involvement in the economy. This was, in part, because of the growing failure of the Iranian economy to provide the job opportunities required by an emerging demographic boom.
- Third, there was a growing realization that the petroleum sector's output was facing geological challenges. The natural decline rate in the fields was rising, and the recovery factor was far below what might have been expected on the basis of comparable geology elsewhere in the world.

4.11 The grand plan for a secondary recovery developed by a consortium[42] in 1977–78 had been postponed by the withdrawal of the IOCs and the war with Iraq. Field productivity was falling dramatically, and huge investments were needed to implement the recovery program, not least to develop the gas resources for reinjection. At the same time, a number of senior managers in the NIOC were well aware of how far the NIOC had fallen behind the technological evolution in oil production-techniques triggered by the 1986 oil price collapse.

Box 4.1 The Oil and Gas Upstream Opening in Iran

The story of the opening of the sector since 1990 is worth relating in some details since it illustrates many of the basic problems with the way the sector is structured, organized, and controlled.

When Iran decided to open up its oil upstream it began offering terms that did not appear as sufficient incentive to investors, given the growing competition from other prospective acreage, particularly the new prospects that emerged in Russia after the collapse of the Soviet Union. Facing reality, the Ministry of Petroleum improved the terms, and the interest of international oil companies (IOCs) began to come forward. In 1995, three agreements were signed: Sirri blocks A and E (Total), Balal (Bow Valley Canada), and the 2nd and 3rd phase of the South Pars (Total). These were essentially service contracts, offering IOCs a fixed rate of return. They were explicitly designed to get around article 44 of the constitution, which forbade private sector involvement in the oil upstream. The returns at this stage were reasonable, with the nominal rate of return on Sirri reported at 20–23 percent and on Balal at 24 percent. But there was a feeling that the ministry had swung too far the other way and there were attempts to lower the returns.

In 1995, the United States introduced executive orders enabling sanctions against U.S. companies investing in Iran, explicitly targeting the petroleum sector. Following complaints that this opened the door to non-U.S. companies in 1996, U.S. Congress passed the Iran Libya Sanction Act (ILSA) in 1996, which could be used against non-U.S. companies investing in Iran. IOC interest declined, but did not disappear.

In 1998, the United States announced that it would not invoke ILSA against three companies who were involved in deals in Iran: Total, Petronas, and Gasprom. Shortly after, Iran unveiled new buy-back agreements. These did not offer much difference to service contracts. The IOCs were putting up all the capital at risk. Although this was fairly common in other types of agreements, some aspects were much less attractive. The companies would not be able to book the reserves on their accounts, which was a major drawback for the IOCs. Once production began, the IOCs could recover their costs, and a fixed rate of return. If the oil price changed, then the speed of their recovery

[42] The consortium refers to the group of foreign companies created in 1954 to run oil operations following the overthrow of Mohammad Mossadegh. It was effectively disbanded as a result of the Iranian Revolution in 1979.

changed, although there was a time-out clause, which meant that, after a certain time, if all costs had not been recovered, they were the IOCs' loss.

In June 1998, there was a "road show" in London offering 19 offshore development blocks, 17 exploration blocks, and, for the first time, 15 onshore development blocks. Interest was high and over 150 companies attended, including a number of U.S. companies who thought sanctions would soon be lifted. However, after reflection on the terms, interest significantly diminished. In particular, it was apparent that all the IOC risks were on the downside, with no possibility of gaining on the upside. In effect, IOCs were contractors working for a fixed rate of return that could only decrease. In the event, the follow-up seminar in Tehran had to be cancelled because of lack of interest. Some negotiations continued at a slow pace.

In November 2000, a new form of buy-back was launched to try and revive interest. In it, the length of the contract offered was expanded. The earlier deals had relatively short time periods. The fixed rate of return was dropped, and the IOCs' return now had an element of reward and penalty based upon production levels. This, together with the prospect of a change of government in Washington, revived IOC interest. But since production levels were controlled by the National Iranian Oil Company (NIOC), the IOCs' return was effectively outside their influence.

Early in 2001, control of the negotiations on the Iranian side switched from the international affairs division of the NIOC to a newly created Petroleum Engineering Development Company (PEDEC). NIOC reforms of the previous five years resulted in a fragmented structure, and its capability to negotiate the buy-back terms was extremely limited because of lack of skilled manpower. In the late 1990s, the oil sector began fundamental restructuring. In 2000, an attempt was made to separate policy making from day-to-day operations by appointing a separate head of the NIOC who was not the minister. At the same time, the NIOC was split into more than 100 operating units. In early January 2002, control of eight large fields producing 1.19 million barrels per day (mb/d) was transferred from the National Iranian South Oil Company to PEDEC, further slowing the negotiation of the buy-back agreements.

The consequent chaos and extremely confused lines of responsibility from all these changes caused serious operational problems in the sector. These spilled over into existing buy-back contracts. There are three groups responsible for examining and monitoring the buy-back agreements: three Majlis deputies; representatives from the ministries of oil, finance and economic affairs, and foreign affairs; and, finally, a committee from the organization and information ministry, and the security bureau selected by the president. Yet despite this monitoring, the energy commission of the Majlis announced in 2002 that it was concerned about "lack of transparency" and demanded a greater say in the operation of the contracts.

In 2000, the Majlis began to get involved and the buy-back agreements became the focus of political struggles. Reforming elements in the petroleum ministry and the NIOC continually clashed with the conservative Guardian Council. The Majlis, especially since its conservative domination, targeted the oil sector with debates and investigations. As one report stated in 2005, there was no integrated approach in the sector and each group was effectively negotiating on its own. Thus, NIOC officials were reluctant to make decisions and the few buy-back deals struck were either with Iranian firms or joint ventures with other national oil companies (NOCs).

Buy-backs remained politically very unpopular within Iran. The history of IOC involvement in Iranian oil had not been a happy one, even going back before the extremely acrimonious nationalization in 1951. IOCs effectively became one of the key political "footballs" used in various internal struggles between the so-called "conservatives" and "liberals" since the 1990s. This greatly increased the involvement of the Majlis in day-to-day issues within the sector, which impacted the operation of private foreign companies. In 2002, there was an attempt by the judiciary, led by Ayatollah Ahmad Janati and other elements in the Majlis, to accuse the sector of corruption, especially in the context of the development of the South Pars gas field. Although this was widely seen as a conservative retaliation for efforts by the Majlis to investigate the financing of the broad network that supported the conservatives, the repercussions were extremely serious for the oil sector.

In March 2002, a number of officials, including Behzad Nabavi (former chairman of Petropars, an Iranian company involved in phase 1 of the South Pars development), were charged with corruption by the courts. The head of the NIOC, Mehdi Mirmoezi, was also charged, although claims that the oil minister, Bizhan Zanganeh, was also charged were subsequently denied. Whatever the reality of who was charged with what, the outcome was that, after 2002, senior members of the oil establishment spent a large amount of time defending themselves against such charges rather than running the sector. While the charges appear to have been dropped, they still make IOCs uncertain about the dependability of negotiations. This was not helped when the Guardian Council consistently ruled the buy-backs "un-Islamic and unconstitutional." While the expediency council overturned these decisions, such behavior does not create confidence among IOCs, and raises serious concerns about Iran's reliability as a business partner.

In June 2001, Eni (Italy) signed an agreement to develop the Darquin Field, which was the first onshore buy-back deal. This was under the old style buy-backs, with a reported rate of return of 12–13 percent. It was also claimed that Eni had managed to get around the problem of reporting the reserves, and that these would be booked. The agreement was greeted with dismay by the other IOCs as an undesirable precedent. Other negotiations dragged on, but, subsequently, only one other agreement was struck, in early 2004 with the Azadegan field going to INPEX, a Japanese consortium. In November 2003, Shell announced it was downsizing its Tehran office, and, in December, British Petroleum (BP) announced it was no longer interested. In January 2004, negotiations with CEPSA (Spain) and OMV (Austria) on Cheshmehkhosh were terminated after over 18 months of talks.

In late 2003, 16 exploration blocks were offered with new terms that included an automatic right of development from an exploration license. They also involved long-term contracts and gave the IOC a decision-making role in operations. Initially the IOCs welcomed the move, not least because it was an explicit admission by Iran that the previous terms had been unrealistic, therefore diminishing the damage done by the Eni deal. But once the acreages on offer were unveiled, interest disappeared given that they were geologically unattractive. They were located in various border areas, prompted by Majlis concern that certain areas of Iran needed a "development boost." Subsequently, the deals were signed with the Iranian private sector or joint ventures with other NOCs.

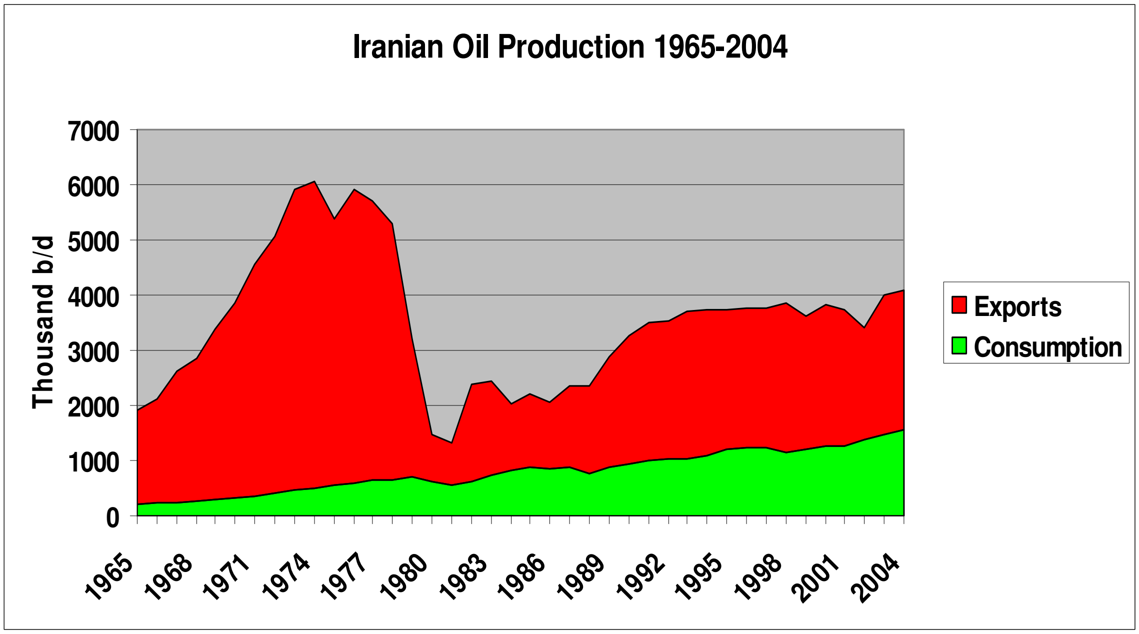
In 2004 Sinopec (China) signed a preliminary agreement for 50 percent of the Yadavaran field (150,000 b/d for 25 years). In May 2005, CNPC (China) created a joint venture with NIOC for an exploration and development license for the Kuhdasht block, one of the first blocks awarded under the revised buy-back terms. In gas, a number of deals are under discussion. In May 2005 it was announced that CNPC would replace Petronas in the Pars liquefied natural gas (LNG) project. More recently, China has also expressed interest in extending the gas pipeline from Iran to Pakistan and India. India's main interest is in gas. The projected pipeline is expected to cost over $7 billion. There is also interest in LNG, and, in June 2005, a $22 billion contract was signed to supply 5 million tons per year (mty) for 25 years, starting in 2009. In May 2005 PTT (Thailand) signed a joint venture for exploration and development of the Saveh block, based on the revised buy-back terms. PTT has also been in negotiation for other acreage. But there is a strong sense that many of the deals are promoted for reasons that are not purely commercial.

Source: authors.

4.12 The results of these policies can be seen in figure 4.2. From 1988 to 1991, production rose from 2.3 (a war-constrained level) to 3.5 million barrels per day (mb/d). This was largely a result of having resources released by the end of hostilities. A fairly steady plateau followed, apart from two dips. The first dip was in 1999, when annual production fell by 0.3 mb/d. This was entirely due to observation of Organization of Petroleum Exporting Countries (OPEC) quotas designed to reverse the oil price collapse of 1998. In 2000, as quotas became less onerous, production returned to pre-1999 levels. In 2002, there was another dip of some 0.3 mb/d, largely because of major managerial reorganization in the sector imposed by political pressures. The Ministry of Petroleum was struggling to mitigate the natural decline rate that was speeding up, while the poor development of the South Pars gas field slowed the reinjection program.[43]

[43] Figures on natural decline rates in Iran are extremely sensitive. There are no official data, and different sources give differing numbers probably because of a wide range of experience across different fields.

Figure 4.2 Iran: Oil Production, 1965–2004



Source: British Petroleum (BP), 2005.

4.13 The Iranian petroleum sector faces very serious constraints despite having crude capacity expansion at the heart of its sectoral objectives. The result has been a decline in production that has caused Iran to consistently fail to fill its OPEC quota.[44] This carries serious implications for the nature of fiscal linkages. Current, sustainable production capacity was estimated at 4.2 mb/d in 2005, which was the same as eight years previous and is far short of the official target for 2004 of 5 million b/d. These gaps could be filled by foreign or domestic private investment, bringing with it access to scarce funds and modern technology. This contribution is acknowledged in the fourth five-year plan (2005–10) and fixes a target for total foreign direct investment (FDI) of $13.8 billion. The NIOC has been given explicit permission to consider making use of FDI in upstream oil and gas, especially for shared fields and exploration. But the sector's failure to attract FDI, for reasons already explained, reflects poorly on its structure. Current NIOC aspirations for 7 mb/d capacity by 2020 will require an estimated $50 billion in investment. Even the fourth five-year plan target of 5.4 mb/d crude capacity and 600 million cubic meters per day of gas by 2010 looks unattainable unless there are dramatic changes.

4.14 One objective was to develop Iran's huge gas potential.[45] This was seen as a necessary condition to meet crude capacity targets, given the need for gas reinjection in the Iranian fields. But the story of the development of contracts to allow IOC entry into gas is similar to that of oil. The massive South Pars field plan was divided into numbered projects and offered to companies for development. The initial objective was to develop gas as part of a secondary recovery project

[44] This has been compounded, of course, by the rapid growth of domestic oil consumption eating into the surplus available for export.
[45] BP 2006 gives Iranian gas reserves at the end of 2005 as 26.74 trillion cubic meters, which are the third largest in the world (after Russia and Qatar) and amount to some 15 percent of world gas reserves.

being revived by the NIOC, but, over time, interest began to develop in an export option, both in pipelines in and a liquefied natural gas (LNG) plant. In the third five-year plan of 2000–05, it was intended to inject 141 million cubic meters per day (mcmd) of gas, but only 80 mcmd were injected. The fourth plan target for 2006–07 is an injection of 158 mcmd, which looks unattainable. In addition, there are significant delays in both the existing phases of the South Pars field development and phases yet to be contracted.

4.15 Objectives downstream are driven by Iran's growing consumption of gasoline. But a key objective is to increase refinery capacity, especially the capacity to produce gasoline. Iran's refinery capacity currently stands at 1.65 mb/d. This has increased from 1.35 mb/d over the last five years as a result of unit optimization and a decrease in bottlenecking. The current plans in the budget are to increase this to 2 mb/d in the "short-medium term."

4.16 As for objectives related to the NIOC'S "national mission," one is to keep the sector operating under difficult circumstances with minimal resources. This corporate culture has developed out of necessity following first the revolution and then the Iraq-Iran war. There is a strong sense that oil and gas are national resources that should ideally be developed for the good of the country, and that forward and backward linkages are important. The NIOC and its subsidiaries have considerable pride in their achievements in the face of war and sanctions, which feeds the sense of national mission. At the same time, the strong potential for politicization of the decision-making process may thwart attempts to turn the national mission into effective action. To some extent, recent attempts within the NIOC to promote more commercial thinking coupled with greater capacity by national, regional, and local governments have tended to reduce the imperative of the national mission.

The Objectives: Conflict and Cohesion

4.17 In Iran, there appears to be no clear vision for the sector. There are divisions between those who favor public ownership and those who seek a greater role for the private sector, those who favor national development of the oil and gas sector and those who seek to encourage foreign investors, and those who favor developing gas for export and those who prefer to prioritize greater domestic use. Generally, in the economy there are clear divisions between those seeking a greater role for the private sector and those wishing to retain state control, especially of the strategic economic sectors. This lack of a clear vision clearly prevents the various actors from aligning. This goes a long way toward explaining why the oil and gas sector has lacked effective and convincing direction, a situation that has long affected its supply ability.

4.18 A good example of the lack of cohesion is the growing opposition to the idea of developing gas for export. The NIOC's priorities in terms of what projects to pursue are set by government directives. Instructions come via the Ministry of Petroleum, but, in practice, as has been explained, the NIOC and the Ministry of Petroleum are effectively one body, not least because managers simultaneously hold posts in both entities. Thus there are many cross-over linkages between the Ministry of Petroleum, the board of the NIOC, and NIOC subsidiaries. The government sets the NIOC budget, and, once it is set, there is effectively no room to maneuver.

But who sets objectives and priorities is becoming increasingly confused as oil policy suffers from a multiplicity of official views. This confusion is likely to get worse. The Ministry of Petroleum is institutionally strong and can set realistic targets for the sector. But both the ministry and the NIOC face considerable interference from the Majlis, the Guardian Council, the Expediency Council, and the ministries of finance and foreign affairs. The result is that it is very difficult to get political support for new projects. It is also to be remembered that there has been an ongoing battle between the so-called “reformists” and “conservatives.”

4.19 It is far from clear what current policies actually are. During his election campaign, President Ahmadinezhad raised doubts about foreign investment in Iranian oil. For some time, he has been linked to the Abadgaran faction, which is strong in the Majlis and believes in state involvement in the economy and greater use of subsidies. In his first press conference after the election, Ahmadinezhad committed himself to maintaining the subsidies on domestic oil product prices; attacked corruption in the oil sector, promising to remove the influence of “one family” (a veiled reference to former president Rafsanjani and his sons); and argued that Iranian resources should be developed by Iranians and not foreigners.

4.20 After three attempts to appoint an oil minister, Kazem Vaziri-Hamaneh was appointed. But while the sector is in flux, with numerous personnel changes being absorbed, its policy is not at all clear, especially with respect to foreign investment. While it is true that, as indicated above, the Asian national oil companies (NOCs) appear to be welcome partners, it is likely that this has more to do with Iran’s attempts to gain support in the fight over its nuclear program than anything to do with the petroleum sector.

4.21 There are continuous rumors, dating back to before the most recent presidential elections, that new buy-back terms will be unveiled to try and attract reluctant IOC interest. At the same time, it is reported that the Majlis energy commission, one of the three bodies overseeing buy-back contracts, is trying to amend existing contracts on the grounds in the belief that they are too beneficial to IOCs and have the potential to harm reserves. The reality is that there are extremely unrealistic views as to what constitutes a “good deal” for the IOCs.

SECTOR STRUCTURE AND PERFORMANCE

Productive Efficiency

4.22 There is little quantified evidence available to assess the productive efficiency of the sector. But casual observation suggests efficiency is low. This view is reinforced when the list of missed targets, many of which are referred to in this case study, is considered.

4.23 The nationalization of the Anglo-Iranian Oil Company in 1951 forced a degree of self-reliance. While the creation of the Iranian consortium in 1954 brought back expatriate management, the sector developed a strong sense of the need to nurture managers in a position to monitor and understand what the consortium partners were doing. Thus the NIOC developed considerable capacity during the 1960s and 1970s that helped improve the efficiency of the operations. The Iranian Revolution in 1979 and the subsequent Iraq-Iran war caused an exodus of skilled manpower from the sector. The sector’s underlying education system and the NIOC training institutions survived, and, over time, the managerial capacity of the sector was to a degree restored. More recently, management, especially at senior levels, has become increasingly politicized, inhibiting the capacity of the sector to enhance performance. One of the reasons for the slow development of buy-back contracts is that the details of each contract had to be negotiated individually by PEDEC, which lacked sufficient skilled manpower to negotiate more than one or two deals at a time. Since the election of President Ahmadinezhad and the even greater politicization of the sector, many very experienced managers within the Ministry of Petroleum and the NIOC and its subsidiaries have left the industry. In the Ministry of Petroleum alone, staff has been reduced from 150,000 to 112,000 since the last presidential election in 2005.

4.24 There is little doubt that upstream operations in Iran are extremely profitable simply because of the very large amounts of economic rent in the oil price. This has been reinforced in recent years by the persistent strength of the oil price. But production costs have also been high, in part because of poor geology. For example, recovery rates on the Bangestan and Asmara fields are reported as only 10–15 percent. The structures are those of tight carbonates, which require costly fracturing to keep the oil flowing. At the same time, the natural decline on Iranian fields is high. The natural decline on the Zagros fields is 6–8 percent, described as “extremely high.” This means that some 350,000 b/d of production is lost across the nation each year.

4.25 Costs are also high because of problems associated with side-stepping sanctions on service activities in the fields and importing equipment into Iran. For example, the World Bank (2006) shows that 45 signatures are needed to import equipment into Iran (compared to only 15 on average across the Middle East and North Africa, MENA) and it takes 51 days on average to import into Iran (34 on average in MENA). Regarding access to infrastructure, this normally has to be developed specifically for oil and gas projects since they are often located far from existing infrastructure. A particular cost problem in the parts of Iran close to the Iraqi border, where much of the new exploration acreage is located, is that of mine clearing, a legacy from the Iraq-Iran war. For example, Japanese operations in the Azadegan field have been suspended until mines are cleared.

Linkages

Fiscal Linkages

4.26 Oil and gas revenues play a vital part in the economy of Iran. Therefore, the effectiveness of fiscal linkages is crucial. The government budget is heavily dependent upon oil revenues. The budget that commenced on March 21, 2006, set at $70.3 billion, was based upon a projected oil revenue of $36.5 billion. Oil is the major source of foreign exchange for the economy, accounting for 89 percent of merchandise exports in 2000.

4.27 The lack of data makes it impossible to decide if the government's take on petroleum export revenues could be larger. The vast majority of the revenue earned seems to stay within the sector. It is highly likely that a significant part of this revenue is kept from the government through rent seeking and corruption. The complex structure of the sector makes it impossible to determine what actually constitutes oil revenues.

4.28 The volume of revenues from which the government's share is taken depends upon the sector's ability to deliver on expanding capacity to produce oil and marketable gas. Iran frequently fails to meet its OPEC quota and its own targets for capacity and production. In part, this reflects the way in which the sector is financed.

4.29 Iran follows the budget model, with hybrid elements. Funding for upstream operations is determined in a budget set by the Ministry of Petroleum and approved by the Ministry of Planning and the Majlis. The NIOC is treated as a cost center, and this has caused significant problems. Every time the government needs extra money to meet its general expenditure requirements, the NIOC budget is a favorite target. Given that for much of the period the government has been running budget deficits and the NIOC's capital requirements are large (5–6 percent of GDP), the NIOC has increasingly found itself desperately short of capital. Not surprisingly, this funding problem has caused the NIOC to struggle to meet its crude-production capacity targets. It has therefore resorted to borrowing from European and Japanese banks and export credit agencies. It also explains the NIOC's pushing of buy-back contracts to try and fill the funding gap.

4.30 Since the third five-year plan, the funding system has undergone some changes to try and address this problem. The NIOC can now generate its own revenues by gas sales, product exports, domestic crude sales, and assets created through buy-back contracts. The NIOC gets crude oil for domestic use free. The refining company, NIORDC, pays the NIOC an internal price roughly based upon average production costs, and receives its capital and operational expenditures (less the cost of the feedstock) from the government budget. Revenue from product exports can be kept by the NIORDC, although it must also pay for product imports. Given that gasoline imports are large and rising (see forward linkages), this represents a considerable drain on the sector's resources. As for the NIOC's share of buy-back production, this is sold by the Jersey-based Naftiran Intertrade Company, and no tax is paid to the Iranian government. In the past, when the government has been short of funds, there has been a tendency for the government to raise a special tax on government agencies, including the NIOC.

4.31 There are plans to change the funding system downstream by forcing the refineries to pay market prices for their crude slate, and then sell at market prices and secure funding from capital markets if the outcome is a funding deficit. This system has been suggested to improve accountability in the sector rather than to solve the funding problems. But such a system is unlikely to function until something is done to reduce the massive levels of subsidy on final oil product prices. In short, the Iranian petroleum sector faces severe constraints on increasing the volume of petroleum export revenues. Hopes that the funding gap might be filled by IOC investment are fading. As described at length above, buy-backs were never an attractive option. Recent attempts to make them more attractive to IOCs have been overshadowed since the election of President Ahmadinezhad. His overt nationalism makes the political risk of investment by IOCs much higher, and the row over Iran's nuclear ambitions has raised the prospects of more sanctions. Fear of sanctions has been especially influential in causing some countries (such as Japan) to rethink their investment options in the Iranian upstream.

4.32 For gas, the situation is different. There is much less rent in the gas price since there is, as yet, no cartel encouraging high prices. The high cost of transporting gas inevitably eats into the rate of return on projects. Given that much of the gas produced is for reinjection, this effectively gives the NIOC a position to dictate the price of gas as delivered to the oil fields. This further eats into pretax rates of return on gas projects. Poor rates of return in part explain the painfully slow progress being made in the South Pars developments, and the fact that a number of the phases have been given to Iranian companies (subsidiaries of the NIOC) following limited interest by IOCs. In mid-2005 there was talk that phases 21 and 22 would involve a newly formed private Iranian company comprised of seven major Iranian investors, including Bank Melli, Ghadir Investment Company, and Bahman Industrial Group. As for the gas export option, there appears to be growing opposition within Iran, creating considerable added uncertainty among potential private investors in gas export projects.[46] Thus, the direct fiscal linkages from gas operations are extremely weak and appear unlikely to improve in the foreseeable future.[47]

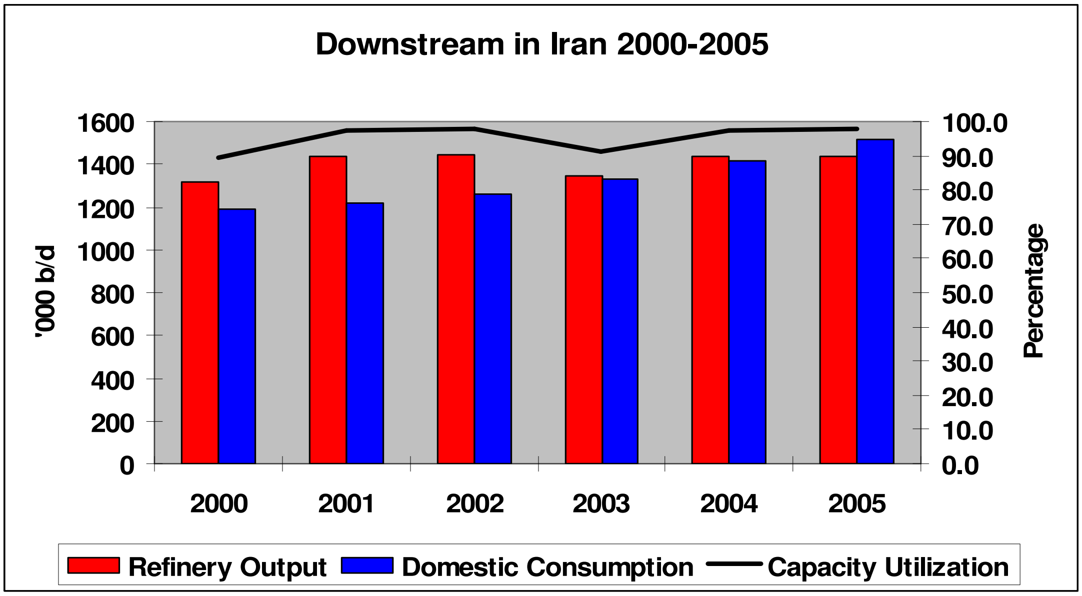
4.33 Failure to expand crude exports has been a major cause of relatively weak fiscal linkages. Failure to fulfill OPEC quotas in recent years has meant a lost opportunity to secure greater revenue for the central government.

Forward Linkages

4.34 In the case of Iran, forward linkages are of considerable importance. In terms of the provision of oil products to the domestic economy, the problems are well-illustrated in figures 4.3 and 4.4.

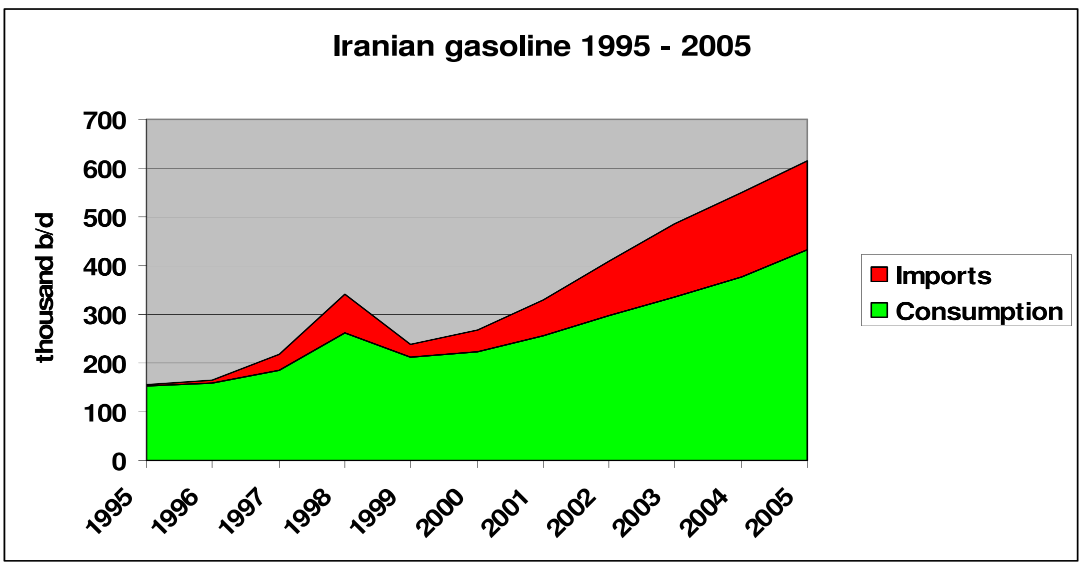
[46] In January 2007, Iran suspended its gas exports to Turkey, pleading shortages of gas for the domestic market in what was a very cold winter.
[47] Of course there is an indirect fiscal linkage is so far as gas production can be used to increase the recovery factor for the oil fields.

Figure 4.3 Iran: Downstream Petroleum Production and Consumption, 2000–05



Source: Organization of Petroleum Exporting Countries (OPEC) Statistical Bulletin 2005.

Figure 4.4 Iranian Gasoline, 1995–2005



Sources: 1995–2004 OPEC except production 2001, 2002, and 2004 authors' estimates. Middle East Economic Survey for 2005.

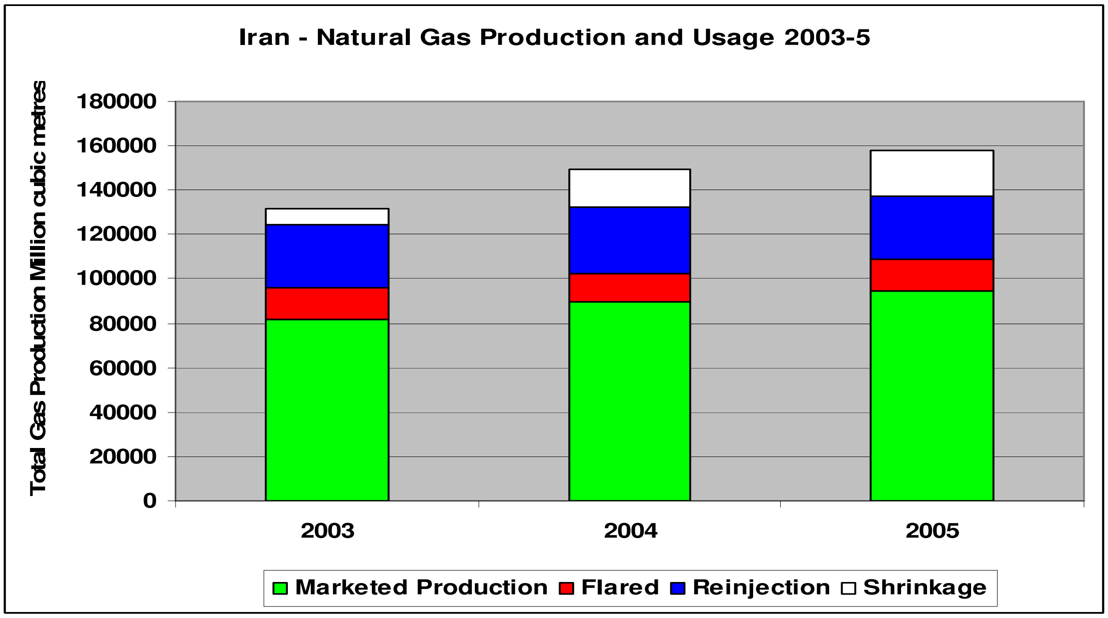
4.35 Highly subsidized prices for gasoline have meant that domestic consumption has been rising fast in the past (see Annex 2). The result has been that the domestic capacity to produce gasoline has failed to keep up, forcing ever-greater import levels. While this obviously puts a heavy burden on both government budgets and foreign exchange—2006 imports were estimated at $4.5 billion—the low prices encourage car use.[48] One serious economic consequence is very bad urban traffic congestion, which adds significantly to business transaction costs. This is most painfully obvious in Tehran.

4.36 But it is apparent that the oil sector has failed to deliver in meeting domestic demand. Clearly, the main responsibility for this lies with the continued subsidies, but there have also been problems in attempts to fund and build more refinery capacity. The increase in capacity over the last five years has been the result of decreased bottlenecking and unit optimization rather than the construction of new capacity. While no figures are available, it is almost certain that all Iranian refineries are operating with financial losses as a result of not being fully compensated for the requirement to charge far below international prices. There is no private sector investment in refineries as yet, although, given that the downstream is much less sensitive in terms of national sovereignty, this could change, and there has been talk of extending privatization to the oil downstream. While current subsidy levels are maintained, however, there will be little or no interest in private investment. There are moves to try and reduce the level of subsidy on oil products in an effort to curb consumption. Clearly, to bring prices close to border prices—or even prices based upon marginal costs—would require price increases of such levels as to cause serious political problems. While such a move might improve refinery profitability, it would have to go a long way before profitability reached levels that might encourage private sector involvement.

4.37 Forward linkages from the provision of gas also have a story of disappointment and failed opportunities as a result of lack of direction and finance. The recent pattern is presented in figure 4.5. As can be seen, the volume of marketed gas has grown slowly. Based on the BP Statistical Review of World Energy 2006, gas consumption growth in Iran averages about 3.4 percent per year from 2003 to 2005. The reason for the very slow progress in developing gas-production capacity has already been outlined. But the failure represents a significant lost opportunity to provide a development impetus to the rest of the Iranian economy.

[48] There is also a great deal of smuggling into neighboring countries where the domestic gasoline price is much higher.

Figure 4.5 Iran: Natural Gas Production and Usage, 2003–05



Source: OPEC Statistical Bulletin 2005.

Backward Linkages

4.38 On the positive side, U.S. sanctions have significantly increased the availability of local services. This has two clear benefits. First, this development of backward linkages has done much to boost the wider Iranian economy as new companies, including private sector companies, spring up to supply the sector's needs. Indeed, private Iranian companies can not only work as contractors in the sector but can also take part in buy-back ventures. Second, it means that many of the factor inputs for the sector are cheaper than in a context of greater dependence on foreign service companies. On the potentially negative side, there has been recent legislation that buy-back operations must use at least 51 percent local content. This may be viewed as positive since it might develop the sectors' backward linkages even further. But experience elsewhere suggests such legislation leads to increased cost when the local service industry lacks the capacity to deliver, or simply leads to *avoision*[49] of the regulations by the creation of joint-venture paper companies when the local content consists of a local sleeping partner. It remains to be seen how this plays out in Iran, but the existence of a growing local service capability suggests it may not be as negative as elsewhere.

4.39 Among service industries, competition has greatly eroded margins. But private sector involvement is only a relatively recent development, and, given competition with NIOC subsidiaries, it is hardly surprising that rates of return are not especially attractive. The rise of the private sector service companies was encouraged by the presence of sanctions, but they are struggling to emerge after a long period of state domination in the service sector. According to the World Bank (2006), the tax regime for businesses in general is quite favorable, averaging only 14.6 percent of an enterprise's gross profits compared to an average of 31.3 in MENA. The

[49] Evasion of regulations is illegal, avoidance is legal. *Avoision* is an uncertain half-way house between the two.

highly politicized nature of the oil sector—and an environment in which property rights remain uncertain and corruption likely—inhibit private sector interest in developing a local service industry capability.[50] As indicated below, there are some attempts of private sector entry.

4.40 Since the Majlis allowed it in November 1999, there are a number of independent Iranian exploration and production (E&P) companies. But they are small and have difficulty accessing capital. By its nature, exploration is very high risk. Small investors are not able to diversify that risk in the way that large IOCs can. Realistically, they cannot risk bidding alone because the cost of capital would be prohibitive. One solution is to be involved under the protection of some sort of consortium. Internationally, there are exceptions to this rule. In the United States and Canada especially, there are small private companies involved in exploration, although this might be better described a "prospecting" in the old sense of the word. Also, in the U.K., there have been small private companies buying into exploration acreage. An absolutely necessary condition for this is absolute confidence regarding property rights so that if the high-risk investment pays off, the investor will be allowed to keep the returns.

4.41 There is undoubted scope for greater private sector involvement in the service industry. Current legislation requires a 51 percent level of local content, which gives local companies a strong advantage. The NIOC has privatized some service companies such as the Oil Exploration Operation Company for seismic work. There are also a number of other private companies such as Dana Energy and Keps involved in seismic drilling. In March 2006, it was reported that the National Iranian Drilling Organization had contracted the private, local Arak Machinery Production Company to build a drilling rig. There was some skepticism that such a rig could compete with international standards, although this will undoubtedly be helped by the serious global shortage of drilling rigs. There are, however, a number of constraints. Specifically, the private sector is trying to compete with the longstanding, state-owned service sector, putting the new entrant at a disadvantage. As illustrated extensively throughout this case study, the oil sector is also more vulnerable to politics than other sectors of the economy. For example, recently, a couple of companies—Oriental Oil Kish and OIEC—were targeted in anticorruption drives, but it has been implied that this may be linked to settling domestic political scores. Uncertain property rights are likely to be a major constraint on further private sector involvement in oil and gas.

[50] World Bank (2006) indicates a score for Iran of 2.7 on the investor protection index compared to 4.3 for the MENA region and 9.7 for the most protected (New Zealand).

Box 4.2 Key Observations – Iran

The oil sector seems to suffer from significant political interference. This is due to the nature of the Iranian political system and the constitution's specific checks and balances, but clearly tends to fragment the control and operations of the sector. In particular, there seem to be different views on the leading strategy to adopt either greater or lesser private sector involvement. Attempts to secure greater foreign direct investment (FDI) upstream by means of buy-back contracts have generally raised limited interest among investors. The fragmentation of the sector itself also shows the gaps in the coherence and coordination of its operations. The main result is that the sector faces difficulties delivering on its capacity expansion targets and faces serious problems reducing the decline in crude export levels. This problem has been compounded because the hybrid budget model under which the national oil company (NOC) operates means that the NOC has limited access to revenues for investments to offset what is a high natural decline rate on the fields. The key lesson is that both private and public (NOC) investment is difficult to mobilize in an unpredictable environment with high regulatory risk.

The decline in export capacity is also driven by downstream policy. High levels of subsidy on oil product prices have led to excessive growth in domestic consumption and smuggling, eroding the crude export surplus, and challenging the delivery of products to the economy. Development of the gas potential has been delayed because of growing opposition within Iran to developing gas for export purposes and the poor financial returns obtained from gas sales at subsidized prices to the domestic power sector. As for backward linkages, the existence of sanctions has encouraged a degree of increasing self-reliance within the sector, but a business climate that offers limited comfort to private investment has meant that the potential to develop the local economy has not been fully realized.

5. Yemen Case Study

POLITICAL ECONOMY OF THE SECTOR

Who Sets the Objectives?

5.1 Yemen has development plans drawn up by the Ministry of Planning and International Cooperation. The second five-year plan ran from 2001 to 2005 and was accompanied by a longer-term view in "Yemen's Strategic Vision 2025." Yemen also has a poverty reduction strategy program (PRSP). The first, covering 2003–05, was produced in May 2002. The third five-year plan was due to run in the period 2006–10, but it was merged with the second PRSP. The joint document was approved in September 2006.

