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The Changing Balance of US and Global Dependence on Middle Eastern Energy Exports

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Note: This is a working draft based largely on material taken from various reports issued by the Energy Information Agency of the US Department of energy, and contains many excerpts and paraphrased portions from that reporting. It is being circulated for discussion purposes and to obtain other views on US government estimates. The author would greatly appreciate comments, criticisms, and suggestions.

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Introduction

It is too soon to draw any firm conclusions about the impact of high oil prices on Middle Eastern and North African (MENA) oil exports, on US and other imports, and on increases in conservation and the supply of alternative fuels. MENA countries are only beginning to reexamine their long-term energy export capacity investment strategies and

plans. Importing countries are equally slow to announce changes in national policy, and the private sector is only beginning to seriously react to what may or may not be significant shifts in long-term energy prices and the viability of alternative investments.

Equally important, the key modelers of global energy supply and demand have not yet had time to fully react to the recent rises in oil prices and examine cases that go above \$35 a barrel in detail. International Energy Agency (IEA), Energy Information Agency (EIA), and Organization of Petroleum Exporting Country (OPEC) projections need to be revised or expanded to examine such cases.

It is also far from clear that any form of estimate and analysis will have long-term reliability. The trends in oil supply and demand are dependent on unpredictable fluctuations in the global economy, and sudden shifts in the stability and security of exporting states, and are notoriously volatile. The short and long term elasticities in conservation, increased energy efficiency, and increases in alternative energy supplies are at least as uncertain -- in spite of a vast amount of advocacy analysis and special pleading to the contrary.

Nevertheless, analysts must try to deal with uncertainty, and recent work by the US Department of Energy, and its Energy Information Agency (EIA), provide some important potential insights into what may be happening. The EIA also has a unique mix of data collection capabilities, intelligence access, and modeling capabilities. Accordingly, this report draws heavily on excerpts from that reporting, paraphrases its conclusions in other cases, and bases its tables on material developed by the EIA.

An executive summary of its conclusions is simple: Major increases have taken place in the oil revenues of MENA oil exporting countries and potentially increase both their capital holdings and incentive to invest in added oil production capacity. A country-by-country survey shows that most major MENA exporters have both the plans and capacity to make significant increase in at least their short to mid-term exports.

If oil prices do return to the level of \$25 to \$27 a barrel in constant dollars assumed in the EIA reference case, the EIA estimates that oil will account for some 39% of the world's energy consumption through 2015, and that the US and its major trading partners in developing Asia will account for 60% of the increase in world demand through this period.¹

If oil prices stay at \$35 and above, however, the EIA assumes that major reductions will take place in the rate of increase in US and other global imports. This will not reduce strategic dependence on imports in the near-term, only slow the rate of increase in dependence. The US and other importers can and must find substitutes for MENA petroleum in the long run, but this will take decades. In the interim, the US and the global economy will actually become steadily more dependent on energy imports, and particularly on energy imports from the Gulf.

Near-Term Trends and Developments

The Department of Energy has not yet made its long-term forecasts for US and international energy developments. These are issued in April. As a result, the EIA calculations are still pegged around projections of \$25-\$27 per barrel oil. The Energy Information Agency has, however, noted that several major world events shaped world oil supply and demand during 2004, and drove them towards higher oil prices.

These events included:

- Low U.S. crude oil inventories held in commercial storage, particularly during the early months of the year;
- Uncertainty about the flow of Iraqi oil exports in the face of the high level of turmoil within that country;
- Damage inflicted on U.S. Gulf Coast and offshore oil installations following hurricanes Charley, Frances, and Ivan;
- An unexpectedly strong surge in world oil demand, particularly in China; and
- Capacity constraints (upstream, downstream, and transportation). In addition, Venezuelan political instability, Nigerian labor strikes, and internal strife between the Russian government and oil giant Yukos also contributed to push crude oil and other petroleum prices higher in 2004.

Demand Forecast

The EIA has also made more recent short-term forecasts that project that World petroleum demand growth during the 2005 and 2006 period will average about 2.5 percent per year, a rate that exceeds expected growth in non-OPEC supply and global refinery capacity.

Although the EIA notes that this is still strong growth, it is down from the 3.4-percent demand growth (2.7 million barrels per day) in 2004. The lower global oil demand growth rate in 2005 and 2006 is attributed to several factors, including the impact of high world oil prices and slower projected Chinese oil demand growth. The EIA continues to make upward revisions in the level of expected Chinese oil demand.

The EIA also estimates that the growth in U.S. demand will decline in 2005. The EIA estimates that petroleum demand averaged 20.5 million barrels per day in 2004, up 2.4 percent from 2003. Although all the major categories contributed to that increase, distillate demand grew the fastest, at 3.3 percent, buoyed by substantial growth in industrial activity and on-highway diesel fuel consumption. Motor gasoline use, accounting for almost half of total petroleum demand, increased by only 1.4 percent.

The EIA projects that U.S. petroleum demand is projected to increase by an average of 1.9 percent during 2005-2006. Motor gasoline demand growth is projected to average 1.8 percent over that period. Moderation in industrial activity growth is expected to slow average annual distillate demand growth to about 2.0 percent during 2005 and 2006.

Trends in Oil Revenuesⁱⁱ

These trends have already had a powerful impact on the economies of MENA oil exporting states, as is shown in the table below. Moreover, high oil demand, high oil prices and high revenues give MENA exporting countries the resources to buy added

internal stability and to invest in added production – if they choose to use them. As the table below shows, oil revenues have been high by historical standards over the last few years, and the U.S. Energy Information Administration (EIA) does not project significant near-term cuts in such revenues.

The EIA's January 2005 "reference case" forecast for world oil prices and production makes the following key points:ⁱⁱⁱ

- In real terms (constant \$2004), OPEC revenues peaked in 1980, at \$556 billion OPEC's worst revenue year in constant dollar terms since the early 1970s (\$90 billion in 1972) was 1998, when revenues fell to only \$120 billion, slightly below the previous low revenue year of 1988 (\$121 billion in earnings), following the oil price collapse of late 1985/early 1986. For the 1990s as a whole (1991-2000), OPEC net oil export revenues (in constant \$2004) were \$1.7 trillion, compared to \$2.3 trillion in the 1980s, and \$3.0 trillion in the 1970s. Thus, total OPEC oil export revenues in real terms during the 1990s were less than 60% of revenues in the 1970s. So far, OPEC oil export revenues (in constant \$2004) for 2001-2004 are averaging \$247 billion per year, about 47% above the annual average during the 1990s.
- Since their collapse to under \$10 per barrel in December 1998, the lowest oil price since prior to the Arab Oil Embargo of 1973, oil prices have rebounded strongly. The OPEC "basket" price (a weighted average of Algeria's Saharan Blend, Indonesia's Minas, Nigeria's Bonny Light, Saudi Arabia's Arabian Light, Dubai's Fateh, Venezuela's Tia Juana, and Mexico's Isthmus), for instance, averaged about \$36 per barrel during 2004, nearly triple its 1998 level. For 2005 and 2006, the OPEC basket is forecast to average just over \$36 per barrel. (Note: OPEC reportedly is considering changes to the composition of the basket.)
- OPEC net oil export revenues in real (inflation adjusted) terms are currently running about double the average annual revenues seen during the 1990s, but remain well below the peaks reached in 1980 and 1981. The boom-bust cycle of oil revenues seen over the past 30 years (the 1973 and 1979 oil price shocks; the 1985/86 oil price collapse; the 1990/91 Iraq crisis and oil price spike; the 1997/98 Asian economic crisis and oil price collapse; the current uncertainty regarding terrorist threats, Middle East instability, surging oil demand, etc.), makes long-term budgetary planning a challenge in many OPEC countries, and also complicates efforts to deal with balance of payments deficits, accumulated debt, budget problems, economic reform and rapid population growth.
- OPEC net oil export revenues for 2005 are projected to be \$345 billion (see table), a 2% increase from 2004 revenues of \$338 billion, and a 42% increase from 2003 revenues of \$243 billion. OPEC net oil export revenues in 2006 are expected to remain roughly flat (up 1%, to \$349 billion) compared to 2005.
- Higher oil prices come as world spare oil production capacity hovers near historic lows and as world oil demand continues to grow strongly. As of January 2005, some of the trends seen in 2003 and 2004 are continuing: 1) instability and attacks on oil infrastructure in Iraq; 2) troubles in Nigeria, resulting in a frequent loss of oil production in that country; and 3) terrorist attacks in Saudi Arabia and elsewhere.
- Although OPEC oil export revenues over the past three years have been significantly higher than during the oil price collapse of 1998/99, they remain, in inflation-adjusted, per capita terms, far below peaks reached in the late 1970s/early 1980s. For OPEC as a whole, per capita oil export revenues are projected at \$606 in 2005, or only about 34% the \$1,771 in real (constant \$2004) per capita oil export revenues achieved in 1980. This continues to have significant implications for OPEC oil price preferences and policies.
- Iraq earned an estimated \$20.0 billion in oil export revenues during 2004, more than double the \$9.8 billion earned in 2003. By 2006, Iraq's oil export earnings are expected to approach \$25 billion as net oil exports approach 2 million bbl/d, up from 1.6 million bbl/d in 2004. Forecasts for

- Iraqi oil export revenues are complicated by high levels of uncertainty regarding future Iraqi oil exports, as well as continuing attacks on oil infrastructure.
- Saudi oil export revenues increased sharply (35%) in 2004 compared to 2003, but are projected to level off during 2005 and 2006. For much of 2003 and 2004, Saudi Arabia benefited both from higher world oil prices as well as from its ability to increase production and exports sharply and rapidly due to the country's large spare production capacity. As a result, Saudi Arabia was able to replace some of the lost production from Venezuela, Iraq, and Nigeria and to reap higher revenues as a consequence. Saudi spare production capacity is now down to around 1.0-1.5 million bbl/d, however, leaving little room for increased Saudi production if needed.
 - Saudi Arabia maintains the highest share of OPEC oil export revenues (at 34% of the OPEC total in 2004). By 2006, Saudi Arabia's share of OPEC oil export revenues is expected to fall to 32%, as Iraq's share increases to 7% (from 6% in 2004). Saudi Arabia consistently has earned more oil export revenues than any other single member of OPEC, with the Saudi share ranging from below around 16% in 1971 to as high as 46% in 1981, and 34% in 2004.
 - Iran's revenue share fell after the 1978/79 Iranian Revolution (followed soon thereafter by the Iran-Iraq War for much of the 1980s), and has not recovered since. Today, Iran accounts for about 10% of total OPEC net oil export revenues, down from 17%-19% in the 1970s.
 - Iraq's oil export revenue share has fluctuated sharply, from a high of around 14% in the late 1980s, to basically 0% for several years following its August 1990 invasion of Kuwait (and the subsequent U.N. oil embargo, which continued until May 2003). Iraqi oil export revenues increased since late 1996 under the U.N. "oil-for-food" deal, which permitted Iraqi oil exports to buy food and medicine, for war reparations, and for other U.N.-authorized purposes. For 2004, Iraq's share of total OPEC oil revenues was about 6%, with the share expected to reach 7% in 2006.
 - Rapidly fluctuating oil export revenues over the past few years also have affected non-OPEC countries, such as Russia and Mexico, significantly. The economic situation in Russia, for instance, improved significantly (with positive economic growth since 1999, following a sharp downturn in 1998), in part as a result of a rebound in the country's oil and gas export revenues since 1998. Russia earned an estimated \$86 billion in net oil export revenues during 2004, up from just \$38 billion in 2001. Russian inflation-adjusted net oil export revenues in 2005 are projected to be the highest since 1990, prior to the breakup of the Soviet Union.

OPEC Net Oil Export Revenues

	<u>Change 2004/2003</u>	<u>Nominal Dollars (Billions)</u>				<u>Constant \$2004 (Billions)</u>				
		<u>2004E</u>	<u>2005F</u>	<u>2006F</u>	<u>1972E</u>	<u>1980E</u>	<u>1998E</u>	<u>2005F</u>	<u>2006F</u>	
Algeria	32%	\$22.6	\$25.3	\$25.1	\$4.8	\$25.6	\$6.3	\$24.8	\$24.2	
Indonesia	111%	-\$0.2	-\$1.3	-\$1.6	\$3.2	\$29.6	\$3.5	-\$1.3	-\$1.5	
Iran	36%	\$32.5	\$32.3	\$32.0	\$14.9	\$26.1	\$11.7	\$31.7	\$30.8	
Iraq	105%	\$20.0	\$21.3	\$24.8	\$5.2	\$53.8	\$7.5	\$20.9	\$23.9	
Kuwait	40%	\$27.4	\$28.0	\$30.0	\$10.0	\$37.3	\$8.9	\$27.5	\$28.9	
Libya	38%	\$18.1	\$19.4	\$19.6	\$10.6	\$44.3	\$6.6	\$19.0	\$18.9	
Nigeria	46%	\$29.8	\$30.6	\$32.1	\$7.5	\$47.5	\$9.8	\$30.1	\$30.9	
Qatar	43%	\$13.5	\$13.8	\$13.6	\$1.6	\$10.7	\$3.8	\$13.5	\$13.1	
Saudi Arabia	35%	\$115.1	\$113.8	\$111.0	\$16.8	\$207.8	\$39.0	\$111.7	\$107.0	
UAE	32%	\$30.3	\$31.3	\$32.4	\$3.8	\$37.5	\$10.7	\$30.7	\$31.2	
Venezuela	47%	\$29.1	\$30.3	\$29.8	\$11.0	\$36.2	\$13.2	\$29.7	\$28.7	
TOTAL	39%	\$338.4	\$344.7	\$348.9	\$89.5	\$556.2	\$120.9	\$338.4	\$336.3	

Short Term Case Studies in Increased MENA Oil and Gas Production

There are a wide variety of factors that drive the behavior of MENA countries in increasing their oil and gas production capacity, and it is far too soon to make long-term predictions about what MENA states will do if prices and revenues remain high. It is clear from EIA country surveys, however, that high prices, high demand, and high revenues have already most MENA countries to either increase production capacity or develop new plans to do so. The exceptions are those countries with major political or internal security problems.

Excerpts drawn from the key points in EIA reporting on key countries provide the following picture of regional developments in increasing oil production:^{iv}

Algeria

Algeria contains an estimated 11.8 billion barrels of proven oil reserves. Analysts consider Algeria underexplored, even though the country has produced oil since 1956, and Algeria's National Council of Energy believes that the country still contains vast hydrocarbon potential. With recent oil discoveries and plans for more exploration drilling, proven oil reserve estimates could climb upward in coming years. Algeria should also see a sharp increase in crude oil exports over the next few years, due to the rapid substitution of natural gas

- Algeria's average crude oil production during 2004 was 1.23 million barrels per day (bbl/d). Together with 445,000 bbl/d of lease condensate and 250,000 bbl/d of natural gas plant liquids, Algeria averaged about 1.93 million bbl/d of total oil production during 2004, up steadily from 1.86 million bbl/d in 2003 and 1.57 million bbl/d in 2002. In coming years, it is likely that Algeria's oil production capacity will rise, as the country plans to increase investments in exploration and development efforts. Algeria's production goal is 1.5 million bbl/d of crude oil by 2005 and 2.0 million bbl/d by 2010, a level it will likely reach at current levels of production growth.
- Over the last few years, there have been significant new oil and gas discoveries, largely by foreign companies: Algeria's oil sector, unlike that of most OPEC producers, has been open to foreign investors for more than a decade. Algeria hopes to increase its crude oil production capacity significantly over the next few years by attracting more foreign investment. Energy Minister

Chekib Khelil has stated that his goal is to double the number of companies operating in Algeria, restructure the domestic oil industry, and establish new regulatory bodies independent of the Energy and Mining Ministry.

- In late 2001, President Boutaflika introduced an important hydrocarbons reform bill. The bill would reform Sonatrach along corporate lines, allow foreign operators to act independently of Sonatrach, and possibly private Sonatrach or its subsidiaries. Progress on the bill stalled in 2003, when labor unions demonstrated against the law and Parliament rejected it. The Algerian government re-introduced the hydrocarbons bill in 2004, and meetings between Algeria's largest labor union, UGTA, and the government seemed to produce some consensus. In February 2005, the president's Council of Ministers approved the hydrocarbon bill, which included some amendments but mostly resembled the 2001 proposal. If Parliament approves the bill this time, and political analysts predict that it will because of these new amendments, then the hydrocarbons reform bill will become national law. Passage of the hydrocarbons reform would be an important, concrete step towards Algeria's goal of increasing crude oil production.
- Sonatrach, owned by the Algerian government, dominates Algeria's oil sector. Through its subsidiaries, the company has a domestic monopoly on oil production, refining, and transportation. However, Algeria has aggressively sought foreign investment in its oil sector, and the share of Algeria's oil production controlled by foreign companies has increased steadily over the past several years; in the third quarter of 2004, foreign companies controlled some 44% of Algeria's crude oil production. Algeria's oil sector, though, is not completely open to foreign companies. All foreign operators must work in partnership with Sonatrach, with Sonatrach usually holding majority ownership in these production-sharing agreements.
- Sonatrach operates the largest oil field in Algeria, Hassi Messaoud. Located in the center of the country, Hassi Messaoud produced about 350,000 bbl/d of 46° API crude in 2004, down from 550,000 bbl/d in the 1970s, but up from 300,000 bbl/d in 1989. The Hassi Messaoud area contains an estimated 6.4 billion barrels, just under 60% of the country's proven oil reserves, and Sonatrach hopes to double production at the field to 700,000-750,000 bbl/d within 5-7 years. Sonatrach also operates the Hassi R'Mel field (north of Hassi Messaoud, south of Algiers), which produced 180,000 bbl/d of 46.1° API crude in 2004. Other major fields operated by Sonatrach include Tin Fouye Tabankort Ordo, Zarzaitine, Haoud Berkaoui/Ben Kahla, and Ait Kheir. In February 2004, Sonatrach announced that it had discovered a new oilfield near Rhourde El Baguel, east of Hassi Messaoud, with possible oil reserves of 360 million barrels.
- Foreign oil operators have steadily increased their share of Algeria's oil production. The largest foreign oil producer is Anadarko, with output of 530,000 bbl/d. The company operates the Hassi Berkine South (300,000 bbl/d) and Ourhoud (230,000 bbl/d) fields in eastern Algeria. Anadarko is developing seven new oil and gas fields in Block 208 of the Berkine Basin; first production from the fields (EKT, El Merk, El Merk N, El Merk E, El Merk C, El Kheit, and El Tessekha) is possible by 2007, with output eventually reaching 150,000-200,000 bbl/d of crude oil and condensate. Exploration success rates in the Berkine Basin have been high, and several billion barrels of oil may lie within 15 miles or so of the area.
- Besides Anadarko, there are many foreign companies active in the country. BHP-Billiton operates the Rhourde Oulad Djemma (ROD) project in eastern Algeria, a series of six satellite fields that should produce 80,000 bbl/d once fully on-stream in late 2005. Amerada Hess has operated the Gassi el Agreb/Zotti field since 2000, with annual production of 40,000 bbl/d. In July 2000, several companies (Burlington Resources, Talisman, and Sonatrach) announced that they would develop the MLN (Menzel Ledjmat North) field in Block 405a. MLN should produce around 35,000-40,000 bbl/d when completed, with initial output of 14,000 bbl/d. Other major foreign producers in Algeria include Cepsa (Ourhoud, Rhourde El Krouf), and Agip (Bir Rebaa).
- Although Algeria has experienced a significant influx of foreign investment in recent years, it still has many oil fields in need of additional foreign capital and enhanced oil recovery (EOR) investment. Halliburton has an eight-year contract to provide EOR services and boost production at Hassi Messaoud, which saw production fall sharply beginning in the mid-1980s. In February

1996, Arco (now owned by BP) signed a \$1.3 billion partnership with Sonatrach to increase production at Rhourde El Baguel. The Rhourde El Baguel field is Algeria's second largest, containing about three billion barrels of proven oil reserves, but the field has produced less than 450 million barrels since 1963. BP expects to raise the field's output from 27,000 bbl/d to 125,000 bbl/d by 2010.

- In September 2003, Brazil's Petrobras signed a deal with Sonatrach to explore for oil in Algeria, and in December 2003, Algeria and China's CNPC reached a similar agreement. Also in December 2003, Cepsa and Total won drilling and exploration rights on the Bechar block in the Sahara desert. Sinopec won a \$525 million contract in October 2002 to help increase the crude oil recovery rate at Zarzataine, near Hassi Messaoud. In November 2002, the Kuwait Foreign Petroleum Exploration Company (KUFPEC) and Anadarko announced a partnership to further explore the Berkine Basin; KUFPEC has not been active in Algeria for over 10 years.
- During 2004, Algeria held its fifth licensing round for foreign development of oil and natural gas reserves. The country received eight bids for ten blocks in various parts of the country. Companies that won exploration rights included Amerada Hess (U.S.), BHP-Billiton (Australia), CNPC (China), Petroceltic (Ireland), Repsol-YPF (Spain), Sinopec (China), and Statoil (Norway). During its fourth licensing round in 2003, the country awarded 12 blocks for exploration. Algeria held its sixth licensing round in late 2004, and the country planned two more rounds in 2005.

Bahrain

All of Bahrain's 125 million barrels of onshore proven oil reserves are located in the Awali field, the first oil field to be developed in the Persian Gulf. Discovered in 1932, Awali's crude oil production peaked at more than 75,000 barrels per day (bbl/d) in the 1970s, but has declined since then. As of late 2004, Awali is producing around 35,000 bbl/d of crude oil.

- In addition to Awali, Bahrain also might have undiscovered oil reserves offshore in the Gulf of Bahrain. These areas became available for exploration and potential exploitation following the International Court of Justice's March 2001 resolution of a territorial dispute between Bahrain and Qatar over islands located between the two countries. The court awarded sovereignty over the Hawar Islands to Bahrain, allowing Qatar to retain the neighboring islands of Zubarah and Janan. Bahrain has since offered concessions to foreign investors.
- In November 2001, Bahrain awarded two blocks off the country's southeastern coast to Petronas (Malaysia) and another similarly located block to ChevronTexaco. Both companies have since begun to explore their concessions. Since then, the Calgary-based EnCana Corporation has also become involved in offshore exploration. To date, no new discoveries of oil in commercial quantities have been reported.

Iran

Iran produced 6 million bbl/d of crude oil in 1974, but has not surpassed 3.9 million bbl/d on an annual basis since the 1978/79 Iranian revolution. The EIA estimates that Iran's current sustainable crude oil production capacity is estimated at around 3.9 million bbl/d. Some analysts believe that Iran's capacity is lower, and that it could fall even further until new oilfield developments (Azadegan, Bangestan -- see below) come online in a few years. Iran's existing oilfields have a natural decline rate estimated at 200,000-250,000 bbl/d annually and are in need of upgrading and modernization. With sufficient investment, however, it is widely believed that Iran could increase its crude oil production capacity significantly.