5.2 This joint document could (and should) inform the policy objectives of the petroleum sector. But strong asymmetries of information among the different ministries that formulated the plan led to objectives that are of limited use in defining production targets. Responsibility for the state dimension of the sector's objectives lies with the Ministry of Oil and Minerals, but there appears to be a limited process for central coordination, and individual companies are setting their own objectives and agendas.

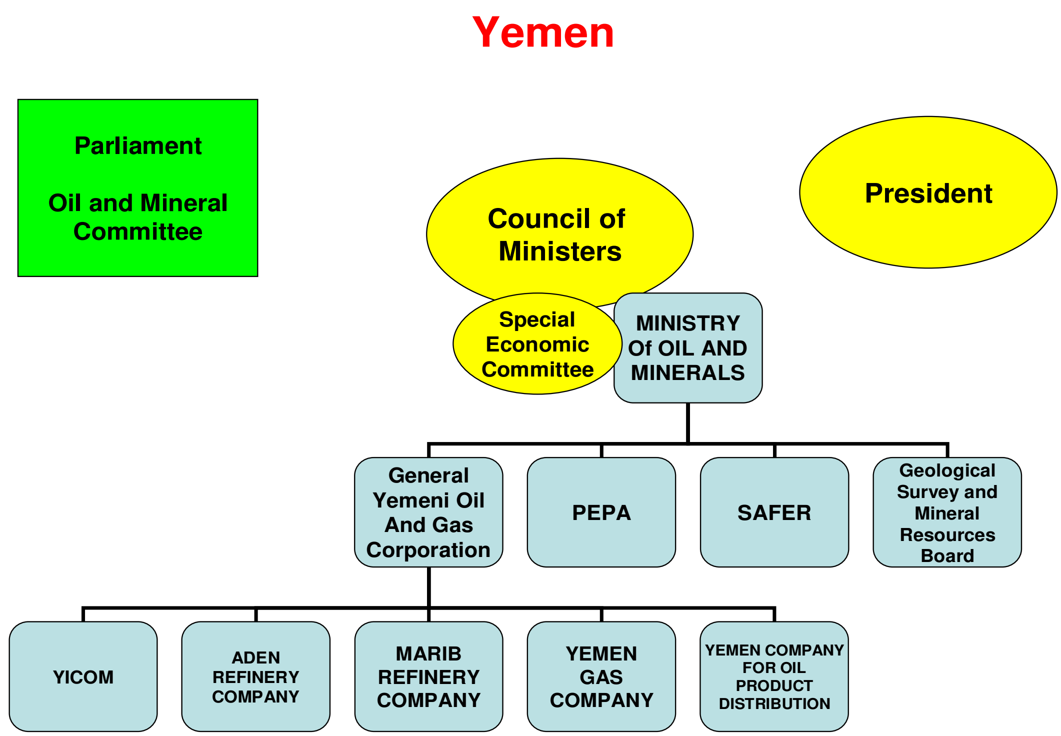
5.3 The apparent lack of coordination in determining goals is compounded by political tensions between the government and the parliament over the implementation of such goals. Numerous examples illustrate this point:

- In 2001, the ministry announced plans to privatize the Aden Refinery Company, but was subsequently forced to backtrack when faced with stiff opposition from parliament.
- In June 2004, claiming contravention of the constitution, parliament opposed plans to sell off 60 percent of the state's share in Block 53 to Gulf Cooperation Council (GCC) investors.
- Finally, in March 2005, the parliament terminated Hunt Oil Company's production sharing agreement (PSA) in Block 18 when it was due to expire in November. Hunt claims the ministry had promised to extend this for a further five years. Strategic choices related to crucial issues such as the expiration of PSAs do not appear to be the object of long-term planning in the management of the country's hydrocarbon resources.

The Players and Their Interactions

5.4 Figure 5.1 shows the players in the Yemeni oil sector. The parliament has an oil and mineral committee whose function is to oversee the sector and, at a more specific level, to make recommendations to parliament regarding PSAs. There is no equivalent of the supreme petroleum council (SPC) present in many countries, but there is a special economic committee whose function is to scrutinize PSA agreements and make recommendations to the Council of Ministers, which then passes comments to the parliamentary committee.

Figure 5.1 Yemen: Petroleum Sector Structure



Source: authors.

5.5 Central to the sector is the Ministry of Oil and Minerals, which tries to operate through a number of different institutions. In upstream oil, the main player is the Petroleum Exploration and Production Authority (PEPA). The depository of all exploration data, PEPA also supervises the international oil companies (IOCs) operating the PSAs and is responsible for processing all oil concessions. The Safer Oil Exploration and Production Company (referred to in this report as SAFER, but is also called SEPOC) is a separate entity. The company was formed in March 1997 as the Yemeni national oil company (NOC) for exploration and production (E&P). In November 2005, it assumed all the operations on Marib-Jawf Block 18, previously undertaken by Hunt Oil, when Hunt's PSA expired. It also controls elements of infrastructure including a major crude oil pipeline (440 km; 24–26 inch) to the export terminal at Ras Issa, and floating storage. SAFER's position in the oil sector hierarchy is unclear. At one level it is important since it accounts for production of 70,000 barrels per day (b/d) out of Yemen's total production of 426,000 b/d (2005). It also produces 2.6 billion cubic feet per day (bcfd) of associated gas, mostly reinjected. But its legal status is still under development. Its control over Block 18 was vested in Law 18 and Cabinet Declaration 333, and its bylaws are being finalized. The cabinet initially approved these, but they are now being revised, expanding on the details concerning internal management. In particular, it remains unclear whether the chief executive officer (CEO) will also be the chairman or whether the oil minister will act as chairman. Currently, the president of Yemen—via the oil ministry—appoints the chairman.

5.6 Yemeni Oil and Gas Corporation (YOGC) acts as a holding company for upstream and downstream oil and gas. In upstream oil, Yemen Investment Company for Oil and Minerals (YICOM) supervises and monitors operators in Blocks 4, 5, and 20, and has responsibility for developing Block 42. Downstream, there are a number of companies that run the two refineries—Aden and Marib—plus several companies responsible for marketing and distribution. The Yemen Gas Company (YGC) is the distributor of liquefied petroleum gas (LPG), but it has ambitions to expand its current operations into supplying natural gas to the domestic market, including the development of compressed natural gas (CNG). YGC hopes to achieve this with private sector involvement. Currently, YGC is one of the government's shareholders in Yemen LNG (YLNG) (with 16.7 percent equity)[51] and is supervised by a small gas division in the oil ministry.

5.7 The ministry also has a number of other departments ranging from the Ministerial Commission for Oil Marketing, which is responsible for marketing the government's share of crude production, to the Geological Survey and Mineral Resources Board, which looks after other minerals. The high-powered Commission for Oil Marketing consists of the Minister of Oil and Minerals, Minister of Finance, the Central Bank chairman, Minister of Commerce, the general manager of the Oil Authority, and the general manager of the Crude Oil Marketing Administration. As will be seen below, this multitude of players in what is a decentralized system leads to a great deal of conflict and lack of coordination at an operational level. There has been talk of trying to create a proper NOC (Petro-Yemen) to take over all the various operating companies in order to provide a clear strategic direction.

5.8 In addition, Yemen has significant elements in oil and gas drawn from the private sector—predominantly, but not entirely, from overseas. The upstream has always been dominated by foreign oil companies through the mechanism of PSAs. But in the mid- to late 1990s many of the larger international oil companies (IOCs) withdrew as the result of a combination of poor economics and rising security concerns. There remain more than 20 IOCs operating in Yemen, although the majority are smaller E&P companies. Downstream, the only two operating refineries—the Aden Refinery Company and the Marib Refinery Company—are state-owned, but there is private sector interest. There are plans to upgrade the 100,000 b/d Aden refinery by involving private sector investment, and eight companies are apparently bidding. In December 2002, the Hadramout Refinery Company signed a deal with the government to build a 50,000 b/d refinery—rising to 100,000 b/d—at al-Muhalla. A number of foreign companies have expressed interest in building refinery capacity. ONGC (India) has offered to build a 100,000 b/d refinery if it is awarded an exploration block, and Reliance (India) is planning to build a 50,000 b/d refinery at Ras Issa, with Yemen's Hood Oil taking 50 percent of the equity (with International Finance Corporation financing approved in April 2006). Marketing and distribution is state-owned except in the area of gasoline and LPG filling stations, where the private sector dominates.

5.9 As for gas, under the current terms of the PSAs, any gas discovered or produced has been the property of the government until now, but the government is considering the possibility of introducing new incentives to gas E&P. The YLNG company was contracted to take the associated gas from Block 18. YLNG is a joint venture in which the Yemen government has a

[51] The other is the General Authority for Social Security and Pensions, with 5 percent.

21.7 percent share[52] together with six other partners, with the majority (39.6 percent) held by Total. The project is well underway in terms of construction.

Control Operation and Monitoring

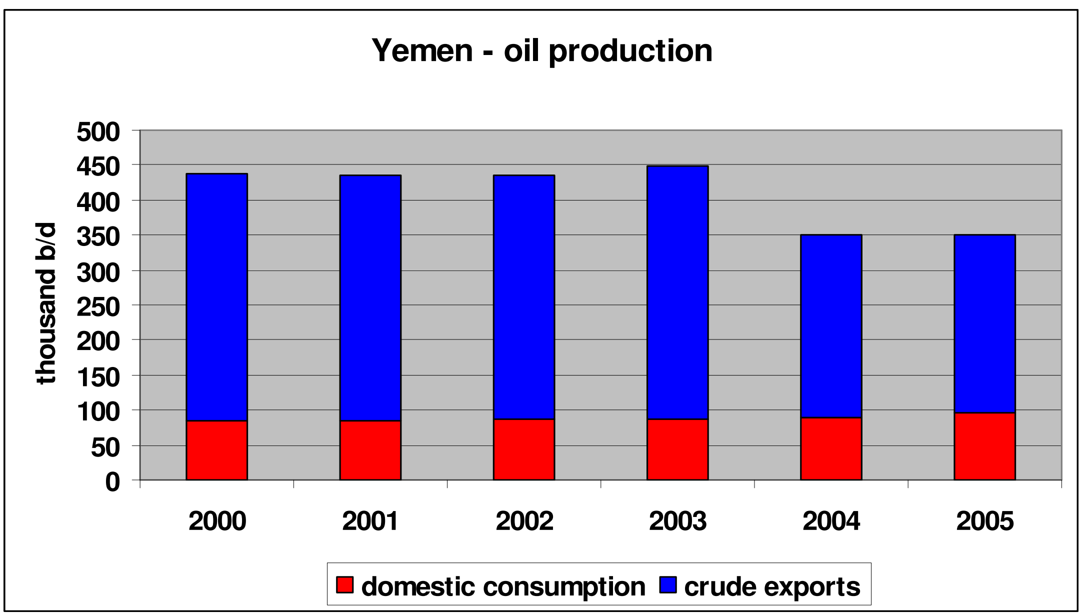
5.10 Ultimate control over the strategy of the sector lies with the president. But there has been limited comprehensive, coordinated, and explicit oil and gas sector policy and strategy. Upstream, licenses for E&P are authorized by the ministry, subject to ratification by parliament. There is no petroleum law, so each PSA is treated as a separate piece of legislation. This lack of strategic direction has led to problems of coordination that have reduced the incentives of operators to exploit hydrocarbon resources.

Objectives of the Sector

What Are the Objectives?

5.11 The oil and gas sector is central to Yemen's economy. Oil accounts for some 85 percent of export revenues and 30 percent of gross domestic product (GDP). But Yemen's oil production has been falling steadily, as can be seen from figure 5.2**,** and, with rising domestic consumption, the export surplus has also been falling.

Figure 5.2 Yemen: Oil Production



Source: Organization of Arab Petroleum Exporting Countries (OAPEC) Annual Statistical Bulletin 2006.

5.12 The gradual decline of oil production is expected to continue and accelerate, especially after 2010. The objectives of the sector are to try and reverse the decline in oil production, which

[52] 16.7 percent with YGC and 5 percent with the General Authority for Social Security and Pensions.

in the view of the International Monetary Fund, as stated in March 2005, is causing "serious concerns about long term sustainability" of the Yemeni economy.

5.13 The official sector policy is publicly disclosed[53] and aims to diversify the revenue sources. To accomplish the oil upstream objectives, the government plans to:

- Increase proven reserves to balance the decline in existing fields
- Promote exploration in new areas
- Review PSA terms and procedures in line with international petroleum industry practice
- Grant tax and customs exemptions and free transfer of funds
- Encourage the private sector to play an important role in all stages of hydrocarbon development
- Encourage the development of marginal fields through the reduction of investment requirement by:
    - Public access to existing infrastructures at nominal rates
    - New investment opportunities created jointly or severally with the private sector in upstream projects (PSA, gas, petroleum services) as well as downstream projects (transportation, refining)
    - Facilitating the transfer of technology by participating directly in petroleum operations through carried interests
    - Encouraging the Yemenization of international companies operating in the country by developing plans for the replacement of the expatriate workforce
    - Improving the control of petroleum costs through the establishment of operating committees

5.14 All these actions are intended to improve the investment climate.[54] This was first tried in late 1999 in response to the departure of many of the major IOCs. Signature bonuses, paid to the government at the start of the license, were lowered, cost recovery oil was increased from 25-45 percent to 50–70 percent, and the fixed royalty of 10 percent was converted to a sliding scale of between 3 and 10 percent. In mid-2001, further changes were made involving contract extensions, increased flexibility on negotiations, and increased transparency. By 2004, however, of the 84 concession blocks covering the country, only 33 were licensed for E&P, and only 7 were actually producing. By 2007, there were 87 blocks, of which 13 were being produced by 11 companies. There were 26 blocks at the exploratory stage, operated by 16 companies, and 7 blocks pending approval for the PSA.

5.15 Licensing rounds appear to be more frequent. A third round is being completed in 2007 and the first offshore round is expected in 2007–08. The third licensing round started in late 2006. As of December 2006, offers were expected from IOCs prequalified to bid—32 companies for 17 blocks. The current PSA contract is a hybrid based upon the experience of a number of countries. It specifies minimum requirements in the fiscal share, work program, and project budget. A signature bonus is optional. The government has plans to increase output to 500,000 b/d in the next few years (output in 2005 was 413,300 b/d).

[53] See PEPAs' website for more details at www.pepa.com.ye
[54] There appears to be strong interest in the possibility of investment into the sector from private money in the Gulf Cooperation Council (GCC) countries.

5.16 As for gas, there is a general expectation that revenue from gas exports—and switching the power sector away from heavy fuel oil (HFO) and diesel—could help offset the loss of oil export revenue. There is a clear awareness within PEPA that the current PSA arrangements for gas are less than satisfactory since they provide no incentive for IOCs to look for gas or indeed develop any find on a commercial basis. The current PSAs include "preemptive" rights that prevent the operator from marketing and utilizing associated gas beyond that needed for field operations. This arrangement is being addressed, and it is hoped that the next licensing round of PSAs will offer greater incentives. There is considerable uncertainty over the precise size of Yemen's gas reserves, which is leading to conflict within policy-making bodies over export versus domestic use of gas. Two independent evaluations of gas reserves have been commissioned to try and establish the numbers—one by SAFER and one by PEPA. As will be developed below, objectives for the gas sector are unclear, and there is a noticeable lack of coordination between gas developments and the need for power (and, eventually, water desalination).

The Objectives: Conflict and Cohesion

5.17 The lack of a central strategy and direction is freezing many projects for lack of agreement. An example is Block 18, which still holds oil and is expected to provide natural gas for export contracts signed in 2005 and for gradual supply of new power plants to be commissioned in the coming 10–15 years.

5.18 The terms of supplying gas to YLNG were set in the original agreements signed in 1995/7. These were based upon the PSA that governed Hunt's operations in Block 18. Since the expiration of that PSA in November 2005, SAFER, which took over the operations of the fields in Block 18, argues that the legal commitment to supply gas to YLNG is unclear, although the company is fully aware of the government of Yemen's commitment to supply gas to YLNG. SAFER is expressing concerns about the possibility of meeting the gas supply commitments to YLNG, based upon the old contract, and at the same time pursuing production of oil at passed levels—since part of the gas is expected to be used for reinjection into the fields. This argument entered the context of the dispute with the previous operator of the field, Hunt Oil, over past management of the fields. Uncertainties about oil production in the fields operated by SAFER hamper investor confidence in upstream oil E&P. It is clearly in SAFER's interest to make the government aware of the issues, if only to persuade the government to provide additional resources for exploration of further gas reserves. In this specific case, the absence of clear policy objectives for the oil sector, and conflicts of interest between the role of the government as shareholder of the NOC and of YLNG, could result in increased perceived risks by international investors.

5.19 Although the petroleum sector in Yemen offers room for continuous foreign direct investment (FDI), opposing views on the use of national resources such as natural gas undermine the strategic alignment of the government and affect incentives provided to E&P investors, especially for natural gas.

SECTOR STRUCTURE AND PERFORMANCE

Productive Efficiency

5.20 In upstream oil there is little available information regarding costs and the general efficiency of the sector. Problems appear to be threefold:

- Oversight and monitoring is difficult.
- The geology and its many players further complicates the situation.
- When a new project requires review and approval, the process is long and convoluted.

5.21 SAFER's funding is based on a work program budget for capital expenditure that provides little incentive to improve performance. But the fact that 15 percent of the revenue can be retained to cover operational expenditures may create an incentive for SAFER to lower those costs, assuming it is then allowed to retain 15 percent. SAFER and the other state-run production blocks produce no accounts assessing their performance.[55] Furthermore, there are a large number of private companies operating in differing geologies, which also makes benchmarking difficult.

5.22 So far, the process of licensing exploration blocks seems cumbersome. Once a draft PSA has been negotiated, it is sent to the special economic committee, which then makes recommendations to the Council of Ministers. The council, in turn, sends the draft to the oil and mineral committee in parliament. The PSA is then approved by parliament and ratified by a presidential decree. This process can take between 12 and 18 months. In general, production is falling, notably in the two large basins of Masila and Marib, although this is likely the consequence of geology rather than inefficient operations. One positive dimension of upstream efficiency is the large presence of privately owned oil companies that could be concerned about keeping costs down. SAFER's oil export pipeline to Ras Issa is subject to third-party access on a "first come, first served" basis charged at a per barrel fee based upon a formula treatment of costs.

5.23 It appears that SAFER can bid on new exploration blocks along with other companies, but it is not clear how far it may expect to receive special treatment. Clearly, there are numerous operating problems likely to damage productive efficiency. There are recurrent security problems, and the security of oil workers remains a concern. IOCs frequently reference customs and excise issues in the context of importing equipment. Specifically, there is a shortage of rigs in Yemen because the process of acquiring them is slow, complex, and cumbersome.

[55] Indeed, the Safer Oil Exploration And Production Company (SAFER) does not have a website.

Linkages

Fiscal Linkages

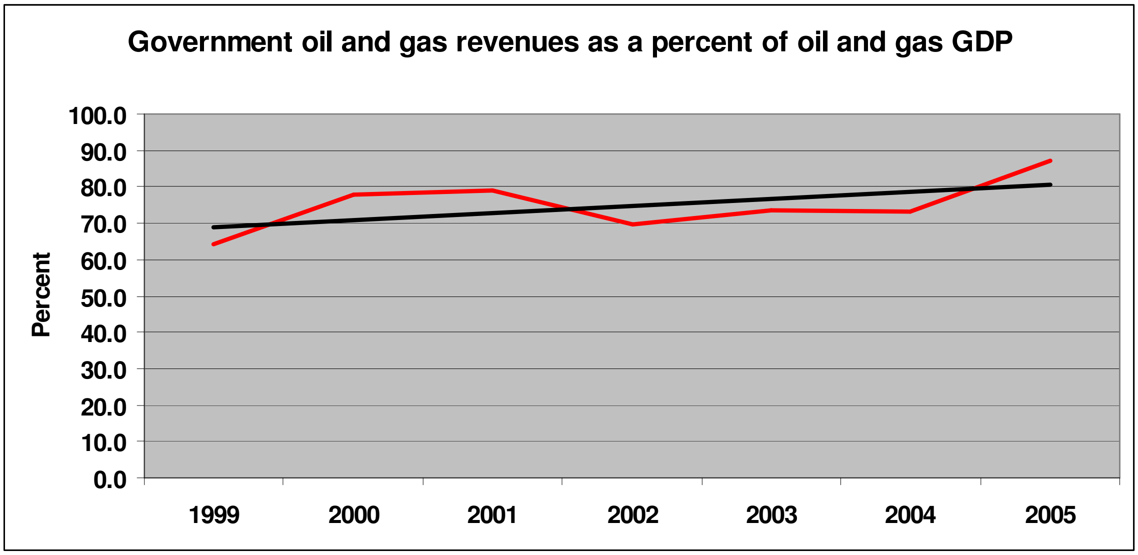
5.24 Oil revenues are important to central government finances. In 2005, it was estimated that oil and gas would contribute 76 percent of total revenue. This is compared to 64.1 percent in 1999, and the steady rise reflects higher international oil prices rather than increased production output. The oil revenues come from a variety of sources, reflecting the existence of PSAs and state-owned operations such as SAFER. For SAFER, the oil is sold and all revenue accrues to government, except for 15 percent, which is retained to cover operational expenditures. SAFER is anticipating that the government will endow the company with more powers over its financial arrangements.

5.25 The terms of PSAs vary considerably and often involve many elements. Royalties are based upon a sliding scale. Cost oil has a maximum level of 30 percent, which means exploration and development capital expenditures are recovered in four to six years while operational expenditures are recovered in the same year.[56] As for shared oil, for Hunt it is 60 percent up to 100,000 b/d and 50 percent above 100,000 b/d. Private operators pay their share in crude oil to YOGC, which then supplies its two refineries, exporting the remainder. Roughly one-third of the shared oil goes to the refineries, and two-thirds are exported. Government tax is 50 percent on the private operator's portion of shared oil for Hunt, but there is no government tax on the other PSAs. There are signature and development bonuses that vary between blocks, and there is an exploration tax of 3 percent on the actual exploration costs.

5.26 The efficiency with which the government of Yemen manages to collect rent on oil operations can be seen from figure 5.3. The trend is for the government's share of the oil and gas contribution to GDP to rise, which would be expected with a progressive fiscal system in a world of rising international prices. The government of Yemen collects a lower proportion of the value added from oil and gas than in Saudi Arabia, but this simply reflects the large-scale presence of IOCs in Yemen, who require a higher rate of return than might be expected from an NOC. Several factors explain this. The IOC must pay taxes to its home government and satisfy its shareholders with dividends and share buy-backs. Thus, it must secure higher gross profits than an NOC. The political risk of IOCs also increases the required return. An NOC faces a different political risk than an IOC. NOCs face the risk of being used as a rent-creation mechanism that in the end hampers the performance of the company (as in Iran) but they do not face the kind of regulatory risks IOCs face (such as expropriation). In return, with PSAs, all the financial costs and risk associated with exploration, development, and production are transferred to the private operators.

[56] Cost oil is a portion of produced oil that the operator applies on an annual basis to recover defined costs specified by a production sharing contract.

Figure 5.3 Yemen: Government Oil and Gas Revenues as a Percent of Oil and Gas GDP



Source: Central Bank of Yemen.

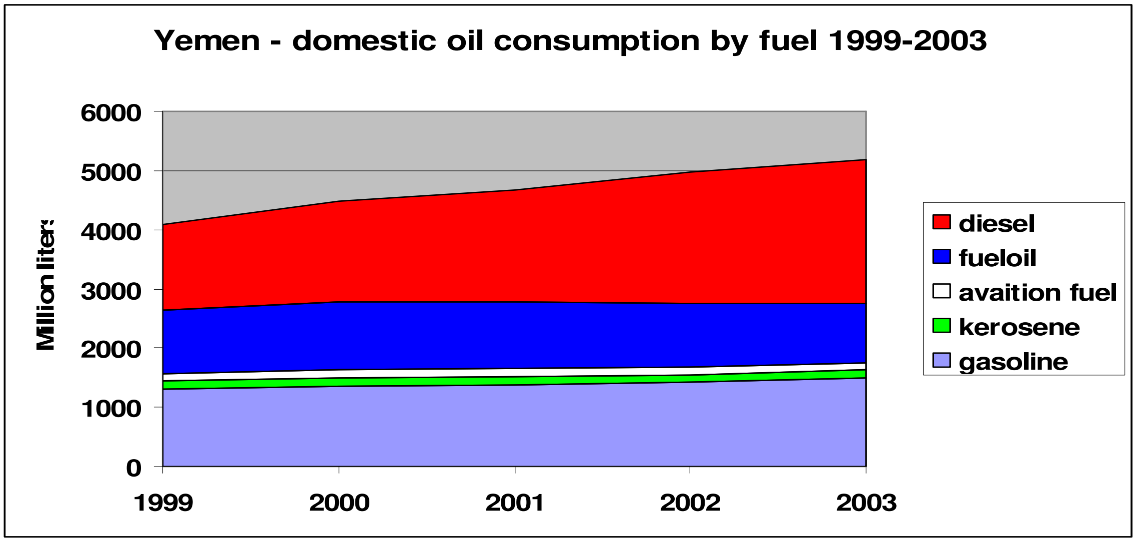
Forward Linkages

5.27 The ability of Yemen's oil and gas sector to deliver forward linkages offers a mixed picture. In the oil downstream, there is relative inefficiency. The sector is dominated by the state, with the exception of gasoline and LPG filling stations—so there is no competition. YGC wants to expand its field of operations into natural gas distribution, especially CNG for the transport sector, and is hoping to do this in a joint venture with the private sector. But it is uncertain whether this fits with the vision of the ministry.

5.28 The two refineries are old and in urgent need of modernization. Their operating costs reflect their age, and were described by the World Bank in 2004 as "relatively high." But, as with the state-owned upstream, there are no hard figures to support this. There is talk of expanding refinery capacity through private sector involvement, but this plan's status is not clear. The sector also suffers from a classic problem encountered in developing countries: a demand barrel that does not match the product barrel of the domestic refineries. For example, Yemen produces far more naphtha than it can use domestically. In 2002, some 3.1 million barrels (bbls) of naphtha were exported.

5.29 Domestic consumption of oil products, with the exception of diesel, has been relatively sluggish, as can be seen from figure 5.4. Given that the recent economic growth record of Yemen has been relatively strong (non-oil GPD grew, on average, at 6.4 percent annually between 1999 and 2005), this is rather surprising.

Figure 5.4 Yemen: Domestic Oil Consumption by Fuel, 1999–2003



Source: World Bank, 2004c.

5.30 The explanation is, quite simply, that Yemen suffers from a shortage of oil products. The capacity utilization of the two refineries is low, reflecting poor operating practices. According to data from the Organization of Arab Petroleum Exporting Countries Statistical Bulletin for 2006, on average the annual utilization of Yemen's refinery capacity during 2000–05 was only 60 percent. There are high import tariffs on imported oil products, which act as a significant barrier to entry. For oil, the forward linkages are not what they could or should be.

5.31 These subsidies present the economy and the sector with serious problems. For the economy in 2004, World Bank–estimated subsidies (excluding LPG) cost the government YR 38.5 billion, which represented 2.19 percent of GDP. Other estimates have put the subsidy burden much higher, at over 8 percent of GDP. Prices were raised closer to border levels in July 2005, but this decision led to severe riots.

5.32 As for the oil sector, the system works in the following way. YOGC supplies the refineries with a share of crude oil, sold at a small discount to Brent crude oil prices. YPC then buys the products from the refineries. The price paid is based upon world spot prices plus certain additional charges.[57] This implies that the refinery sales are based upon market prices depending upon the price charged for the crude. YPC acts as a monopoly supplier, selling to filling stations and large industrial users. Both the wholesaler and consumer prices are administered and regulated.

5.33 As for gas, as detailed earlier, domestic pricing principles are yet to be fixed. One problem is that there is some uncertainty regarding the size of gas reserves. In November 2006, the Ministry of Oil commissioned a detailed study of Yemen's potential gas reserves. This is in addition to the study commissioned by SAFER on Block 18, and the implication for oil recovery if the gas is supplied for LNG and domestic consumption.

[57] For Marib it is the spot price fob Italy (Platts) plus a sum covering operating costs. For Aden it is spot price fob Rotterdam plus a notional freight charge of $17 per ton.

5.34 As explained earlier, under the PSA, any gas discovered reverts to the government, its commerciality subject to negotiation. But its commercial viability is a function of the availability of markets, and the availability of markets is a function of commercial discovery, because investments in production are not undertaken if there is no prospect for selling the gas. This indeterminate circle creates a major barrier to the development of a domestic gas market. Also, the current system offers no incentive for IOCs to explore for gas or develop it once it has been discovered. The government of Yemen is aware of these problems and was seeking ways to rectify them by changing the terms of the PSA before licensing round of June 2007.

Backward Linkages

5.35 The oil and gas sector in Yemen is decidedly "technologically strange" to the economy. It is therefore not surprising that backward linkages are limited. Much is made by the government of the importance of Yemenization. Ministers take every opportunity to remind IOCs that this is a prime objective of the government. The IOC Nexen is often cited as a model, with 78 percent of its workforce being Yemen nationals. Recently, there has been emphasis on operating companies moving their head offices to Yemen so that Yemenis could be able to acquire experience and competencies in the oil sector at the regional or international levels.

Box 5.1 Key Observations – Yemen

The oil sector in Yemen shows that a lack of coordination among the petroleum sector stakeholders can limit investment and reduce the possible growth of the extraction rate. In the past, in spite of Yemen's limited strategic direction, a general encouragement to private sector investment to expand upstream oil output was sufficient to generate foreign direct investors' interest in exploration and production. Now, however, the government will need to formulate a clear long run goal in terms of petroleum resource expansions and use of crude oil and gas for domestic market and exports to boost investments, especially in E&P.

Given that Yemen has been experiencing significant oil production declines in recent years, the lack of a clear vision on the sector's contribution raises concerns for future government revenues, which remain highly dependent upon the oil sector.

An important lesson is that the centralized formal authority of the Ministry of Oil and Minerals needs to be accompanied by capacity and political power to ensure quality and strategic supervision of the sector.

Another broader lesson is that if temptation is high for a government to nationalize the management of its hydrocarbon assets, it must refrain from hampering the level playing field with IOCs to avoid drying out investors' interest.

Downstream, the sector's performance is questionable, not least because of a lack of competition. Existing refinery capacity suffers from a lack of investment, modernization, product selection, and high levels of price subsidy that lead to excessive domestic consumption and smuggling.

ANNEX 1: THE MIDDLE EAST AND NORTH AFRICA IN GLOBAL OIL AND GAS MARKETS

Introduction

This annex looks at oil sector trends in the Middle East and North Africa (MENA) and examines the region's role in the world oil market. It also presents long-term projections for the region's oil production from recent outlooks produced by the International Energy Agency (IEA), the U.S. Department of Energy, and Petroleum Economics Limited (PEL).

MENA countries possess more than 60 percent of the world's reported oil reserves, with the vast majority in the Middle East (North Africa has less than 5 percent of global reserves). MENA accounts for 37 percent of world oil production, which it has largely maintained the past decade—down from 43 percent in the 1970s but up from 24 percent in 1985. MENA oil export revenues have fluctuated greatly the past three decades, from less than $100 billion during much of the 1980s/90s to nearly $500 billion in 2006.

The large fluctuations in oil prices and production levels have been due, in large measure, to the pricing/production policies—and consequences thereof—of the Organization of Petroleum Exporting Countries (OPEC) oil producers. As the dominant OPEC oil producers are mainly from the Gulf, it can be argued that the large fluctuations in MENA oil revenues and production levels are a reflection of their "own" pricing and production policies.

The recent rise in oil prices is similar to the first oil price shock that began in 1973/74. Oil prices are generally expected by most forecasters to stay elevated and OPEC/MENA oil production levels are expected to rise—similar to projections in the 1970s and early 1980s. However, there is great uncertainty about the path of oil prices, and of oil supply and demand. Strong oil demand in developing countries may well support such projections, but unexpected supply disruptions and policies to sustain ever higher prices could once again lead to large upheavals in the oil market and on MENA oil revenues.

1. MENA Oil and Gas Reserves

MENA countries hold two-thirds of the world's oil reserves of 1.2 trillion barrels (bbls). The Middle East has 61 percent of global oil reserves, and includes the world's five largest countries with proved reserves. Saudi Arabia, the largest with 264 billion bbls, has more than one-fifth of the total, followed by Iran, Iraq, Kuwait and the UAE, each with reserves of roughly 100 billion bbls.[58] MENA North Africa also has sizeable oil reserves, but at 58 billion barrels is less than 5 percent of the world total. MENA's oil reserves-to-production (R/P) ratio is a relatively high 73 years.[59] The Middle East R/P is 80 years, and is double the

[58] For Canada, BP includes only these oil sands reserves under development. If total oils sands reserves of 170 billion barrels are included, Canada is the second largest oil reserve country.

[59] R/P ratios are reserves divided by production, and assumes production continues at the same levels. It is more an indication of the size of reserves, rather than of the life or path of production, as it does not take into account future discoveries, new technologies, and changes in prices and other market conditions.

world average. In North Africa, only Libya has a relatively high R/P ratio, at 62 years. While MENA has the bulk of world reserves, it has little more than one-third of world oil production.

Table A1.1 World Crude Oil and Natural Gas Reserves and Production, 2006

	Oil Reserves	Oil Production	Gas Reserves	Gas Production
	(billion barrels)	(thousand barrels per day)	(trillion cubic meters)	(billion cubic meters)
North America	59.9	13,700	7.98	754.4
South/Cent. America	103.5	6,881	6.88	144.5
Europe and Eurasia	144.4	17,563	64.13	1,072.9
Middle East	742.7	25,589	73.47	335.9
North Africa	58.1	4,586	7.76	144.0
MENA	***800.9***	***30,175***	***81.23***	**479.9**
Sub Saharan Africa	59.0	5,403	6.42	36.4
Asia Pacific	40.5	7,941	14.82	377.1
World	**1208.2**	**81,663**	**181.46**	**2,865.3**
MENA Share (%)	***66.3%***	**37.0%**	***44.8%***	**16.7%**

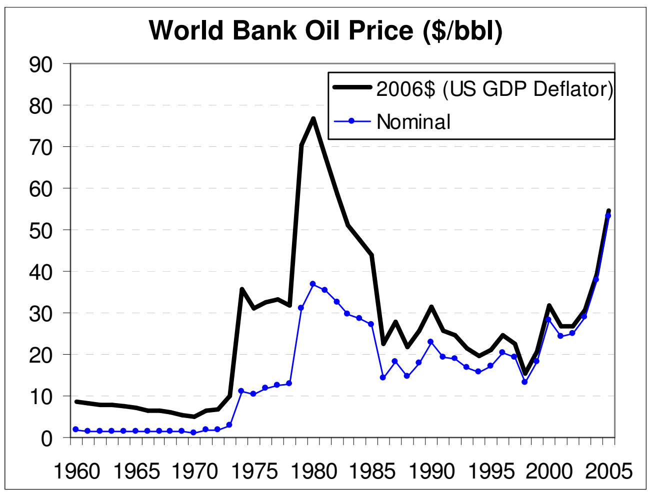
Source: British Petroleum (BP). BP Statistical Review of World Energy, June 2007.

MENA has less than half of the world's natural gas reserves, and only 17 percent of world gas production. Three countries dominate global gas reserves—Russia, Iran, and Qatar—and together possess 56 percent of global reserves. Russia is the leader at 48 trillion cubic meters (tcm), or more than one-quarter of world reserves, followed by Iran at 28 tcm and Qatar at 25 tcm, with each possessing some 14-15 percent of the world total. The region also has the largest reserve holders in the next tier of countries, with Saudi Arabia having the world's fourth largest gas reserves at 7 tcm, and the UAE at 6 tcm. As gas production is at a much less developed stage than oil, the R/P ratios for many MENA countries are very large—with Qatar at more than 500 years. Proven gas reserves are a poor indicator of MENA's ultimate gas production, as some parts of the region have hardly been explored, and the exploration that has been undertaken has focused on oil. The region clearly has enormous potential to raise production for domestic use and export markets for decades to come. See Annex 2 for country detail on MENA's oil and gas reserves and production.

2. Global Oil Market 1960-2006

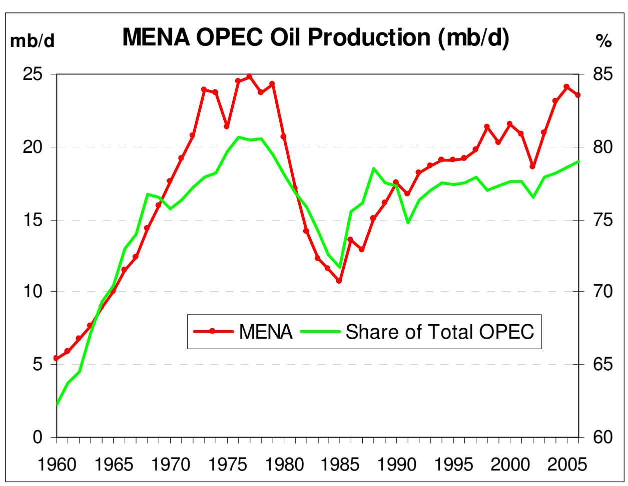
Oil prices have fluctuated significantly the past 30 years, and have been heavily influenced by OPEC production and pricing decisions. Since the early 1970s, OPEC has sought to keep oil prices well above the cost of production, in order to "maximize" oil export revenue. At times OPEC has managed its production and pricing decisions well, contributing to revenue maximization and lower volatility, but at other times it has not, particularly during the early 1980s. Geopolitical disruptions have both aided and complicated OPEC's task of maintaining higher revenues. OPEC has generally been more successful at establishing a floor to prices than it has at enforcing a ceiling, the latter primarily due to production capacity constraints, e.g., in 1980 and 2004.

Figure A1.1 World Bank Oil Price, 1960-2006



Source: World Bank, Bloomberg, Energy Intelligence Group.

Figure A1.2 MENA OPEC Oil Production, 1960-2006



Source: OPEC, IEA.

There have been four large upward oil price shocks since the early 1970s, all precipitated with supply disruption and/or OPEC production cutbacks. The first (1973/74) was associated with the Arab oil embargo; the second (1979/80) was the result of the revolution in Iran; and the third (1990) the loss of output in Iraq and Kuwait prior to the first Gulf war in 1991. The recent price increase was driven by a demand shock in 2004 and the erosion of surplU.S.capacity, but OPEC production restraint prior to the demand surge set the stage for higher prices. With the exception of the relatively brief 1990 shock, the organization subsequently cut production in order to keep prices high. The average oil price[60] in 2006 of just over $64.3/bbl is the highest annual average on record in nominal terms, but well below the peak of $77/bbl in real terms in 1980 (2006 constant prices). The daily peak in August 2006 of near $76/bbl was close to the 1980 average real price, but was well below the monthly real peak of over $90/bbl in late 1979.

MENA OPEC oil producers represent nearly 80 percent of OPEC[61] production. Venezuela, Nigeria, and Indonesia are the other OPEC members, and all support OPEC's quest for higher prices via production restraint. Output has also been constrained in all three countries, due to geopolitical issues (Venezuela), rebel attacks (Nigeria), and technical/investment (Indonesia). It can be argued that OPEC policy decisions largely reflect decisions by the MENA oil producers, and more specifically, decisions by the major Gulf producing countries. ThU.S.the levels and fluctuations of MENA oil export revenues over the past three decades are, in large part, a function and consequence of its "own" pricing and production decisions.

[60] World Bank average oil price is a simple average of Brent, Dubai and WTI prices.
[61] OPEC excludes Angola, which joined in 2007.