- During the 1980s, it is believed that Iran may have maintained production levels at some older fields only by using methods that have permanently damaged the fields. Despite these problems,

Iran has ambitious plans to double national oil production -- to more than 5 million bbl/d by 2009 and 7 million bbl/d by 2024.

- The country is counting on billions of dollars in foreign investment to accomplish this, but this is unlikely to be achieved without a significant change in policy to attract such investment. To date, the Economist Intelligence Unit (EIU) estimates that Iran has attracted some \$15-\$20 billion in foreign investment for its hydrocarbons sector (the largest being Eni's investment in the South Pars gas field).
- Iran exports around 2.6 million bbl/d, with major customers including Japan, China, South Korea, Taiwan, and Europe. Iran's main export blends include Iranian Light (34.6° API, 1.4% sulphur); Iranian Heavy (31° API, 1.7% sulphur); Lavan Blend (34°-35° API, 1.8%-2% sulphur); and Foroozan Blend/Sirri (29-31° API). Iran is also the largest heavy fuel oil exporter in the Middle East.
- Iran's domestic oil consumption, 1.4 million bbl/d in 2003, is increasing rapidly as the economy and population grow. Iran subsidizes the price of oil products heavily, to the tune of \$3 billion or so per year, resulting in a large amount of waste and inefficiency in oil consumption. Iran also is forced to spend over \$2 billion per year to import oil products (mainly gasoline) that it cannot produce locally. In April 2004, as part of an effort to curtail the rise in gasoline subsidy expenditures, gasoline consumption and imports (both of which are growing rapidly), Iran's parliament voted to more than double gasoline prices, to around 95 cents per gallon. Currently, Iran's gasoline prices are amongst the cheapest in the world. In November 2003, Iran announced that it might even be forced to start rationing gasoline.
- State-owned National Iranian Oil Company (NIOC)'s onshore field development work is concentrated mainly on sustaining output levels from large, aging fields. Consequently, enhanced oil recovery (EOR) programs, including natural gas injection, are underway at a number of fields, including Marun, Karanj, and the presently inactive Parsi fields. EOR programs will require sizeable amounts of natural gas, infrastructure development, and financing. Overall, Iran's oil sector is considered old and inefficient, needing thorough revamping, advanced technology, and foreign investment.
- In May 2004, the Iranian parliament concluded a probe into a kickback and corruption scandal involving Statoil and various Iranian officials, including Mehdi Hashemi Rafsanjani, son of the country's former President and Chairman of an NIOC subsidiary. The probe determined that no Iranian officials were involved in the case. In July 2004, Oil Minister Zanganeh said that Iran would sue Statoil over the allegations.
- In October 1999, Iran announced that it had made its biggest oil discovery in 30 years, a giant onshore field called Azadegan located in the southwestern province of Khuzestan, a few miles east of the border with Iraq. Reportedly, the Azadegan field contains proven crude oil reserves of 26 billion barrels, but the field is also considered to be geologically complex, making the oil more challenging and more expensive to extract. In January 2001, the Majlis approved development of Azadegan by foreign investors using the so-called "buyback" model (see below). In February 2004, a Japanese consortium led by Inpex signed a final agreement on the \$2-\$2.8 billion project. Inpex, which has no upstream experience of its own, hopes to bring in an international partner -- possibly Total, Statoil, Sinopec, or Lukoil (while Shell has indicated that it is not interested) -- as the field's operator. One Japanese partner in the Inpex consortium -- Tomen -- has pulled out of the project (possibly under U.S. pressure), while another member -- Japex -- is considering pulling out as well. Initial production of medium-sour crude oil from Azadegan could come in 2007, ramping up from 50,000 bbl/d to 260,000 bbl/d by 2012. At its peak, Azadegan production could account for as much as 6% of Japan's oil imports.

- Since 1995, NIOC has made several other sizable oil discoveries, including the 3-5-billion-barrel Darkhovin onshore oilfield, located near Abadan and containing low sulfur, 39° API crude oil. In late June 2001, Eni signed a nearly \$1 billion, 5 1/2-year buyback deal to develop Darkhovin, with the added incentive of a limited risk/reward element (payment is to be linked to production capacity). Eni has a 60% stake in the project, with NIOC holding the remaining 40%. Ultimately, production at Darkhovin is expected to reach 160,000 bbl/d.
- NIOC also would like to develop five oil and natural gas fields in the Hormuz region: Henjam A (known as West Bukha by Oman; the two countries are discussing possible joint development); the A field near Lavan Island; the Esfandir field near Kharg Island; and two structures near the South Pars natural gas field. According to NIOC, the five Henjam fields hold an estimated 400 million barrels of oil and have a production potential of 80,000 bbl/d. Other Iranian oil fields slated for increases include Doroud, Nosrat, Farzam, and Salman.
- In February 2001, NIOC announced the discovery of a very large offshore oil field, named Dasht-e Abadan, in shallow waters near the port city of Abadan. According to a top NIOC official, Dasht-e Abadan could contain reserves "comparable" in size to Azadegan.
- The Iranian constitution prohibits the granting of petroleum rights on a concessionary basis or direct equity stake. However, the 1987 Petroleum Law permits the establishment of contracts between the Ministry of Petroleum, state companies and "local and foreign national persons and legal entities." "Buyback" contracts, for instance, are arrangements in which the contractor funds all investments, receives remuneration from NIOC in the form of an allocated production share, then transfers operation of the field to NIOC after the contract is completed. This system has drawbacks for both sides: by offering a fixed rate of return (usually around 15%-18%), NIOC bears all the risk of low oil prices. If prices drop, NIOC has to sell more oil or natural gas to meet the compensation figure. At the same time, companies have no guarantee that they will be permitted to develop their discoveries, let alone operate them. Finally, companies do not like the short terms of buyback contracts.
- The first major project under the buyback investment scheme became operational in October 1998, when the offshore Sirri A oil field (operated by Total and Malaysia's Petronas) began production at 7,000 bbl/d (Sirri A currently is producing around 20,000 bbl/d). The neighboring Sirri E field began production in February 1999, with production at the two fields expected to reach 120,000 bbl/d.
- In March 1999, France's Elf Aquitaine and Italy's Eni/Agip were awarded a \$1 billion contract for a secondary recovery program at the offshore, 1.5-billion-barrel Doroud oil and natural gas field located near Kharg Island. The program is intended to boost production from around 136,000 bbl/d to as high as 205,000 bbl/d. Total is operator of the project, with a 55% share, while Eni holds the other 45%.
- In April 1999, Iran awarded TotalFinaElf (46.75% share), along with Canada's Bow Valley Energy (15% share), a buyback contract to develop the offshore Balal field. Eni is also involved, with a 38.25% stake. The field, which contains some 80 million barrels of reserves, started producing at a 20,000-bbl/d rate in early 2003, and reportedly reached 40,000 bbl/d in February 2004.
- A much-sought-after deal to develop the giant Bangestan field has been delayed several times after an expected award in 2001. Bangestan includes three oilfields (Anwaz, Mansuri, Ab-Teymour) that currently produce about 250,000 bbl/d of oil, but the field is one of the oldest in the country and requires investment and technology to compensate for natural decline. In April 2003, Shell stated that it was frustrated with the slow pace of negotiations on Bangestan, including numerous changes to terms of the project. Currently, bidders on the project include Total and BP,

- with Total considered the favorite. Development of Bangestan could cost \$3 billion over 10 years, and aims to raise output to 600,000 bbl/d.
- In May 2002, Iran's Oil Ministry signed a \$585 million buyback contract with NIOC subsidiary PetroIran to develop the Foroozan and Esfandiar offshore oilfields. PetroIran is expected to increase production at the fields from around 40,000 bbl/d at present to 105,000 bbl/d by late 2005. The two oilfields straddle the border with Saudi Arabia's Lulu and Marjan fields.
 - In other news related to "buyback" deals, the Cheshmeh-Khosh field, which previously had been awarded to Spain's Cepsa for \$300 million, was re-awarded in January 2004 to state-owned Central Iranian Oil Fields Company (CIOFC). In December 2003, Cepsa and OMV withdrew from lengthy negotiations after a reported failure to agree on development costs and buyback terms. It remains possible, however, that Cepsa and OMV could still be involved at Cheshmeh-Khosh in some way. The objective is to raise crude production at the field from 40,000 bbl/d currently to 80,000 bbl/d within four years.
 - Recently, Iran appears to have had some second thoughts about buybacks (including charges of corruption, insufficient benefits to Iran, and also worries that buybacks are attracting too little investment), and reportedly is considering substantial changes in the system. In late May 2002, Canada's Sheer Energy became the first foreign company since Eni's Darkhovin deal to reach agreement (\$80 million to develop the Masjed-I-Suleyman, or MIS, field) under the Eni terms. Sheer's goal was to boost MIS production from 4,500 bbl/d to 20,000 bbl/d, but the company was replaced by China's CNPC after reported delays and difficulties in fulfilling contract terms. In general, the addition of a limited risk/reward element has not attracted the flood of foreign energy investment which Iran both needs and wants. In January 2004, Iran announced modifications to the "buy-back" model, extending the length of such contracts from the current 5-7 years to as many as 25 years, while allowing for continued involvement of oil companies after the field is handed over to NIOC.
 - In early November 2003, NIOC announced the launch of a new tender for 16 oil blocks. The contracts reportedly are to be based on the buyback model, but for the first time will cover exploration, appraisal, and development. In September 2003, Russia's Lukoil said it had been granted approval by NIOC to explore for oil in the Anaran block along the border with Iraq. Norsk Hydro is currently in charge of the project.
 - The Doroud 1&2, Salman, Abuzar, Foroozan, and Sirri fields comprise the bulk of Iran's offshore oil output. Iran plans extensive development of existing offshore fields and hopes to raise its offshore production capacity to 1.1 million bbl/d (from around 675,000 bbl/d currently). It is estimated that development of new offshore Persian Gulf and Caspian Sea oil fields will require investment of \$8-\$10 billion. In early October 2003, Iran re-launched a tender for eight exploration blocks in the Persian Gulf after receiving little interest from a January 2003 announcement. One area considered to have potential is located near the Strait of Hormuz. Another interesting area is offshore near Bushehr, where Iran claimed in July 2003 to have discovered three fields with potentially huge -- 38 billion barrels oil reserves. In May 2004, Brazil's Petrobras signed a 3-year, \$32-\$34 million deal to develop the Tousan fields of the Persian Gulf.
 - In late 2001 and early 2002, Shell brought part of the \$800 million Soroush-Nowrooz development online, with production of around 60,000 bbl/d. The two fields are located offshore, about 50 miles west of Kharg Island, and contain estimated recoverable reserves of around 1 billion barrels of mainly heavy oil. Although Soroush was shut down briefly in March 2003 at the outset of war with Iraq, output from the field is still expected to reach 190,000 bbl/d in the next few months (the original target had been May 2004, and in late July 2004 NIOC's managing director said he believed Shell should be fined for the delay). In early 2003, a consortium of three Japanese companies bought a 20% share in the Soroush/Nowrooz development project. In March 2004, the Iranian Offshore Oil Company (IOOC) awarded a \$1.26 billion contract for recovery of

NGLs and natural gas from Soroush, Nowrooz, Foroozan, and Abuzar to Japan's JGC Corporation. Ethane from the gas will feed an ethylene complex at the Kharg petrochemical complex.

- Iran has potentially significant Caspian reserves of its own, although nothing has been "proven" at this point to be recoverable. Currently, Iran has no oil or natural gas production in the Caspian region. In early 2004, a 3-D seismic survey of the southern Caspian was being conducted by Iran's Oil Survey Co.
- At the present time, Iran continues to maintain that regional treaties signed in 1921 and 1940 between Iran and the former Soviet Union, which call for joint sharing of the Caspian's resources between the two countries, remain valid. Iran has rejected as invalid all unilateral and bilateral agreements on the utilization of the Sea. As such, Iran is insisting that either the Sea should be used in common, or its floor and water basin should be divided into equal (20%) shares. Under this plan, the so-called "condominium" approach, the development of the Caspian Sea would be undertaken jointly by all of the littoral states. However, using the equidistant method of dividing the seabed on which Kazakhstan, Azerbaijan, and Russia have agreed, Iran would only receive about 12%-13% of the Sea. In March 2002, Iran's Oil Minister Zanganeh asserted that Iran would begin exploiting its fifth of the Sea within a short time, and would not permit "any other party to engage in oil exploration" in this area. In January 2003, Iranian Foreign Minister Kamal Kharrazi reiterated the country's claim to a 20% share of the Caspian..
- As of July 2004, no agreement has been reached among Caspian Sea region states on this matter. In March 2003, Iran and Turkmenistan noted "the need to achieve a consensus between the five [littoral] countries," while the two countries reportedly moved ahead in charting their common border in the Sea. In late April 2002, a meeting between the five Caspian littoral states ended without agreement on a new treaty. On May 20, 2002, Iran and Azerbaijan also failed to reach agreement on Caspian Sea division. On July 23, 2001, tensions flared in the Caspian Sea region when an Iranian gunboat intercepted two BP oil exploration vessels off Azerbaijan's coast. Following the incident, BP suspended exploration in the disputed block (which Iran calls Alborz).
- Iran's desire to become a player on the Caspian oil front has led it to push forward in the area of oil "swaps." This arrangement involves the delivery of Caspian oil to refineries in northern Iran for local consumption, while an equivalent amount of Iranian oil is exported through Persian Gulf terminals such as Kharg Island. Shippers normally pay a "swap fee" of \$1.50-\$2.00 per barrel, with swaps handled by Naftiran Intertrade Co. (Nico), the Swiss-based trading arm of NIOC. As of May 2004, about 130,000 bbl/d of Russian, Turkmen, and Kazakh oil were being shipped to Neka, and then on to Tehran by the existing 170,000-bbl/d capacity Neka-Tehran pipeline. Eventually, Iran hopes to upgrade its facilities in order to greatly expand oil swaps, partly in order to compete with the 1-million-bbl/d Baku-Tbilisi-Ceyhan (BTC) pipeline, scheduled to open in late 2005. Iran plans to boost capacity at its northern refineries at Arak, Tabriz, and Tehran to about 800,000 bbl/d in order to process additional Caspian oil, to boost Neka-Tehran pipeline capacity to 500,000 bbl/d, and also to increase port capacity at Neka to 500,000 bbl/d. In August 2003, a \$500 million tender was issued to upgrade the Tehran and Tabriz refineries in order to handle 370,000 bbl/d of Caspian crude. This follows a \$330 million project, completed in late 2003, to expand storage at Neka and to upgrade the Tehran and Tabriz refineries. Among other issues, Caspian crude oil has a high sulfur content (specifically, a substance known as "mercaptans"), makes it challenging to refine. Ultimately, Iran hopes to transform Neka into the "Rotterdam of the Caspian."
- Aside from Caspian "swaps," there were reports in early August 2004 that Iran and Iraq had reached a framework swap agreement involving possible construction of a 24-mile, 350,000-bbl/d oil pipeline from Basra to the Abadan refinery in southwestern Iran. In exchange, Iran would export a similar volume of oil from Kharg Island, crediting Iraq minus a swap fee. The pipeline idea was discussed by Iraqi Oil Minister al-Uloum visited Tehran in December 2003 and met with Iranian Oil Minister Zanganeh.

Iraq

Iraq contains 115 billion barrels of proven oil reserves, the third largest in the world (behind Saudi Arabia and Canada), concentrated overwhelmingly (80% or so) in southern Iraq. Estimates of Iraq's oil reserves and resources vary widely, however, given that only about 10% of the country has been explored. Some analysts (the Baker Institute, Center for Global Energy Studies, the Federation of American Scientists, etc.) believe, for instance, that deep oil-bearing formations located mainly in the vast Western Desert region, for instance, could yield large additional oil resources (possibly another 100 billion barrels or more), but have not been explored. Other analysts, such as the US Geological Survey, are not as optimistic, with median estimates for additional oil reserves closer to 45 billion barrels. In August 2004, Iraqi Oil Minister Ghadban stated that Iraq had "unconfirmed or potential reserves" of 214 billion barrels.

- According to Tariq Shafiq, a founding Vice President of INOC, Iraq's oil development and production costs are among the lowest in the world, ranging from as low as \$750 million for each additional million bbl/d day in Kirkuk, to \$1.6 billion per million bbl/d near Rumaila, and as high as \$3 billion per million bbl/d for smaller fields in the northwestern part of the country.
- In contrast, Cambridge Energy Research Associates (CERA) estimates an average cost for Iraqi oil development of \$3.5 billion per million bbl/d for the country as a whole, which is higher than Tariq Shafiq's estimates, but still relatively low by world standards. Either way, Iraq is considered a highly attractive oil prospect, with only 17 of 80 discovered fields having been developed, and few deep wells compared to its neighbors. Overall, only about 2,300 wells reportedly have been drilled in Iraq (of which about 1,600 are actually producing oil), compared to around 1 million wells in Texas, for instance.
- Historically, Iraqi production peaked in December 1979 at 3.7 million bbl/d, and then in July 1990, just prior to its invasion of Kuwait, at 3.5 million bbl/d. From 1991, Iraqi oil output increased slowly, to 600,000 bbl/d in 1996. With Iraq's acceptance in late 1996 of U.N. Resolution 986, which allowed limited Iraqi oil exports in exchange for food and other supplies ("oil-for-food"), the country's oil output began increasing more rapidly, to 1.2 million bbl/d in 1997, 2.2 million bbl/d in 1998, and around 2.5 million bbl/d during 1999-2001. Iraqi monthly oil output increased in the last few months of 2002 and into early 2003, peaking at around 2.58 million bbl/d in January 2003, just before the war.
- Iraq's southern oil industry was decimated in the 1990/1991 Gulf War, with production capacity falling to 75,000 bbl/d in mid-1991. That war resulted in destruction of gathering centers and compression/degassing stations at Rumaila, storage facilities, the 1.6-million bbl/d (nameplate capacity) Mina al-Bakr/Basra export terminal, and pumping stations along the 1.4-million bbl/d (pre-war capacity) Iraqi Strategic (North-South) Pipeline. Seven other sizable fields remain damaged or partially mothballed. These include Zubair, Luhais, Suba, Buzurgan, Abu Ghirab, and Fauqi. Generally speaking, oilfield development plans were put on hold following Iraq's invasion of Kuwait, with Iraqi efforts focused on maintaining production at existing fields.
- One major challenge in maintaining, let alone increasing, oil production capacity, was Iraq's battle with "water cut" (damaging intrusion of water into oil reservoirs) especially in the south. In 2000, Saybolt International had reported that NOC and SOC were able to increase their oil production through use of short-term techniques not generally considered acceptable in the oil industry (i.e., "water flooding," injection of refined oil products into crude reservoirs). The Saybolt report now appears to have been largely accurate. In addition, a U.N. report in June 2001 said that Iraqi oil production capacity would fall sharply unless technical and infrastructure problems were addressed. Oil market consultants PFC Energy have stated that "unless water injection used to maintain pressure in the southern fields is restarted, there is a strong possibility that [they] will go into more rapid decline and suffer permanent reservoir damage." PFC added that "this means the rehabilitation work at the Qarmat Ali water processing plant is crucial." U.N. oil experts reportedly have estimated that some reservoirs in southern

Iraq have been so badly managed that their ultimate recovery rates might be only 15%-25%, well below the 35%-60% usually seen in the oil industry.

- Throughout most of the 1990s, Iraq did not generally have access to the latest, state-of-the-art oil industry technology (i.e., 3D seismic, directional or deep drilling, gas injection), sufficient spare parts, and investment. Instead, Iraq reportedly utilized sub-standard engineering techniques (i.e., overpumping, water injection/"flooding"), obsolete technology, and systems in various states of decay (i.e., corroded well casings) in order to sustain production. In the long run, reversal of all these practices and utilization of the most modern techniques, combined with development of both discovered fields as well as new ones, could result in Iraq's oil output increasing by several million barrels per day. In February 2004, former Iraqi Oil Minister Issam al-Chalabi stated that recent efforts to boost Iraqi production might be harming the country's oil reserves.
- The northern Kirkuk field, first discovered in 1927, forms the basis for northern Iraqi oil production. Declining crude oil qualities -- and an increased "water cut" as well -- was likely the result of overpumping -- as high as 680,000 bbl/d, well above the field's estimated optimal production rate of 250,000 bbl/d-- as Iraq attempted to sell as much oil as possible in the months leading up to the March/April 2003 war. In addition, some analysts believe that poor reservoir management practices during the Saddam Hussein years --including reinjection of excess fuel oil (as much as 1.5 billion barrels by one estimate), refinery residue, and gas-stripped oil -- may have seriously, even permanently, damaged Kirkuk. Among other problems, fuel oil reinjection has increased oil viscosity at Kirkuk, making it more difficult and expensive to get the oil out of the ground.
- Besides Kirkuk, other fields in northern Iraq include Bai Hassan, Jambur, Khabbaz, Ajil (formerly "Saddam"), and Ain Zalah-Butmah-Safaia. An estimated 60% of Northern Oil Company's (NOC) facilities in northern and central Iraq were damaged during the Gulf War.
- During the war, seven Iraqi oil wells were set on fire, out of around 1,500 total wells. On April 14, 2003, the last of these fires were extinguished at the South Rumaila field. This was considered a significant accomplishment, given pre-war speculation that Iraq might set many of its oilfields ablaze as it did with Kuwaiti oilfields in 1991. However, in spite of the fact that little damage was done to Iraq's oil fields during the war itself, looting and sabotage after the war ended was highly destructive, accounting for perhaps 80% of total damage. On April 22, 2003, the first oil production since the start of the war began at the Rumaila field, with the restart of an important gas/oil separation plant (GOSP).
- Since the 2003 war the country has been exporting a "cocktail of crudes" rather than the normal Basra Blend from southern Iraq, in part due to a shortage of storage facilities at Persian Gulf terminals. As of early November 2004, Iraqi production (on a net basis) had reached perhaps 2.0 million bbl/d, with "gross" production (including reinjection, water cut, and "unaccounted for" oil) of around 2.2 million bbl/d. For the first ten months of 2004, Iraqi crude oil output was averaging around 2.0 million bbl/d. Although Iraq is a member of OPEC, its oil output has not been constrained by OPEC quotas since it resumed oil exports in December 1996.
- Starting in mid-May 2003, the USACE -- which had the lead in restoring Iraq's oil output to pre-war levels -- began a major effort to ramp up production in the country. In May 2004, Iraq's Qarmat Ali water injection facility reportedly was 75% operational again, helping boost production from Rumaila and other southern oil fields.
- As of early November 2004, Iraqi oil output was fluctuating somewhat, but generally was averaging around 2.2 million barrels per day (bbl/d) on a "gross" basis (and about 2.0 million bbl/d on a net basis). Officially, Iraq aims to reach 3.0 million bbl/d of oil output by the end of 2004, although this looks unlikely. In June 2004, former UK Ambassador to Iraq, Jeremy Greenstock, estimated that Iraq would require \$10-\$20 billion in foreign investment in order to reach oil production of 4 million bbl/d, and in August 2004, Oil Minister Ghadban said that it would take four years to reach this level of output. On October 31, 2004, Ghadban said that \$1.2 billion had been allocated for investment in Iraq's upstream oil sector with the aim of boosting the country's oil production to 3.2 million bbl/d.
- Prior to the toppling of Iraq's Ba'athist regime, Iraq reportedly had negotiated several multi-billion dollar deals with foreign oil companies mainly from China, France, and Russia. Deutsche Bank