Figure A1.3 Developing Country Oil Product Consumption, 1965-2006

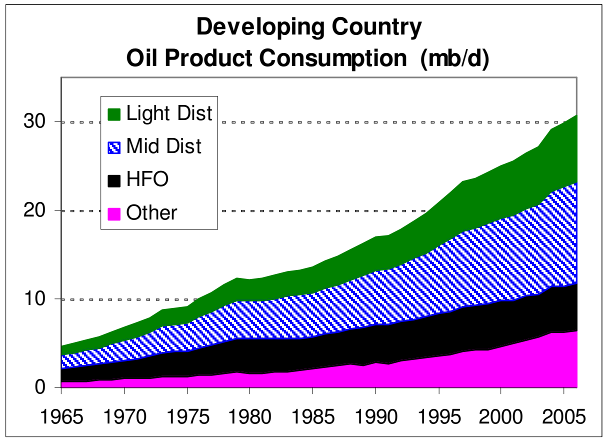


Figure A1.4 OECD Oil Product Consumption, 1965-2006

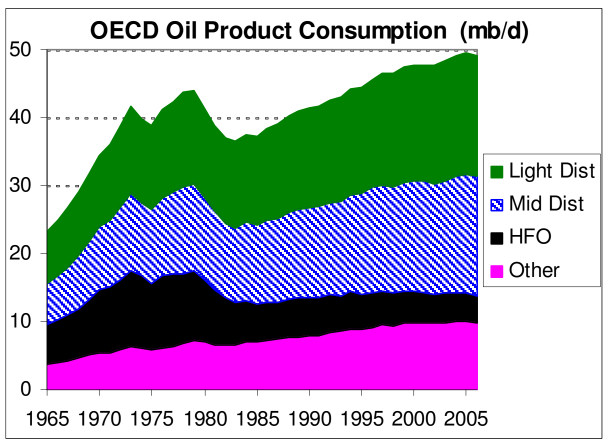
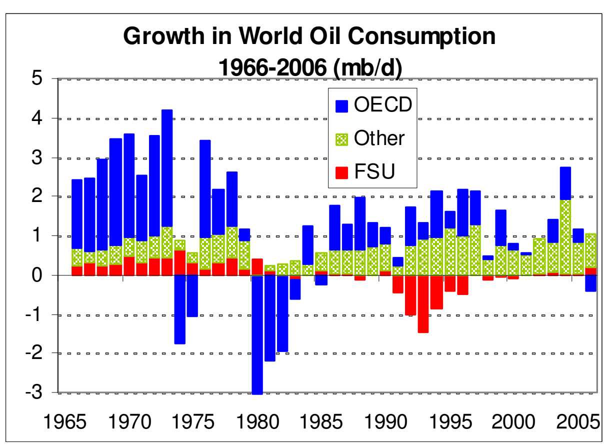
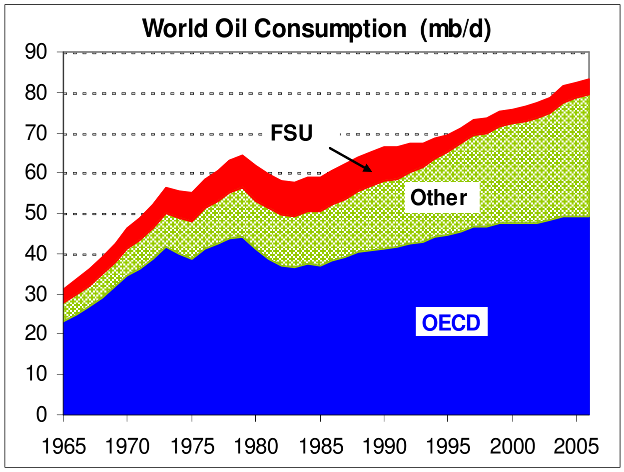


Figure A1.5 Growth in World Oil Consumption, 1965-2006



Source: BP

Figure A1.6 World Oil Consumption, 1965-2006



Source: BP.

The large fluctuations of oil prices have significantly impacted global oil demand. In the 1960s and early 1970s, world oil demand grew by 7.5 percent per year, faster than economic growth. Following the first oil price shock, world oil demand growth slowed to about 4 percent in the latter 1970s, but following the second oil shock, world oil demand plunged 10 percent between 1979 and 1983. Since the collapse of oil prices in 1986, oil demand outside the former Soviet Union (FSU) rebounded, but growth slowed to just over 2 percent. Much of the growth in oil demand has shifted to the developing countries, where demand outside the FSU has increased by 4 percent p.a. since 1985. Developing countries' share of world oil demand has risen from 15 percent in 1973 to 37 percent in 2006.

Virtually all the net decline in oil product consumption following the first two oil price shocks occurred in the Organization of Economic Cooperation and Development (OECD) countries. Between 1979 and 1983, OECD oil demand dropped 17 percent. Over half of the decline was heavy fuel oil (HFO), which was relatively easy to substitute with other fuels in the power and industrial sectors. There were also decreases in the other main product groups, but demand had started to rebound in these products in 1983 (and earlier depending on the product and country). In the developing countries, oil demand growth paused after the second oil price shock, and started to accelerate after oil prices declined in 1986. There was some reduction in HFO use in Latin America and the Middle East in the early 1980s, but HFO consumption has since risen in all developing regions.

Figure A1.7 World Oil Production, 1965-2006

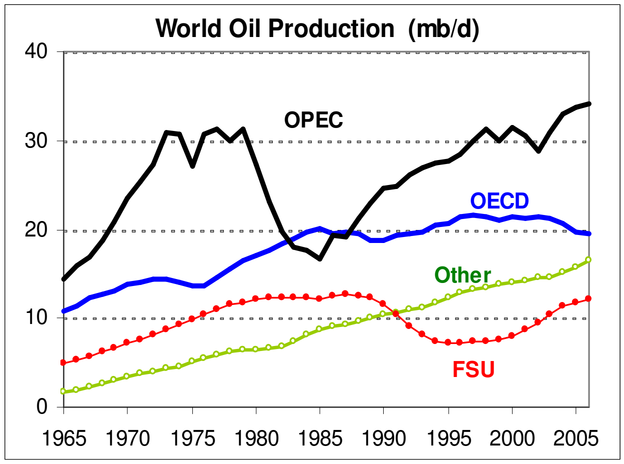
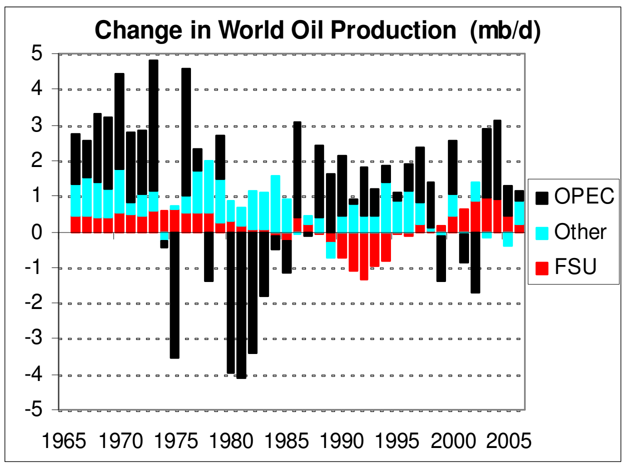
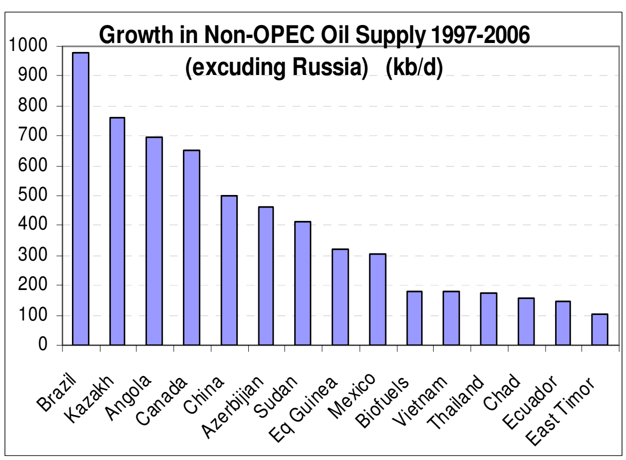


Figure A1.8 Change in World Oil Production, 1965-2006



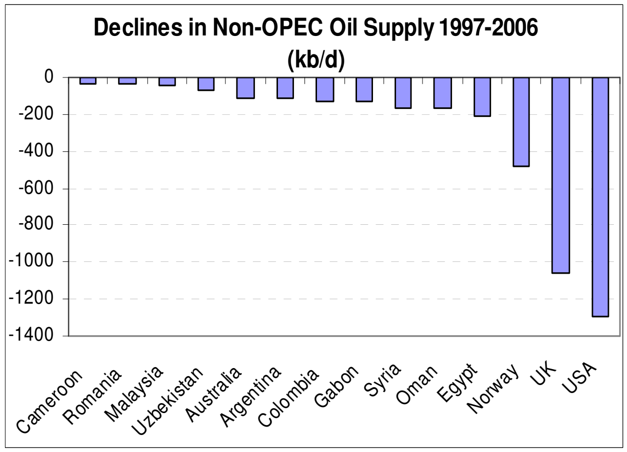
Source: BP, IEA.

Figure A1.9 Growth in Non-OPEC Oil Supply (excluding Russia), 1997-2006



Source: IEA.

Figure A1.10 Decline in Non-OPEC Oil Supply, 1997-2006

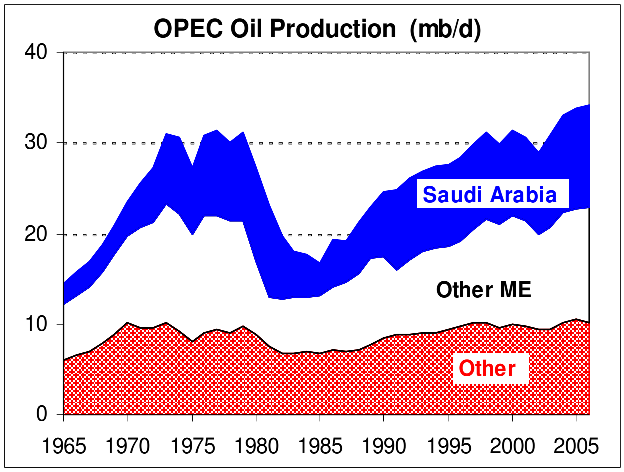


Source: IEA.

Non-OPEC oil production outside the FSU has increased at an average rate of 2.6 percent or nearly 0.6 mb/d since 1965. However growth was more rapid through the first 20 years rising by more than 4 percent or 0.8 mb/d, including large gains in the OECD, i.e., the North Sea, Alaska, and Canada. Growth slowed sharply after the 1986 price collapse, but rebounded in the 1990s until prices plunged once again in 1998. Since then, production outside the FSU grew by 0.5 percent p.a. or little more than 0.2mb/d, as large declines in the OECD nearly largely offset increases elsewhere. The rebound in FSU oil production has provided much of the non-OPEC gains in recent years, mainly from Russia where output rose by 3.6 mb/d between 1997 and 2006. The OECD declines were mainly in the U.S.and North Sea, but also Australia, while non-OECD declines occurred in three MENA countries (Egypt, Oman and Syria), as well as a few other countries. The output gains outside of Russia since 1997 have been relatively large in Brazil, Kazakhstan, Angola, Canada, China and Azerbaijan, as well as in a number of other countries in Africa, Latina America and Asia.

The changes in oil prices and other market developments have had significant impact on OPEC oil production the past 4 decades. Prior to the first oil price shock, OPEC capacity was increasing at 10 percent per annum, with plans by the international major oil companies to raise capacity significantly during the 1970s and beyond. However, the quadrupling of oil prices in 1973/74 brought that growth to an abrupt halt, as the demand for OPEC oil nearly flattened. In addition, subsequent nationalizations of oil company assets in OPEC countries in the 1970s put greater control of production and investment in the hands of NOCs. The second oil price shock was more severe than the first, as the effects of falling oil demand and rising competing energy supplies sharply reduced the demand for OPEC oil. The bulk of the reduction in OPEC's oil production was in the Middle East countries, and particularly in Saudi Arabia which became the group's swing producer. By mid-1985, Saudi Arabia's oil production had fallen by more than 80 percent, and it became increasingly clear that the prevailing high prices were unsustainable, lest the country be driven entirely out of the market When the Kingdom decided to recapture part of its market share, prices collapsed in early 1986.

Figure A1.11 OPEC Oil Production, 1965-2006



Source: BP, IEA.

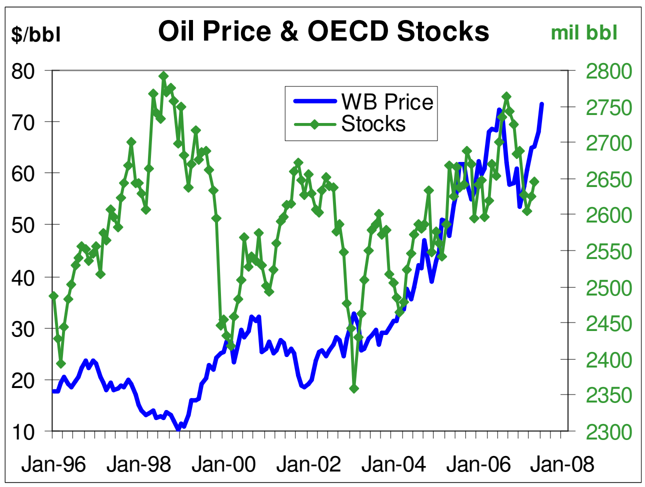
Lower oil prices in the latter 1980s helped boost the demand for OPEC oil and moderate the growth in non-OPEC supply. OPEC was content to leave prices in the $17-18/bbl range in order for the demand for its oil to grow. The price shock of 1990 was short lived, as large spare capacity, particularly in Saudi Arabia, replaced the loss of some 5 mb/d from Iraq and Kuwait. There was no intent on the part of OPEC to keep prices high, and this allowed prices to fall back into the mid-teens shortly after the Gulf war commenced in early 1991.

Following the loss of Iraq and Kuwait production in 1990, Saudi oil's production quickly jumped by 3 mb/d to more than 8 mb/d late that year. However, its production largely stagnated during the 1990s as other OPEC members captured much of the growth in demand for OPEC oil. While much of the gains were due to recovery in production in Kuwait and Iraq, Venezuela's production increased by more than 0.8 mb/d from 1991 to 1998, well above gains of the other members. In late 1997, Saudi Arabia raised production in order to increase its share, and led the organization to a 10 percent increase in quotas on January 1, 1998. This coincided precisely with the full outbreak of the Asian financial crisis, and oil prices plunged to $10/bbl in 1998. Soon after, Hugo Chavez came to power in Venezuela, and changed some of the oil policies of the previoU.S.government. He supported a strong, united OPEC, and a desire for higher prices. This led to large production cuts and a recovery of prices, and set the stage for the recent price shock, described in more detail below.

3. Recent Global Oil Market Developments and the Fourth Oil Price Shock

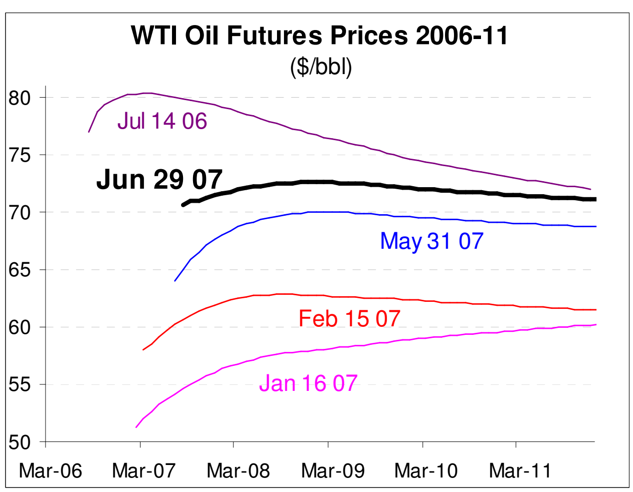
World oil prices increased sharply during 2004-06, with the World Bank price (average of West Texas Intermediate (WTI), Brent, and Dubai) exceeding $75/bbl in early August 2006. Prices were initially driven upwards by an unexpected demand shock in 2004 that pushed the global oil industry up against capacity all along the supply chain—exacerbated by low inventories and earlier OPEC production cuts. After a brief fall in prices in late-2004 and accommodating production increases from OPEC, oil prices surged higher in 2005 and 2006, despite slowing oil demand growth and rising inventories. Prices were driven higher by expectations of continued strong growth in demand, capacity constraints, and fears of supply disruption in a number of countries, for example, Iraq (insurgency), Nigeria (civil strife), and Iran (nuclear program). In addition there were concerns about reliability of supplies from other countries, for example, Russia (following cut off gas supplies to Ukraine) and Venezuela, as well as unexpected accidents and weather disruptions e.g., hurricanes in the Gulf of Mexico.

Figure A1.12 Oil Price and OECD Stocks, 1996-2007



Source: IEA.

Figure A1.13 West Texas Intermediate Oil Future Prices, 2006-11



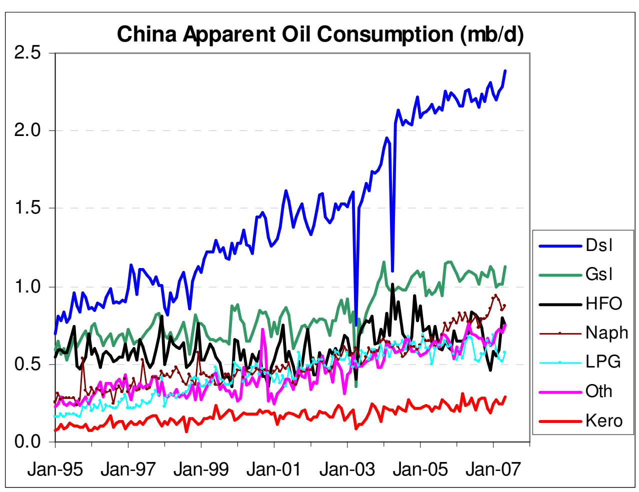
Source: NYMEX

Following the peak in oil prices in August 2006, prices fell by a third, or more than $25/bbl, to near $50/bbl in early 2007. The decline was due to high stocks, easing of political tensions, and weak demand from mild winter weather, and investors liquidated positions on futures markets. Crude oil futures prices moved into steep contango (forward contract prices above near-by prices) which created a large financial incentive to build inventories, accentuating the surplus. However, investor expectations—as reflected in the forward price curve—continued to show high forward prices, based on expectations of strong demand growth and supply constraints. In addition, it was felt that OPEC would keep sufficient oil off the market to support much higher prices than in 1990s, or than during early part of this decade when their target range was $22-28/bbl for its basket of crudes (since abandoned). It is presently felt that OPEC will try to defend a price floor above $50/bbl, although there is much debate by market analysts and forecasters, and considerable uncertainty about the preferences of individual OPEC members.

3.1 Demand

World oil demand growth has been moderate the past decade, rising on average by 1.4 mb/d or 1.8 percent p.a. Non-OECD oil demand, excluding the FSU, grew by nearly 1.0 mb/d or 3.8 percent p.a. The demand shock in 2004 amounted to a 3.0 mb/d or 3.8 percent global gain, the largest annual increase in almost 30 years. Demand increased sharply in most regions due very strong global economic growth. China's demand increased by 0.8 mb/d or 15 percent, while demand in the U.S.grew by 0.7 mb/d or 3.4 percent. The surge in demand was particularly large in the second quarter of 2004, when demand leapt by nearly 4.5 mb/d or nearly 6 percent. It was this sudden, unexpected growth that pushed the industry up against capacity constraints and drove oil prices upward. World oil demand growth has slowed since 2004 due to weaker economic growth, higher prices, and the effects of weather.

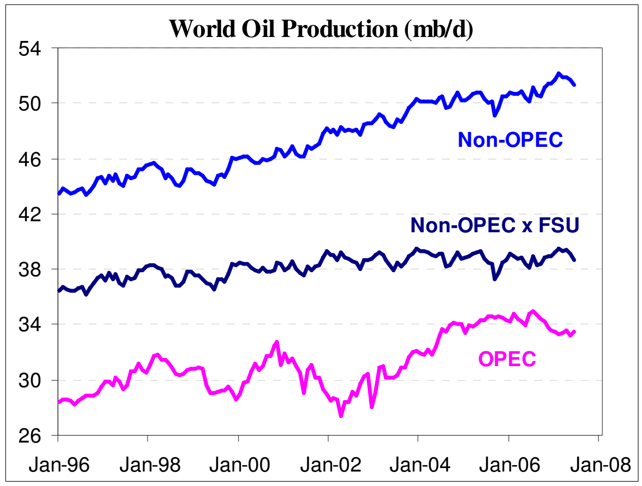
Figure A1.14 China Apparent Oil Consumption, 1995-2007



Source: PEL.

China's oil demand in 2003-04 was augmented by extremely large growth in diesel use in back-up generators because of chronic power shortages. Recent significant expansion of power capacity in China has subsequently reduced diesel consumption in this sector.

Figure A1.15 World Oil Production, 1996-2007



Source: IEA.

3.2 Non-OPEC Supply

Non-OPEC oil supply growth from outside the FSU has been rather disappointing in recent years, particularly given high oil prices. Much of the net growth in non-OPEC supply has been in the FSU where output has rebounded from a low of 7.1 mb/d in 1996 to 12.1 mb/d in 2006. The rather sluggish growth elsewhere has been the result of large declines in the North Sea and the United States, where each fell more than 1.0 mb/d between 1998 and 2005. There were also relatively large declines in Argentina, Australia, Colombia, Egypt, Gabon, Oman and Syria. These were more than offset by relatively large increases in a number of countries, for example, Angola, Brazil, Canada, Chad, Ecuador, Equatorial Guinea, Sudan, Thailand, and Vietnam. Non-OPEC supplies in aggregate began to increase quite strongly in the second half of 2006, and large gains of nearly 1 mb/d are expected in 2007.

3.3 OPEC

OPEC has had significant influence on the run-up in prices in recent years. After oil prices fell to $10/bbl in 1998 (which was partly due to OPEC over-production), OPEC began heavily intervening in the market by adjusting production to force inventories to low levels and thereby raise prices. Between 2000 and 2003, OPEC lowered and raised output substantially in an attempt to keep prices within its target range of $22-28/bbl. Much of the intentional shifts in production occurred in the Gulf countries outside of Iraq. The unexpected demand shock in 2004 coincided with cuts in OPEC quotas and production, and the industry was soon pushed up against capacity constraints.

Figure A1.16 OPEC–10 Production and Quotas, 1996-2007

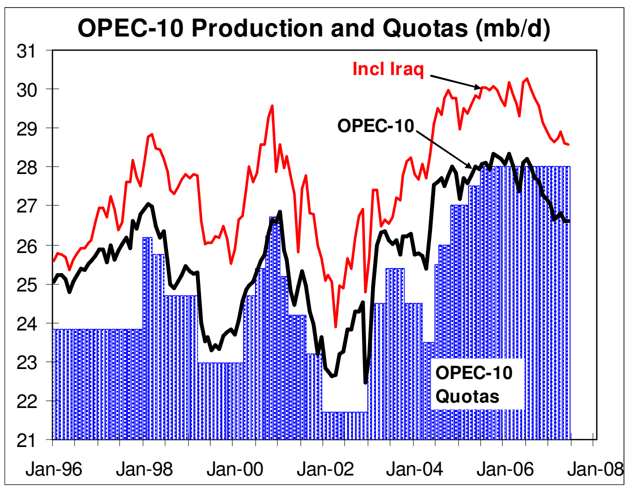
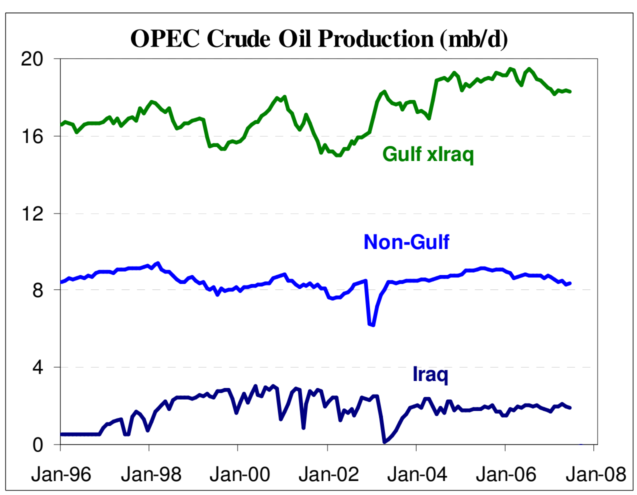
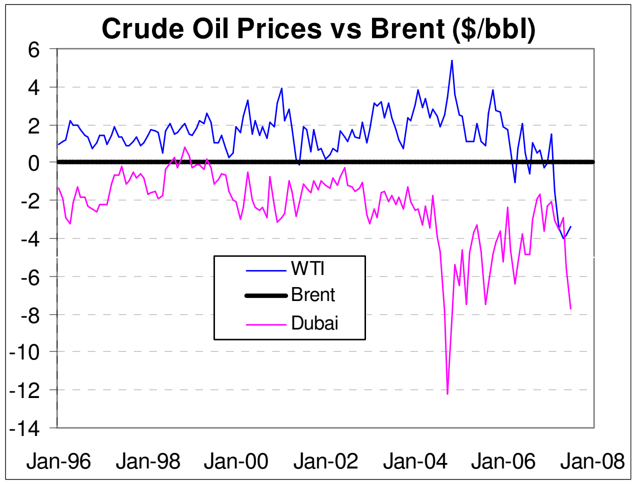


Figure A1.17 OPEC Crude Oil Production, 1996-2007



Source: IEA.

Figure A1.18 Crude Oil Prices vs. Brent, 1996-2007

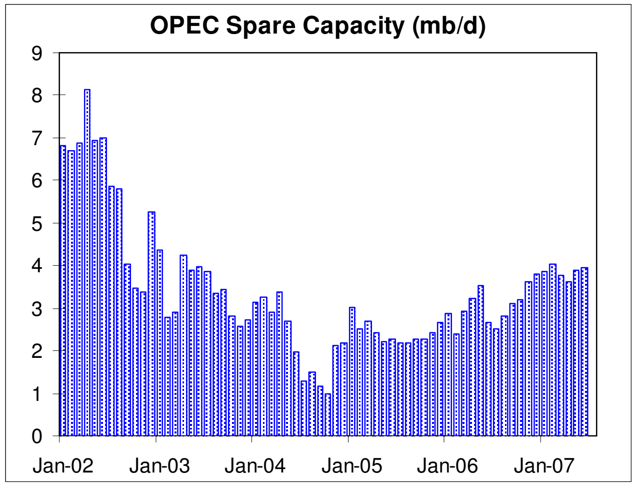


Source: Bloomberg.

Prices surged above $50/ bbl in the fall of 2004, and OPEC swiftly raised production to stem a further rise in prices. They pushed what surplU.S.production they had onto the market, including heavy crude oil, and prices for all crude oils fell. The decline in heavy crude oil prices was especially large, because of the surplU.S.of heavy oils on the market, including the increase in heavy fuel oil output from refineries as they endeavored to meet the surge in demand for light products. As a result, the differential between Dubai crude and Brent increased to more than $14/bbl during October 2004. Oil prices slumped from more than $50/bbl to around $40/bbl in late-2004, and OPEC again reined in production to limit the price decline. The cutback in OPEC heavy oil output raised the relative prices of heavy crudes, though not back to earlier levels.

In 2005 and 2006 oil prices surged to all-time nominal highs, despite increasing stocks and a more comfortable oil balance (as affirmed by increasing contango in futures markets), largely because of actual and feared supply disruptions. During this period OPEC pledged to keep the market well supplied, but vowed not to flood the market with heavy crude oil, as it would only depress all crude prices, as before. Increases in new OPEC capacity of light crude generally displaced heavy crude oil production. OPEC surplU.S.capacity increased, but this was mainly heavier crude. OPEC essentially took the position that they would make available its surplU.S.capacity, but would not force it into the market, and would let the market determine overall price level.

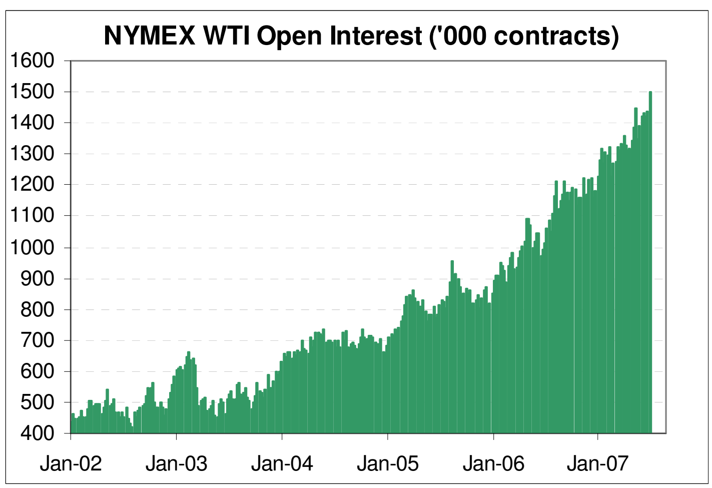
Figure A1.19 OPEC Spare Capacity, 2002-07



Source: IEA.

As prices rose in 2006, demand weakened, and stocks and OPEC surplU.S.capacity increased. After prices peaked in the summer of 2006, investors began to focU.S.more on the softening oil balance and less on geopolitical issues, which were generally easing. As prices slumped, OPEC agreed to reduce output by 1.2 mb/d on November 1, 2006, and a further 0.5 mb/d on February 1, 2007.

Figure A1.20 NYMEX West Texas Intermediate Open Interest, 2002-07



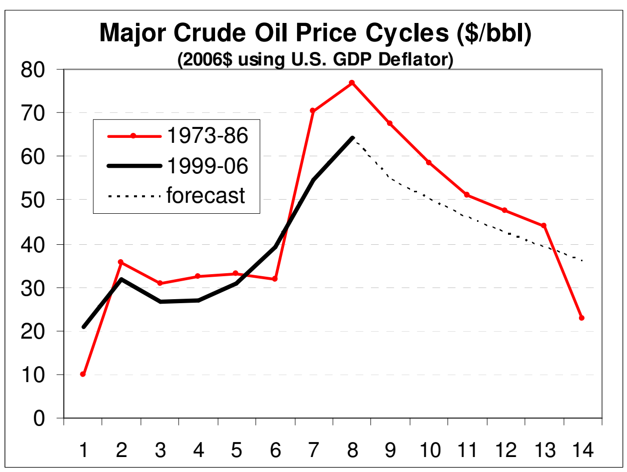
Source: NYMEX.

In the near term (2007), OPEC would clearly like to remove the surplU.S.overhang in the market and stabilize prices, at some relatively high level (consensU.S.currently is $50-60/bbl). However some OPEC members do not want prices to surge again for fear of dampening global economic growth and oil demand. OPEC's challenge, then, is to stabilize prices at its preferred level but to also prevent prices from rising too rapidly when they attempt to tighten the oil market balance by forcing inventories lower. It is difficult to stabilize prices because of the relatively swift response of traders in futures in markets to anticipated changes in the market, and of the relatively lengthy delay for OPEC in deciding upon and implementing an oil production agreement among its members. It is also difficult for the organization (or other forecasters) to judge how inventories might evolve in the weeks and months ahead, the pace of oil demand, and other unforeseen developments in crude oil and refined products markets. OPEC also wants to be careful about trying to cap oil prices too firmly, lest investors see no upside potential to oil prices and withdraw from futures markets. Open interest in WTI crude oil futures on the NYMEX has tripled since 2002, and noncommercial positions have increased four-fold to more than 400,000 contracts (each contract comprised of 1,000 barrels).

3.4 Comparison With Previous Oil Price Shocks

The price increases of 2004-06 are different from the previoU.S.price shocks. In 1973, 1979, and 1990, there were significant disruptions to supply that drove up prices. Following the first price shock, global demand continued to rise, and OPEC's production remained flat overall, although its share of global oil production fell from 53 percent to 47 percent (in that sense OPEC may have raised prices too high). The second oil price shock was more severe. OPEC clearly overreached and its output was nearly halved by 1985. In its wake, OPEC was left with large surplU.S.capacity and structurally lower oil demand growth. In 1990, OPEC had no intention of keeping prices high, and the brief spike in prices did little to affect long term demand or competing supplies.

Figure A1.21 Major Crude Oil Price Cycles, 1973-86 and 1999-06



Source: World Bank.

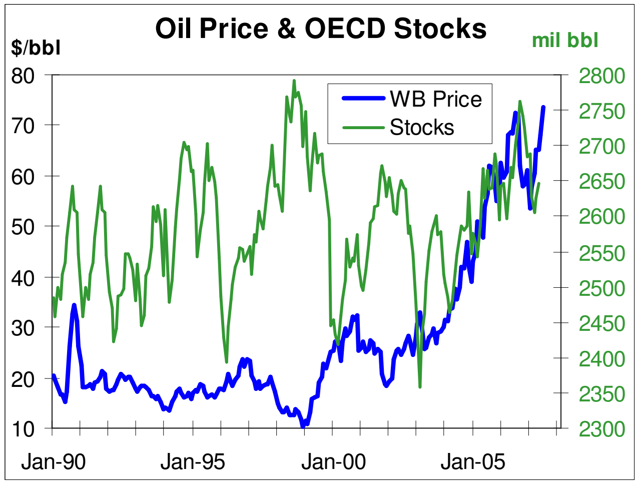
The recent price increase is more like the first oil price shock in 1973/74, when OPEC cut production to secure a "reasonably" higher price for its oil. As then, the price target today (assumed to be $50-60/bbl) is not unduly large, and oil demand is expected to continue to rise. In both instances OPEC was near production capacity. [In the recent case it took OPEC nearly 20 years to wear off the surplU.S.that resulted from the upheaval in oil markets in the early 1980s.] OPEC's output is again stagnating, as global oil demand slows and non-OPEC supplies are starting to rise significantly. However, it is too soon to judge if OPEC's share of world oil output will fall, given the uncertainty over oil demand growth in developing countries, and the pace of non-OPEC supply growth. Most long-term forecasts expect OPEC's share to rise (see below). The challenge for oil producers, in essence, is to optimize oil output so as to maximize oil revenues and not adversely affect its market share. Thus, an optimum price for OPEC might be one in which oil revenues and oil production are sufficiently large, and yet the demand for its oil exports continues to rise, even if only modestly. This was nearly the case in the latter 1970s, and appears to be the case now, but large uncertainties remain.

What is different from the 1970s is the volatility of oil prices. In the 1970s, OPEC fixed official prices and had to align differentials for each grade of crude so that any country or grade of crude was not at a competitive disadvantage.[62] In the 1970s, spot markets for crude oil were only beginning to develop in large fashion, and expanded after the nationalization of the major oil company assets—that is, the major oil companies became buyers of crude oil and searched for crude oil at the lowest price. There were no futures markets for crude oil in the 1970s, and no sudden movements in prices, in the absence of supply disruptions.

Today, international crude oil purchases are indexed to major benchmark crude prices, for example, Brent and WTI, established on futures market exchanges. Reported developments in oil markets are immediately reflected in oil futures prices, and it is much more difficult for OPEC to contain prices within a target range. Between 1986 and the late 1990s, OPEC was comfortable leaving oil prices roughly between $15-20/bbl. It kept its monthly production levels relatively "constant" (allowing for market growth), and permitted commercial oil inventories to fluctuate seasonally, as typical, thereby minimizing fluctuations in prices. It simply withheld sufficient production from the market to support an acceptable overall level of prices. In essence, there were large fluctuations in oil inventories, but relatively little variation in OPEC oil production and oil prices.

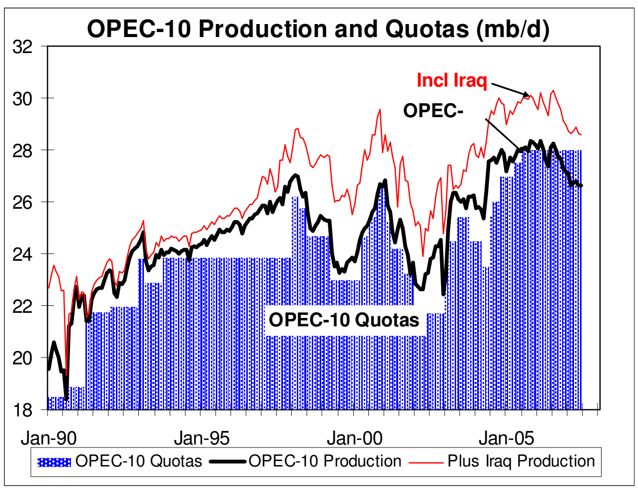
[62] Fixed-prices were problematic, as constantly changing net-back values from refineries would alter the competitiveness of individual crude oils, and led to price discounting.

Figure A1.22 Oil Price and OECD Stocks, 1990-2007



Source: IEA.

Figure A1.23 OPEC-10 Production and Quotas, 1990-2007



Source: IEA.

Beginning in the late 1990s, OPEC wanted a higher price for its oil. To achieve this, it forced consumer inventories lower by adjusting production accordingly. Because of the seasonality of oil demand and counter-cyclical movements in oil inventories, OPEC had to intervene heavily in the market to keep stocks low, by both raising and lowering production during the year (see graph). Keeping inventories low pushed oil futures prices into backwardation (near-by prices above forward prices), which discourages refiners from building discretionary stocks. However, it is difficult to anticipate the appropriate level of production for the next quarter or two in order to keep stocks low. Consequently, oil producers tend to over and undershoot the market—with lags—which can lead to large volatility of prices. This heavy intervention by OPEC occurred from 1998 to 2003, when they were successful in keeping prices generally within their then target range of $22-28/bbl.

In 2004, prices "got away" from OPEC, as an unexpected demand shock pushed the industry and OPEC up against capacity constraints. OPEC responded by raising output, and helped reduce prices from more than $50 to $40/bbl. However, they quickly cut back output to prevent prices from falling further. In 2005-06, fears of supply disruption sent prices to record highs, and OPEC chose to keep the market well-supplied, but did not force its surplU.S.heavy crude onto the market. When oil prices slumped in the second half of 2006, OPEC again cut output.

OPEC faces a difficult challenge of stabilizing prices at a relatively high level, yet not letting prices get too high because of its impact on demand, or not firmly capping prices and causing investors to leave the market. The expansion of financial markets and increasing volatility of oil prices makes OPEC's job that much more difficult.

What continues to be uncertain in the current oil price shock—in progress—is what the price cycle may ultimately look like. Will MENA producers continue to push for higher prices? Will they again overshoot, and risk permanently damaging long-term demand? Will they keep prices relatively low to preserve market share? As previously, the global oil market will continue to evolve, and producers will continue to search for an optimal production and pricing policy, often in a trial-and-error mode. While each price shock and cycle has had common economic aspects, each has also had quite different characteristics and surprises, and most forecasters have erred in their aftermath. This cycle may not prove any different.

4. MENA Energy Production, Consumption and Trade[63]

4.1 Energy Production

The MENA region has vast resources of oil and gas, with crude oil accounting for 80 percent of domestic energy production, and much of the rest natural gas. The concentration of oil and gas in the total energy mix is far higher than for global energy output, where oil and gas represents 56 percent of world primary energy output. MENA oil production has recovered from the slump in the mid-1980s, and along with new oil developments is now slightly above the peak in the 1970s. MENA has expanded its gas production significantly the last two decades, with output rising 7.6 percent p.a. Much of the increase has been for power generation, in part to free up oil for export, but also to utilize the often "stranded" resources in domestic markets. Gas exports have also increased, mainly in the form of liquefied natural gas (LNG) from the Gulf, and both piped gas to Europe and LNG from Algeria. There is large potential to expand the use of natural gas, both domestically and for export. MENA's non-oil/gas energy production is very small, representing less than 0.5 percent of total energy output. There are not any nuclear power facilities in the region.

[63] The IEA publishes comprehensive global energy data each summer. Presently coverage extends to 2004.