estimated that \$38 billion worth of contracts were signed on new fields -- "greenfield" development -- with potential production capacity of 4.7 million bbl/d if all the deals came to fruition (which Deutsche Bank believed was highly unlikely). Now, the legal status of these agreements is up in the air, increasing the uncertainty level for companies interested in doing business with Iraq. Besides legal issues, companies are also looking for a relatively stable security situation, a functioning government, and other conditions to be in place before they move heavily into the country. In February 2004, Iraqi Interim Trade and Investment Minister, Ali Allawi, announced that negotiations with potential investors in Iraq's upstream oil sector would be left for an elected, sovereign government, possibly delaying such deals until 2005 or 2006. In September 2004, Prime Minister Allawi stated that he preferred production sharing contracts (PSCs) as a means of attracting foreign investment into Iraq's oil sector.

- Russia, which is owed billions of dollars by Iraq for past arms deliveries, has a strong interest in Iraqi oil development. This includes a \$3.7 billion, 23-year deal to rehabilitate Iraqi oilfields, particularly the 11-15 billion barrel West Qurna field (located west of Basra near the Rumaila field). West Qurna is believed to have production potential of 800,000-1 million bbl/d. In mid-December 2002, the Iraqi Oil Ministry had announced that it was severing its contract with the Lukoil consortium on West Qurna due to "fail[ure] to comply" with contract stipulations. Specifically, the Iraqis had cited Lukoil's failure to invest a required \$200 million over three years. Two other, smaller, stakes in West Qurna by Russian companies Zarubezhneft and Mashinoimport apparently were left intact. During the summer of 2004, Lukoil began training Iraqi oil specialists at facilities in western Siberia, an initiative reportedly aimed at saving Lukoil's West Qurna contract. The company also announced that it aimed to begin oil production from West Qurna in 2005 (although this seems highly unlikely).
- In addition, three exploration and production deals were signed between Iraq and Russian companies (Soyuzneftegaz, Stroytransgas-Oil, and Tatneft, to develop the 100,000-bbl/d Rafidain field, the Western Desert's Block 4, and the Western Desert's Block 9, respectively). Despite all this, Russia's Foreign Ministry had stated that it viewed the Iraqi decision on Lukoil and West Qurna "with regret." In May 2003, Lukoil said it would fight to keep the contract, and Russia's Deputy Foreign Minister said that Russia would seek compensation if contracts signed under the Saddam Hussein regime now were not honored. As of April 2004, Soyuzneftegaz reportedly was talking to several other companies about developing Rafidain.
- In early April 2001, Russia's Zarubezhneft received U.N. approval to drill 45 wells in the Ajil (formerly "Saddam") field, plus Kirkuk and Bai Hassan, as part of an effort to reduce water incursion into the fields. The Ajil field contains 3 billion barrels of oil and 5 trillion cubic feet (Tcf) of associated gas. Iraq had been seeking foreign assistance for a second-phase Ajil development, which would raise oil production capacity to 50,000 bbl/d, as well as 300 Mmcf/d of gas.
- In May 2003, another Russian company, Tatneft, set up a joint venture with Germany's MRH in order to win work in Iraq's oil sector. According to Tatneft's President, the company had been close to reaching a deal on exploring Block 9 in Iraq's Western Desert region prior to the war. In October 2001, a joint Russian-Belarus oil company, Slavneft, had signed a \$52 million service contract with Iraq on the 2-billion-barrel, Suba-Luhais field in southern Iraq. Full development of Suba-Luhais could result in production of 100,000 bbl/d (350 API) at a cost of \$300 million over three years. In early February 2004, Iraq's Oil Ministry issued a tender for development of Suba-Luhais, with bids due by April 15, 2004 (and a possible award by the end of 2004).
- In January 2004, Iraq's State Company for Oil Projects (SCOP) issued tenders for development of the Khurmala dome -- the largest complex in the Kirkuk field -- with the goal of increasing production at Kirkuk by 100,000 bbl/d. Development of Khurmala is aimed at compensating for declines in output at the mature Kirkuk field. SCOP also invited bids for the Hamrin field, north of Tikrit, for production of 60,000 bbl/d. In September 2004, the head of SCOP, Ahmed al-Shammaa, stated that he expected development licenses on Khurmala (plus Hamrin and Suba-Luhais) to be awarded by the end of the year. In July 2004, SCOP began evaluating bids -- from Romania's Petrom, Ireland's Petrel Resources, and UAE's Dome, among others -- for projects to develop Khurmala, Hamrin, and Suba-Luhais.

- Another large oilfield slated for development is Majnoon, discovered by Braspetro of Brazil in 1975, and containing reserves of 11-30 billion barrels of 28o-35o API oil. Majnoon is located 30 miles north of Basra on the Iranian border. In the 1990s, French company Elf Aquitaine (now merged with Total) negotiated on a possible \$4 billion deal with Iraq on development rights for Majnoon. In 1999, however, TotalFinaElf declined to sign a 23-year production sharing agreement (PSA) with Iraq on Majnoon. Following this, the field reportedly was brought onstream (under a "national effort" program begun in 1999) in May 2002 at 50,000 bbl/d. Future development on Majnoon ultimately could lead to production of 450,000 bbl/d within two years or so at an estimated (according to Deutsche Bank) cost of \$4 billion. Eventually, Majnoon could produce significantly more oil than that, possibly as high as 3 million bbl/d.
- In early June 2003, China's National Petroleum Company (CNPC) refuted a comment by Thamir Ghadban that CNPC's contract on the 90,000-bbl/d al-Ahdab development was now "void by mutual agreement." CNPC agreed in 1997 to spend \$1.3 billion on Al-Ahdab, located in southern Iraq, but no progress was made while sanctions remained in place.
- The 2.5-5 billion-barrel Halfaya project is the final large field development in southern Iraq. Prior to the war, several companies (BHP, CNPC, Agip/ENI) reportedly had shown interest in Halfaya, which ultimately could yield 200,000-300,000 bbl/d in output at a possible cost of \$2 billion. Smaller fields with under 2 billion barrels in reserves also had received interest from foreign oil companies. These fields included Nasiriya (Eni, Repsol), Tuba (ONGC, Sonatrach, Pertamina), Ratawi (Shell, Petronas, CanOxy), Gharaf (Mashinimport, Rosneftgasexport), Amara (PetroVietnam), Noor (Syria), and more.
- In May 2003, Thamir Ghadban stated that three exploration agreements for blocks in Iraq's Western Desert were still valid. These included Indonesia's Pertamina on Block 3, Russia's Stroitransgas on Block 4, and Indian's Oil and Natural Gas Corp. for Block 8. In January 2003, Stroitransgas signed a \$33.5 million contract for exploration on Block 4, and in July 2003, it indicated its interest in winning post-war business in Iraq. In September 2003, Pertamina announced that it planned to begin oil and gas exploration in Block 3, investing around \$24 million over the next three years. The small Irish company, Petrel Resources, also has expressed interest in exploring and developing oil resources in western Iraq. In May 2004, Pertamina suspended its exploration activities in the Western Desert region due to security co

Kuwait

Kuwait itself contains an estimated 96.5 billion barrels of proven oil reserves, around 8% of the world total, and around 1,600 producing oil wells. The Saudi-Kuwaiti Neutral Zone (also known as the "Divided Zone") area, which Kuwait shares with Saudi Arabia, holds an additional 5 billion barrels of reserves, half of which belong to Kuwait., bringing Kuwait's total oil reserves to 99.0 billion barrels.

- The bulk of Kuwait's oil production capacity is located in the southeastern onshore Greater Burgan field, whose Burgan, Magwa, and Ahmadi structures have production capacity of around 1.6 million bbl/d. Kuwait's other main producing fields include the northern fields of Raudhatain (220,000 bbl/d of production capacity, with higher "surge" capacity) and Sabriya (95,000 bbl/d of production capacity, with plans to raise this to 200,000 bbl/d); the southwestern fields of Minagish and Umm Qudayr (200,000 bbl/d); Abdali, Bahra and Ratqa (50,000 bbl/d) in the north; and Kuwait's share of the Saudi-Kuwaiti Neutral Zone (270,000 bbl/d).
- Construction of new gathering centers is a major focus of Kuwait's upstream capacity expansion program. Prior to the Iraqi invasion in 1990, Kuwait had 26 gathering centers (GCs), with a total capacity of 4 million bbl/d. Reportedly, 23 out of 26 GCs were either damaged or destroyed during the war. By 1993, operations at 18 GCS had been restored. In January 1996, KPC awarded China Petroleum Engineering Construction Corporation (CPECC) a \$390 million contract to build two new GCS, a significant step in Kuwait's efforts to increase its oil production. CPC and Kuwait Oil Company (KOC) constructed the GCS, designated GC-27 and GC-28, at the Umm Gudair and

Minagish fields, respectively. Work was completed in early 2001, three years behind the original schedule, mainly due to construction delays. The Umm Gudair GC has capacity of 190,000 bbl/d, and Minagish has design capacity of 210,000 bbl/d. The two facilities are part of Kuwait's plan to raise oil output from West Kuwait to more than 500,000 bbl/d (from 120,000 bbl/d), and overall production capacity to more than 3 million bbl/d (from around 2.2 million bbl/d currently).

- Kuwait continues to plan for significant expansion in its production capacity. Kuwait hopes to reach capacity of 4 million bbl/d by 2020, up from around 2.3-2.4 million bbl/d at present. As part of this plan, known as "Project Kuwait," Kuwait is considering permitting foreign oil companies to invest in upstream production, although only on "incentivised buy-back contract" (IBBC) arrangements, which do not involve production sharing, concessions, or the "booking" of reserves by foreign companies. Kuwait's constitution -- and longtime policy -- bars foreign investment in the country's natural resources, except as provided for by law. KPC reportedly is offering rates of return in the 5%-8% range over 20/25 years, while the international oil companies would prefer 16%-20%. Unlike PSA's, the structure of the IBBC agreements allows the Kuwaiti government to retain full ownership of oil reserves, control over oil production levels, and strategic management of the ventures. Foreign firms are to be paid a "per barrel" fee, along with allowances for capital recovery and incentive fees for increasing reserves, in their role as service provider/contractor.
- "Project Kuwait" is a \$7 billion, 25-year plan, first formulated in 1997 by the SPC, to increase the country's oil production (and to help compensate for declines at the mature Burgan field), with the help of international oil companies (IOCs). In particular, Kuwait aims to increase output at five northern oil fields -- Abdali, Bahra, Ratqa, Raudhatain, and Sabriya (Kuwait's third largest field) -- from their current rate of around 600,000 bbl/d to 900,000 bbl/d within three years. To date, "Project Kuwait" has made little headway, however, in large part due to political opposition and resistance from nationalists and Islamists in parliament to the idea of allowing foreign companies into the country's oil sector. Reportedly, parliamentary elections in July 2003 resulted in the defeat of several "Project Kuwait" opponents, as well as the appointment of a new energy minister (Sheikh Ahmad al-Fahd al-Sabah) and Prime Minister (Sheikh Sabah al-Ahmad al-Sabah).
- In February 2003, KPC completed a draft contract and proposed financial terms for Project Kuwait. There are three major consortia competing for the project, led by: 1) ChevronTexaco (along with Total, PetroCanada, Sibneft and Sinopec); 2) ExxonMobil (along with Shell, ConocoPhillips, and Maersk); and 3) BP (along with Occidental, ONGC/Indian Oil Corp.). Bidding is set to begin in the second half of 2004. Reportedly, KPC prefers to have three groups working under three separate IBBCs: one for Raudhatain and Sabriya (the largest IBBC); one for Ratqa, Bahra and Abdali; and one for Minagish and Umm Gudair. Currently, foreign companies like BP, Shell, and ChevronTexaco operate in Kuwait strictly under service contracts (SCs).
- The fields which the Kuwaiti government intends to open to foreign investment are all currently operating fields in northern or western Kuwait, including Raudhatain, Sabriya, Ratqa, Bahra, Minagish, and Umm Gudair. Kuwait's largest field, Burgan, is to remain off-limits to foreign investment under the new plan. Kuwait also reportedly is planning to invest \$6 billion in three areas near the Iraqi border -- Abdali, Ratqa, and Raudhatain -- while utilizing enhanced oil recovery (EOR) techniques in order to increase production capacity at Minagish from 150,000 bbl/d to 250,000 bbl/d. One challenge that often comes along with EOR techniques like water injection is an increasing "water cut." KPC has estimated that increasing Kuwait output to 4 million bbl/d will produce 10 million bbl/d of water, which will need to be processed and disposed of.
- Kuwait's current policy, in place since 1975, limits the participation of foreign oil companies to providing technical assistance and construction and maintenance services under contracts, which pay them fixed prices for specific activities. In fact, Kuwait's constitution forbids the award of concessions which give an ownership interest in Kuwait's natural resources to foreign entities. Nevertheless, the government has repeatedly hinted at a desire to find a way to involve foreign oil companies in increasing production without violating the constitution. The Supreme Petroleum

Council (SPC), which controls Kuwait's oil and gas sectors on a day-to-day basis, approved foreign cooperation in principle in 1997, but opening upstream activities to deeper involvement by foreign oil companies is highly controversial with opposition members of the Kuwaiti parliament. In February 2000, the Kuwaiti parliament passed a resolution calling on the government not to proceed with the program until legal issues involving foreign interests in the Kuwaiti oil sector were resolved. New legislation dealing with the foreign investment program is currently under consideration in the Kuwaiti parliament.

- The Neutral Zone (or "Divided Zone") encompasses a 6,200 square-mile area partitioned equally between Kuwait and Saudi Arabia under a 1992 agreement. The Neutral Zone contains an estimated 5 billion barrels of oil and 1 trillion cubic feet (Tcf) of natural gas. Oil production in the Neutral Zone, which currently is running around 620,000 bbl/d (around half offshore and half onshore), is divided equally between Saudi Arabia and Kuwait. Major Neutral Zone onshore fields include Humma, South Fawaris, South Umm Gudair, and Wafra. Offshore fields include Hout and Khafji, which produce 33o API and 28o API gravity oils, respectively.
- In July 2002, Kuwait and Saudi Arabia formed a 50/50 joint venture to maintain and increase oil production at offshore Neutral Zone oilfields.

Libya

Libya has total proven oil reserves of 39 billion barrels. The country has 12 oil fields with reserves of 1 billion barrels or more each, and two others with reserves of 500 million-1 billion barrels. However, Libya would like foreign company help to increase the country's oil production capacity from 1.60 million bbl/d at present to 2 million bbl/d by 2008-2010, and to 3 million bbl/d by 2015. In order to achieve this goal, and also to upgrade its oil infrastructure in general, Libya is seeking as much as \$30 billion in foreign investment over that period. Libya is considered a highly attractive oil province due to its low cost of oil recovery (as low as \$1 per barrel at some fields), the high quality of its oil, its proximity to European markets, and its well-developed infrastructure.

If Libya reaches 2 million bbl/d in oil production capacity, this would take the country back to a level it has not seen since the late 1970s. During that decade, Libya's revolutionary government imposed tough terms on producing companies, leading to a slide in oilfield investments and oil production -- from 3.3 million bbl/d in 1970 to 1.5 million bbl/d in 1975, before rising again to 2.1 million bbl/d in 1979. During the 1980s, Libyan oil production averaged around 1.2 million bbl/d, rising to around 1.4 million bbl/d in the 1990s.

- Libya remains "highly unexplored" according to Wood Mackenzie Consultants, and has "excellent" potential for more oil discoveries. In addition, despite years of oil production, only around 25% of Libya's area covered by agreements with oil companies. The under-exploration of Libya is due largely to sanctions and also to stringent fiscal terms imposed by Libya on foreign oil companies.[more]
- The lifting of U.N. and U.S. sanctions, along with possible changes to Libya's 1955 hydrocarbons legislation (the country is drafting a new hydrocarbons law to cover all types of contracts), is likely to prove extremely helpful in boosting the country's oil output. Sanctions had caused delays in a number of field development and Enhanced Oil Recovery (EOR) projects, and had deterred foreign capital investment to a significant extent. Also the full lifting of sanctions is important for Libya's oil industry since U.S. companies are leaders in advanced oil and gas technologies, many of which they have under patent.
- On January 30, 2005, Libya held its first round of oil and gas exploration leases since the United States ended most sanctions against the country. Known as EPSA 4, the round -- launched in

August 2004 -- offered 15 exploration areas for auction. Approximately 56 companies registered 104 bids, but in the end only a handful of companies actually won acreage in the intensely competitive bidding. In the end, acreage in 9 areas (5 onshore oil blocks and 4 offshore, gas-prone blocks) went to U.S.-based Occidental Petroleum, while ChevronTexaco and Amerada Hess won acreage in 1 block each. Other companies with winning bids included the Indian Oil Corp., Liwa (UAE), Oil Search Ltd. (Australia), Petrobras (Brazil), Sonatrach (Algeria), Verenex (Canada), and Woodside (Australia). Significantly, no European companies were awarded acreage in this round.

- Specifically, an Occidental-Liwa consortium won onshore blocks 131 and 136 in the Murzuq basin, plus onshore blocks 106 and 124 in the Sirte area, and block 59 in the Cyrenaica area near the Egyptian border. Occidental also won offshore block 53 (Gulf of Sirte), with offshore blocks 35, 36 and 52 (all Gulf of Sirte) going to an Occidental/Liwa/Woodside consortium. Sonatrach won onshore block 65 (Ghadames), with a Verenex-led group getting onshore block 47 (North Ghadames, near Tunisia). Petrobras won offshore block 18 (Gulf of Sirte), Indian Oil Corp. won block 86 (West Sirte), and Amerada Hess won offshore block 54 (Gulf of Sirte). It is believed that winning companies paid a high price for Libyan acreage -- reportedly on both signature bonuses and production shares -- highlighting the great degree of interest in the relatively underexplored country. Occidental, for instance, paid \$25.6 million for Block 106 alone.
- NOC also announced that Libya would offer 40 more licenses for bid in mid-March 2005, plus possible additional rounds later in the year. In the March 2005 round, it is likely that major oil companies like ExxonMobil, ConocoPhillips, ChevronTexaco, Shell, BP, and Statoil will submit bids. This should, once again, lead to a great deal of competition and significant signing bonuses. In the first EPSA IV round in January 2005, mid-sized companies won most of the blocks on offer. For the March 2005 bidding, it is possible that EPSA-IV terms will be modified, although how significantly is not certain at the moment.
- Under EPSA IV, winners are determined largely based on how low a share of production a company is willing to offer NOC. Effectively, this means that whichever companies offer NOC the greatest share of profits will most likely win under EPSA IV. In addition, oilfield developers initially bear 100% of costs (exploration, appraisal, training) for a minimum of 5 years, while NOC retains exclusive ownership. EPSA IV provides for a management committee comprised of two NOC representatives and one from the outside investor; voting is unanimous, unlike under the previous exploration and production sharing agreement (EPSA III). Other features of EPSA IV include: open competitive bidding and transparency; joint development and marketing of nonassociated natural gas discoveries; standardized terms for exploration and production; and non-recoverable bonuses.
- Despite the fact that EPSA IV is underway, and that EPSA V may be forthcoming, several EPSA III contracts remain outstanding. Shell, for instance, is still waiting for approval on an EPSA III deal for an LNG venture. Other companies reportedly still negotiating under EPSA II terms include OMV, Repsol, Talisman and Wintershall. In October 2004, Ukraine's Naftogaz Ukrainy reached a deal on four Libyan exploration blocks under EPSA III terms.
- Under the government of reform-minded Prime Minister Shukri Ghanem, some privatization of the country's oil sector, particularly the downstream sector, now appears more likely than in the past. As described above, Libya is attempting to attract foreign companies with improved incentives and production terms (i.e., access to exploration acreage, small field developments, large field incremental production opportunities, adoption of international competitive bidding practices).

Oman

Oman's oil fields are generally smaller, more widely scattered, less productive, and more costly per barrel than in other Persian Gulf countries. Oman has proven recoverable oil reserves of 5.5 billion barrels, the bulk of which are located in the country's northern and central regions. The largest and traditionally most reliable fields are in the north. These

fields, which include Yibal (the biggest), Fahud, al-Huwaisah, and several others, are now mature and face future declines in production. Oman 's total (i.e. including condensate and other liquids) production figure fell sharply from its height of 972,000 bbl/d in 2000 to 784,000 bbl/d in 2003. In the first ten months of 2004, output has averaged 756,000 bbl/d. If output continues at the present pace and no major new reserves are discovered, Oman has less than 20 years left as a significant oil-exporting nation. Given that estimates suggest that the amount of oil originally in place in Oman is around 50 billion barrels, finding ways to increase recoverability is a top priority. As part of its attempts to expand its reserves, in 2003, Oman signed a six-year contract with Spectrum Energy and Information Technology (UK) to have old seismic studies reprocessed.