Figure A1.24 MENA Primary Energy Production Growth, 1985-2004

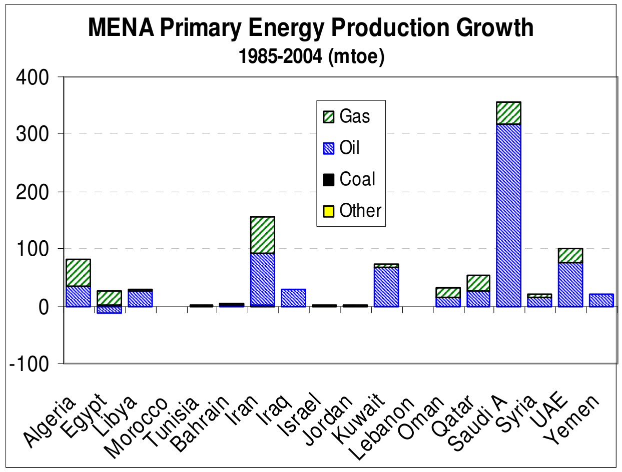


Figure A1.25 World Primary Energy Production, 1971-2004

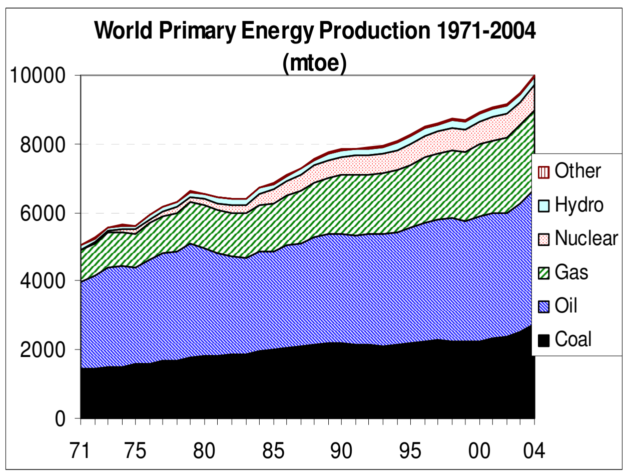
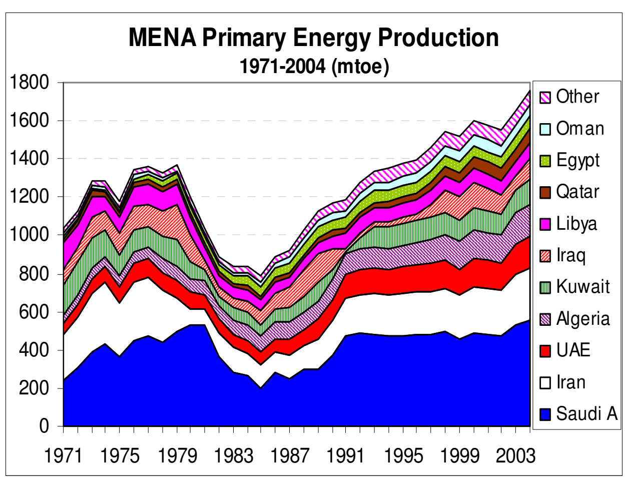
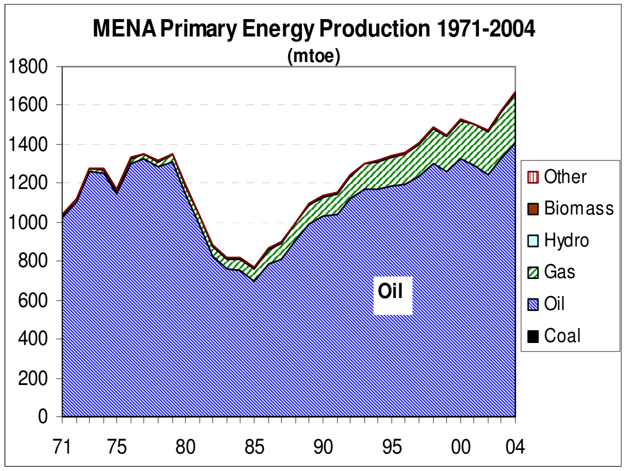


Figure A1.26 MENA Primary Energy Production, 1971-2004



Source: IEA.

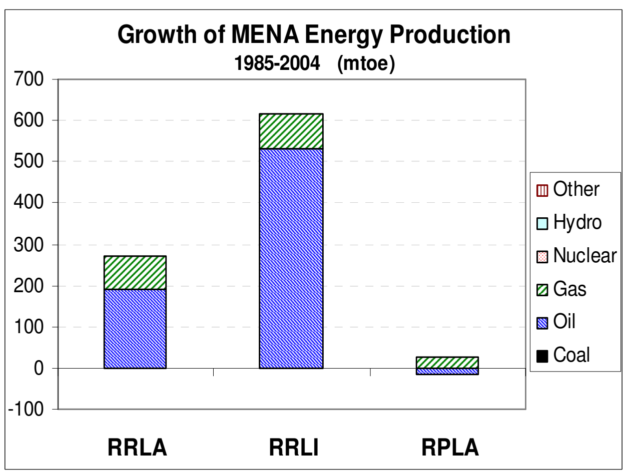
Figure A1.27 MENA Primary Energy Production, 1971-2004



Source: IEA.

Over half of the growth in energy production between 1971 and 2004 was in the two largest producing countries, Saudi Arabia and Kuwait. Among main country groupings, two-thirds of the growth was in the resource-rich, labor-importing (**RRLI**)[64]countries. Much of the increase has been recovery from the large contraction in crude oil production in the 1980s. However, output has also come from new oil output growth in Oman, and from natural gas in all producing countries. Well over half of the growth in energy production for the RRLI occurred in Saudi Arabia. There is no coal or hydro production in the group, and only a tiny amount of other energy production.

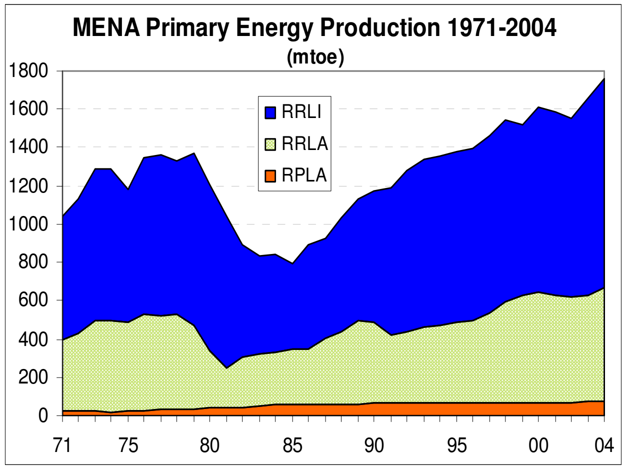
Figure A1.28 Growth of MENA Energy Production, 1985-2004



Source: IEA.

[64] Resource-rich, labor-importing countries are Bahrain, Kuwait, Libya, Oman, Qatar, Saudi Arabia and the United Arab Emirates (UAE).

Figure A1.29 MENA Primary Energy Production, 1971-2004



Source: IEA.

In the resource-rich, labor abundant (**RRLA**)[65] countries, much of the growth in energy production has also been recovery from earlier contractions in oil output, which included geopolitical disruptions, for example, the Iran-Iraq war. However, there has also been rising oil output in Syria and new output growth from Yemen. There has also been rising production of natural gas in all countries outside of Yemen, primarily in Iran and Algeria. There is some production of coal in Iran, as well as hydro, particularly in Iran and Syria. Biomass production is present in all countries, but reported volumes are relatively small.

In the resource-poor, labor abundant (**RPLA**)[66] countries, where energy production is relatively low, oil production has fallen in the two main producing countries, Egypt and Tunisia. Natural gas production has risen significantly in Egypt, and also in Tunisia. There is hydro, biomass, and solar energy output in all countries in this group, especially in Egypt. There is also small output of coal in Israel. Annex 2 contains country detail of the three country groups.

Most of the non-oil/gas production occurs in the RPLA countries, particularly in Egypt and Israel, and also in Iran among the resource-rich countries. However, these sources are extremely small fractions of total energy use. The main beneficiaries of hydropower are Egypt, Iran, Syria, and Morocco, while most solar power facilities are located in Israel. Reported biomass use mainly occurs in the RPLA and RRLA countries, with Egypt, Tunisia and Iran being the largest users. Only three countries produce coal, and is mainly dominated by Iran. Morocco no longer produces coal.

[65] Resource rich, labor-abundant countries are Algeria, Iran, Iraq, Syria, and Yemen.
[66] Resource-poor, labor abundant countries are Egypt, Israel, Jordan, Lebanon, Morocco, and Tunisia. Data for Djibouti and West Bank and Gaza not available.

Figure A1.30 MENA Nonpetroleum-based Energy Production, 1971-2004

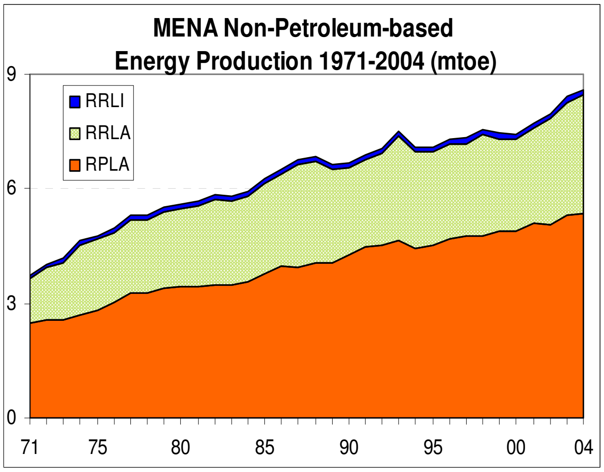
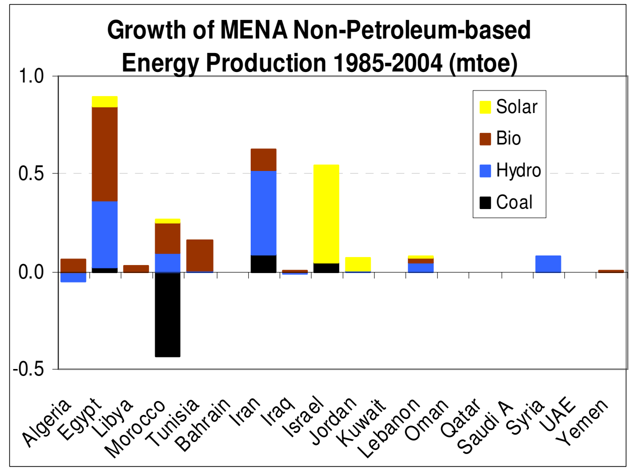


Figure A2.31 Growth of MENA Nonpetroleum-based Energy Production, 1985-2004

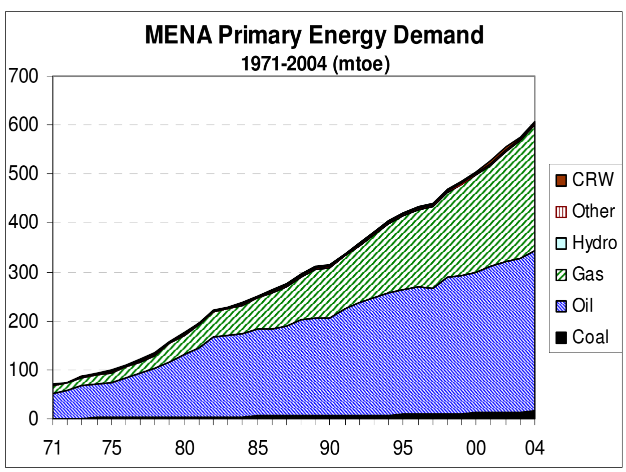


Source: IEA.

4.2 Energy Demand

The vast majority of energy consumption in MENA is comprised of oil and natural gas, given the vast reserves of these fuels, and oil still retains the largest share. Total primary energy consumption grew by 4.8 percent over the 1985-2004 period, with natural gas use expanding twice the rate of oil (7.6 percent p.a. compared with 3.3 percent for oil). The share of other fuels is relatively small, accounting for less than 4 percent of primary energy use. However, coal has relatively large shares in Israel (39 percent) and Morocco (32 percent).

Figure A2.32 MENA Primary Energy Demand, 1971-2004



Source: IEA.

Nearly one-half of domestic natural gas consumption is used for power generation, and the remainder is mainly used in the industrial and residential sectors. Total electricity consumption in the region grew at a rate of about 7 percent during 1985-2004. Oil still retains a relatively large share in the power sector, although it continues to be eroded by penetration of natural gas. Over half of oil's use is in the transport sector, with relatively large shares in the industrial and residential sectors.

Just over half of the growth in energy demand has occurred in the two largest energy consuming countries, Saudi Arabia and Iran, with average growth rates above 5 percent. In Saudi Arabia, the largest volume growth was in oil (5.3 percent p.a.), but gas demand increased by 11.5 percent. In Iran, much of the growth was for natural gas, rising at an average rate of 13 percent. Meanwhile oil demand grew a relatively small 2.5 percent p.a. This reflects the abundance of natural gas reserves in Iran, and the difficulty the country has had raising oil production and sustaining oil exports. The increase of natural gas use exceeded the growth in oil use by a relatively large margin in a number of countries, notably Algeria, Egypt, Oman, Qatar, and the UAE.

Figure A1.33 Growth of MENA Primary Energy Demand, 1985-2004

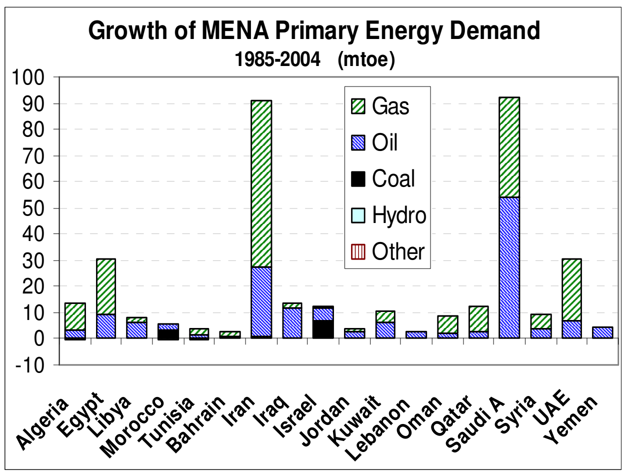
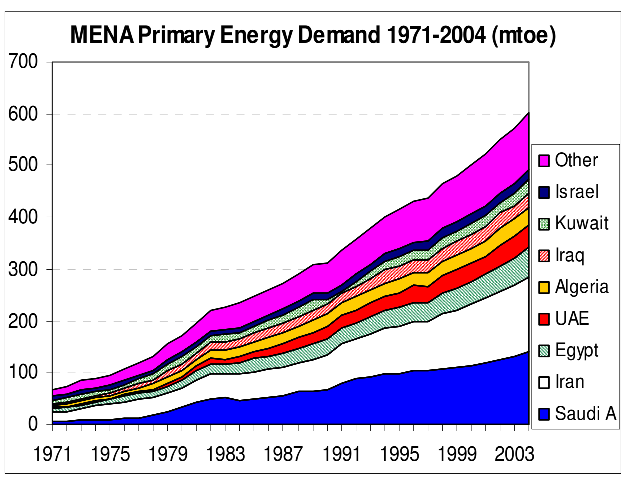
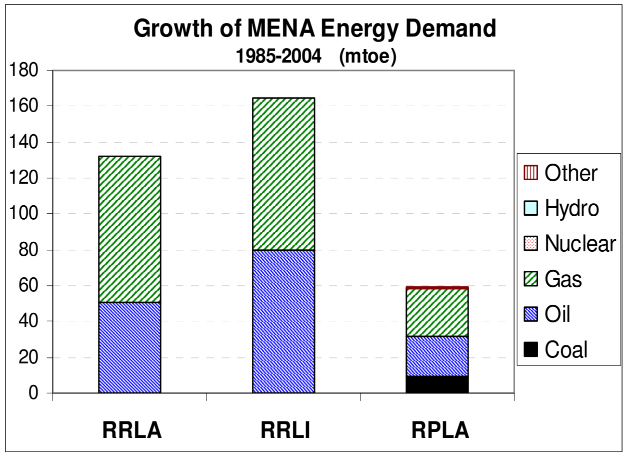


Figure A1.34 MENA Primary Energy Demand, 1971-2004



Source: IEA.

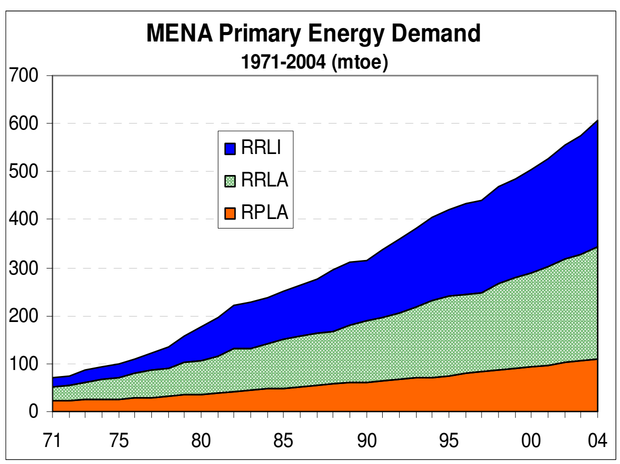
Figure A1.35 Growth of MENA Energy Demand, 1985-2004



Source: IEA.

Energy demand has grown relatively strongly in all three MENA groups, led by the **RRLI** countries where demand grew at an average rate of 5.2 percent during 1985-2004. Oil still represents more than half of total energy consumption. Oil demand grew by an average 4.6 percent over the period, but was well above 5 percent in 2002-04 when oil prices and incomes were higher. More than half of the growth in energy demand has been for natural gas, where demand growth averaged 6.1 percent. Three-quarters of the volume growth in energy demand was in Saudi Arabia and the UAE, but Oman had the highest rate of growth, at 7.5 percent. See Annex 2 for country detail for the three country groups.

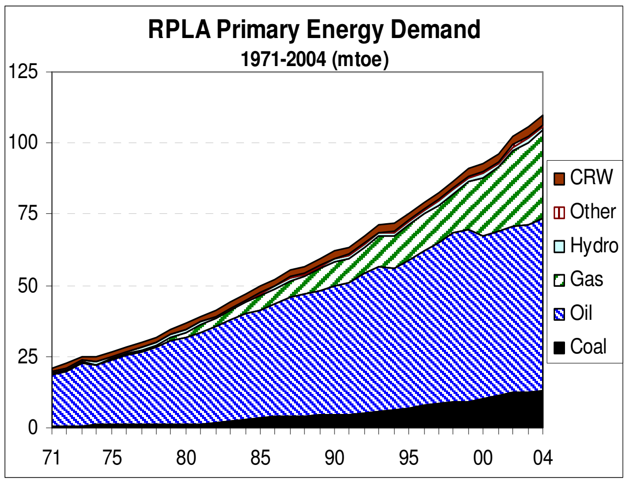
Figure A1.36 MENA Primary Energy Demand, 1971-2004



Source: IEA.

For the **RRLA** countries, energy demand grew 4.5 percent over the 1985-2004 period. The group had a similar energy demand profile as RRLI and for MENA in aggregate, with oil representing a slightly higher share than RRLI, at 56 percent, and most of the growth being for natural gas. Oil demand growth was a more modest 2.6 percent, owing in part to geopolitical disruptions that curtailed demand over the period, for example, in Algeria, Iraq and Iran. Even in the recent period of 2000-04, oil demand only grew 3 percent on average. Oil demand growth was quite moderate in all countries, except for Yemen where rose at an average rate of 6.8 percent. More than 3/5 of the growth in RRLA's energy demand was for natural gas, which grew 9.3 percent over the period. The growth was concentrated in Iran, which accounted for nearly 4/5 of the growth. Iran's power and residential sectors each account for more than 1/3 of the country's natural gas consumption.

Figure A1.37 RPLA Primary Energy Demand, 1971-2004



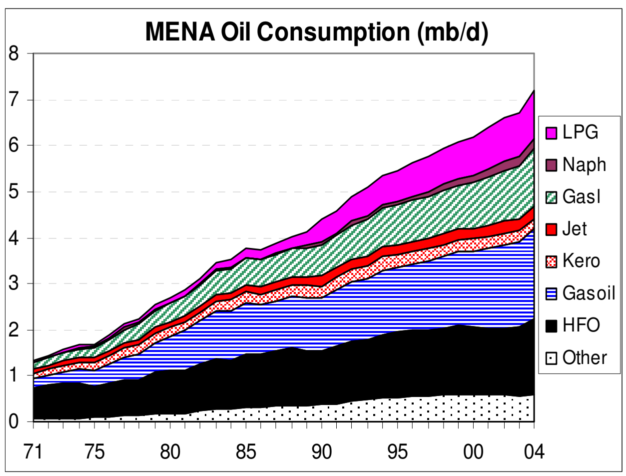
Source: IEA.

The **RPLA** countries account for just 18 percent of total MENA energy demand, but the group has a more diverse mix of fuels, and of relative shares, than the other two groups. Oil also accounts for more than half of total energy demand, but grew by just 2.5 percent over the 1984-2004 period. Oil demand growth was quite moderate in all countries. Natural gas recorded the largest growth, rising by 10.3 percent p.a. The vast majority of gas use, and the growth in demand, occurred in Egypt. However there was also relatively strong growth in Tunisia, as well as commencement in 2004 of production in Israel, and imports into Jordan from Egypt through the new Arab Gasline. The group also benefits from nonhydrocarbon resources, such as biomass (mainly in Egypt, Tunisia and Morocco), hydro (mainly Egypt but also Morocco and Lebanon) and solar (concentrated in Israel but is also in all other countries).

4.3 Oil Consumption

MENA oil consumption has grown by 3.5 percent p.a. the past two decades, and has accelerated in recent years due to higher incomes and low consumer prices in some of the oil exporting countries (See Annex 2 for gasoline and diesel prices in Asia). Oil demand grew by more than 7 percent in 2004, and the IEA estimates that oil demand in the Middle East (only) rose by more than 4.5 percent in both 2005 and 2006. The mix of oil products differs from other regions, particularly with respect to LPGs. Although the overall MENA share of LPG is 15 percent, it is about one-quarter for Algeria, Morocco and Saudi Arabia, and more than 60 percent for Qatar. In the case of Algeria and Morocco, LPG is used primarily in the residential sector, while for Qatar and Saudi Arabia, it is mainly used as feedstock for the petrochemical industry. The highest rates of growth have been for naphtha (12 percent) and LPG (10 percent), mainly due to large increases in petrochemical capacity in Saudi Arabia. LPG also had the largest volume gain among major fuels. Growth for the other products was more moderate.

Figure A1.38 MENA Oil Consumption, 1971-2004



Source: IEA.

Figure A1.39 Growth of MENA Oil Consumption, 1985-2004

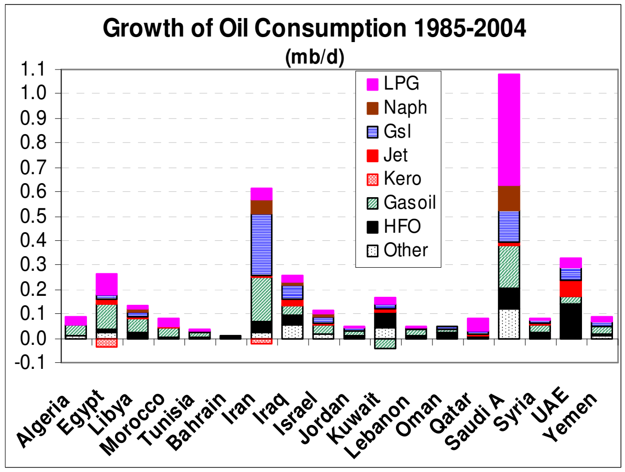
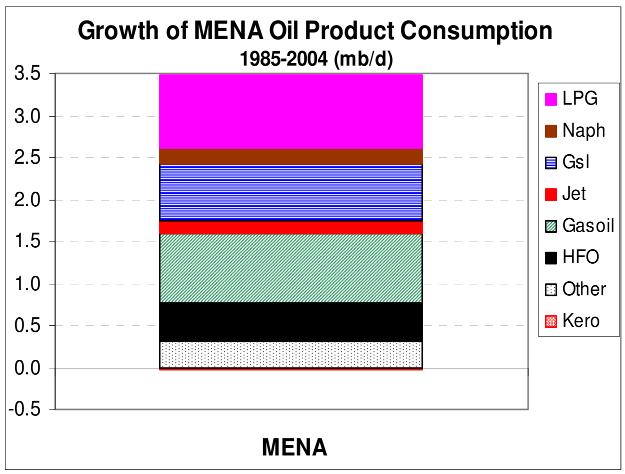


Figure A1.40 Growth of MENA Oil Product Consumption, 1985-2004



Source: IEA.

Gasoil is the largest component of oil demand, at 27 percent, not atypical for most regions outside of North America where gasoline has by far the largest share. Gasoil had the largest volume growth after LPG, and is the most widely consumed fuel, used in the transportation, power, industrial, residential, commercial and agriculture sectors. However its rate of growth over the 1985-2004 period was just under 3 percent. Gasoline had second fastest gain, rising at a rate of more than 4 percent. The share of heavy fuel oil (HFO) is relatively large at 23 percent, and is used mainly in power generation and industry. Growth has been moderate, at less than 2 percent, due to the penetration of natural gas in these sectors. The only fuel to decline over the period was kerosene, as the fuel is typically an inferior good, and used mainly as an intermediary product in the transition from biomass to cleaner end-use fuels (for example, LPG and electricity) in developing countries.

In the **RRLI** countries, oil demand grew fastest among the three groups, at 4.4 percent. Saudi Arabia, MENA's largest consumer, accounted for nearly 60 percent of the growth in this group, and more than one-quarter of MENA total oil demand. The largest growth in RRLI was for LPG, and along with naphtha, accounted for nearly 40 percent of the growth, much of which was for the petrochemical sector. HFO had the second largest gain, and captured most of the increase of HFO among the three country groups. The largest increase for HFO was in the UAE, with virtually all consumed in the industrial sector. The UAE also accounted for much of the increase in jet fuel, as the Dubai has become a major hub for international travel, and an increasing destination for tourism, investment and business gatherings. Gasoline consumption grew by 4 percent on average, with Saudi Arabia and the UAE accounting for much of the growth. Gasoil demand rose at a moderate rate of 2.4 percent, with Saudi Arabia and Libya posting the largest gains. See Annex 2 for country detail for the three groups.

In the **RRLA** countries, oil demand grew less than 3 percent over the 1985-2004 period, with Iran capturing more than half the growth for the group and 1/5 of total MENA oil demand. Gasoline had the largest growth, with much of the increase in Iran and Iraq. Gasoil demand grew almost as much as gasoline, with relatively large gains in all countries, given the importance of the fuel in many end-use sectors. LPG had the next largest gain, with increases in all countries, and largely for use in the residential sector. Naphtha demand had the highest rate of growth, at 12 percent, with nearly all of the increase in Iran for petrochemical feedstock. HFO demand recorded moderate growth in a number of countries, mainly for power and industry. Kerosene use fell overall, with a sizeable drop in Iran.

Figure A1.41 MENA Oil Consumption, 1971-2004

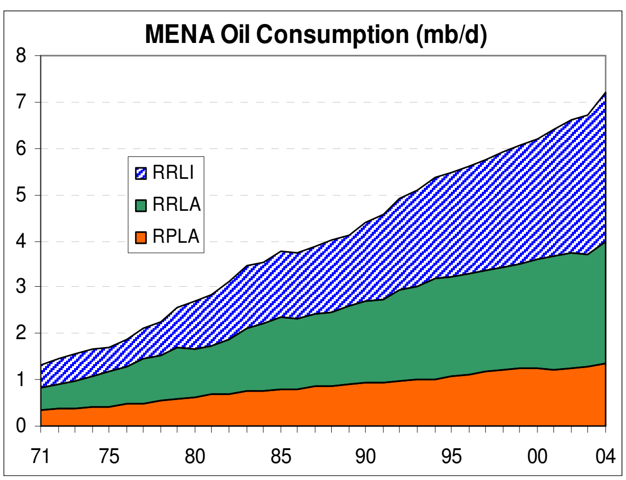
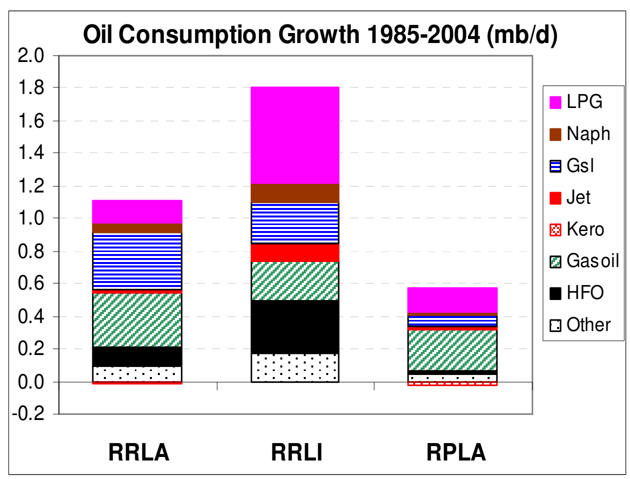


Figure A1.42 Oil Consumption Growth, 1985-2004



Source: IEA.

In the **RPLA** countries, oil demand grew by less than 3 percent during 1985-2004. Egypt consumes nearly half of the group's oil consumption, and about 9 percent of the MENA total. The growth in oil demand was dominated by gasoil and LPG (the latter remains largely subsidized in some MENA countries, for example, Morocco). Gasoil accounted for nearly half of the growth, rising by nearly 5 percent p.a., the fastest growth among all three groups.

There were relatively large rates of growth in all countries. LPG had the second largest gain, and the highest rate of growth, climbing 8 percent p.a. The largest increases were in Egypt and Morocco, but there were relatively strong rates of growth in most countries. Gasoline demand grew a moderate 2.6 percent. HFO consumption was marginally higher over the period, and actually fell from highs in the late-1990s in all countries except Morocco where consumption was slightly higher.

4.4 Energy Intensity and Per Capita Consumption

Energy intensity (energy consumption per unit of GDP) in the oil exporting countries increased sharply in the late 1970s and early 1980s as double-digit growth in energy consumption rose several times faster than GDP. Real output growth in the oil sector (oil production) slowed significantly in the latter 1970s, and fell in the early 1980s, largely because of OPEC pricing and production policies. There was some expansion of oil production in the latter 1970s in most MENA countries, mainly Saudi Arabia and Iraq, which was partly offset by large declines in Iran at the outbreak of the revolution. With the sharp fall of oil revenues and decline in GDP in the mid-1980s, energy consumption growth slowed, but remained positive, and energy intensity continued to increase in the resource-rich countries, particularly in the RRLI. This was partly due to low and subsidized prices for domestically consumed (and produced) fuels. MENA's energy demand elasticity during 1985-2004 was 1.65. In the resource-poor countries, energy intensity has been much less varied, as there was far less fluctuation in GDP and energy consumption, which both climbed at a steady, moderate pace since 1971. The energy demand elasticity for this group was 1.1, which is fairly typical for developing countries, where energy demand is broadly growing about as fast as income.

Figure A1.43 MENA Energy Consumption as Share of GDP, 1971-2004

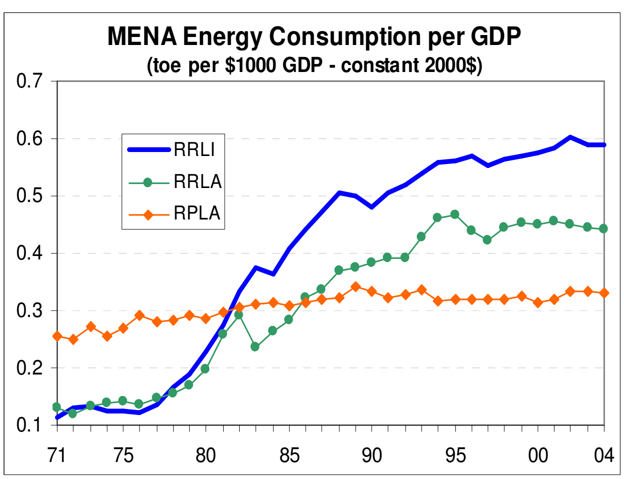
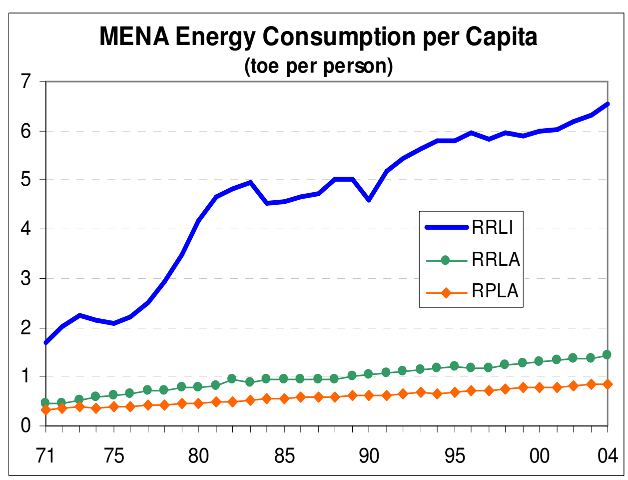


Figure A1.44 MENA Energy Consumption per Capita, 1971-2004



Source: IEA, World Bank.

Energy consumption per capita in the RRLI countries nearly tripled from 1971 to the early 1980s, and then leveled off in the 1980s as incomes fell. Per capita consumption then grew at a rate of around 2 percent, similar to growth rates in the other two regions. However, per capita energy consumption is accelerating again, due to rising incomes and low energy prices. The highest per capita use is in Qatar, while the fastest rate of growth has been in Oman. In the other two groups, per capita energy consumption levels are much lower, and growth rates have been much less. See Annex 2 for country detail.

For oil, the trends are broadly similar, although oil consumption has grown less rapidly than total energy production, largely due to penetration of natural gas and nonpetroleum fuels in the resource-poor countries, as well as higher energy prices in these countries. MENA's oil demand elasticity was 1.2 for the 1985-2004 period, with the resource-rich countries closer to 1.4, and the resource-poor countries at 0.7.

Per capita oil consumption followed similar paths, though "flatter" among the three groups. In the RRLI countries, per capita oil consumption grew just over 1 percent per year during 1985-2004, but has been accelerating in recent years with rising incomes and low prices. In the other two groups, per capita oil consumption has been growing well under 1 percent, particularly in RRLA countries.

Figure A1.45 MENA Oil Consumption as Share of GDP, 1971-2004

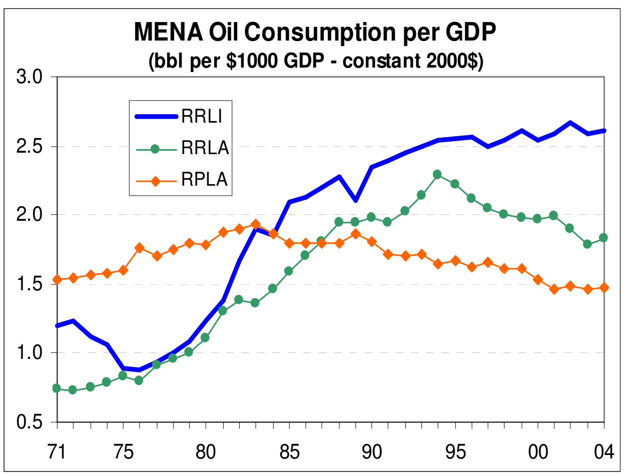
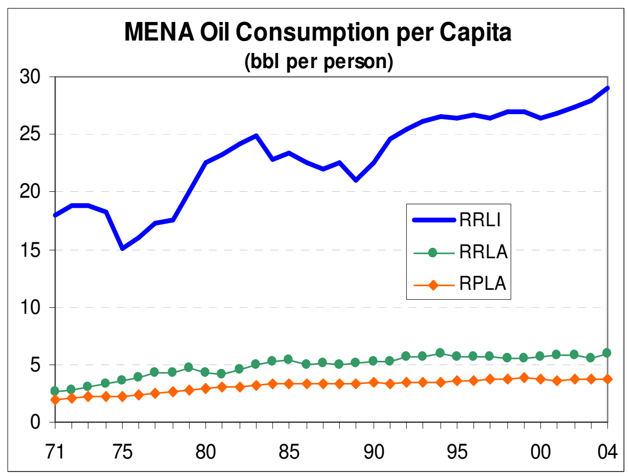


Figure A1.46 MENA Oil Consumption per Capita, 1971-2004



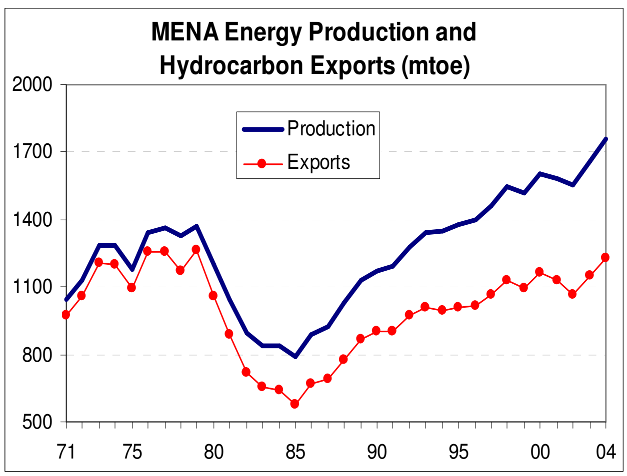
Source: IEA, World Bank.

4.5 Energy Trade

Hydrocarbon Exports

About 70 percent of MENA's primary energy production was exported in 2004. This was down from 77 percent in 1990, and more than 90 percent in the early 1970s, as rapidly expanding domestic consumption reduced the export share of output. High oil prices and production restraint by the OPEC producers significantly affected oil export volumes over the period. However, exports have grown by more than 4 percent p.a. since 1985, following the collapse in oil prices in early 1986.

Figure A1.47 MENA Energy Production and Hydrocarbon Exports, 1971-2004



Source: IEA.

The bulk of hydrocarbon exports was crude oil followed by petroleum products and natural gas. One-third of exports were from Saudi Arabia, all in the form of crude oil and products. Petroleum product exports were relatively sizeable in a number of the Gulf countries, led by Saudi Arabia. Natural gas exports have grown at an average rate of 8 percent since 1985, but have accelerated since the mid-1990s. Growth has been largest in the two main exporting countries, Algeria and Qatar, but there has also been noticeable growth in Oman, the UAE, Iran, and Egypt. More than half of the gas exports is shipped as LNG, originating from Qatar, Algeria, Oman, the UAE, Egypt, and Libya. There are significant volumes from Algeria being transported by pipeline to Europe, as well as smaller pipeline flows from other countries, including Libya to Italy, and Iran to Turkey. See Annex 2 for detailed export flows for 2005.

Figure A1.48 MENA Hydrocarbon Exports by Product, 1971-2004

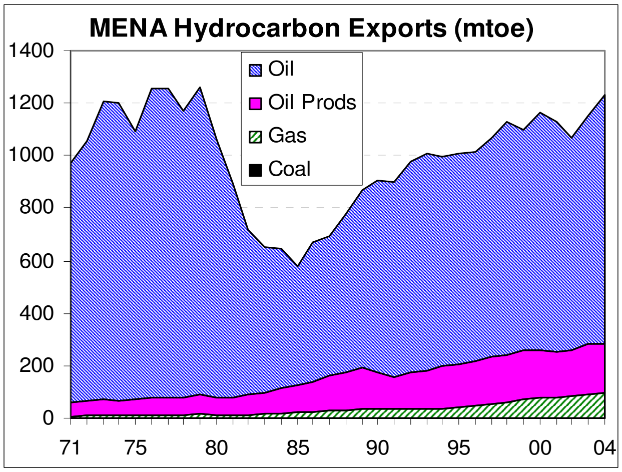
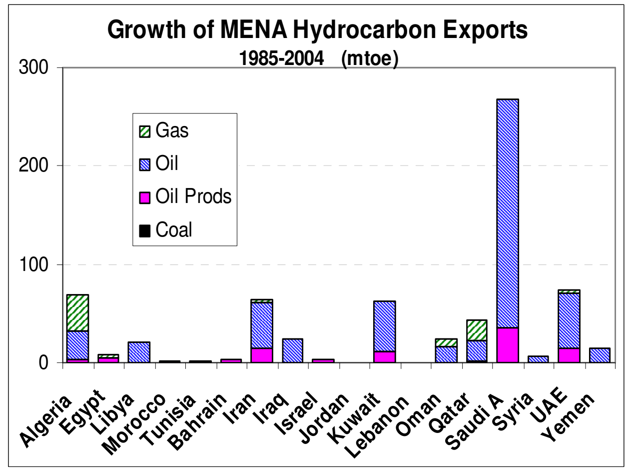


Figure A1.49 Growth of MENA Hydrocarbon Exports by Product, 1985-2004



Source: IEA.

Among the main groups, the RRLI countries accounted for two thirds of hydrocarbon exports, with the remainder mostly from the RRLA group. The **RRLI** countries accounted for three-quarters of the growth in exports over the 1985-2004 period, and in large part reflects a rebound from the slump in the mid-1980s. In 2004, RRLI exports were just shy of the former peak in 1979. Crude oil exports were more than 15 percent lower, and were nearly offset by increases in exports for petroleum products and natural gas. Hydrocarbon exports from Libya were down a third over this period, while those from Saudi Arabia and Kuwait were 10 percent lower. These were partly offset by large increases in Oman and Qatar, which were more than three- and two-times, higher, respectively—partly due to the rise of natural gas exports.