- The average well in Oman produces only around 400 barrels per day (bbl/d), about one-tenth the volume per well of those in neighboring countries. To compensate, Oman uses a variety of enhanced oil recovery (EOR) techniques. While these raise production levels, they increase the cost. Per barrel lifting costs rose from \$4.79 in 2002 to \$6.35 in 2003. While these figures are low by world standards, they remain substantially higher than in most other Persian Gulf oil fields.
- Petroleum Development Oman (PDO) is the country's second-largest employer after the government. The company is a consortium comprised of the Omani government (60%), Shell (34%), Total (4%), and Partex (2%). It holds over 90% of the country's oil reserves, and accounts for about 94% of production. PDO's main hopes of stemming its decrease in production involve increasing recovery rates, and discovering and exploiting new fields, particularly in the south. Among its southern prospects, PDO has the most hope for a cluster of fields that includes Ghafeer, Sarmad, and Harweel. In this "carbonate stringer play," PDO estimates there may be reserves of 250 million barrels, with a potential maximum production level of 100,000 bbl/d. One small new find was reported in July 2004, in the Shuaiba area in northwestern Oman , which tested at 2,600 bbl/d.
- One of the difficulties that PDO will face in the south is the very large water cut in the fields, while water is needed for injection at some northern fields. A proposed solution is the construction of a 300-kilometer (186-mile) pipeline that will carry water from the south for use in reinjection in the north where "water flooding" already has been used successfully on wells in the Yibal and Bahaja fields.
- Despite PDO's dominance, several foreign companies are involved in Oman 's oil sector, particularly in offshore exploration. In March 2002, Total signed an oil and gas exploration and production-sharing agreement with the government, covering a block of around 4,250 square miles off the southeastern coast of Oman . As part of the agreement, Total agreed to spend at least \$17 million on exploration over the initial two-year period. Maersk Oil Oman (a subsidiary of Danish energy group AP Moeller), Mitsui & Co. (Japan), Occidental (US) and Hunt Oil (US) have also recently committed to various offshore exploration projects. China 's CNPC acquired a foothold in Oman in 2002, taking a 50% stake in Block 5 which it acquired after it was relinquished by the Japanese firm Japex. The other major Chinese oil company, Sinopec, acquired two onshore exploration blocks in southern Oman in August 2004.

Qatar

Qatar has proven, recoverable oil reserves of 15.2 billion barrels. Following the coup in 1995, Qatar initiated a number of new policies aimed at increasing oil production, locating additional oil reserves before existing reserves become too expensive to recover, and investing in advanced oil recovery systems to extend the life of existing fields. To accomplish this, the government in recent years has improved the terms of exploration

and production contracts and production sharing agreements (PSA). The improved terms are designed to encourage foreign oil companies to improve oil recovery in producing fields and to explore for new oil deposits. Foreign companies now account for more than one-third of Qatar 's oil production capacity.

- In March 1998, Qatar signed an onshore oil exploration agreement with Chevron (now ChevronTexaco), which is still in effect. It is a five-year PSA and exploration agreement, covering a 4,209 square-mile area known as Block-2. Block-2 covers virtually all of the Qatari peninsula except for the Dukhan field. Seismic surveys were conducted in 1998, and drilling commenced in 1999. ChevronTexaco also holds offshore Block-1 jointly with Hungary 's MOL.
- One of Qatar 's newer oil fields is al-Rayyan, operated by Anadarko Petroleum, which bought the stakes in the project previously owned by BP, BG, Wintershall, and Gulfstream Petroleum in a series of transactions in 2001 and 2002. The field came on stream in November 1996, producing 20,000 bbl/d of heavy oil from four wells. It lies in offshore Block 12 at the southern edge of the North Field near Ras Laffan. The PSA for the field was signed on July 16, 1997 . The field currently is producing about 70,000 bbl/d. Anadarko acquired exploration acreage in May 2004, in Block 4 adjacent to Block 12. The company plans to conduct exploratory drilling in Block 4 over a five-year period.
- Qatar 's latest offshore oil field to come onstream is al-Khalij. Production began in March 1997, after five years of exploration and appraisal work, at an initial rate of 6,000 bbl/d. Al-Khalij is located in Block-6, along Qatar 's maritime border with Iran , and to the east of the North Field. Development of the field had been delayed since 1991 as Elf Aquitaine Qatar, the field's operator, sought improved production sharing terms from Qatar Petroleum (formerly QGPC). TotalFinaElf (the result of mergers between the three French oil majors, including Elf Aquitaine) completed a capacity expansion in mid-2004 that brought the field's total production capacity to 80,000 bbl/d. Al-Khalij produces a medium/sweet (28 o API) oil with about 1% sulphur. The oil is piped to Halul Island for processing and transportation. TotalFinaElf holds a 100% interest in the 25-year PSA, with an option for a five-year extension, having acquired ENI's 45% equity stake in May 2002.
- Maydan Mahzam became operational in 1965, and its production is currently around 60,000 bbl/d, down significantly from its peak. However, Qatar Petroleum is currently undertaking a renovation intended to extend the life of the field. The field was producing around 70,000 bbl/d in late 2004.
- Bul Hanine came on line in 1973, producing well over 100,000 bbl/d, but production began falling off in the early 1990s. Current production is around 100,000 bbl/d. Development plans to boost production include drilling 86 new wells. Bul Hanine holds approximately 700 million barrels of recoverable reserves.
- Al-Shaheen, operated by Maersk Oil Qatar of Denmark, has become one of Qatar's most productive oil fields, with production capacity of around 130,000 bbl/d, though production in recent months has been around 110,000 bbl/d. Located in Block-5 about 43 miles off Qatar's northeastern coast, al-Shaheen produces a heavy (29 o-33 o API) oil with 1.7%-2% sulphur content. The field is thought to be linked to a section of the North Field. Current production is around 200,000 bbl/d. More than 70 new wells are being drilled. Maersk also concluded an agreement with Qatar Petroleum in April 2004 for the development of the Block 5 Extension Area, adjacent to the al-Shaheen field, which is expected to product around 20,000 bbl/d when it comes onstream in late 2005.
- Id al-Shargi North Dome (ISND), first discovered by Shell in 1960 and now operated by Occidental Petroleum, lies 59 miles east of Qatar's northern tip. In 1994, the field was producing 12,000 bbl/d when Occidental signed a 25-year PSA with Qatar Petroleum, agreeing to invest \$700 million in field development, reservoir repairs, gas and water injection systems, and further exploration. Output from ISND currently is about 100,000 bbl/d.

- In September 1997, Occidental signed another PSA with Qatar Petroleum (then known as QGPC) to develop the Id al-Shargi South Dome (ISSD) oil field. ISSD is located 15 miles from ISND, and Occidental will operate ISSD as a satellite of ISND, keeping overall per-unit operating costs lower. The field came onstream in November 1999 at 11,000 bbl/d, and it currently is producing around 17,000 bbl/d. Occidental's ownership interest in ISSD is 44%. ISSD is estimated to contain recoverable reserves of 200 million-300 million barrels.
- Qatar Petroleum and Cosmo Oil concluded a contract in October 2003 for the development of two small offshore oil deposits, Al-Karkara and A-North. Production from seven wells, four in Al-Karkara and three in A-North, is set to begin in 2005, and reach a peak of about 10,000 bbl/d.

Saudi Arabia

Saudi Arabia is the world's leading oil producer and exporter, and its location in the politically volatile Gulf region adds an element of concern for its major customers, including the United States.

- Saudi Arabia maintains crude oil production capacity of around 10.5-11.0 million bbl/d, and claims that it is "easily capable" of producing up to 15 million bbl/d in the future and maintaining that production level for 50 years. The Saudis also have stated recently that they intend to raise production capacity to 12.5 million bbl/d over the next several years. One challenge for the Saudis in achieving this objective is that their existing fields sustain 5%-12% annual "decline rates," (according to Aramco Senior Vice President Abdullah Saif, as reported in *Petroleum Intelligence Weekly* and the *International Oil Daily*) meaning that the country needs to add 600,000-800,000 bbl/d in new capacity each year just to compensate.
- Aramco claims that the average total depletion for Saudi oil fields is 28%, with the giant Ghawar field having produced 48% of its proved reserves. Aramco also claims that, if anything, Saudi oil reserves are underestimated, not overestimated. Some outside analysts, notably Matthew Simmons of Houston-based Simmons and Company International, have disputed Aramco's optimistic assessments of Saudi oil reserves and future production, pointing to -- among other things -- more rapid depletion rates and a higher "water cut" than the Saudis claim. EIA forecasts that Saudi oil production capacity could reach 18.2 million bbl/d by 2020, and 22.5 million bbl/d by 2025, a prediction which the Saudis have said is "unrealistic." In recent months, Saudi Arabia reportedly has stepped up oil drilling and exploration activity, aiming to maintain a total of 60 rigs -- double the number as of December 2004.
- During 2004, Saudi Arabia produced around 10.4 million bbl/d of total oil -- including crude oil, natural gas liquids, and "other liquids" oil, and also including half of the Saudi-Kuwaiti Divided Zone's 610,000 bbl/d). This was up sharply from Saudi Arabia's 8.5 million bbl/d of total oil production in 2002 (see graph). Saudi oil production surged in 2003 as the country utilized its spare production capacity to help compensate for losses from Venezuela, Nigeria, and Iraq. Also, in early June 2004, OPEC met and agreed to raise crude oil output quotas by 2 million bbl/d as part of an effort towards lowering oil prices, which had surpassed \$40 per barrel. As a result, beginning on July 1, 2004, Saudi Arabia's official OPEC crude oil production quota was raised to 8.288 million bbl/d, up from the country's previous quota of 7.638 million bbl/d. Currently (late December 2004), Saudi Arabia is estimated to be producing 9.4 million bbl/d of crude oil, well in excess of its current quota level of 8.775 million bbl/d (effective November 1, 2004). In addition to crude oil, Saudi Arabia produces around 1.3 million bbl/d of natural gas liquids (NGLs) and "other liquids," not subject to OPEC quotas.
- Saudi Arabia's long-term goal is to develop its lighter crude reserves, including the Shaybah field located in the remote Empty Quarter area bordering the United Arab Emirates. Shaybah contains an estimated 15.7 billion barrels (or higher) of premium grade 41.6o API sweet (nearly sulfur-free) crude oil, with production potential believed to be 1 million bbl/d (output as of early April 2004 was around 560,000 bbl/d). Also, in October 2004, Aramco announced that it had discovered 54o API super-light crude oil in the Abu Sidr region, 115 miles south of Riyadh.