Figure A1.50 MENA Hydrocarbon Exports by Country Category, 1971-2004

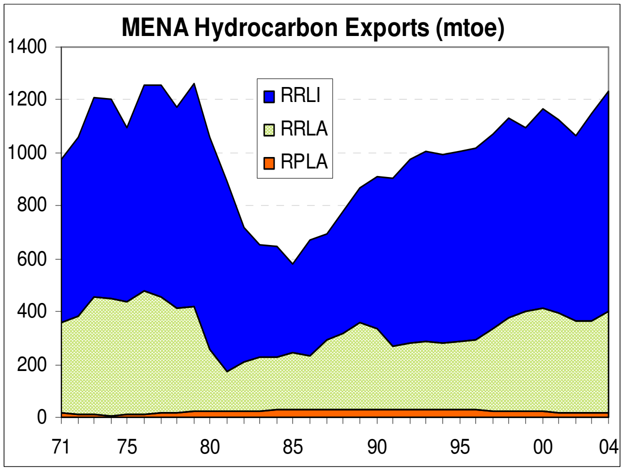
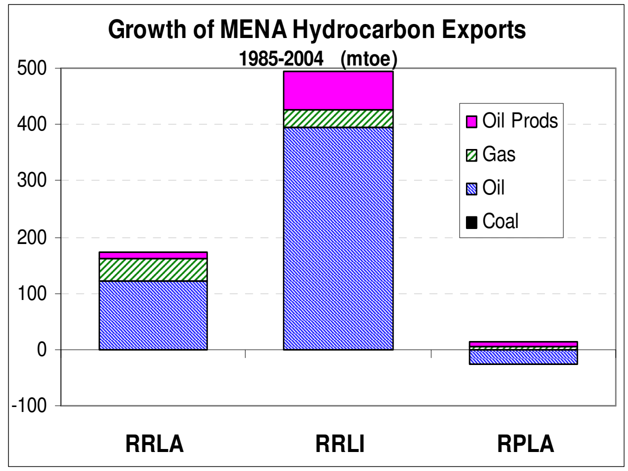


Figure A1.51. Growth of MENA Hydrocarbon Exports by Country Category, 1985-2004

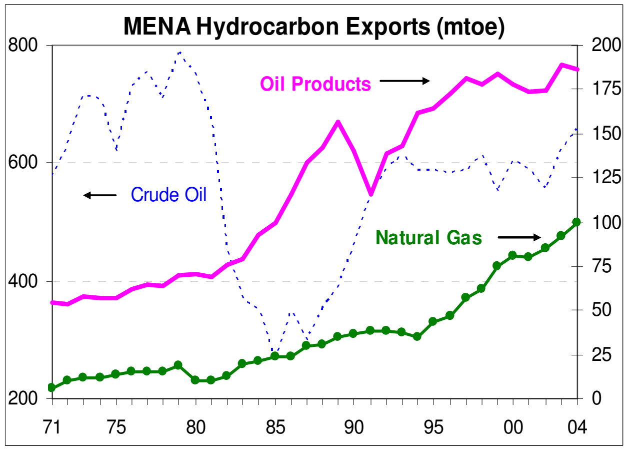


Source: IEA.

In the **RRLA** countries, hydrocarbon exports were 17 percent below the former peak of 1976, as Iran's exports were barely half, and Iraq's exports were a third lower. These were partly offset by significant growth in Algeria, as well as higher exports from Yemen and Syria, although output in the latter two countries has been in decline in recent years. Over half of the growth in Algeria's exports over the 1985-2004 period were for natural gas, while crude oil exports also increased significantly. Iran's hydrocarbon exports rebounded by nearly the same volume growth in Algeria over the period, but were mainly oil-based. The increase in exports in all other countries since 1985, including Iraq, was all in the form of crude oil. See Annex 2 for country detail.

In the **RPLA** countries, only Egypt has the resources to be an energy exporter. However, its hydrocarbon oil exports peaked in 1985, and have since fallen by nearly two-thirds due to falling oil production and rising domestic consumption. Its natural gas production has risen rapidly, and in part has helped restrain domestic oil consumption growth and support its oil exports—although oil exports were only 5 percent of its peak level in 1985. Egypt became an exporter of natural gas in 2003, with gas piped to Jordan through the Arab gasline. The other resource-poor countries are net energy importers, and discussed below.

Figure A1.52 MENA Hydrocarbon Exports by Type, 1971-2004



Source: IEA.

While crude oil exports have fluctuated substantially the past three decades, exports of petroleum products and natural gas have generally increased. The drop in total oil product exports in the early 1990s was due to loss of Iraq's refined product exports because of the Gulf War. Growth over the 1985-2004 period was concentrated in Saudi Arabia, Iran, Kuwait, and the UAE.

Natural gas exports have steadily increased and have accelerated since 1995 due to expansions in Algeria, Qatar, and Oman. MENA possesses large reserves of natural gas, and has the potential to increases exports significantly. One of the benefits of developing natural gas exports is that they are unencumbered by OPEC-style production restraint policies. Markets can expand relatively freely, depending on demand and investment. It is more attractive for foreign companies to invest and implement the latest technologies if there are no restrictions on production and exports. See Annex 2 for MENA gas export trade by country.

Hydrocarbon Imports

Gross energy imports in MENA are less than 10 percent the size of gross energy exports. Imports have risen fairly steadily since the mid-1980s, at about 3 percent p.a., but have accelerated since the mid-1990s, rising at 5 percent. Well over half of the growth was for oil products, with the largest increase in the UAE. Crude oil imports remained rather flat overall, with decreases in Syria and Yemen offset by increases elsewhere, notably Israel. The second largest increase in imports was for coal, and most went to Israel and Morocco. Natural gas imports have grown quite rapidly, but still remain a small share of total imports. The largest increase was in Iran, which receives gas from Turkmenistan. The other notable gas imports are in Tunisia and Jordan. The largest increase in total energy imports was in Israel, with increases in coal, crude oil, and oil products. Morocco's energy imports also included all three fuels, with more than half in the form of coal. Most other countries' imports were predominantly oil and gas.

Figure A2.53 MENA Hydrocarbon Imports, 1971-2004

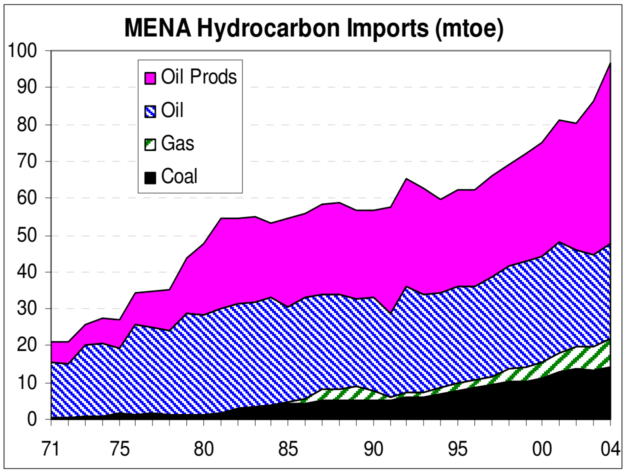
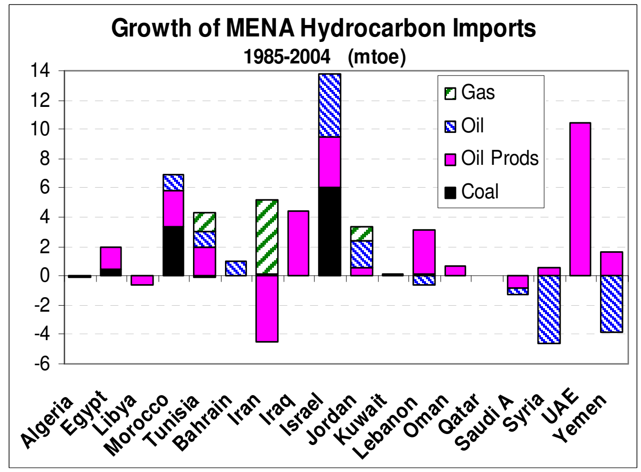
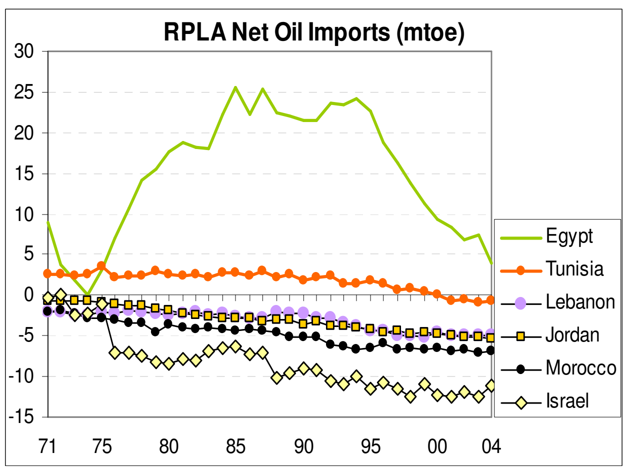


Figure A1.54 Growth of MENA Hydrocarbon Imports, 1985-2004



Source: IEA

Figure A1.55 RPLA and Oil Imports, 1971-2004



Source: IEA.

There are five net oil importing countries, all in the RPLA group, the largest being Israel. Tunisia became a net oil importer in 2001, and the rest have been net oil importers throughout the period covered (1971-2004). Egypt was a significant oil exporter in the 1980s and 1990s, but declining production and rising consumption the past decade has reduced the county to being a small net oil exporter. Should production continue to fall, it is possible that Egypt would become a net oil importer in the not-too-distant future.

4.5 Oil Export Revenues

MENA oil revenues have fluctuated greatly, due to large changes in production and prices over the past 35 years. [This section extends the data through 2006, incorporating latest IEA oil production figures to 2006, and World Bank estimates of oil revenues for 2006.[67]] MENA oil export revenues (both crude and petroleum products) spiked to $235 billion in 1980 due to the more than doubling of oil prices following the second oil price shock. Production was already contracting in most OPEC countries in 1980, especially Iran, but Saudi Arabia temporarily pushed its production to near 10 mb/d in an effort to slow the price spike. However, the Kingdom soon after agreed to become swing producer and cut production to support an official price of $34/bbl. Revenues plunged during the early 1980s due to falling demand for its oil. In 1986, when oil prices collapsed, revenues incurred a further drop, hitting a low of $64 billion. Revenues have since grown due to recovery in oil production, and more recently to the large jump in oil prices. Revenues are estimated to have reached $480 billion in 2006, with the RRLI capturing three-quarters of the total, at nearly $360 billion. The RRLA countries had the remainder, as the RPLA countries (essentially Egypt) fell toward becoming a net oil importer.

Figure A2.56 MENA Oil Production and Oil Prices, 1971-2004

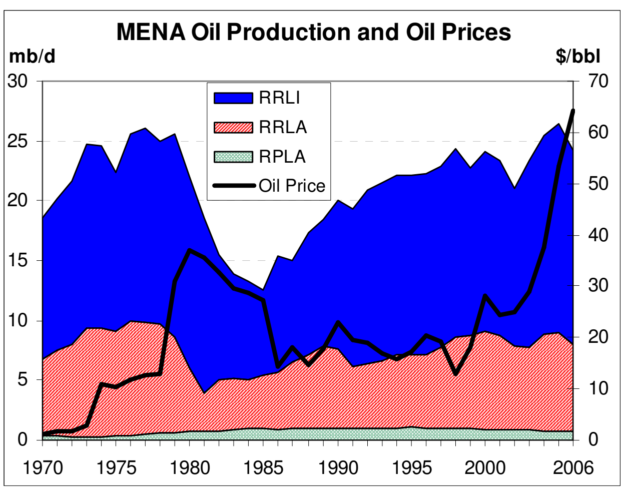
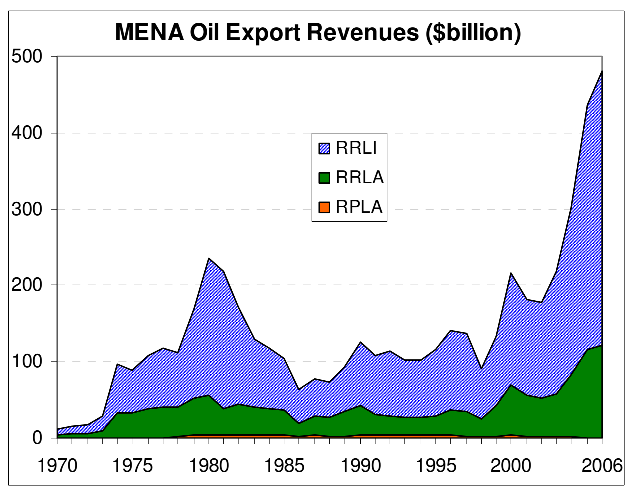


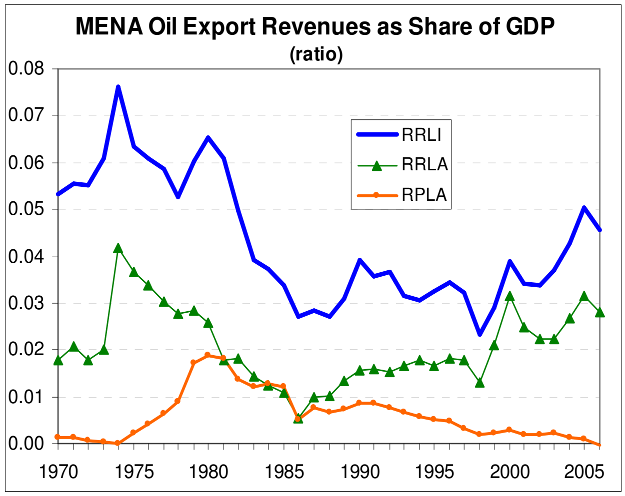
Figure A1.57 MENA Oil Export Revenues, 1970-2006



Source: IEA, OPEC, World Bank.

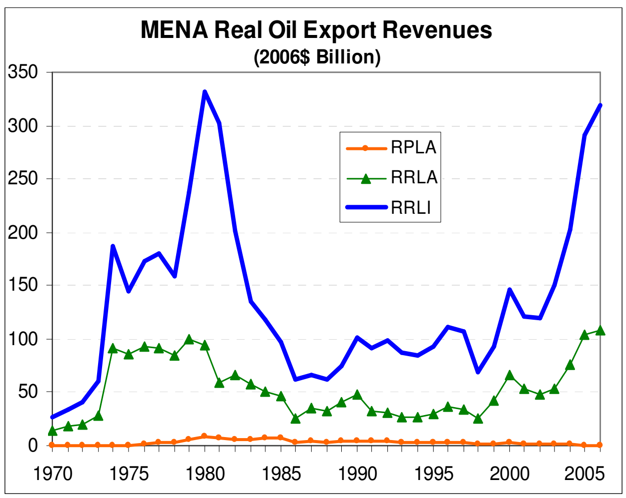
[67] Revenues for OPEC oil producers are from the OPEC Secretariat, and revenues for non-OPEC MENA countries are calculated using production and consumption data, and the World Bank average oil price. These revenue data should taken as approximate.

Figure A1.58 MENA Oil Export Revenues as Share of GDP, 1970-2006



Source: IEA, OPEC, World Bank.

Figure A1.59 MENA Real Oil Export Revenues. 1970-2006



Source: IEA, OPEC, World Bank.

In real terms, oil revenues in 2006 returned to near the former peak levels in 1980, even though average real oil prices were more than $10/bbl (constant 200$) below the 1980 peak. Revenues for the RRLI group were just shy of the former peak, as oil exports returned above 1980 levels, including significantly higher export levels in Oman, Qatar, and the UAE, while other country's exports were somewhat lower. In the RRLA countries, real oil revenues were slightly above the former peak, as production expanded significantly in Algeria, and as Iran's production exports partly recovered, although these were offset by significantly lower exports from Iraq. The RPLA countries (which is essentially Egypt), have fallen back toward zero, as Egyptian production and exports continue to slide.

Oil revenues as a share of GDP, have risen recently to more than one-third for total MENA. The share of oil revenues for the RRLI countries has risen to near 50 percent of nominal

GDP, with Libya at two-thirds and Saudi Arabia at one-third. Oil revenues are a smaller share of GDP in the RRLA countries, with most countries below one-third.

Oil revenues per capita (excluding Iraq and Libya) are only slightly above the 1980 peak in current dollars, as population levels have nearly doubled over the period. In real terms, however, per capita revenues were little more than half the former peak, although real incomes were well above former highs, having risen by almost 2 percent p.a. since the trough in 1987 (and real income growth has accelerated in recent years).

Figure A1.60 MENA Per Capita Oil Revenue and GDP (except Iraq Libya), 1970-2006

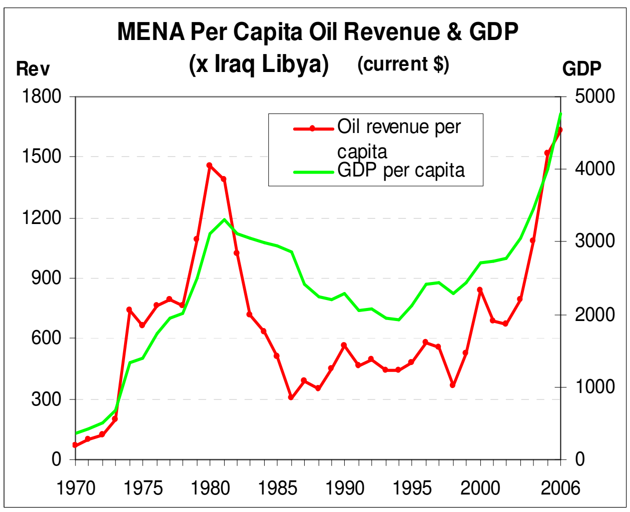
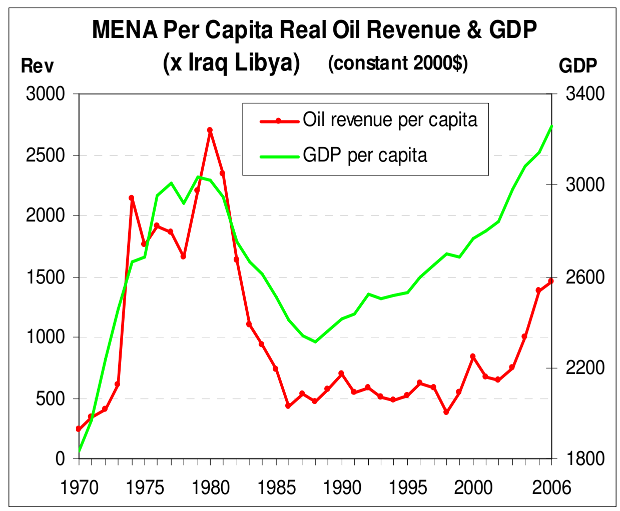


Figure A1.61 MENA Per Capita Real Oil Revenue and GDP (except Iraq and Libya), 1970-2006



Source: IEA, OPEC, World Bank.

In the **RRLI** countries (excluding Libya), where population is two-and-a-half times higher, nominal per capita oil revenues in 2006 were more than 20 percent lower than in 1980, and real per capita revenues were little more than one-third the 1980s peak. Real per capita incomes grew by less than 1 percent since the late-1980s, although they have been accelerating in recent years along with surge in oil prices.

In the **RRLA** countries (excluding Iraq), where the population has not quite doubled since 1980, nominal per capita oil revenues are more than 20 percent above the former peak, but in real terms were only about 50 percent of the peak in the mid-1970s. Meanwhile per capita incomes have risen by about 2 percent p.a., although they have been accelerating in recent years, and is nearing the former peak of the 1970s. See Annex 2 for country detail on oil revenues, and per capita revenues and incomes, for the three groups.

5. LONG-TERM OUTLOOK FOR OIL AND GAS PRODUCTION

5.1 Oil

In the IEA *World Energy Outlook (WEO) 2006*, OPEC total oil production is expected to rise rapidly after 2010, reaching to 56 mb/d in 2030 (this includes increases in NGLs, and non-conventional output in Venezuela). OPEC *crude* oil production is projected to reach 46 mb/d in 2030, up two-thirds from the 2005 level. The OPEC Middle East is expected to account for more than 80 percent or 14 mb/d of the OPEC growth in crude oil output, and reach 35 mb/d in 2030. MENA's total oil production (crude, NGLs, and non-conventional) is estimated to rise from 27 mb/d in 2005 to 44 mb/d in 2030, an increase of 2 percent per year. The forecast is predicated on real oil prices averaging around \$50/bbl (2005 dollars), reaching \$55/bbl in 2030. The IEA cautions that the projections are not a forecast, but rather a baseline scenario if government policies to affect long-term energy trends do not change. See Annex for detailed tables on the IEA's oil demand and supply projections.

Table A1.2 IEA World Oil Demand and Supply Projections, 2005-2030 (mb/d)

	2005	2010	2015	2030	2005-30 (% p.a.)
Demand					
OECD	47.7	49.8	52.4	55.1	0.6
Transition economies	4.3	4.7	5.0	5.7	1.1
Developing countries	28.0	33.0	37.9	51.3	2.5
World Demand	**83.6**	**91.3**	**99.3**	**116.3**	**1.3**
Supply					
OECD	15.2	13.8	12.4	9.7	-1.8
Transition economies	11.4	13.7	14.5	16.4	1.5
Developing countries	15.1	17.9	18.5	17.4	0.6
Natural Gas Liquids (NGLs)	5.1	5.5	5.8	6.8	1.2
Nonconventional oil	1.4	2.5	3.7	7.4	7.0
Total Non-OPEC	**48.1**	**53.4**	**55.0**	**57.6**	**0.7**
Middle East OPEC	20.7	22.0	25.7	34.5	2.1
Other OPEC	8.4	8.2	9.1	11.2	1.2
OPEC NGLs	4.3	5.4	6.3	9.0	3.0
OPEC Nonconventional	0.2	0.3	0.8	1.5	8.8
Total OPEC	**33.6**	**35.9**	**42.0**	**56.3**	**2.1**
Processing Gains	1.9	2.0	2.3	2.5	1.2
World Supply	**83.6**	**91.3**	**99.3**	**116.3**	**1.3**
MENA Total (est. World Bank)	*26.7*	*28.7*	*33.1*	*43.7*	*2.0*

Source: IEA, 2006.

The IEA projects world oil demand to continue increasing moderately, at an average rate of 1.3 percent over the period, reaching 116 mb/d in 2030. Total non-OPEC oil supplies are projected to increase by less than 1 percent per year, and all of the net growth is expected in the form of

NGLs and nonconventional oils. Non-OPEC *crude* oil production is expected to peak around 2010 and then decline, with the sharpest decrease after 2015. Most of the decline will be in mature OECD oil producing regions, partly offset by fairly strong growth in the Transition economies. OPEC is expected to fill the growing gap between demand and supply, with the demand for OPEC crude rising by 2 percent per year over the forecast period.

There are a number of risks with this (and other) scenarios of future oil supplies and demand. For more than two decades, OPEC production has been forecast to increase rapidly in the not-too-distant future, mainly because of expected relentless declines in non-OPEC production—but so far this has not happened. Rather non-OPEC production continues to increase. Between 1971 and 2006, non-OPEC supplies (excluding the FSU) grew by 0.6 mb/d or 2.2 percent per year, capturing well over half of the growth in world oil demand. In recent years, non-OPEC supply outside the FSU has been extremely weak, while much of the growth has been from the Transition economies. Still, since 2000 total non-OPEC supplies have increased by 0.8 mb/d or 1.7 percent p.a. Moreover, non-OPEC supplies outside the Transition economies are now rising once again. Meanwhile OPEC production is only approaching its former peak of more than 20 years ago. Between 1990 and 2005 its crude oil production rose from 23.0 mb/d to just under 30.0 mb/d, an annual increase of less than 0.5 mb/d.

The IEA projects non-OPEC supply to grow at a rate if 2.1 percent between 2005 and 2010, before slowing to just 0.4 percent from 2010-2030. Should non-OPEC supplies beyond 2010 increase at the same rate of growth as during 1995-2006 (1.6 percent), the demand for OPEC crude oil would barely grow over the forecast period, and its share of global oil supply would fall from about one-third to one-quarter. This may or may not occur, but the forecast for the demand for OPEC oil is very sensitive to non-OPEC supply assumptions. To its credit, the IEA has significantly increased its non-OPEC supply projections from previoU.S.reports (for 2020 it raised non-OPEC supply from 46 mb/d in its 2000 *World Energy Outlook*, to 56 mb/d currently). However, as has been the case in all of the past projections, the projected decline in non-OPEC *crude* oil production and the slowdown in total non-OPEC supply continue to be pushed further into the future.

At present, there is growing pessimism about future non-OPEC supply growth, owing to the lack of access to much of the world's oil reserves by major international companies, increasing costs, and depletion. Some analysts suggest an imminent peaking of non-OPEC supplies. While there may be a peak in future due to the difficulty finding new supplies (the peak could also be due to lack of demand growth because of environmental constraints and technological advances), that would entail a systematic rise in costs. The recent rise in costs is largely due to capacity constraints for labor, materials and services (which has been partly fueled by high oil revenues and higher demand for these inputs), and are not due to increasing difficulty extracting a barrel of oil from the earth.[68] The inflationary rise in costs is similar to the "boom" in the late-1970s/early-1980s, that was also precipitated by burgeoning oil revenues. In principle, a large portion of the higher costs for equipment and materials could reverse once sufficient capacity comes on-stream. Such decrease along with on-going technological advances would lead to lower development costs.

[68] While companies are developing reserves in harsher and more expensive environments, e.g., deep water, they are also finding larger reserves.

There is also a fair bit of uncertainty about oil demand when looking 20-30 years ahead. The IEA has revised its projections of world oil demand downward in recent years. Its projection of world oil demand for 2020 has fallen from 115 mb/d in the *WEO-2000* to 105 mb/d in *WEO-2006*, and the current projection for 2030 is now 116 mb/d. It has slowed projected growth in world oil demand for 2015-2030 to just 1.1 percent p.a., and this compares with growth of 1.7 percent over the 1985-2006 period. As most of the growth in global oil demand is expected to be in developing countries, there is the possibility of stronger-than-projected growth over the next couple of decades from China and India, as well as other developing countries. World oil demand could conceivably be higher than presented by the IEA. However, oil demand growth could also be curbed in both the high-income and developing countries because of environmental constraints, the effects of high prices, improved efficiency, and development of new technologies and alternative fuels. While new technologies may have long lead-times to take affect, for example, to change the capital stock and infrastructure for alternative fuels and vehicles, the changes could be "permanent", and result in lower oil consumption in future. World oil demand has grown only moderately the past twenty years—in large part due to upheavals in oil prices of the 1970s and 1980s, and is likely to grow only moderately in future. Any determined effort to reduce oil demand further would directly affect MENA oil producer volumes, and possibly oil prices as well.

Table A1.3 World Oil Projections by U.S. EIA and Petroleum Economics Limited (mb/d)

U.S. EIA	**2010**	**2015**	**2020**	**2025**	**2030**	**2010-30***
Demand	91.6	98.3	104.1	110.7	118.0	1.3
Non-OPEC Capacity	54.4	58.8	63.7	68.2	72.6	1.5
OPEC Capacity	39.9	42.8	43.9	46.7	50.7	1.2
Surpls OPEC	2.7	3.3	3.5	4.2	5.3	3.4
PEL	**2010**	**2015**	**2020**	**2025**		**2010-05***
Demand	90.86	97.6	103.1	106.33		1.1
Non-OPEC	52.1	51.4	49.7	47.8		-0.6
OPEC	34.7	40.8	46.3	49.4		2.4
Processing Gain	2.3	2.6	2.9	3.2		2.2

Sources: U.S. Energy Information Agency, International Energy Outlook 2006. Petroleum Economics Limited, Outlook for World Energy, 2006.

The U.S. Energy Information Agency (EIA) projects similar oil demand growth as the IEA, but Petroleum Economics Limited (PEL) projects slightly slower growth at 1.1 percent.[69] PEL is most pessimistic on non-OPEC supply, with total non-OPEC supply declining after 2010. They project growth only in the FSU while output in the OECD and "other" regions decline. The EIA, on the other hand, projects relatively strong growth of non-OPEC supplies, rising at 1.5 percent p.a. It has OECD supply increasing modestly, while other non-OPEC output grows at more than 2 percent p.a. in both the FSU and "other" regions. These differences significantly affect the

[69] U.S.EIA and PEL oil prices assumptions similar to IEA.

residual demand for OPEC oil. The EIA projects 51 mb/d of total OPEC capacity in 2030, but projects the demand for OPEC oil (including NGLs and nonconventional) at little more than 45 mb/d (compared with 56 mb/d for the IEA). PEL has the demand for OPEC at nearly 50 mb/d already in 2025 largely due to its more pessimistic projections of non-OPEC supply (PEL did not have projections for 2030).

The outlook for the demand for MENA oil is quite uncertain, because of the uncertainty of future global oil consumption and development of competing supplies. Oil consumption could be higher or lower, depending on the pace of demand in China and India, as well as the affects of high prices, environmental constraints, and new technologies. Given long-lead times of implementing new technologies, the greater negative impact on oil demand may well be beyond 2030, but introduction of policies to seriously reduce oil demand could be felt during the current forecast period as well. MENA producers should be prepared for smaller growth in oil demand in future, and possible long-term secular decline in oil consumption from policy initiatives and technological advances. They should also not dismiss the potential longer-term affects of high oil prices on oil demand, even though there were statements by some oil producers and analysts that the global economy and oil demand appeared to be relatively unaffected by the recent surge in high oil prices. However, one can never directly observe an economic impact—this can only be calculated, for example, with econometric techniques, counter-factual analysis, and so on. High prices have clearly had some impact on demand as prices have moved up the demand curve—even if demand is quite inelastic.

On the supply side, total non-OPEC oil is widely expected to continue increasing in the medium term, although some suggest that the global oil supplies will peak sometime soon after 2010. Similar dire projections have occurred for the past 30 years, but non-OPEC supplies have steadily increased (although there have been shifts among countries, with declines commencing in some regions, but these have been more than offset by increases in other areas). It is striking that claims of "the world is running out of oil" are most pronounced when oil prices are high, as potential oil supply is greater when oil prices are high than when they are low (assuming no change to real costs). While it is possible that conventional crude oil production could peak in the coming years, there are large resources of non-conventional supplies that can enter the supply chain, for example, oil sands in Canada, heavy oil, oil shale, gas-to-liquids, coal-to-liquids, and biofuels. There is also vast potential of conventional oil in the deepwater offshore, where water-depth records continue to be set. While development and operating costs for all of these sources are much higher than conventional oil extraction, high oil prices bring non-economic sources closer to the threshold of being profitable, and more importantly encourages additional research to reduce costs and bring new hydrocarbon sources into production. MENA oil producers should be prepared for potential steady gains in competing supplies, and potential advances in technologies that bring forth additional supplies of non-conventional hydrocarbon liquids.

Finally, MENA producers should not overreach with regard to oil prices, which can unleash powerful economic forces to reduce oil demand and to develop conventional and alternative supplies. ConsensU.S.forecasts suggest that the demand for MENA oil will continue to rise in future, and that higher oil prices are sustainable. However, such trends are not guaranteed. MENA producers should be prepared for a world that sees both lower and higher demand for its oil. Should demand for their oil be lower than anticipated, surplU.S.capacity could grow, as all large MENA producers are adding new capacity. This potentially could exert significant downward pressure on oil prices. Oil producers may even prefer lower prices to help stimulate, or preserve demand for their oil. In the case of higher demand for its oil, producers will likely continue to seek an acceptable trade-off between oil revenues and investment in new capacity. However, over-reaching decisions taken on prices can significantly impact both global oil demand and development of competing supplies.

5.2 Natural Gas

Global natural gas demand is expected to increase the most rapidly among primary fuels, rising by 2 percent per year to 2030, according to the IEA. More than half of the growth is expected in developing countries, rising by 3.7 percent p.a. The fastest rates of growth are expected in China and India, followed by Africa and the Middle East, at 4.1 percent and 3.7 percent, respectively. (See Annex 2 for details.) In most regions, the increase in gas production generally reflects the relative size of reserves and their proximity to the main markets. The geographical mismatch between resource endowment and demand means that the main gas-producing regions will become increasingly dependent on imports.

Production is expected to grow most in volume terms in the Middle East and Africa, and most of the incremental output will be exported, mainly to Europe and North America. LNG accounts for almost 70 percent of the increase in interregional trade, and this is expected to open up the opportunities for arbitrage, leading to a degree of convergence of regional gas prices. New export pipeline capacity will also boost exports from North Africa to Europe. The Middle East and Africa account for 72 percent of the increase in global gas exports over the forecast period. Middle East gas exports are projected to rise from 40 billion cubic meters (bcm) in 2004 to 232 bcm in 2030. Qatar will record the largest growth, rising to more than 150 bcm by 2030. It is expected to surpass Algeria as MENA's largest gas producer by 2010. Iran will emerge as a significant gas exporter, and to a lesser extent Libya and Iraq. Egypt, which began exporting LNG in 2005, will also see its exports rise markedly. Nevertheless, a small number of countries are expected to provide the bulk of the gas to be exported this region, mainly as LNG, and there is some uncertainty (as expressed by the IEA), as to whether the high rates of increase are achievable from this and other developing country regions, in light of institutional, financial, and geopolitical factors and constraints.

Gas-to-liquids (GTL) plants are expected to emerge as a significant market for gas. Global GTL demand for gas is projected to increase from 8 bcm in 2004 to 29 bcm in 2010, and to 199 bcm in 2030. Recent high oil prices have made GTL a more attractive option form of monetizing stranded natural gas reserves. In 2006, a new 34,000 b/d plant called Oryx was commissioned in Qatar, built by Qatar Petroleum (QP) and Sasol. This doubled existing global capacity, which consisted of two small plants in South Africa and Malaysia. Most of the gas used by GTL is for the conversion process, which is extremely energy intensive. The long-term rate of growth in GTL production will hinge on reduced production costs, lower energy intensity, the ratio of gas-to-oil prices, the premium available for high-quality GTL fuels over conventional products, and the economics of LNG which compete with GTL for use of available gas.

There will also be increasing gas trade between MENA countries, as several countries in the region face a growing deficit in indigenoU.S.gas supplies and need to import gas to meet power generation and other gas needs. The Dolphin Project, which will be commissioned in 2007, will supply piped gas from Qatar to the UAE and Oman. Kuwait is also expecting to import gas from neighboring countries. In North Africa, Algeria is expected to expand exports to Tunisia, and Egypt plans to ship piped gas to Israel, either on land or subsea. There are also plans to expand the Arab gasline—which runs from Egypt to Jordan—to Syria and Lebanon and, possibly Turkey.

The IEA estimates that to realize these projections, MENA needs to invest a cumulative $436 billion (2000 dollars) over the 2004-30 period, or $16 billion per year. Over 60 percent will be needed in the upstream sector, and the rest will go to liquefaction plants, transmission and distribution networks, and storage facilities. Qatar, where production will grow the most, will have by far the largest investment needs, at $100 billion—about 2/3 for upstream development, including processing.

6. MENA Near-Term Oil Development Plans (OPEC Producers)

6.1 Development plans

In the longer-term projections presented above, it is assumed OPEC producers will invest in the necessary capacity as required by the market. But this would partly depend on OPEC's policy on pricing and production, as they may seek higher prices and forgo some portion of investment in new capacity. At present, all MENA producers are developing new capacity, and have plans to continue to increase investment in their oil sectors over the medium term. The largest producer, Saudi Arabia, is planning to reach 12 mb/d by 2009, and states that it will continue to invest to ensure surplU.S.capacity of 1.5-2.0 mb/d.

Table A1.4 Crude Oil Production Capacity (tb/d)

	2005	2006	2007	2008	2009	2010
Algeria	1,285	1,335	1,365	1,400	1,555	1,665
Iran	4,070	3,995	3,975	4,025	4,025	3,975
Kuwait	2,610	2,610	2,700	2,850	2,850	2,950
Libya	1,670	1,820	1,850	1,850	1,850	1,875
Qatar	825	825	925	925	925	970
Saudi Arabia	11,050	11,075	11,375	11,375	11,700	11,900
United Arab Emirates	2,455	2,555	2,625	2,675	2,700	2,760
Total	**10,460**	**10,585**	**10,815**	**11,050**	**11,205**	**11,435**

Source: Petroleum Economics Limited.

MENA's OPEC producers (excluding Iraq) have development projects underway that will raise net production capacity by nearly 1 mb/d from 10.5 mb/d in 2005 to 11.4 mb/d by 2010. This includes replacement of declines in existing capacity, which are particularly large in the case of

Iran. Annex 2 presents detailed volume estimates (from PEL) for each of the 7 MENA countries presented below, regarding existing capacity and new developments. All countries are expected to raise total capacity by 2010, with the exception of Iran because of declines in existing capacity. However, all countries, including Iran, have the potential to significantly raise capacity beyond 2010, with PEL projecting that the 7 producers excluding Iraq reach 13 mb/d by 2015.

Algeria's biggest challenge is redeveloping the massive Hassi Messaoud field which contains over 6 billion bbls and accounts for more than 60 percent of the country's proven reserves. Rising production is only available using secondary recovery techniques. Large participation of foreign oil companies in the upstream sector has expanded capacity in recent years, and continued investment whould help the country to steadily raise production to 2010 and beyond.

Iran's major problem is that many of its large fields have been producing for several decades and are facing declining reservoir pressures. Massive gas injection schemes planned over the past few years should result in a rebound before a natural decline reasserts itself. Despite this, existing capacity is expected to decline by 1 mb/d by 2010, and will be nearly offset by new field developments. Sustaining 4 mb/d capacity will be difficult unless negotiations and perhaps more favorable terms are put in place with foreign oil companies. Threats of further sanctions and military action regarding the country's nuclear program may make it difficult to boost foreign interest in the upstream sector. However, sufficient investment could raise production above 4 mb/d beyond 2010.

Kuwait's production has approached capacity recently, and there is now greater urgency to develop its resources in the north. Capacity is expected to reach nearly 3 mb/d by 2010, largely due to expansions at the Greater Burgan field. The timing of capacity additions in northern fields depends crucially on when Project Kuwait is completed. Under the project, the country is considering permitting foreign companies to invest in the upstream sector, in order to raise production to 5 mb/d by 2020.

Libya's prospects for the upstream sector have improved dramatically since the lifting of sanctions in 2004 and the restoration of U.S. diplomatic relations with the country. Libya has the largest proven reserves in North Africa, and has substantial undiscovered resources. On January 30, 2005, Libya held its first round of oil and gas exploration leases (known as EPSA 4) following the lifting of sanctions, which offered 15 exploration blocks for auction. It proved to be an intensely competitive round with 9 blocks being awarded to Occidental Petroleum, and other blocks being granted to other companies. Subsequent and future auctions are expected to raise capacity by 1.9 mb/d by 2010, and restore output to its previoU.S.peak of more than 3 mb/d in the coming 2 decades.

Qatar has placed much greater emphasis on raising production within a joint venture structure involving foreign oil companies. The most important increase has been expansion of the Al-Shaheen field, which recently doubled to 0.2 mb/d, but further expansion there and in other fields will raise output to 1 mb/d by 2010, and should continue to rise steadily thereafter.

Saudi Arabia's main task is to keep its biggest field, Ghawar, flowing at about 4 mb/d. A number of new fields are producing well below their potential capacity, especially those containing heavy crude. Although new volumes of light crude have been brought on stream in recent years, overall production has not increased as heavier crudes have been shut-in. Significant volumes are expected on stream this decade, with expansion from the Khursaniyah, Fadhill, and Abu Hadriyah fields due to commence production in 2007. The next major set of expansions in Saudi capacity is expected to occur after 2010. With massive reserves, the country has the potential to increase capacity significantly (see case study).

The UAE is expected to raise capacity to 2.8 mb/d in 2010, in part due to expansion at the Upper Zakum field with ExxonMobil. The field has a challenging geological structure, and the company will introduce enhanced recovery techniques to raise output from the field. The UAE could raise its oil production rapidly, but only at the cost of extensive and costly gas flaring of associated gas. However, there remain significant reserves within foreign oil partners' existing acreage, many of which are planned to be developed. Despite declines in more mature upstream assets, new capacity and enhanced development are expected to more than exceed these decreases.

Investment requirements. In 2005, the IEA estimated that MENA's oil sector (crude oil production and refining) would require investment of $614 billion (2004 dollars) to 2030. Exploration and production account for about three-quarters of total investment, and annual investment would rise from $16 billion in the current decade to $28 billion in the last decade, reflecting much higher demand for OPEC output. The IEA estimates that this would amount to 6 percent of projected oil revenues and about 1 percent of gross domestic product (GDP) over the projection period. MENA countries have the lowest total production costs in the world, typically averaging between $3 and $5 per bbl of oil produced.[70] Thus, financing should not pose a problem to expansion of output in most countries. Most of the investment is expected to be financed out of internal cash flows of national and international companies operating in the region.

The IEA estimate of investment needs in its WEO-2005 was based on MENA oil production rising to 50 mb/d in 2030. However in its 2006 outlook, the demand for OPEC oil has been downgraded to about 44 mb/d, and thU.S.investment needs would be correspondingly lower. However, this adjustment again highlights the uncertainty of future oil supply requirements.

6.2 National Oil Companies

NOCs dominate the region's petroleum industry, and are likely to continue to be responsible for most of the investment in MENA's upstream sector over the forecast period. The region's 11 NOCs rank among the top 35 oil and gas companies, with Saudi Arabia's Aramco and Iran's National Iranain oil Company (NIOC) ranking number one and three, respectively, overall.[71] (See Annex 2 for all Top 40 companies.) These two companies are the world's largest petroleum

[70] International Energy Agency, *World Energy Outlook 2005, Middle East and North Africa Insights*, p. 133.
[71] The overall PIW rankings use other indicators not shown below, such as oil and gas reserves, refining, employees, sales and assets. Revenue figures are not always comparable due to differing accounting practices and definitions.

liquids producers, with Kuwait's Kuwait Petroleum Company (KPC) number five. Iran's NIOC is also the fourth largest gas producer, and Algeria's Sonatrach is the sixth.

Table A1.5 Ranking of MENA's Top Oil and Gas Companies by Selected Indicators

Rank	Company	Country	State Owned %	Rank	Liquids Output (kb/d)	Rank	Gas Output (mmcf/d)	Rank	Revenues $ million
1	Saudi Aramco	Saudi Arabia	100	1	11,035	7	6,721	5	180,000
2	Exxon Mobil	U.S.		7	2,523	2	9,251	1	338,992
3	NIOC	Iran	100	2	4,049	4	8,414	22	45,500
4	Petroleos de Venezuela	Venezuela	100	4	2,650	18	2,795	11	85,700
5	British Petroleum	UK		6	2,562	3	8,424	3	251,003
6	Royal Dutch Shell	UK/ Netherlands		9	2,093	5	8,263	2	306,731
7	PetroChina	China	90	8	2,270	12	3,681	13	67,427
8	Chevron	U.S.		14	1,701	10	4,233	4	189,481
9	Total	France		15	1,621	9	4,780	7	151,902
10	Pemex	Mexico	100	3	3,710	13	3,575	10	87,262
11	ConocoPhillips	U.S.		19	1,447	15	3,337	6	166,327
12	Sonatrach	Algeria	100	10	1,934	6	8,152	24	41,200
13	KPC	Kuwait	100	5	2,643	43	938	25	40,250
17	Adnoc	UAE	100	16	1,601	19	2,623	38	22,750
22	Libya NOC	Libya	100	19	1,447	39	962	35	24,500
23	INOC	Iraq	100	12	1,820	78	256	50	15,700
24	EGPC	Egypt	100	41	348	27	1,678	74	7,850
25	QP	Qatar	100	23	1,097	17	3,029	44	19,900
34	SPC	Syria	100	36	469	62	522	76	7,650
35	PDO	Oman	60	37	437	41	948	67	9,900

Source: Energy Intelligence Group. *Petroleum Intelligence Weekly*, December 18, 2006.
Note: MENA countries are shown in blue.

ANNEX 2: STATISTICS ON MENA OIL AND GAS RESERVES, PRODUCTION, CONSUMPTION AND REVENUES

Table A2.1 MENA Oil: Proved Reserves (billion barrels) and Production (thousand b/d)

	Reserves end 2006 (Bbbl)	Share of total (%)	Production 2006 (tb/d)	Share of total (%)	Reserves to Production (R/P) ratio
Iran	137.5	11.4	4,243	5.4	86.7
Iraq	115.0	9.5	1,999	2.5	*
Kuwait	101.5	8.4	2,704	3.4	*
Oman	5.6	0.5	743	0.9	20.5
Qatar	15.2	1.3	1,133	1.3	36.8
Saudi Arabia	264.3	21.9	10,859	13.1	66.7
Syria	3.0	0.2	417	0.5	19.7
UAE	97.8	8.1	2,969	3.5	90.2
Yemen	2.9	0.2	390	0.5	20.0
Other M. East	0.1	0.0	32	0.0	6.6
Middle East	**742.7**	**61.5**	**25,589**	**31.2**	**79.5**
Algeria	12.3	1.0	2,005	2.2	16.8
Egypt	3.7	0.3	678	0.8	15.0
Libya	41.5	3.4	1,835	2.2	61.9
Tunisia	0.7	0.1	69	0.1	27.5
North Africa	**58.1**	**4.8**	**4,586**	**5.6**	**34.7**
MENA	***800.9***	***66.3***	***30,175***	***37.0***	***72.7***
WORLD	**1208.2**	**100.0**	**81,663**	**100.0**	**40.5**
OECD	*79.8*	*6.6*	*19,398*	*23.3*	*11.3*
OPEC	*905.5*	*74.9*	*34,202*	*41.7*	*72.5*
Non-OPEC	*174.5*	*14.4*	*35,162*	*43.0*	*13.6*
FSU	*128.2*	*10.6*	*12,299*	*15.3*	*28.6*

Table A2.2 MENA Natural Gas: Proved Reserves (tcm) and Production (bcm)

	Reserves end 2006 (tcm)	Share of total (%)	Production 2006 (bcm)	Share of total (%)	R/P ratio
Bahrain	0.09	0.0	11.1	0.4	8.1
Iran	28.13	15.5	105.0	3.7	*
Iraq	3.17	1.7	n/a	n/a	*
Kuwait	1.78	1.0	12.9	0.4	*
Oman	0.98	0.5	25.1	0.9	39.0
Qatar	25.36	14.0	49.5	1.7	*
Saudi Arabia	7.07	3.9	73.7	2.6	96.0
Syria	0.29	0.2	5.5	0.2	52.3
UAE	6.06	3.3	47.4	1.6	*
Yemen	0.49	0.3	n/a	n/a	*
Other M. East	0.05	0.0	5.6	0.2	9.0
Middle East	**73.47**	**40.5**	**335.9**	**11.7**	*****
Algeria	4.50	2.5	84.5	2.9	53.3
Egypt	1.94	1.1	44.8	1.6	43.3
Libya	1.32	0.7	14.8	0.5	88.9
North Africa	**7.76**	**4.3**	**144.0**	**5.0**	**53.9**
MENA	***81.23***	***44.8***	***479.9***	***16.7***	*****
WORLD	**181.46**	**100.0**	**2865.3**	**100.0**	**63.3**
OECD	*15.90*	*8.8*	*1078.5*	*37.8*	*14.7*
FSU	*58.11*	*32.0*	*779.3*	*27.1*	*74.6*

* More than 100 years; + Less than 0.05; Less than 0.05%; # Excludes Former Soviet Union (FSU); n/a not available.

R/P : reserves to production ratio. Tb/d: thousand barrels per day. Tcm: trillion cubic metres. bcm: billion cubic metres.

Source: BP Statistical Review of World Energy, June 2007

MENA Primary Energy Production

Figure A2.1 RRLI Primary Energy Production, 1971-2004

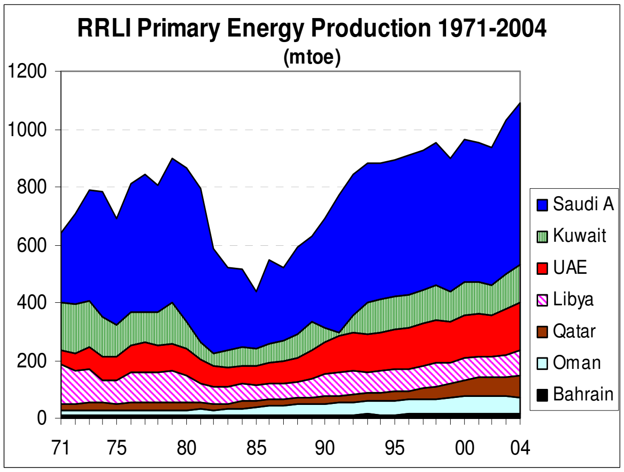


Figure A2.2 Growth of RRLI Primary Energy Production, 1985-2004

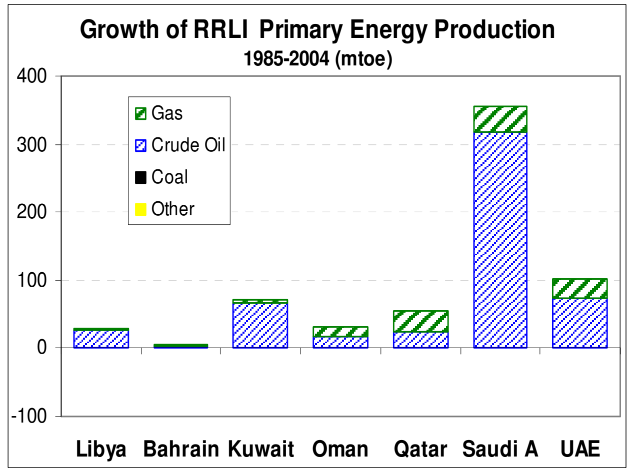


Figure A2.3 RRLA Primary Energy Production, 1971-2004

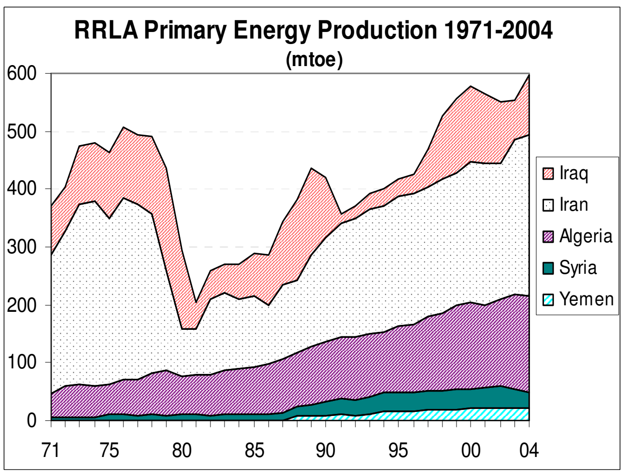


Figure A2.4 Growth of RRLA Primary Energy Production, 1985-2004

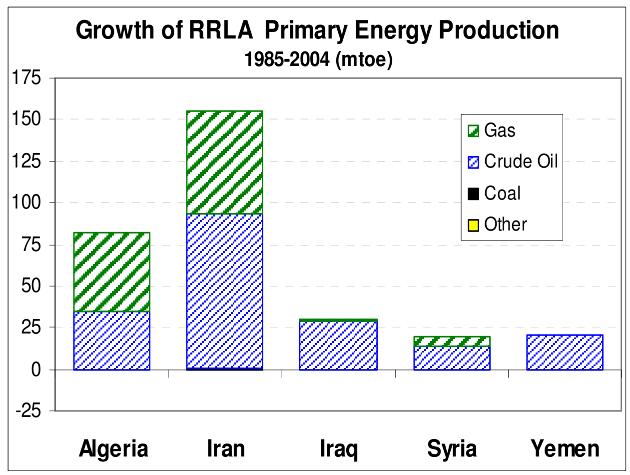


Figure A2.5 RPLA Primary Energy Production, 1971-2004

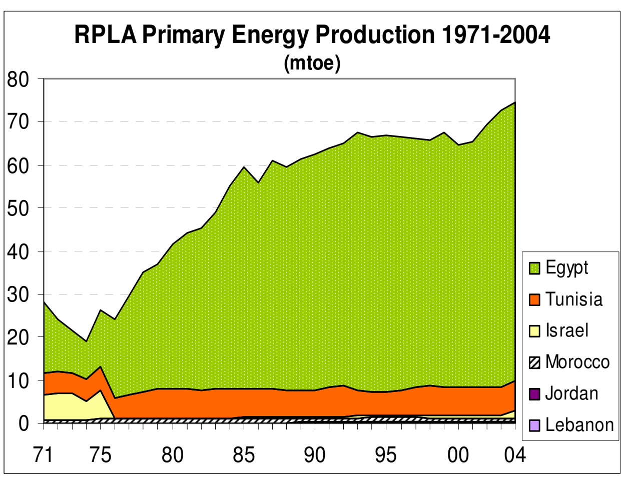
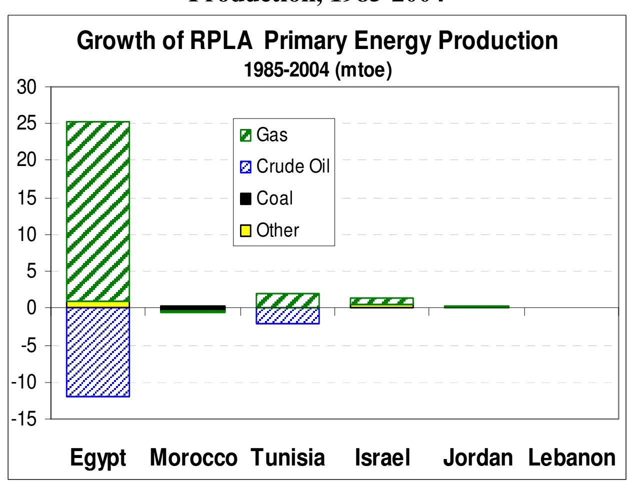


Figure A2.6 Growth of RPLA Primary Energy Production, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006.

MENA Crude Oil Production

Figure A2.7 RRLI Crude Oil Production, 1971-2004

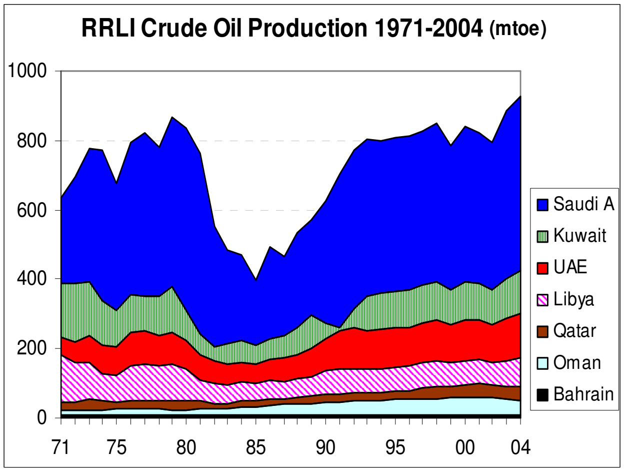


Figure A2.8 Growth of RRLI Crude Oil Production, 1985-2004

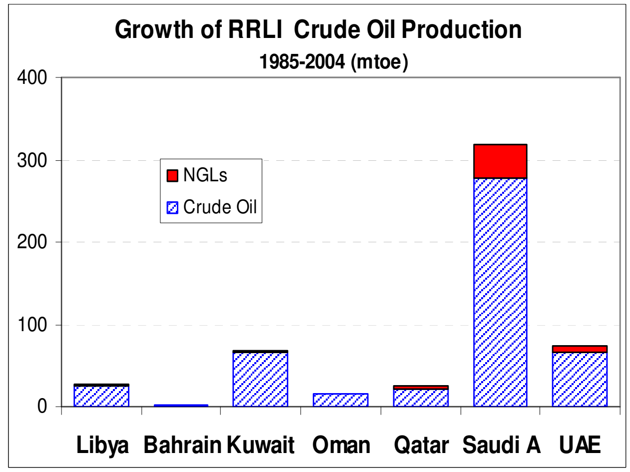


Figure A2.9 RRLA Crude Oil Production, 1971-2004

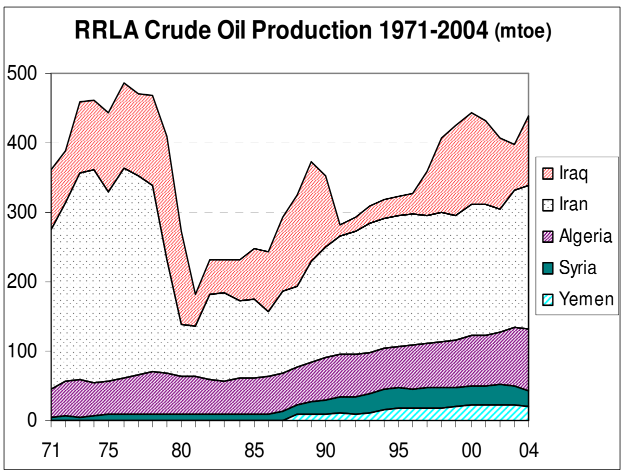


Figure A2.10 Growth of RRLA Primary Energy Production, 1985-2004

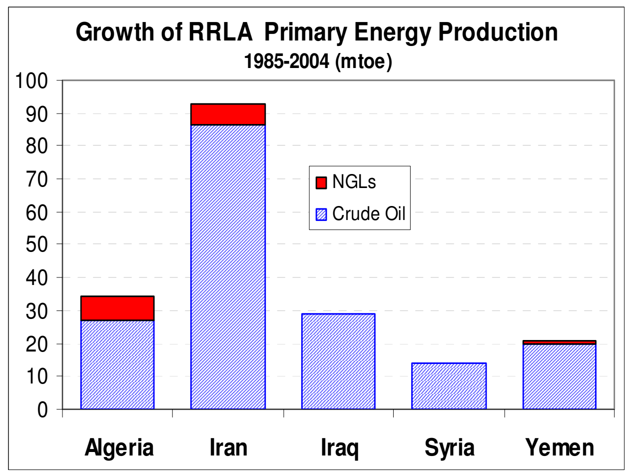


Figure A2.11 RPLA Crude Oil Production, 1971-2004

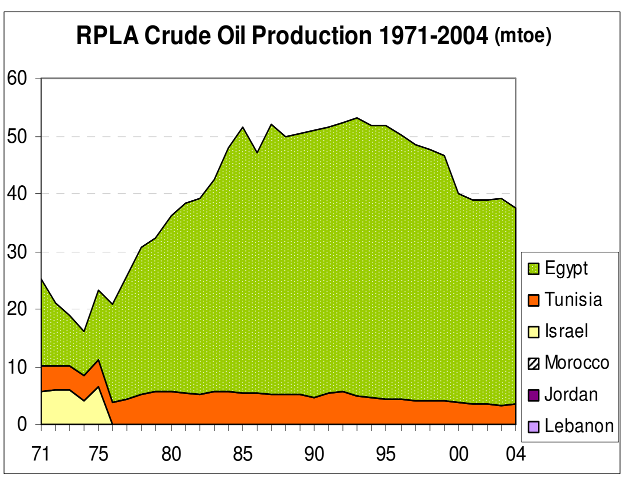
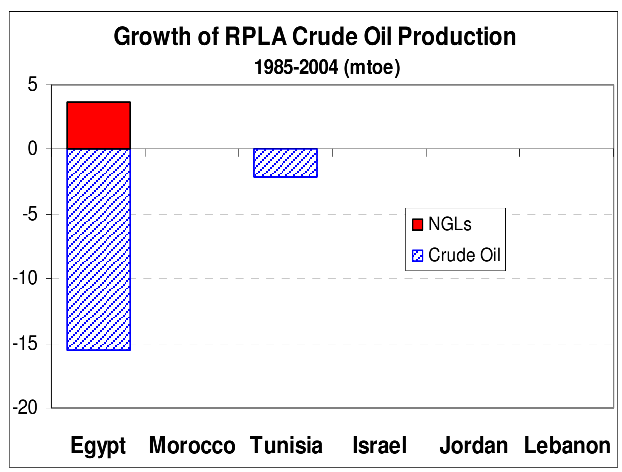


Figure A2.12 Growth of RPLA Crude Oil Production, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006.

MENA Natural Gas Production

Figure A2.13 RRLI Natural Gas Production, 1971-2004

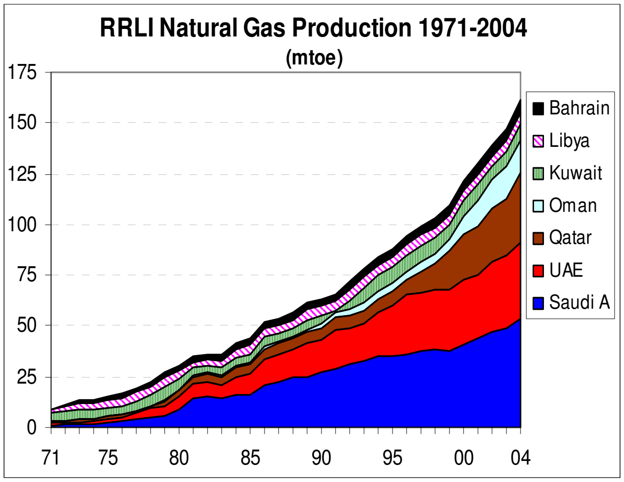


Figure A2.14 Growth of RRLI Natural Gas Production, 1985-2004

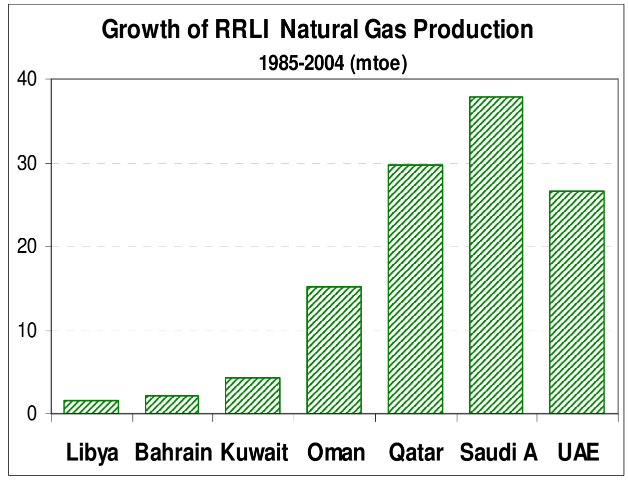


Figure A2.15 RRLA Natural Gas Production, 1971-2004

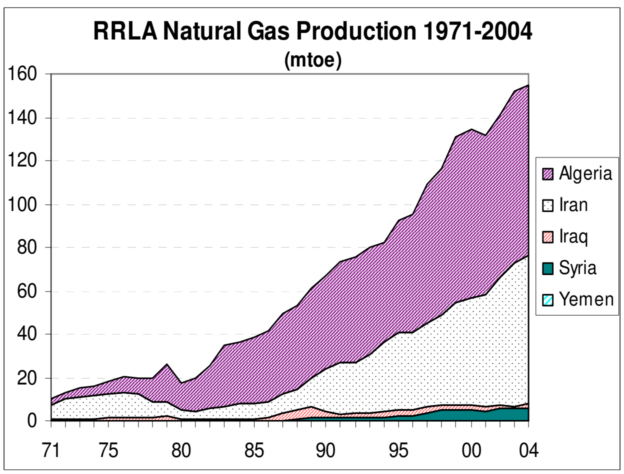


Figure A2.16 Growth of RRLA Natural Gas Production, 1985-2004

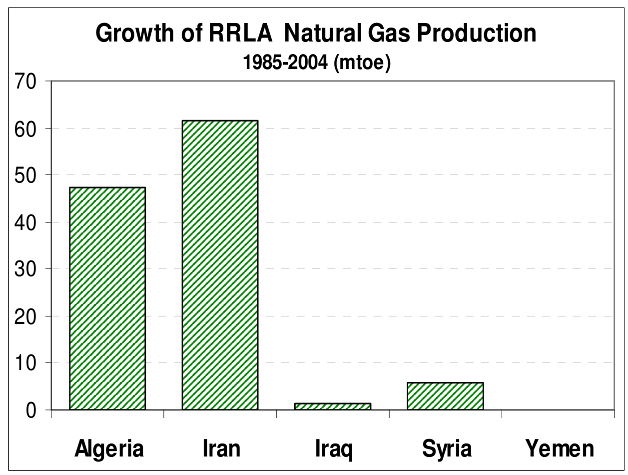


Figure A2.17 RPLA Natural Gas Production, 1971-2004

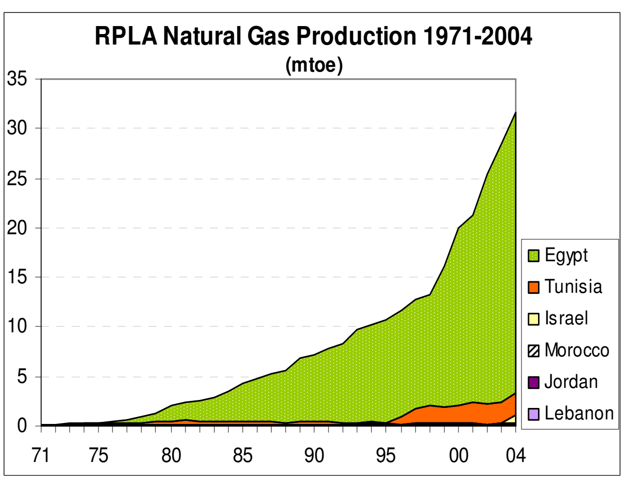
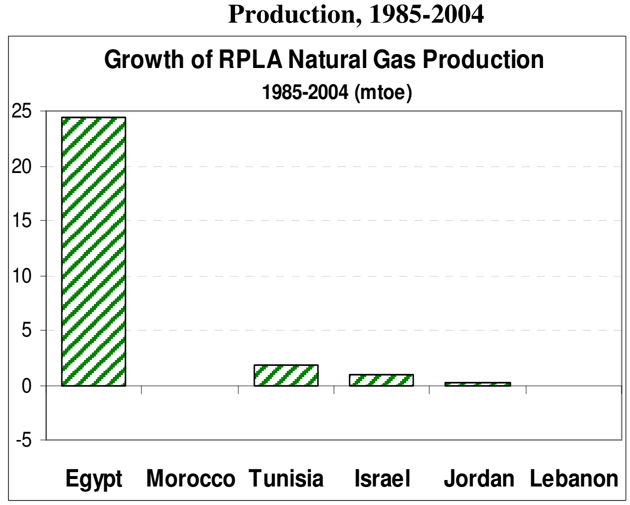


Figure A2.18 Growth of RPLA Natural Gas Production, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006

MENA Primary Energy Demand

Figure A2.19 RRLI Primary Energy Demand, 1971-2004

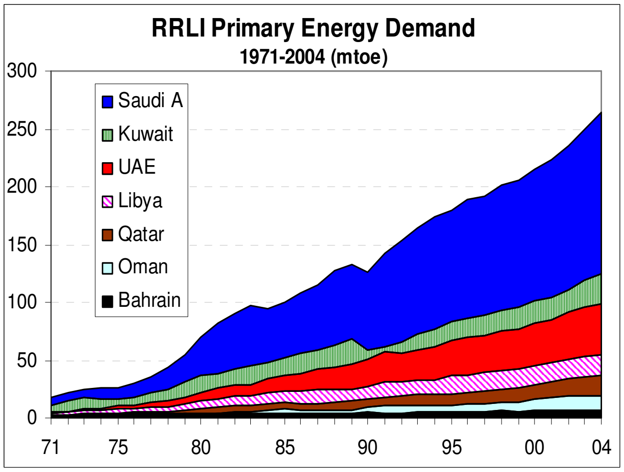


Figure A2.20 Growth of RRLI Energy Demand, 1985-2004

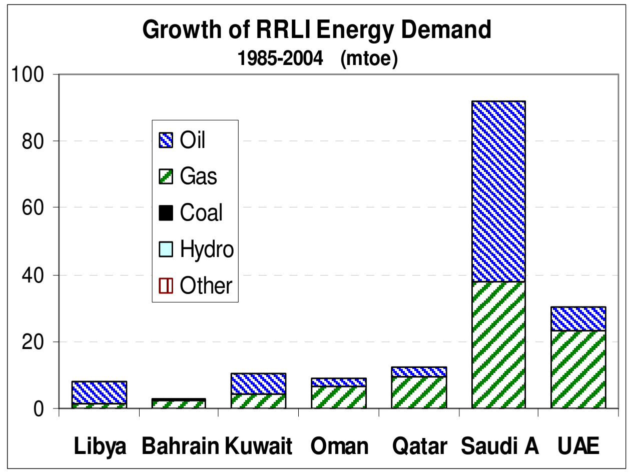


Figure A2.21 RRLA Primary Energy Demand, 1971-2004

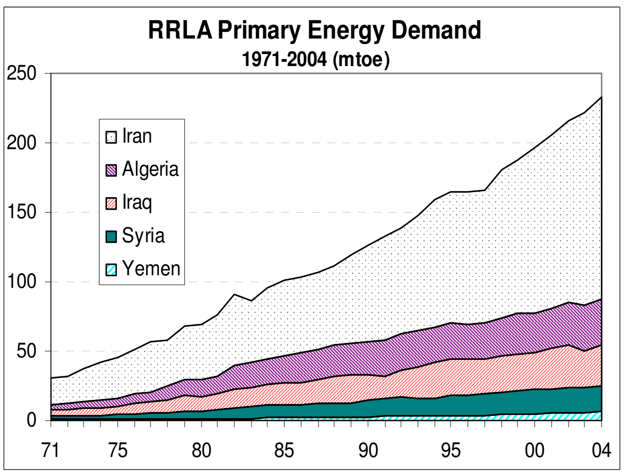


Figure A2.22 Growth of RRLA Energy Demand, 1985-2004

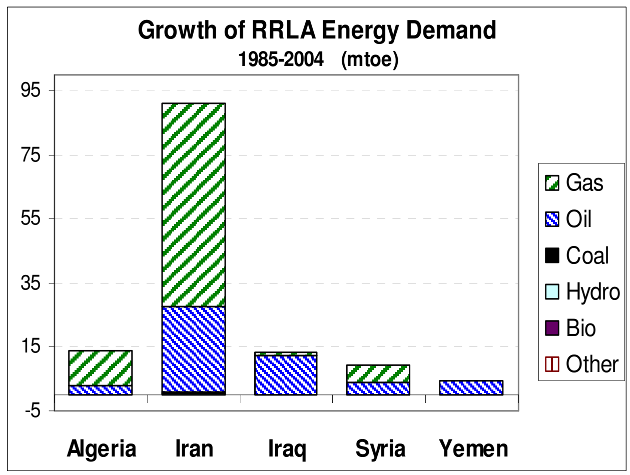


Figure A2.23 RPLA Primary Energy Demand, 1971-2004

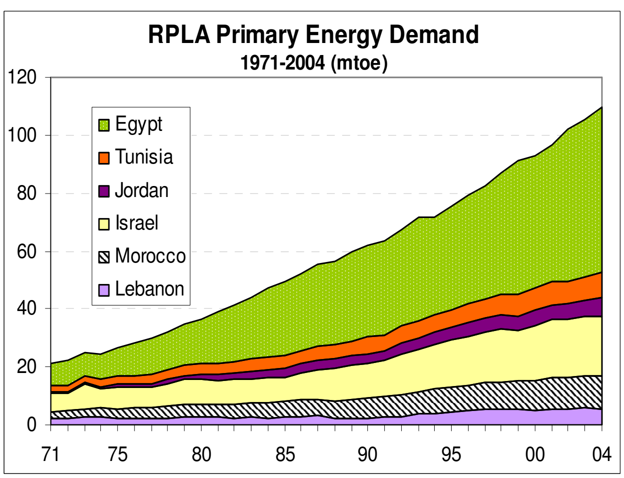
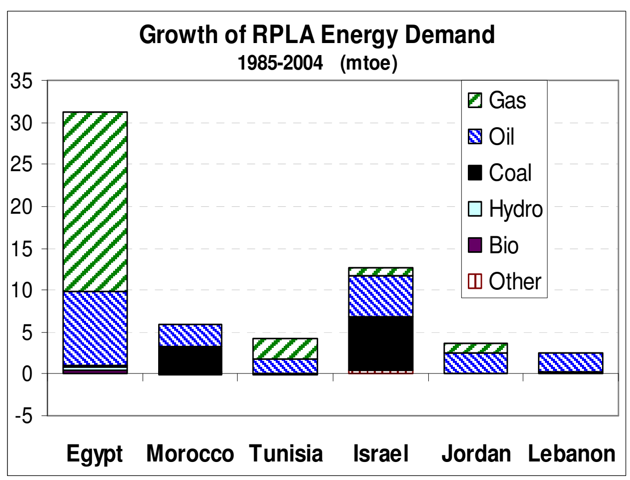


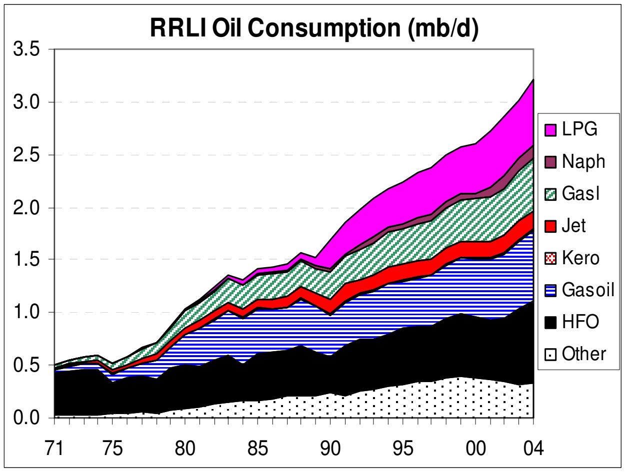
Figure A2.24 Growth of RPLA Energy Demand, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006.

MENA Oil Consumption

Figure A2.25 RRLI Oil Consumption, 1971-2004



FigureA2.26 Growth of RRLI Oil Consumption, 1985-2004

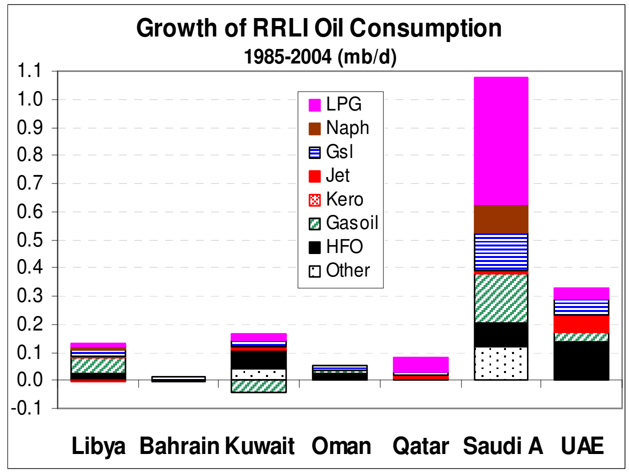


Figure A2.27 RRLA Oil Consumption, 1971-2004

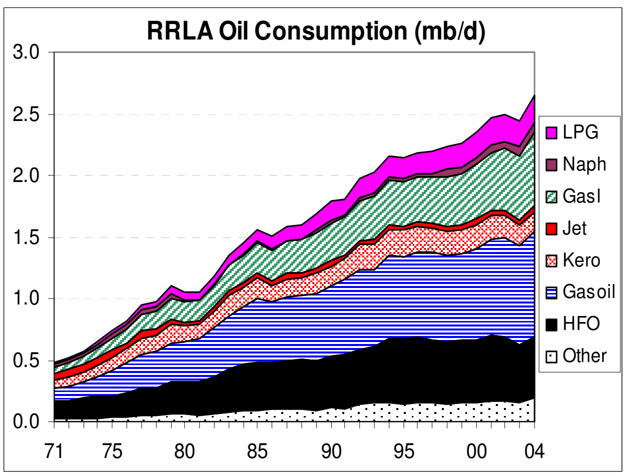


Figure A2.28 Growth of RRLA Oil Consumption, 1985-2004

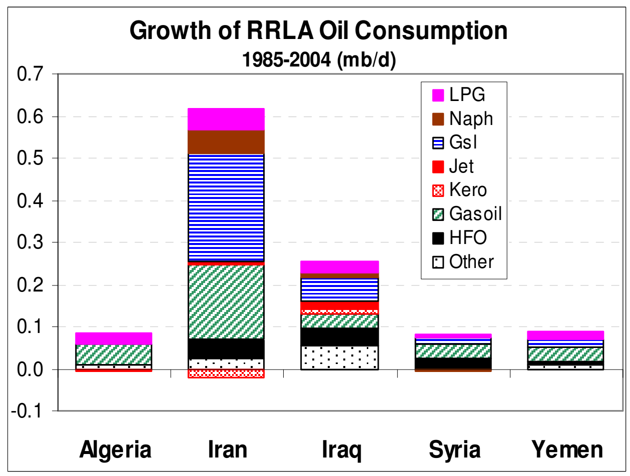


Figure A2.29 RPLA Oil Consumption, 1971-2004

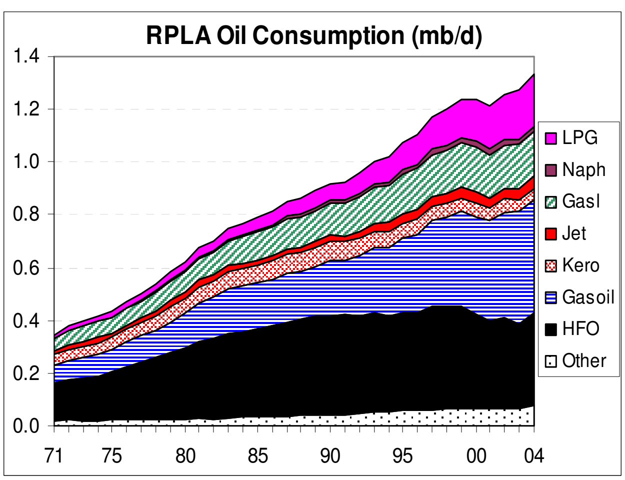
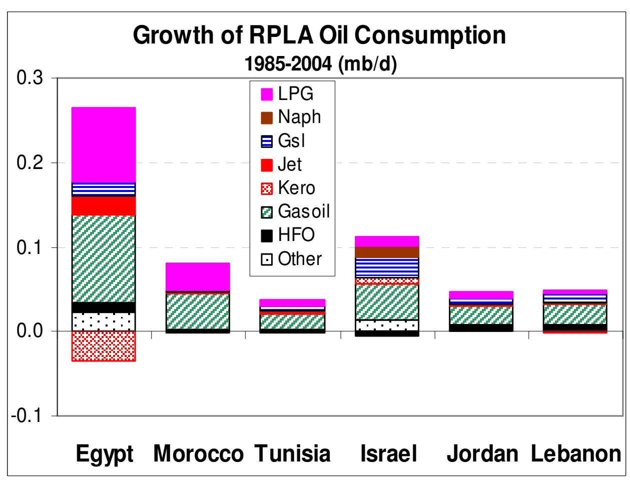
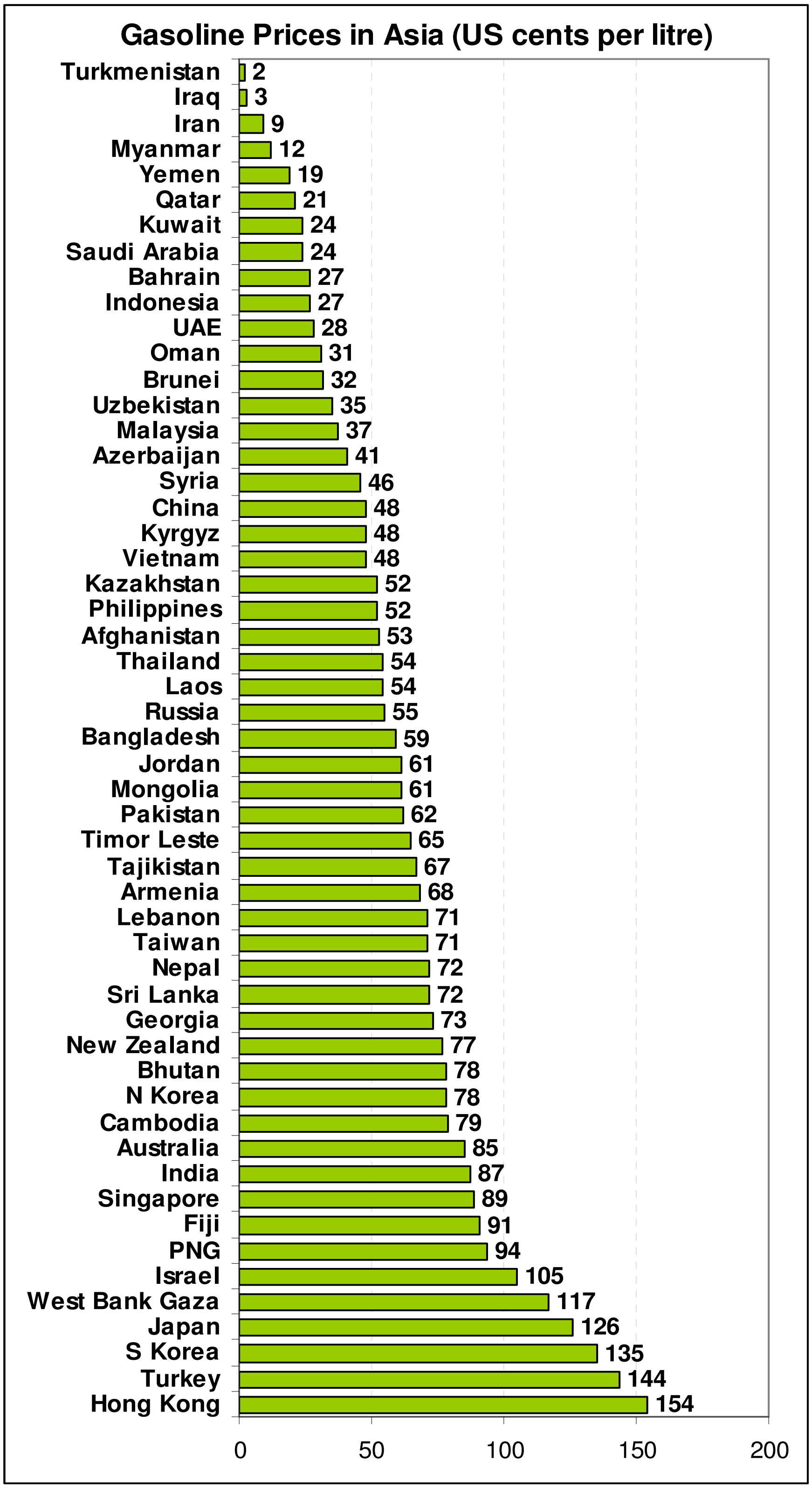


Figure A2.30 Growth of RPLA Oil Consumption, 1985-2004



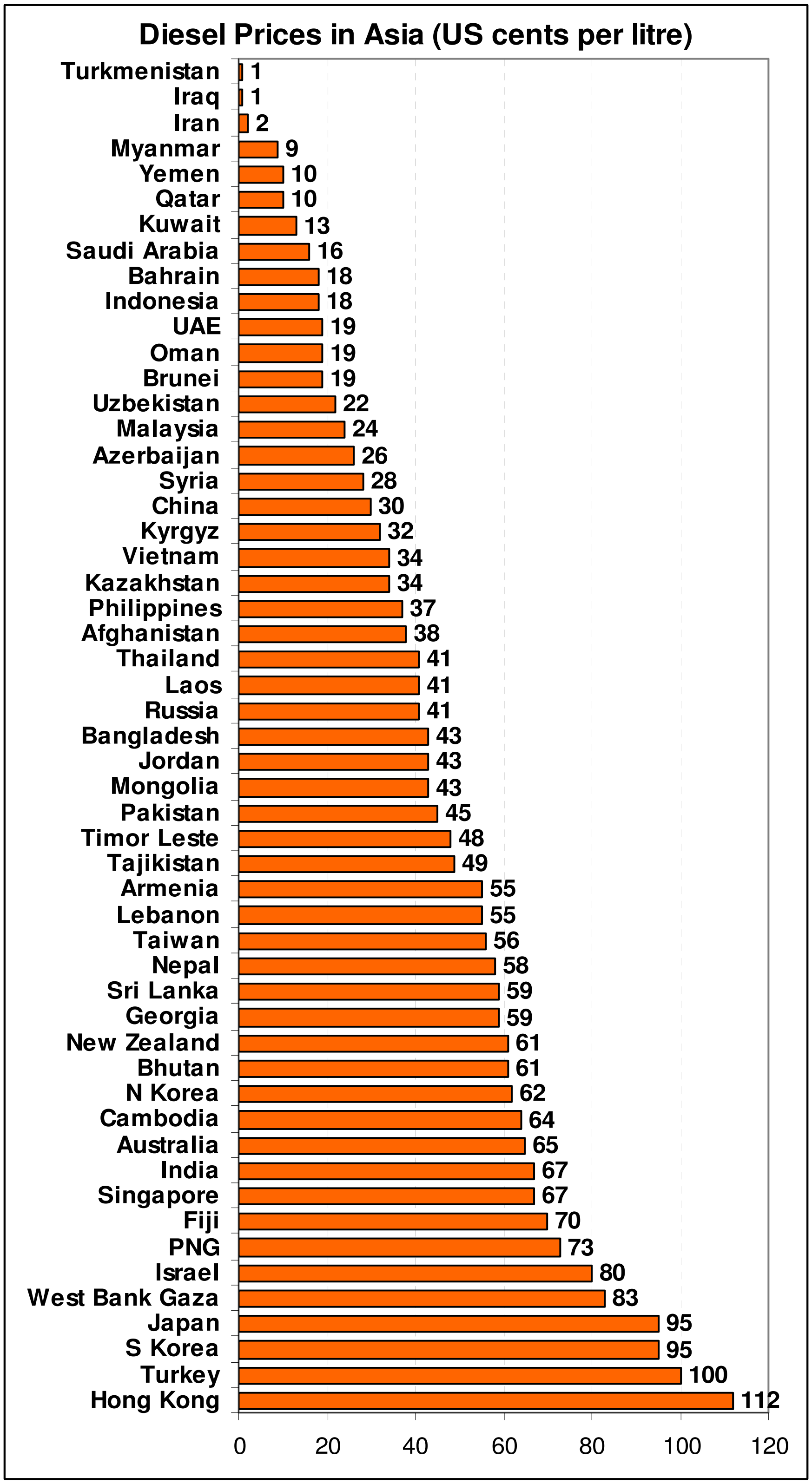
Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006

Figure A2.31 Gasoline Prices in Asia, November 2004



* Super Gasoline as of November 2004
Source: International Fuel Prices, GTZ, 2005

Figure A2.32 Diesel prices in Asia, November 2004

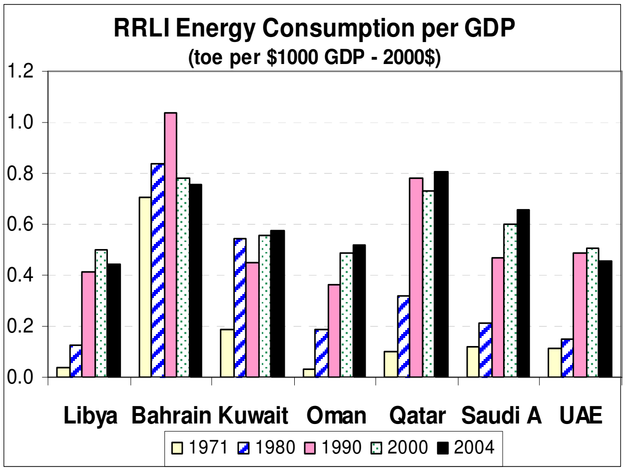


*Diesel as of November 2004

Source: International Fuel Prices, GTZ, 2005

MENA Energy Consumption per GDP and per Capita

Figure A2.33 RRLI Energy Consumption per GDP, 1971-2004



FigureA2.34 RRLI Energy Consumption per Capita, 1971-2004

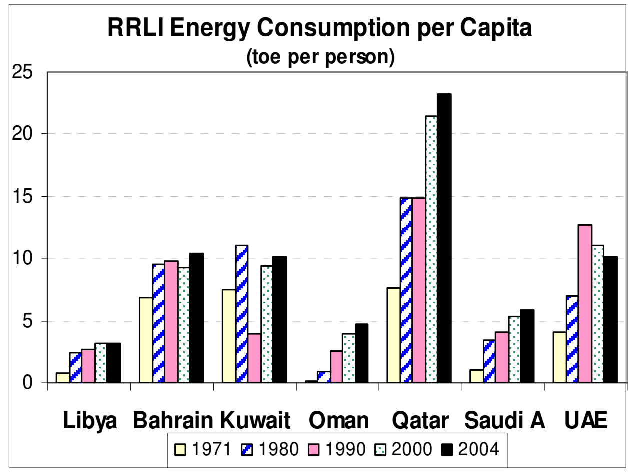


Figure A2.35 RRLA Energy Consumption per GDP, 1971-2004

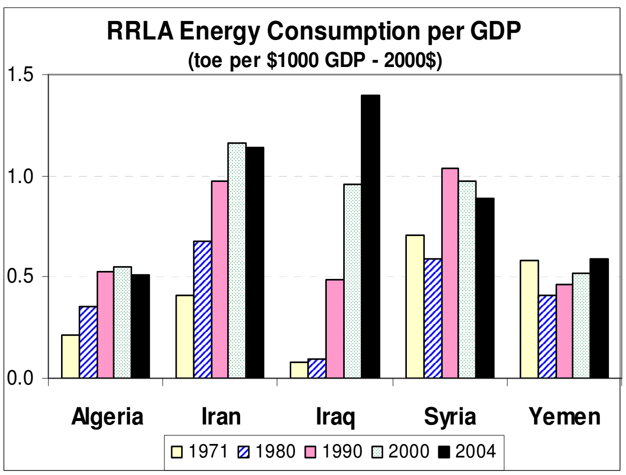


Figure A2.36 RRLA Energy Consumption per Capita, 1971-2004

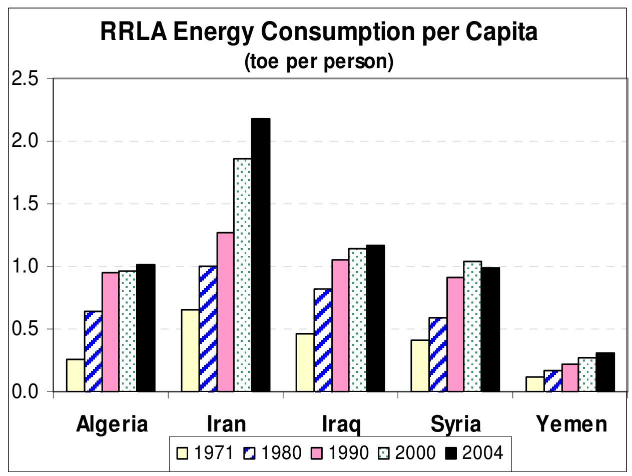


Figure A2.37 RPLA Energy Consumption per GDP, 1971-2004

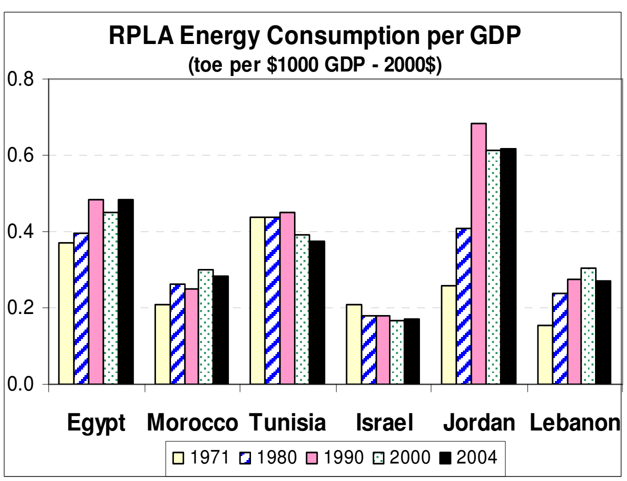
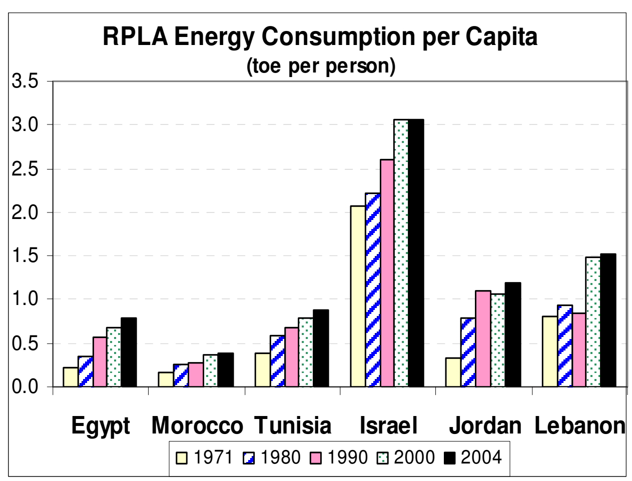


Figure A2.38 RPLA Energy Consumption per Capita, 1971-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006, and World Bank.

MENA Oil Consumption per GDP and per Capita

Figure A2.39 RRLI Oil Consumption per GDP, 1971-2004

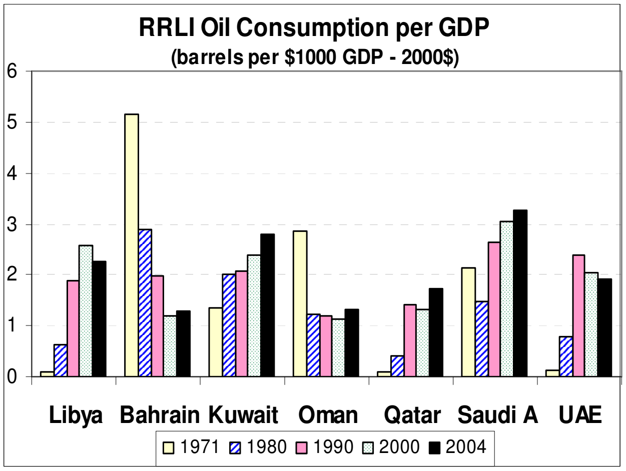


Figure A2.40 RRLI Oil Consumption per Capita, 1971-2004

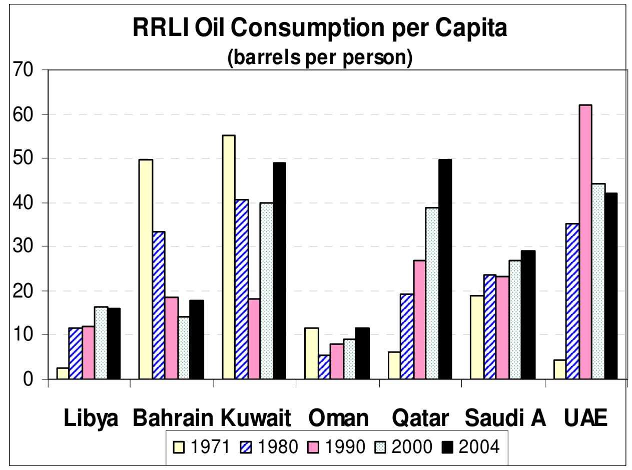


Figure A2.41 RRLA Oil Consumption per GDP, 1971-2004

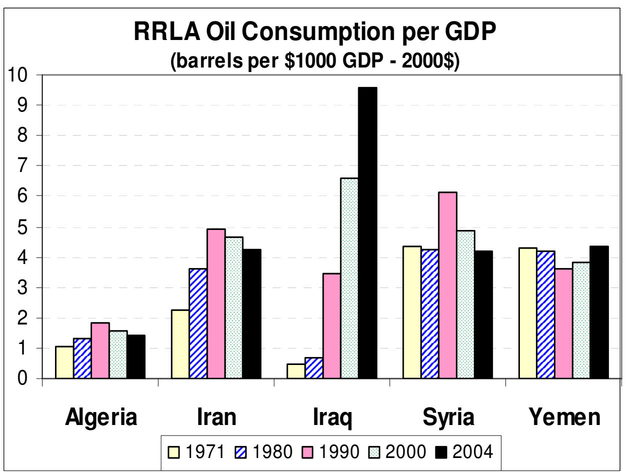


Figure A2.42 RRLA Oil Consumption per Capita, 1971-2004

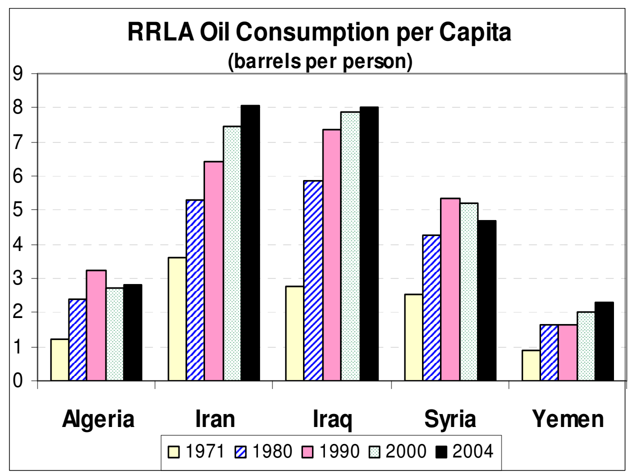


Figure A2.43 RPLA Oil Consumption per GDP, 1971-2004

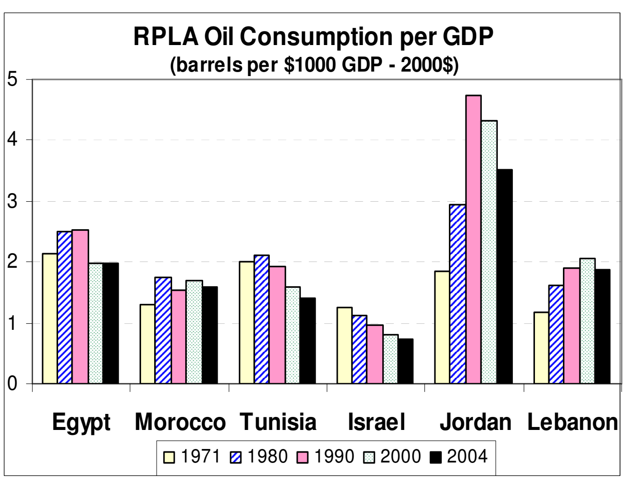
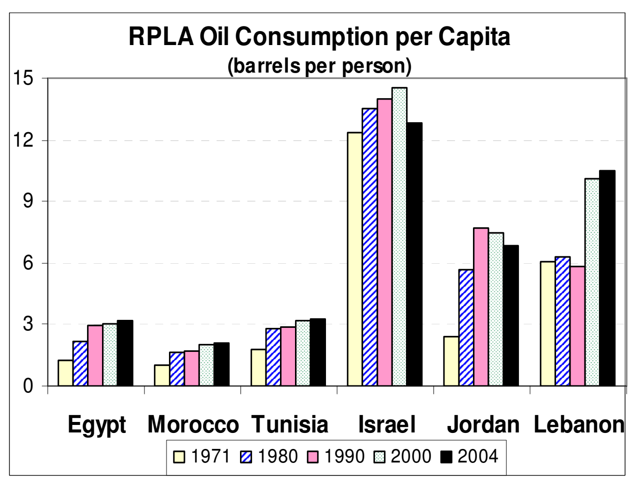


Figure A2.44 RPLA Oil Consumption per Capita, 1971-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006, and World Bank

MENA Hydrocarbon Exports

Figure A2.45 RRLI Hydrocarbon Exports, 1971-2004

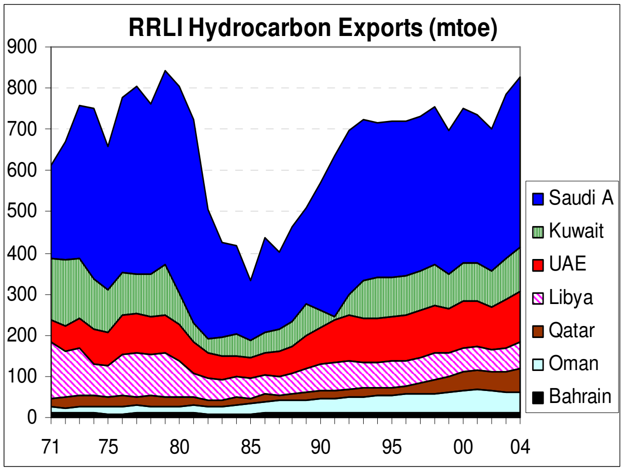


Figure A2.46 Growth of RRLI Hydrocarbon Exports, 1985-2004

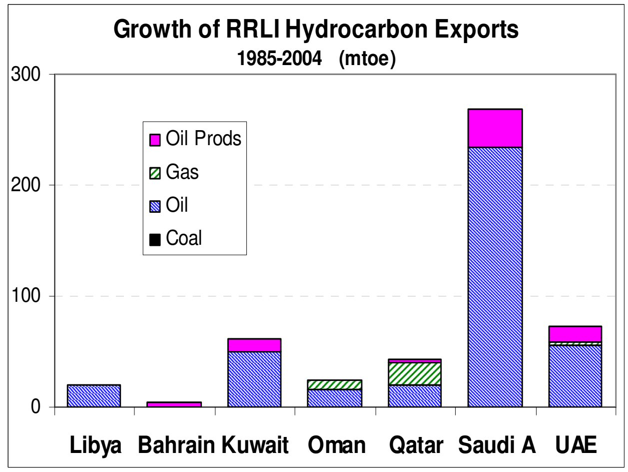


Figure A2.47 RRLA Hydrocarbon Exports, 1971-2004

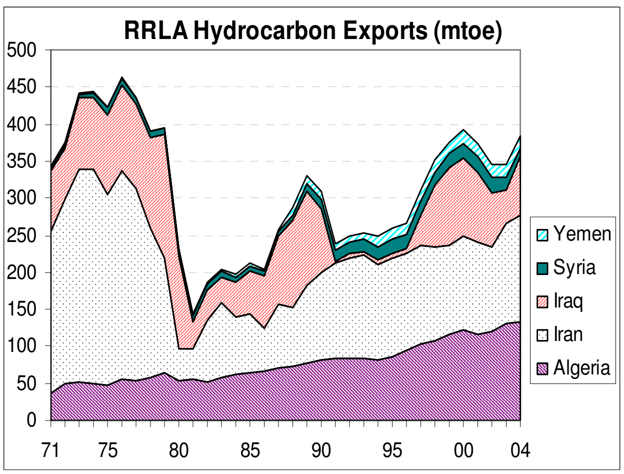


Figure A2.48 Growth of RRLA Hydrocarbon Exports, 1985-2004

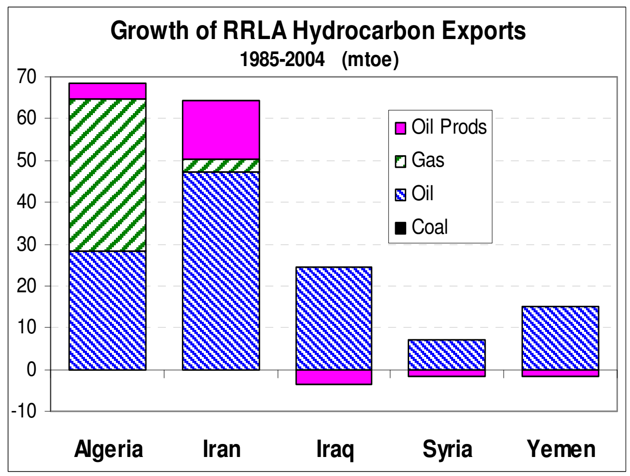


Figure A2.49 RPLA Hydrocarbon Exports, 1971-2004

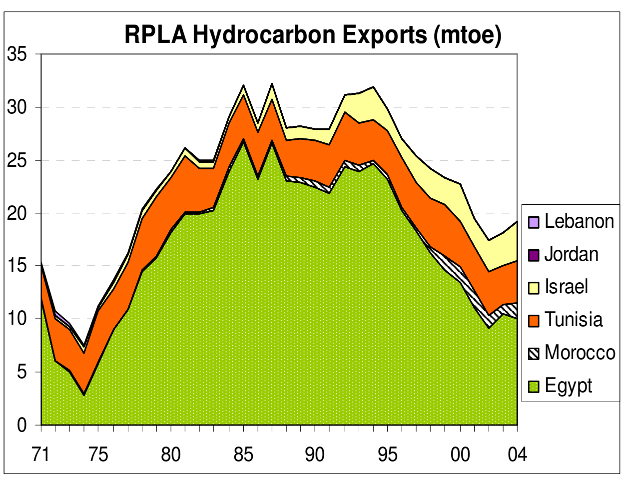
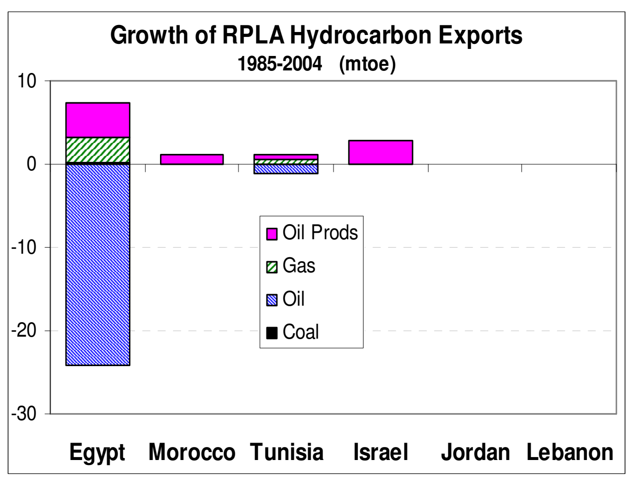


Figure A2.50 Growth of RPLA Hydrocarbon Exports, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006.

MENA Hydrocarbon Exports by Country

Figure A2.51 MENA Crude Oil Exports, 1971-2004

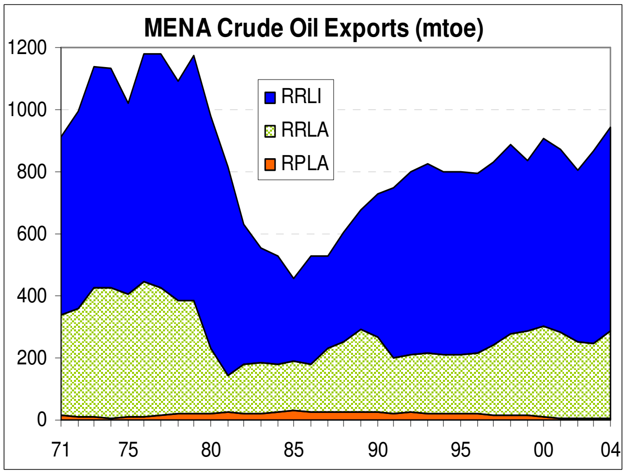


Figure A2.52 Growth of MENA Crude Oil Exports, 1985-2004

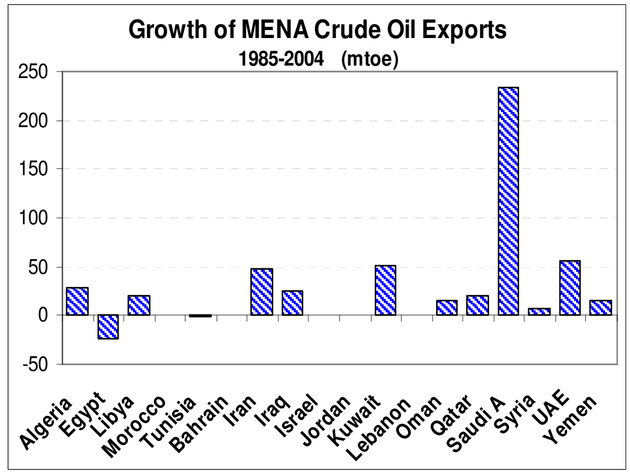


Figure A2.53 MENA Oil Product Exports, 1971-2004

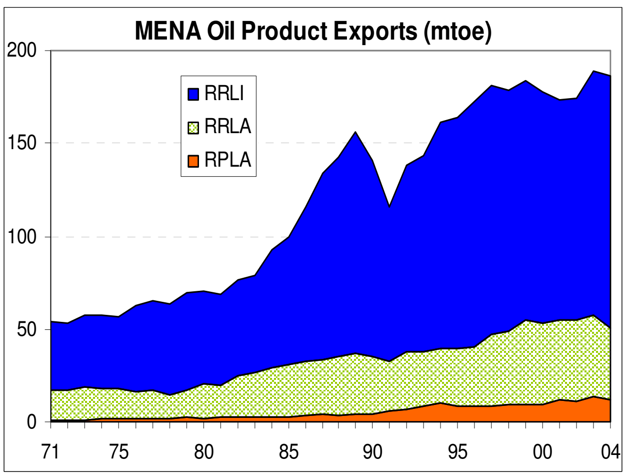


Figure A2.54 Growth of MENA Oil Product Exports, 1985-2004

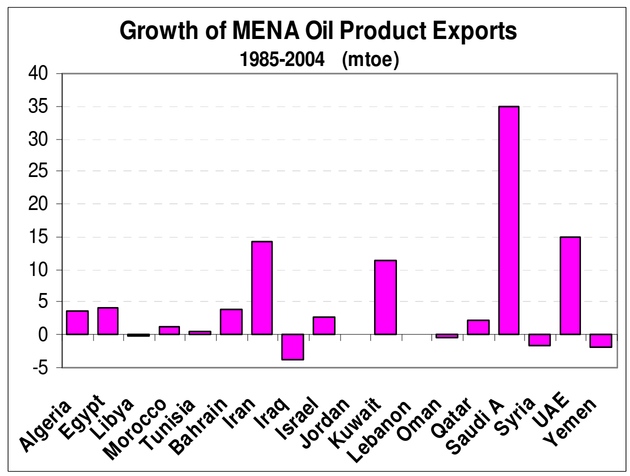


Figure A2.55 MENA Natural Gas Exports, 1971-2004

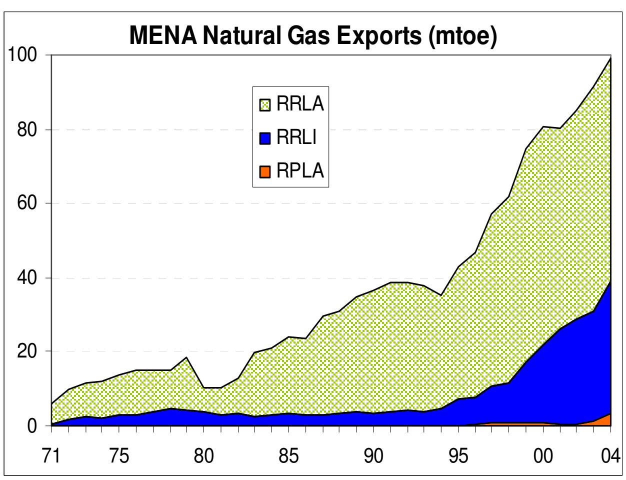
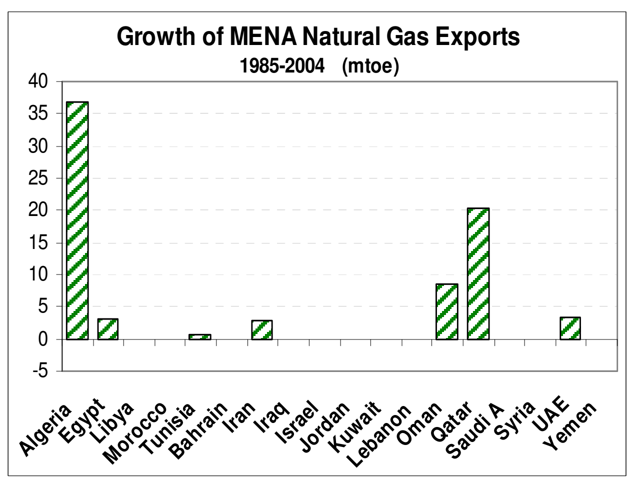


Figure A2.56 Growth of MENA Natural Gas Exports, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006.

MENA Natural Gas Trade Flows by Pipeline and Liquefied Natural Gas, 2006

Table A2.3 MENA National Gas Trade Movements by Pipeline, 2006 (billion cubic metres)

	FROM					
TO	**Iran**	**Oman**	**Algeria**	**Egypt**	**Libya**	**Total Imports**
Italy	-	-	24.46	-	7.69	**74.27**
Portugal	**-**	**-**	2.10	**-**	**-**	**2.10**
Slovenia	-	-	0.44	-	-	**1.10**
Spain	-	-	8.62	-	-	**10.74**
Turkey	5.69	-	-	-	-	**25.34**
Jordan	-	-	-	1.93	-	**1.93**
UAE	-	1.40	-	-	-	**1.40**
Tunisia	-	-	1.30	-	-	**1.30**
TOTAL EXPORTS	**5.69**	**1.40**	**36.92**	**1.93**	**7.69**	***537.06**

Table A2.4 MENA National Gas Trade Movements by Liquefied Natural Gas (LNG), 2006 (billion cubic metres)

	FROM						
TO	**Oman**	**Qatar**	**UAE**	**Algeria**	**Egypt**	**Libya**	**Total IMPORTS**
USA	-	-	-	0.49	3.60	-	**16.56**
Mexico	-	0.08	-	-	0.16		**0.94**
Belgium	-	0.36	-	3.35	0.25	-	**4.28**
France	-	-	-	7.35	2.30	-	**13.88**
Greece	-	-	-	0.45	0.04	-	**0.49**
Italy	-	-	-	3.00	0.10	-	**3.10**
Spain	1.00	5.00	-	2.80	4.80	0.72	**24.42**
Turkey	-	-	-	4.60	-	-	**5.72**
UK	-	-	-	2.00	0.96	-	**3.56**
India	0.24	6.80	0.08	0.08	0.55	-	**7.99**
Japan	3.04	9.87	7.00	0.24	0.80	-	**81.86**
South Korea	7.10	8.98	-	0.32	1.25	-	**34.14**
Taiwan	0.16	-	-	-	0.16	-	**10.20**
TOTAL EXPORTS	**11.54**	**31.09**	**7.08**	**24.68**	**14.97**	**0.72**	****211.08**

Source: BP Statistical Review of World Energy, June 2007
- denotes zero trade
*Total world gas trade pipeline
** Total world gas trade LNG

MENA Hydrocarbon Imports

Figure A2.57 MENA RRLI Hydrocarbon Imports, 1971-2004

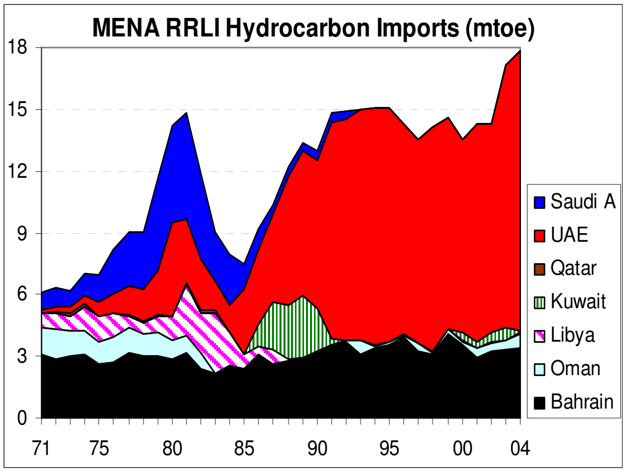


Figure A2.58 Growth of RRLI Hydrocarbon Imports, 1985-2004

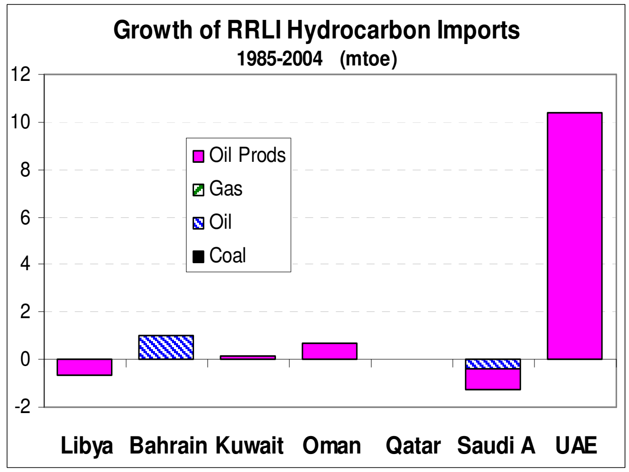


Figure A2.59 MENA RRLA Hydrocarbon Imports, 1971-2004

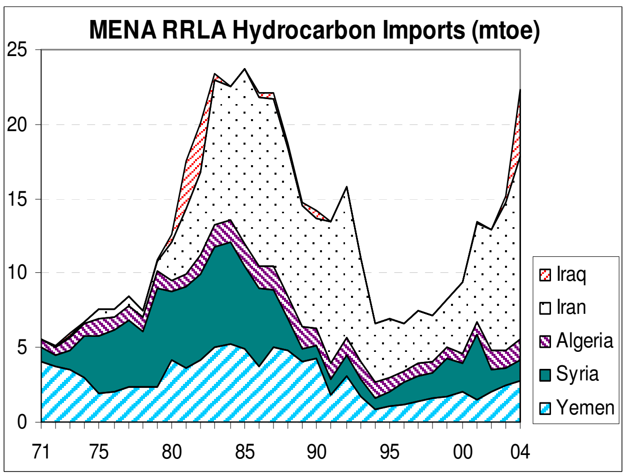


Figure A2.60 Growth of RRLI Hydrocarbon Imports, 1985-2004

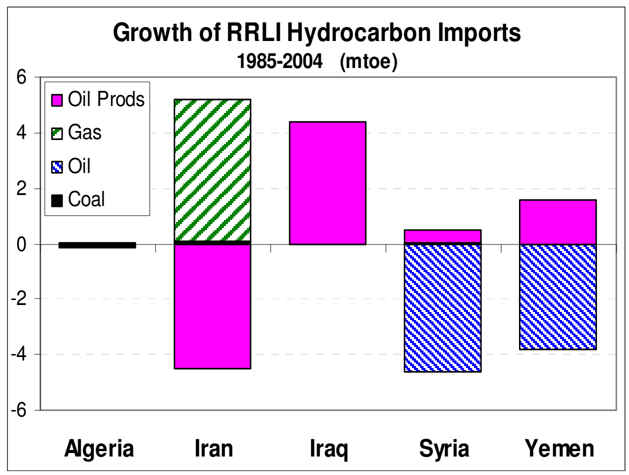


Figure A2.61 MENA RPLA Hydrocarbon Imports, 1971-2004

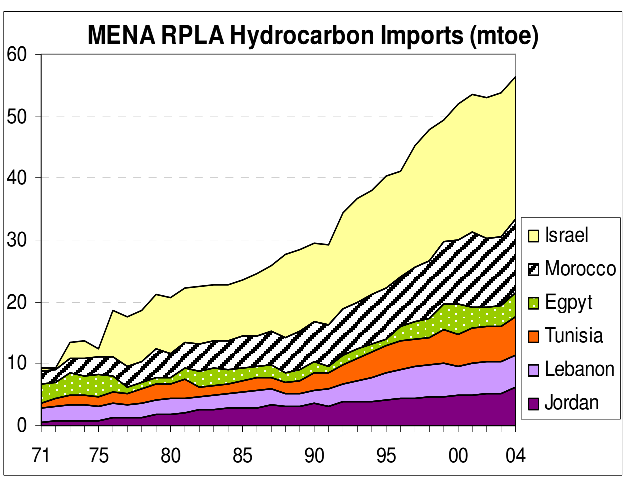
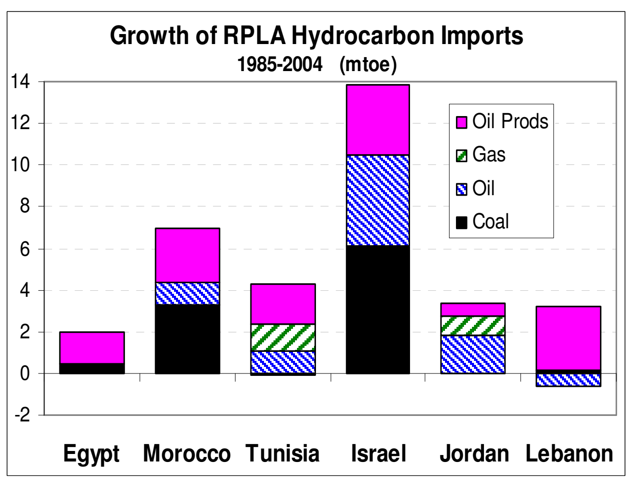


Figure A2.62 Growth of RPLA Hydrocarbon Imports, 1985-2004



Source: *Energy Balances of Non-OECD Countries 2003-2004*. International Energy Agency, 2006.

MENA Oil Export Revenues

Figure A2.63 RRLI Oil Export Revenues, 1970-2006

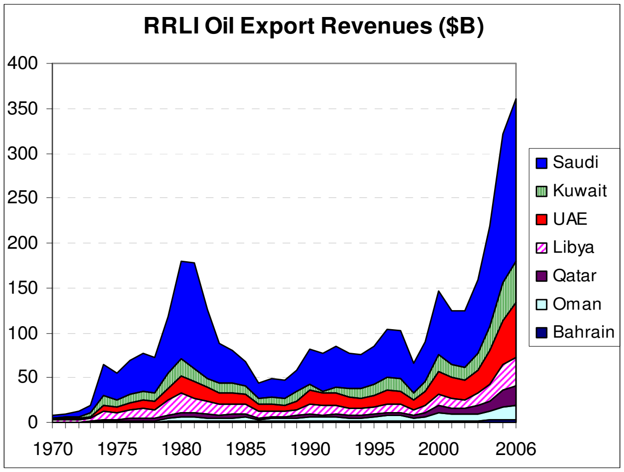


Figure A2.64 RRLI (except Libya) Per Capita Real Oil Revenues and GDP, 1970-2006

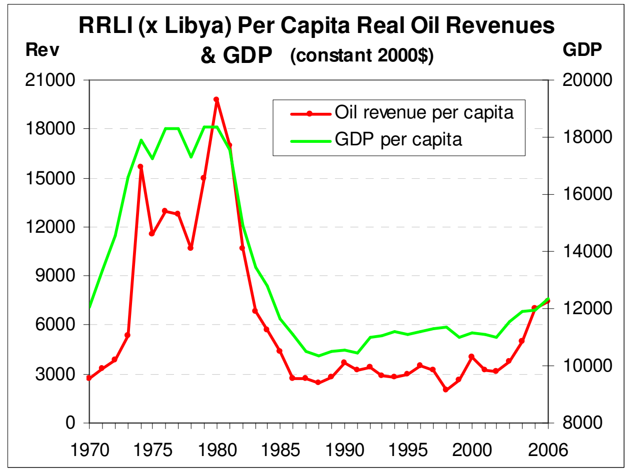


Figure A2.65 RRLA Oil Export Revenues, 1970-2006

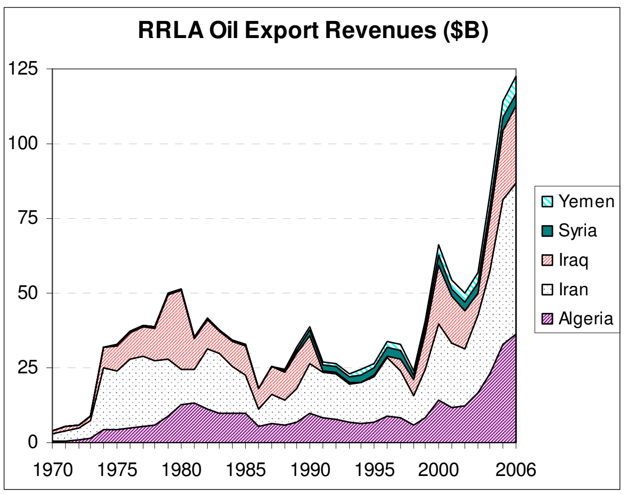


Figure A2.66 RRLA (except Iraq) Per Capita Real Oil Revenue and GDP, 1970-2006

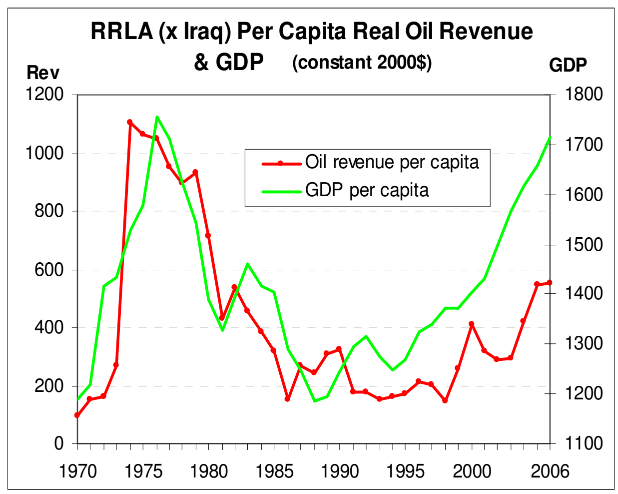


Figure A2.67 RPLA Oil Export Revenues, 1970-2006

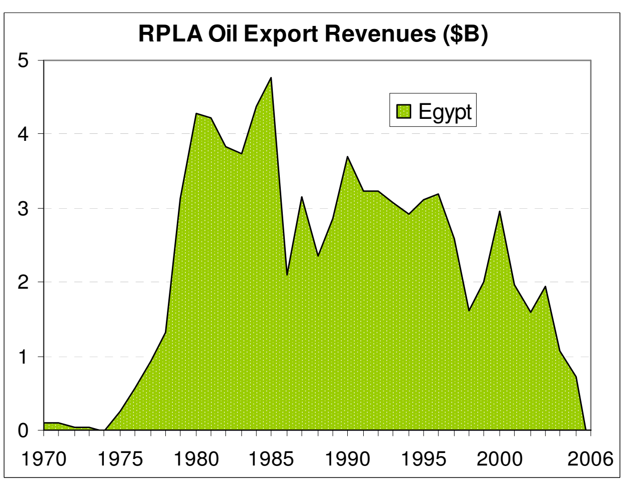
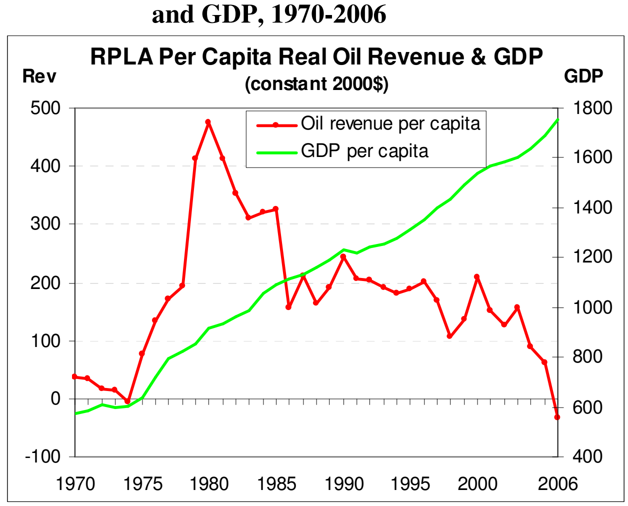


Figure A2.68 RPLA Per Capita Real Oil Revenue and GDP, 1970-2006



Source: World Bank, OPEC, IEA.

Table A2.5 IEA Projections of World Oil Demand (mb/d)

	2005	2010	2015	2030	2005-30 (% p.a.)
OECD	**47.7**	**49.8**	**52.4**	**55.1**	**0.6**
OECD North America	24.9	26.3	28.2	30.8	0.9
United States	*20.6*	*21.6*	*23.1*	*25.0*	*0.8*
Canada	*2.3*	*2.5*	*2.6*	*2.8*	*0.8*
Mexico	*2.1*	*2.2*	*2.4*	*3.1*	*1.6*
OECD Europe	14.4	14.9	15.4	15.4	0.2
OECD Pacific	8.3	8.6	8.8	8.9	0.3
Transition economies	**4.3**	**4.7**	**5.0**	**5.7**	**1.1**
Russia	*2.5*	*2.7*	*2.9*	*3.2*	*1.0*
Developing countries	*28.0*	*33.0*	*37.9*	*51.3*	*2.5*
Developing Asia	*14.6*	*17.7*	*20.6*	*29.7*	*2.9*
China	*6.6*	*8.4*	*10.0*	*15.3*	*3.4*
India	*2.6*	*3.2*	*3.7*	*5.4*	*3.0*
Indonesia	*1.3*	*1.4*	*1.5*	*2.3*	*2.4*
Middle East	5.8	7.1	8.1	9.7	2.0
Africa	2.7	3.1	3.5	4.9	2.4
North Africa	*1.4*	*1.6*	*1.8*	*2.5*	*2.4*
Latin America	4.9	5.1	5.6	7.0	1.5
Brazil	*2.1*	*2.3*	*2.7*	*3.5*	2.0
Int'l marine bunkers	**3.6**	**3.8**	**3.9**	**4.3**	**0.6**
World	**83.6**	**91.3**	**99.3**	**116.3**	**1.3**
European Union	*13.5*	*13.9*	*14.3*	*14.1*	*0.2*

Source: IEA, *World Energy Outlook 2006*.

Table A2.6 IEA Projections of World Oil Supply (mb/d)

	2005	2010	2020	2030	2005-30 (% p.a.)
Non-OPEC	**48.1**	**53.4**	**55.0**	**57.6**	**0.7**
Crude Oil	**41.6**	**45.5**	**45.4**	**43.4**	**0.2**
OECD	15.2	13.8	12.4	9.7	-1.8
North America	9.8	9.4	9.0	7.8	-0.9
United States	*5.1*	*5.3*	*5.0*	*4.0*	*-1.0*
Canada	*1.4*	*1.1*	*0.9*	*0.8*	*-2.2*
Mexico	*3.3*	*3.1*	*3.1*	*3.0*	*-0.5*
Europe	0.5	0.7	0.5	0.4	-1.2
Pacific	4.8	3.8	2.9	1.5	-4.5
Transition economies	**11.4**	**13.7**	**14.5**	**16.4**	**1.5**
Russia	*9.2*	*10.5*	*10.6*	*11.1*	*0.7*
Other	*2.2*	*3.3*	*3.9*	*5.3*	*3.6*
Developing countries	**15.1**	**17.9**	**18.5**	**17.4**	**0.6**
Developing Asia	5.9	6.3	6.1	5.0	-0.6
China	*3.6*	*3.8*	*3.7*	*2.8*	*-1.0*
India	*0.7*	*0.8*	*0.8*	*0.6*	*-0.2*
Other	*1.6*	*1.7*	*1.6*	*1.6*	*0.0*
Latin America	3.8	4.8	5.3	5.9	1.8
Brazil	*1.6*	*2.6*	*3.0*	*3.5*	*3.1*
Other	*2.2*	*2.2*	*2.3*	*2.5*	*0.5*
Africa	3.5	5.2	5.5	4.9	*1.4*
North Africa	*0.6*	*0.6*	*0.6*	*0.7*	*0.4*
Other	*2.9*	*4.6*	*4.9*	*4.3*	*1.6*
Middle East	1.9	1.7	1.6	1.4	*-1.1*
Natural Gas Liquids	**5.1**	**5.5**	**5.8**	**6.8**	**1.2**
OECD	3.7	4.0	4.1	4.4	0.7
Transition economies	0.5	0.4	0.5	0.6	1.2
Developing countries	0.9	1.1	1.3	1.8	2.7
Nonconventional oil	**1.4**	**2.5**	**3.7**	**7.4**	**7.0**
Canada	*1.0*	*2.0*	*3.0*	*4.8*	*6.4*
Other	*0.4*	*0.5*	*0.7*	*2.7*	*8.2*

Source: IEA, *World Energy Outlook 2006*.

Table continued next page

Table A2.6. IEA Projections of World Oil Supply (mb/d), continued

	2005	**2010**	**2020**	**2030**	**2005-30 (% p.a.)**
OPEC	**33.6**	**35.9**	**42.0**	**56.3**	**2.1**
Crude Oil	**29.1**	**30.2**	**34.9**	**45.7**	**1.8**
Middle East	**20.7**	**22.0**	**25.7**	**34.5**	**2.1**
Saudi Arabia	*9.1*	*9.7*	*11.3*	*14.6*	*1.9*
Iran	*3.9*	*3.9*	*4.4*	*5.2*	*1.1*
Iraq	*1.8*	*2.2*	*2.8*	*6.0*	*4.9*
Kuwait	*2.1*	*2.2*	*2.8*	*4.0*	*2.5*
UAE	*2.5*	*2.7*	*3.1*	*3.8*	*1.8*
Qatar	*0.8*	*0.7*	*0.7*	*0.5*	*-1.9*
*Neutral Zone***	*0.6*	*0.5*	*0.5*	*0.5*	*-0.6*
Non-Middle East	**8.4**	**8.2**	**9.1**	**11.2**	**1.2**
Algeria	*1.3*	*1.1*	*1.1*	*0.7*	*-2.7*
Libya	*1.6*	*1.7*	*1.9*	*2.7*	*2.0*
Nigeria	*2.4*	*2.5*	*2.7*	*3.2*	*1.2*
Indonesia	*0.9*	*0.8*	*0.8*	*0.8*	*-0.8*
Venezuela	*2.1*	*2.2*	*2.8*	*3.9*	*2.5*
Natural Gas Liquids	**4.3**	**5.4**	**6.3**	**9.0**	**3.0**
Saudi Arabia	1.5	1.9	2.0	2.7	2.5
Iran	0.3	0.4	0.6	1.1	4.8
UAE	0.5	0.7	0.9	1.3	3.6
Algeria	0.8	0.9	0.9	0.7	-0.3
Others	1.2	1.5	1.9	3.3	4.1
Nonconventional oil	**0.2**	**0.3**	**0.8**	**1.5**	**8.8**
Venezuela	*0.1*	*0.1*	*0.2*	*0.4*	*5.8*
Other	*0.1*	*0.2*	*0.6*	*1.2*	*10.5*
World	**83.6**	**91.3**	**99.3**	**116.3**	**1.3**
Crude oil	*70.8*	*75.7*	*80.3*	*89.1*	*0.9*
NGLs	*9.3*	*10.8*	*12.2*	*15.8*	*2.1*
NonConventional oil	*1.6*	*2.8*	*4.5*	*9.0*	*7.2*
Processing Gains	*1.9*	*2.0*	*2.3*	*2.5*	*1.2*

Source: IEA, *World Energy Outlook 2006*.

Table A2.7 IEA Projections of World Natural Gas Demand, 2004-2030 (bcm)

	2004	2010	2015	2030	2004-30 (% p.a.)
OECD	**1453**	**1593**	**1731**	**1994**	**1.2**
North America	772	830	897	998	1.0
United States	*626*	*660*	*704*	*728*	*0.6*
Canada	*94*	*109*	*120*	*151*	*1.8*
Mexico	*51*	*62*	*74*	*118*	*3.3*
Europe	534	592	645	774	1.4
Pacific	148	171	188	223	1.6
Transition economies	**651**	**720**	**770**	**906**	**1.3**
Russia	*420*	*469*	*503*	*582*	*1.3*
Developing countries	680	932	1143	1763	3.7
Developing Asia	245	337	411	622	3.7
China	*47*	*69*	*96*	*169*	*5.1*
India	*31*	*43*	*53*	*90*	*4.2*
Indonesia	*39*	*56*	*65*	*87*	*3.2*
Middle East	244	321	411	636	3.7
Africa	76	117	140	215	4.1
North Africa	*63*	*88*	*104*	*146*	3.3
Latin America	115	157	180	289	3.6
Brazil	*19*	*28*	*31*	*50*	*3.8*
World**	**2784**	**3245**	**3643**	**4663**	**2.0**
European Union	*508*	*560*	*609*	*726*	*1.4*

Source: IEA, *World Energy Outlook 2006*.

Table A2.8 IEA Projections of Interregional* Natural Gas Trade, 2004-2030 (bcm)

	2004		**2015**		**2030**	
	bcm	**% of Inland Gas** Consumption**	**bcm**	**% of Inland Gas** Consumption**	**bcm**	**% of Inland Gas** Consumption**
OECD	**-328**	**22.6**	**-526**	**30.4**	**-764**	**38.3**
North America	-18	2.3	-77	8.6	-159	15.9
Europe	-214	40.1	-333	51.7	-488	63.0
Pacific	-96	65.0	-116	61.3	-117	52.7
OECD Asia	*-109*	*93.5*	*-145*	*96.7*	*-174*	*97.2*
OECD Oceania	*13*	*29.7*	*29*	*40.3*	*57*	*53.7*
Transition economies	**145**	**18.2**	**152**	**16.5**	**190**	**17.3**
Russia	*202*	*32.7*	*194*	*27.8*	*222*	*27.7*
Developing countries	**183**	**21.2**	**374**	**24.7**	**574**	**24.6**
Developing Asia	60	20.0	11	2.7	-15	2.4
China	*0*	*0.0*	*-27*	*27.6*	*-56*	*33.3*
India	*-3*	*9.7*	*-10*	*19.3*	*-27*	*30.1*
Middle East	40	14.4	189	31.5	232	26.7
Africa	70	45.3	137	49.4	274	56.0
World	**13**	**10.0**	**37**	**17.0**	**82**	**22.2**
European Union	*413*	*14.8*	*634*	*17.4*	*936*	*20.1*
* Trade between for regions only						
**Production for exporters						

Source: IEA, *World Energy Outlook 2006*.

Table A2.9 PIW Top 40 Oil and Gas Companies by Selected Indicators

Rank	Company	Country	State Owned (%)	Rank	Liquids Output (kb/d)	Rank	Gas Output (mmcf/d)	Rank	Revenues $ million
1	Saudi Ararmco	Saudi Arabia	100	1	11,035	7	6,721	5	180,000
2	Exxon Mobil	U.S.		7	2,523	2	9,251	1	338,992
3	NIOC	Iran	100	2	4,049	4	8,414	22	45,500
4	PDV	Venezuela	100	4	2,650	18	2,795	11	85,700
5	BP	UK		6	2,562	3	8,424	3	251,003
6	Royal Dutch Shell	UK/Netherl's		9	2,093	5	8,263	2	306,731
7	PetroChina	China	90	8	2,270	12	3,681	13	67,427
8	Chevron	U.S.		14	1,701	10	4,233	4	189,481
9	Total	France		15	1,621	9	4,780	7	151,902
10	Pemex	Mexico	100	3	3,710	13	3,575	10	87,262
11	ConocoPhillips	U.S.		19	1,447	15	3,337	6	166,327
12	Sonatrach	Algeria	100	10	1,934	6	8,152	24	41,200
13	KPC	Kuwait	100	5	2,643	43	938	25	40,250
14	Petrobras	Brazil	32	11	1,847	24	2,220	17	59,510
15	Gazprom	Russia	50	24	811	1	53,135	14	63,824
16	Lukoil	Russia		13	1,819	59	548	19	56,215
17	Adnoc	UAE	100	16	1,601	19	2,623	38	22,750
18	Eni	Italy		22	1,111	11	3,762	9	92,471
19	Petronas	Malaysia	100	27	715	8	5,113	23	44,282
20	NNPC	Nigeria	100	17	1,548	31	1,265	28	30,650
21	Repsol YPF	Spain		32	531	14	3,415	15	63,056
22	Libya NOC	Libya	100	19	1,447	39	962	35	24,500
23	INOC	Iraq	100	12	1,820	78	256	50	15,700
24	EGPC	Egypt	100	41	348	27	1,678	74	7,850
25	QP	Qatar	100	23	1,097	17	3,029	44	19,900
26	Rosneft	Russia	75	18	1,498	30	1,267	34	25,305
27	Surgutneftegaz	Russia		21	1,282	29	1,389	51	15,158
28	Sinopec	China	55	25	764	56	608	8	101,652
29	Statoil	Norway	71	28	704	20	2,619	16	60,792
30	ONGC	India	74	29	640	21	2,583	55	13,595
31	Marathon	U.S.		53	191	44	932	18	58,919
32	Yukos	Russia		30	637	80	229	130	22
33	Pertamina	Indonesia	100	63	135	83	222	105	2,450
34	SPC	Syria	100	36	469	62	522	76	7,650
35	PDO	Oman	60	37	437	41	948	67	9,900
36	OMV	Austria	32	54	180	46	883	45	19,850
37	Socar	Azerbaijan	100	60	159	70	380		
38	TNK-BP	Russia		26	750	66	423	33	25,753
39	EnCana	Canada		49	230	16	3,219	53	14,266
40	Ecopetrol	Colombia	100	42	312	53	649	81	6,682

Source: Energy Intelligence Group. *Petroleum Intelligence Weekly*, December 18, 2006.
Note: MENA companies are shown in blue

World Largest 15 Companies: Oil and Gas Production, Reserves and Revenues

Figure A2.69 Liquid Reserves of World's Top 15 Companies (million barrels)

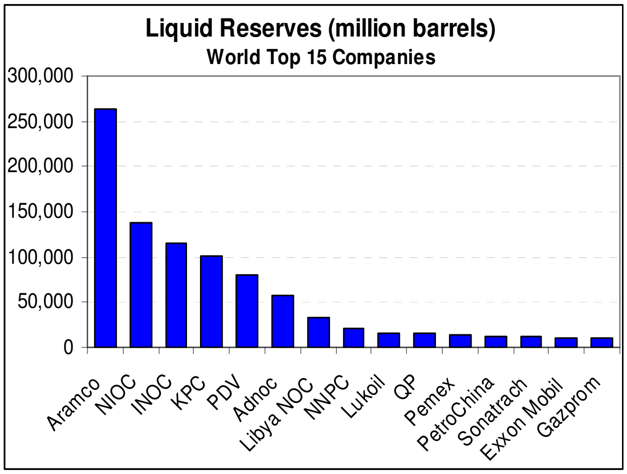


Figure A2.70 Liquids Production of World's Top 15 Campanies (tb/d)

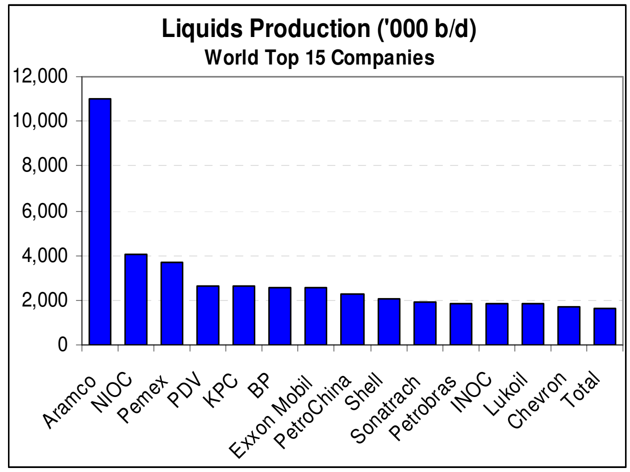


Figure A2.71 Gas Reserves of World's Top 15 Companies (bcf)

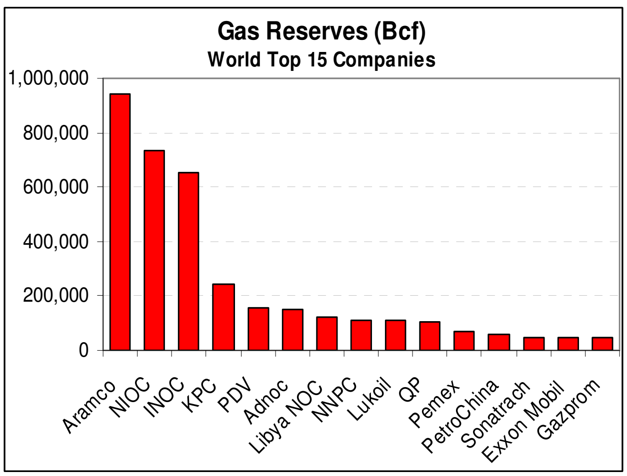


Figure A2.72 Gas Production of World's Top 15 Companies (mmbcf/d)

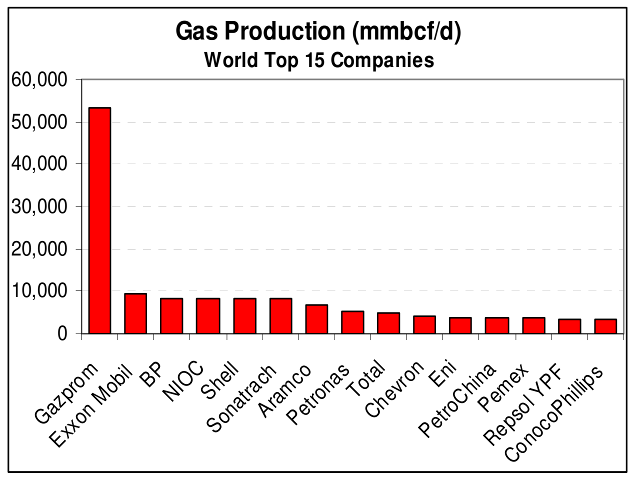
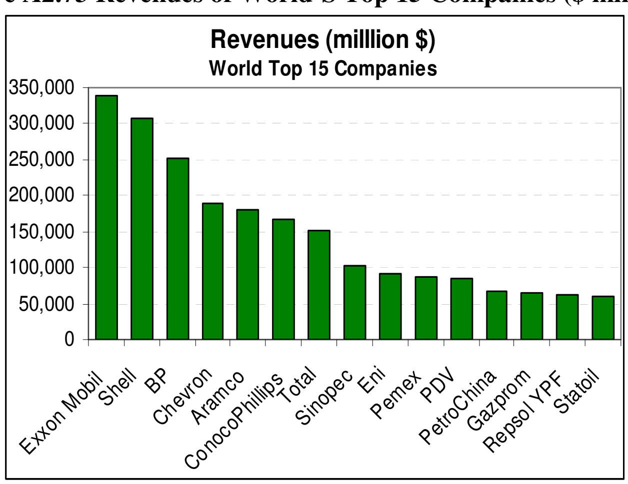


Figure A2.73 Revenues of World'S Top 15 Companies ($ millions)



Source: Energy Intelligence Group: *Petroleum Intelligence Weekly*, December 18, 2006.

Oil Development Plans to 2010 for MENA OPEC Oil Producers in the Region

Table A2.10 Algeria Crude Production Capacity, 2005-10 (tb/d)

Field	**Operator**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Existing capacity	Sonatrach	1,000	1,000	1,000	975	950	925
Menzel Lejmat North	Burlington	80	80	90	90	90	120
el-Gassi, el-Agreb and Zotti	Amerada Hess	50	50	70	70	70	100
Rhourd el Baguel	BP	30	30	30	30	30	30
Rhourde el-Khrouf	Cepsa	20	20	20	20	20	20
Rom, Bir Rebaa N/S/SW	Eni	20	20	20	20	20	20
Tifernine, Tin Masnaguene, Bir el Quetara	Repsol-YPF	5	5	5	5	5	5
Rhourde Oulad Djemma (ROD)	BHP	80	80	80	80	80	80
Bir Berkine / North Bir Berkine	Sonatrach		50	50	50	50	50
Adrar	CNPC				20	20	20
Ledjmet	First Calgary				40	40	40
El Merk	Anadarko					105	105
Block 208	Anadarko					25	50
Hassi Messaoud	Sonatrach					50	100
Total		**1,285**	**1,335**	**1,365**	**1,400**	**1,555**	**1,665**

Source: Petroleum Economics Limited.

Table A2.11 Iran Crude Production Capacity, 2005-10 (tb/d)

Field	**Operator**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Existing Capacity	**NIOC**	**3,100**	**2,900**	**2,700**	**2,500**	**2,300**	**2,100**
Abuzar	NIOC	200	210	220	220	220	220
Reshadat	NIOC	80	85	85	85	85	85
Resalat	NIOC	40	40	40	40	40	40
Salman	NIOC	40	40	90	90	90	90
Yadavaran	NbC	0	0	0	100	200	300
Bahregansar Expansion	NIOC	45	45	45	45	45	45
Bangestan	NIOC	0	50	100	150	200	250
Forouzan	NIOC	50	50	100	100	100	100
Total	**NIOC**	**455**	**520**	**680**	**830**	**980**	**1,130**
Srrri A+E	Total	100	100	100	100	100	100
Soroush/Nowruz	Shell	190	190	190	190	190	190
Darkhovin	Eni	100	140	160	160	160	160
Doroud	Total	85	85	85	85	85	85
Balal	Total	40	40	40	40	40	40
Masjid e Soleiman	CNPC	0	20	20	20	20	20
Azadegan	Inpex	0	0	0	100	150	150
Total foreign		**515**	**575**	**595**	**695**	**745**	**745**
Total all		**4,070**	**3,995**	**3,975**	**4,025**	**4,025**	**3,975**

Source: Petroleum Economics Limited.

Table A2.12 Kuwait Crude Production Capacity, 2005-10 (tb/d)

Field	Operator	2005	2006	2007	2008	2009	2010
Greater Burgan	KPC	1,550	1,550	1,550	1,700	1,700	1,700
Minagish & Umm Qudayr	KPC	200	200	250	250	250	250
Raudhatain	KPC	300	300	325	325	325	375
Sabriya	KPC	175	175.00	175	175	175	225
Abdali, Bahra and Ratqa	KPC	85	85	100	100	100	100
Neutral Zone	KPC	300	300	300	300	300	300
Total		**2,610**	**2,610**	**2,700**	**2,850**	**2,850**	**2,950**

Source: Petroleum Economics Limited.

Table A2.13 Libya Crude Production Capacity, 2005-10 (tb/d)

Libya Crude Production Capacity (tb/d)							
Field	**Operator**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Existing Capacity	Agoco	330	330	330	330	330	330
	Waha Oil	300	300	300	300	300	300
	Agip	280	280	280	280	280	280
	Repsol	210	210	210	210	210	210
	Sirte Oil	150	150	150	150	150	150
	Veba Oil	90	90	90	90	90	90
	Zuetina Oil	60	60	75	75	75	100
	Total	60	60	60	60	60	60
	Wintershall Libya	30	30	30	30	30	30
En-Naga	Petro-Canada	30	30	30	30	30	30
West Libya Gas Project	Eni	45	45	45	45	45	45
Elephant	Eni	0	150	150	150	150	150
A & D fields, Block NC-186	Repsol	65	65	65	65	65	65
B fields, Block NC-137	Total	20	20	35	35	35	35
Total		**1,670**	**1,820**	**1,850**	**1,850**	**1,850**	**1,875**

Source: Petroleum Economics Limited.

Table A2.14 Qatar Crude Production Capacity, 2005-10 (tb/d)

Qatar Crude Production Capacity (tb/d)							
Field	**Operator**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Durkan (onshore)	OP	335	335	360	360	360	375
Bul Hanine	QP	75	75	75	75	75	75
Maydam Mahzam	QP	35	35	40	40	40	40
Idd el-Shargi North	Occidental	100	100	105	105	105	105
ldd el-Shargi South	Occidental	20	20	25	25	25	25
Al-Shaheen	Maersk	200	200	225	225	225	225
Al-Rayyan	Anadarko	30	30	45	45	45	45
Al-Bunduq (Qatar share)	BOC	20	20	20	20	20	20
Al-Khalij	Total	10	10	20	20	20	50
Al-Karkara	QPD			10	10	10	10
Total		**825**	**825**	**925**	**925**	**925**	**970**

Source: Petroleum Economics Limited.

Table A2.15 Saudi Arabia Crude Production Capacity, 2005-10 (tb/d)

Field	Operator	2005	2006	2007	2008	2009	2010
Existing Capacity	Saudi Aramco	10,150	10,075	10,025	9,950	9,900	9,850
Qatif	Saudi Aramco	450	475	500	500	500	500
Abu SaSh	Saudi Aramco	300	300	300	300	300	300
Haradh-S Prolect	Saudi Aramco	150	225	300	300	300	300
KhursafliYah, Fadhill and Abu Hadriyah	Saudi Aramco			250	325	500	500
Khurais	Saudi Aramco					200	200
Shaybah	Saudi Aramco						250
Total		**11,050**	**11,075**	**11,375**	**11,375**	**11,700**	**11,900**

Source: Petroleum Economics Limited.

Table A2.16 UAE Crude Production Capacity, 2005-10 (tb/d)

UAE Crude Production Capacity (tb/d)							
Field	**Operator**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Bab	Adco	275	275	300	300	300	325
Bu Hasa	Adco	545	545	545	545	545	545
Asab	Adco	280	280	280	280	280	280
Shah	Adco	65	65	65	65	65	65
Sahil	Adco	60	60	75	75	75	75
Rijmaitha, Al Dabbiya	Adco	40	40	75	75	75	75
Huwaila	Adco			10	10	10	20
Total Onshore		**1,265**	**1,265**	**1,350**	**1,350**	**1,350**	**1,385**
Umm Shaif	Adma - Opco	290	290	275	275	275	275
Lower Zakum	Adma - Opco	250	250	250	250	250	250
Upper Zakum	Zadco	550	650	650	650	650	650
Other	n.a	100	100	100	150	175	200
Total Offshore		**1,190**	**1,290**	**1,275**	**1,325**	**1,350**	**1,375**
Total		**2,455**	**2,555**	**2,625**	**2,675**	**2,700**	**2,760**
Total		**1,670**	**1,820**	**1,850**	**1,850**	**1,850**	**1,875**

Source: Petroleum Economics Limited.

REFERENCES

Ahmad, E., and E. Mottu. 2002. *Oil Revenue Assignments: Country Experiences and Issues*. IMF WP/02/203. Washington.

Ahmad, E. and R. Singh. 2003. *Political Economy of Oil-Revenue Sharing in a Developing Country: Illustrations from Nigeria*. IMF WP/03/16. Washington.

Al-Abdulrazzaq, A. 2003. "The Challenges Facing the Oil Industry in Kuwait." *Sixth Kuwait Economist Conference*, October 18–19.

Al-Atiqi, I. M. 2005. "Supreme Petroleum Council, Ministry of Energy and Kuwait Petroleum Corporation, Issues of a Trilateral Organization." Good Governance of The National Petroleum Sector Workshop 2. Chatham House / CEPMLP, London, Sept. 25–26.

Al-Moneef, M. 1998. "Vertical Integration Strategies of the National Oil Companies." *The Developing Economies* 36(2).

Al-Obaidan, A. and G.W. Scully. 1991. "Efficiency Differences between Private and State-Owned Enterprises in the International Petroleum Industry." *Applied Economics* 23: 237–246.

Arnot, R. 2003. "Fiscal Tightness: Striking the Right Balance." *Oxford Energy Forum* 63, November.

Auty, R. 2001. *Resource Abundance and Economic Development*. OUP WIDER, New York.

Bacon, R. and A. Mattar. 2005. *The Vulnerability of African Countries to Oil Price Shocks: Major Factors and Policy Options, The Case of Oil Importing Countries*. ESMAP Report 308/05. Washington, DC.

Barnett, S. and R. Ossowski. 2002. *Operational Aspects of Fiscal Policy in Oil-Producing Countries*. IMF WP/02/177. Washington, DC.

BP. 2006. *Statistical Review of World Energy*. London.

Brumberg, D. and A. Ahram. 2007. *The National Iranian Oil Company in Iranian Politics*. Working Paper, James Baker III Institute for Public Policy, Rice University, March.

CEPMLP. 2005. *Good Governance of the National Petroleum Sector*, interim report. London: Chatham House.

Chakravorty, U., F. Fesharaki, and S. Zhou. 2000. "Domestic Demand for Petroleum in OPEC Countries." *OPEC Review*, pp. 23–52.

Coon, S. 1955. *Operation Bultiste: Promoting Industrial Development in Saudi Arabia*. A.W. Sijthoff's Uitgeversmij.

Davis, J. M., R. Ossowski, and A. Fedelino, eds. 2003. *Fiscal Policy Formulation and Implementation in Oil-Producing Countries*. IMF, Washington, DC.

Devlin, J. and M. Lewin. 2004. "Managing Oil Booms and Busts in Developing Countries." In *Managing Volatility and Crisis A Practitioner Guide.* Washington, DC: World Bank.

Eifert, B., A. Gelb, and T. Borje. 2002. *The Political Economy of Fiscal Policy and Economic Management in Oil-Exporting Countries*. Policy Research Working Paper 2899. World Bank, Washington, DC.

Eller, S., P. Hartley, and K. Medlock. 2007. *Empirical Evidence on the Operational Efficiency of National Oil Companies*. Working Paper, James Baker III Institute for Public Policy, Rice University, March.

Fasano, U. 2000. *Review of the Experience with Oil Stabilization Funds and Savings Funds in Selected Countries*. IMF WP/00/112. Washington, DC.

Gately, D. 2007. "What Oil Export Levels Should We Expect from OPEC?" *Energy Journal* 28(2).

Gately, D. 2004. "OPEC's Incentives for Faster Output Growth." *Energy Journal* 25(2): 75–96.

Gately, D. 2001. "How Plausible Is the ConsensU.S.Projection of Oil below $25 and Persian Gulf Oil Capacity and Output Doubling by 2020?" *Energy Journal* 22(4): 1–27.

Gately, D. 1995. "Strategies for OPEC's Pricing and Output Decisions." *Energy Journal* 16(3): 1–38.

Gately, D. 1984. "A Ten-Year Retrospective: OPEC and the World Oil Market." *Journal of Economic Literature* 22(3): 1100–1114.

Gately, D., and H. G. Huntington. 2002. "The Asymmetric Effects of Changes in Price and Income on Energy and Oil Demand." *Energy Journal* 23(1): 19–55.

Hannesson, R. 2001. *Investing for Sustainability: The Management of Mineral Wealth.* Kluwer Academic Publishers.

Hartley, P., and K. Medlock. 2007. *A Model of the Operation and Development of a National Oil Company*. Working Paper, James Baker III Institute for Public Policy, Rice University, March.

Hirshman, A. 1958. *The Strategy of Economic Development*. New Haven CT: Yale University Press.

Huntington, H. G. 1994. "Oil Price Forecasting in the 1980s: What Went Wrong?" *Energy Journal* 15(2): 1–22.

IEA (International Energy Agency). 1995. *Middle East Oil and Gas*. Paris.

———. 1996. *North Africa Oil and Gas*. Paris.

———. 2003. *World Energy Investment Outlook*. Paris.

———. 2005. *Energy Balances of Non-OECD Countries 1971–2003*. Paris.

———. 2005a. *World Energy Outlook 2005—Middle East and North Africa Insights*. Paris.

———. 2006. *World Energy Outlook*. Paris.

Jaffe, A. M., and J. Elass. 2007. *Saudi Aramco: National Flagship with Global Responsibilities.* Working Paper, James Baker III Institute for Public Policy, Rice University, March.

IMF (International Monetary Fund). 2005. *Guide on Resource Revenue Transparency*. Washington, DC.

Isham, J., M. Woolcock, L. Pritchett, and G. Busby. 2005. "The Varieties of Resource Experiences: How Natural Resource Export Structures Affect the Political Economy of Economic Growth." *World Bank Economic Review* 19(2).

Johnston, D. 2003. *International Exploration Economics, Risk, and Contract Analysis*. Tulsa, OK: Penwell.

Marcel, V. 2006. *Oil Titans—National Oil Companies in the Middle East*. London: Chatham House / Brookings Institution Press.

Mommer, B. 2002. *Global Oil and the Nation State.* Oxford: Oxford University Press.

Robins, P. 2004. "Slow, Slow, Quick, Quick, Slow: Saudi Arabia's 'Gas Initiative.'" *Energy Policy* 32(3), February.

Rosser, A. 2006. *The Political Economy of the Resource Curse. A Literature Survey*. Working Paper 268, Institute of Development Studies (IDS), Centre for the Future State. University of Sussex, Brighton.

Simmons, M. R. 2005. *Twilight in the Desert: The Coming Saudi Oil Shock and the World Economy*. Chichester, England: John Wiley and Sons.

Stevens, P. 2007. "Resource Impact: Curse or Blessing? A Literature Survey." *Journal of Energy Development,* IX(1) 1–42.

Stevens, P. 2005. "Resource Curse and How to Avoid It." *Journal of Energy and Development* 31(1).

Stevens, P. 2004. "National Oil Companies: Good or Bad? A Literature Survey." On-line Journal 14/10, August. *www.cepmlp.org.*

UNDP (United Nations Development Programme). 2002. *Arab Human Development Report 2002*. New York.

Van der Linde, C. 2000. *The State and the International Oil Market: Competition and the Changing Ownership of Crude Oil Assets*. Boston: Kluwer Academic Publishers.

Van Meurs, P. 1994. *World Fiscal Systems for Oil and Government to Government Competition*. New York: Gordon Barrows.

World Bank. 2003. *Iran, Country Economic Memorandum*. Washington, DC.

———. 2004. *Iran, Energy—Environment Review Policy Note*. Washington, DC.

———. 2004a. *Lebanon, Hydrocarbon Strategy Study*. Washington, DC.

———. 2004b. *Libya, Country Economic Report*. Washington, DC.

———. 2004c. *Yemen, Background and Issues Paper on Oil and Gas Sector in the Republic of Yemen*. Washington, DC.

———. 2004d. *Yemen, Household Energy Supply and Use in Yemen*. UNDP-ESMAP, Washington, DC.

———. 2004e. *Yemen, Policy Note on Budgetary and Poverty Impacts of Petroleum Pricing in Yemen*. Washington, DC.

———. 2005. *2005 Economic Developments and Prospects—Oil Booms and Revenue Management*. MENA Region, Washington, DC.

———. 2005a. *Jordan, Policy Note on Strategic Options for Energy Sector Development*. Washington, DC.

———. 2005b. *The Impact of Higher Oil Prices on Low Income Countries and on the Poor*. UNDP/ESMAP, Washington, DC.

———. 2006. *Iran: Doing Business 2006*, Washington, DC.

Zanoyan, V. 2004. *Governance of the Hydrocarbon Sector in the Gulf*. PFC Energy, Washington, DC.