- Overall, the Shaybah project cost around \$2.5 billion, with production starting in July 1998. According to Oil Minister Naimi (October 1999), the development of Shaybah showed that "the cost of adding...capacity - that is, all the infrastructure, producing and transportation facilities - necessary to produce one additional barrel of oil per day in Saudi Arabia is, at most, \$5,000 compared to between \$10,000 and \$20,000 in most areas of the world. So both our current production costs, and the costs for developing more production capacity for the future, are probably the world's lowest." The Shaybah complex includes three gas/oil separation plants (GOSPs) and a 395-mile pipeline to connect the field to Abqaiq, Saudi Arabia's closest gathering center, for blending with Arab Light crude (Berri and Abqaiq streams). In addition to oil, Shaybah has a large natural gas "cap" (associated gas), with estimated reserves of 25 trillion cubic feet (Tcf). Gas production of 880 million cubic feet per day (Mmcf/d) is reinjected, along with natural gas liquids (NGLs). A possible gas recovery project could be implemented within 5 or 6 years, potentially for use in petrochemical production.
- In March 2002, Aramco awarded major turnkey contracts to Italy's Snamprogetti (\$630 million) and Technip-Coflexip (\$360 million) aimed at increasing total Saudi oil production capacity by 800,000 bbl/d (500,000 bbl/d of Arabian light and 300,000 bbl/d of Arabian medium), by late 2004. The \$1.2 billion project, known as the Qatif producing facilities development program (QPFDP), is located in the eastern part of the country near Dhahran. QPFDP involves construction of two gas-oil separation plants (GOSPs), as well as gas treatment and oil stabilization facilities, for the Qatif and Abu Safa oilfields. Additional Qatif and Abu Safa production had been slated to replace production elsewhere in Saudi Arabia, not to boost overall capacity, although recently this issue has been thrown into some question as the Saudis attempt to maintain a spare capacity cushion in the face of rapidly growing world oil demand. As of December 2004, Saudi Arabia reportedly had brought production from Qatif and Abu Safa online.
- Another potential project, at the Khurais field (a satellite of Ghawar), could increase Saudi production capacity by 800,000 bbl/d at a cost of \$3 billion. This would involve installation of four GOSPs, with a capacity of 200,000 bbl/d each, at Khurais, which first came online in the 1960s but was mothballed by Aramco.
- Several other fields -- Abu Hadriya (1.8-2.0 billion barrels in reserves), Fadhili (1-1.4 billion barrels), Harmaliyah, Khursaniyah (4 billion barrels), and Manifa -- were mothballed by the Saudis during the 1990s, but could be brought back online given high world oil demand and the desire to maintain Saudi spare production capacity. In particular, Saudi Aramco appears to be pushing ahead with development of the Abu Hadriya, Fadhili and Khursaniya (AFK) onshore fields. Production of 500,000 bbl/d (medium, 35o API) from the AFK fields is slated to begin in late 2007. Besides AFK, the Saudis are considering development of the offshore Manifa field in coming years.
- The \$280 million Haradh-2 project aims to increase production capacity at the Haradh oil field to 900,000 bbl/d -- triple current production -- by 2006. This will involve adding a second, 300,000-bbl/d GOSP to Haradh (in addition to one 300,000-bbl/d GOSP inaugurated in January 2004), while shutting in some heavy oil production in the Ghawar area. Haradh also will produce significant volumes of non-associated natural gas, natural gas condensates (perhaps 170,000 bbl/d), and sulfur. The project is being carried out by Aramco, along with private companies like Foster-Wheeler.
- Saudi Arabia has ambitious plans for expanding petrochemical production using natural gas as a feedstock. State-owned (70%) SABIC, the Middle East's largest non-oil industrial company (and expected to become one of the world's top five ethylene producers by 2005), accounts for around 10% of world petrochemical production. In February 2001, SABIC completed a \$1 billion expansion at the Yanbu petrochemical facility, making it the largest polyethylene plant in the world, and in April 2003, Aramco awarded a turnkey contract to Snamprogetti to build two new units at the complex. In early January 2002, SABIC agreed to a \$1.15 billion loan to fund a new petrochemicals plant in the eastern Saudi Arabian industrial city of Jubail. The complex is scheduled to come online in the second half of 2004, and to produce 1 million tons per year of ethylene, plus olefins, polyethylene, and glycol ethylene.

The United Arab Emirates

The UAE's total production capacity is 2.50 million bbl/d, making it second only to Saudi Arabia for excess production capacity among OPEC member states.

- The Abu Dhabi National Oil Company (ADNOC) is currently planning a limited opening of UAE upstream oil production to foreign firms. The initial asset sale will involve 28% of the offshore Upper Zakhum field. Bids have been solicited from BP, TotalFinaElf, ChevronTexaco, ExxonMobil, and the Japan Oil Development Company (JODCO), and but award has been delayed repeatedly. JODCO already holds a 12% stake in the field from a previous investment in 1972, when the field was first developed.
- Several projects to upgrade infrastructure at existing oilfields are planned or underway. A \$318 million project to increase the capacity of the onshore Bu Hasa field is underway, including construction of natural gas separation units, drilling of natural gas reinjection wells, and water injection. The goal is to increase production capacity to 480,000 bbl/d from the present 100,000 bbl/d. A natural gas reinjection project also is planned for the onshore Bab field, which is expected to increase capacity to 350,000 bbl/d from the current 250,000 bbl/d. Upgrades planned for the onshore Asab field are set to raise capacity from the current 280,000 bbl/d to 310,000 bbl/d by 2006. These projects are part of an overall goal of raising the UAE's production capacity to 3 million bbl/d by the end of 2006, at an overall cost of \$1.5 billion.
- The UAE has two refineries operated by ADNOC. The Ruwais refinery has a capacity of 145,000 bbl/d. A \$480-million contract was awarded to the Italian engineering firm Technip in June 2002 for an expansion of the Ruwais complex to a capacity of 500,000 bbl/d, including refits of existing units and expansion of units for production of unleaded gasoline and low-sulfur fuel oil. Work under this contract is to be completed by 2005. Umm al-Nar, also owned by ADNOC, has a capacity of 88,500 bbl/d. Since its construction in 1976, the Umm al-Nar plant has undergone debottlenecking as well as a recent expansion.
- UAE has three other refineries. The Emirates National Oil Company (ENOC) Jebal Ali condensate refinery, with a capacity of 120,000 bbl/d, began operations in Dubai in May 1999. Metro Oil has a 90,000-bbl/d refinery in Fujairah. A 71,250 bbl/d second-hand unit was set up by the Sharjah Oil Refining Company in 2001.

Yemen

Yemen contains proven crude oil reserves of 4 billion barrels, concentrated in five areas. In 2003, Yemen's crude oil output averaged 448,288 bbl/d, showing a slight increase over 2002. Recently, the government of Yemen announced a 1-million-bbl/d production target for 2006. However, according to Yemen's Petroleum Exploration and Production Authority (PEPA), average production has actually fallen in the first half of 2004 to an estimated 400,000-420,000 bbl/d, due to declining production in Masila and Marib, the country's two largest fields.

- To date, Yemen's territory has been divided into 78 blocks, around half of which have been licensed for exploration and possible production of oil and/or natural gas. Unlike much of the petroleum and natural gas production in the region, Yemeni production is heavily reliant on private foreign companies, with more than 20 foreign firms operating concessions. Dozens of other foreign and domestic companies are partners in the concessions, including ExxonMobil and TransGlobe Energy. Since the withdrawal of major international oil companies in the mid-to-late 1990's, the government of Yemen has targeted smaller, independent oil companies to take part in Production Sharing Agreements (PSAs).

- Currently there are nine PSAs in existence. In 2003, Canada's Nexen, which owns 52% of the Masila block, produced around 230,000 bbl/d. US-based Hunt Oil produced an estimated 165,000 bbl/d --140,000 bbl/d from Marib al Jawf Block and 25,000 bbl/d from the Jannah Block. Hunt's contract on Marib was recently extended for another five years. France's TotalFinaElf produced around 20,000 bbl/d from its East Shabwa concession. U.K. independent Dove Energy, which operates the East-Sarr Block (53, including the Sharyoof field) and the newly online South Howarime Block (43), produced an estimated 25,000 bbl/d. Norway's DNO produced an estimated 20,000 bbl/d in the Howarin Block (32 - including the Tasour field). An independent consortium of local Yemeni operators produced an estimated 800 bbl/d at Iyad (Ayadh). New production for Nexen-operated blocks 35 (Hood) and 51 (East Al Hajr, BAK-A and -B fields), as well as the independent Vintage Oil - operated S1 block (Damis, including the An Nagyah field) is expected to come online in early 2005. The new production is expected to help offset declining production in mature fields.
- The Ministry of Oil and Mineral Resources (MOMR) places oil tenders up for bid on a semi-annual basis. Contracts typically involve a 2-3 year exploration period and a 20-year production concession. All licenses for exploration and production in Yemen are authorized by the Petroleum Exploration and Production Board of MOMR, subject to ratification by parliamentary secession. All contracts are signed between a company or group of companies, as contractor to the government of Yemen.
- In late 1999, the government took steps toward improving investment in the country's oil, gas, energy and petrochemical activities by redefining terms for certain concession agreements. These more favorable terms include lower signature bonuses, an increase in the proportion of oil earnings that companies can claim for development cost recovery to between 50% and 70% (compared with a previous range of 25-45%), and the introduction of a sliding scale of 3-10% for royalties (compared with a previous flat fee of 10%). In mid-2001, Yemeni officials took further steps to improve the energy-related investment climate, announcing a policy of contract extensions, added flexibility on negotiations, and a commitment to amending existing legislation if necessary.
- In August 2003, Canada's Calvalley Petroleum announced the most recent discovery - - four oil bearing wells in the Roidhat field in the Malik Block (9). Calvalley has yet to determine if the oil find is of commercial quality. Nexen continues to explore Block 51, adjacent to their Masila field's and Total's East Shabwa. In June 2004, the Yemeni government offered newly demarcated Blocks 69-74 up for bid (Not on the map: Blocks 69-70 are in the Sabatain Basin, Blocks 71-74 are located in the Masila/ Shabwa Basins). In the same month, a consortium including Norway's DNO and Canada's TransGlobal energy was awarded exploration rights to Block 72. The oil concession encompasses 703 square miles and is located next to Nexen's holdings. China's Sinopec was awarded rights to explore blocks 69 and 71, while Dove Energy acquired Block 73. Blocks 70 and 74 are yet to receive bids. In 2003, 115 exploratory wells were drilled in Yemen, while 140 exploratory wells are forecast for 2004.
- In June 2000, Yemen and Saudi Arabia signed the Treaty of Jeddah, resolving a longstanding border dispute. The agreement opened up opportunities for increased Saudi trade and investment in Yemen, and made possible the award of oil and gas exploration rights for areas in Yemen, adjacent to the border. In 2000, four new blocks were demarcated in this area, and several companies have signed memoranda of understanding (MOU) for exploration rights. In January 2001, Nexen was granted the right to operate Block 59, located adjacent to the Saudi border. Nexen holds a 60% interest, with the other 40% held by Occidental Petroleum (of which Nexen is no longer a subsidiary). In December 2001, Austria's OMV, along with Cepsa of Spain and PanCanadian, concluded an exploration and production contract with the Yemeni government for Block 60.

The MENA Region and Future Global Oil Production Capacity

It seems likely that both the EIA and the International Energy Agency (IEA) will issue forecasts during 2005 that are based on higher oil price cases and lower estimates of

demand. As is shown in the tables below, this may significantly reduce medium to long-term demand, and bring the future requirement for MENA oil production capacity much closer to the levels countries already have or plan to create.

At the same time, it is clear that the MENA region will dominate world oil exports for at least the next two decades, regardless of oil prices and the detailed trends in demand. It has some 63% of all of the world's proven oil resources, and some 37% of its gas. In 2001, the Gulf alone had over 28% of all of the world's oil production capacity, and the entire MENA region had 34%.^v

A combination of these reserves, and low incremental production costs, ensure the region will dominate increases in world oil production capacity regardless of probable variations in oil prices -- at least through at least 2015 and quite possibly through 2025. Much does, however, depend on the long-term trend in world oil prices.

The 2004 reference case projection by the EIA assumes \$25-\$27 per barrel oil, and estimates that OPEC will increase its oil production capacity from 27.2 MMBD in 1990, and 32.6 MMBD in 2001, to 39.7 MMBD in 2010, 44.5 MMBD in 2015, 52.8 MMBD in 2020, and 61.5 MMBD in 2025. The amount of OPEC oil coming from MENA countries is projected increase from 25.7 MMBD to 50.6 MMBD in 2015.

The EIA estimates that Saudi Arabia alone would account for 12.3 MMBD of the total increase in global production capacity by 2025 in the reference case, Iraq for 3.8 MMBD. Kuwait for 2.6 MMBD, and the UAE for 2.5 MMBD. These four Gulf countries alone would account for 21.2 MMBD out of a worldwide total increase of 46.8 MMBD (45%).^{vi} Almost all industry experts and petroleum officials in MENA countries believe these increases are too large to be realistic.^{vii}

The International Energy Agency estimates cover a longer period than the EIA estimates, but produce general similar results from generally similar assumptions and models. They predict that that total conventional and non-conventional oil production will increase from 77 MMBD in 2002 to 121.3 MMBD in 2030. This is a total increase of 44.3 MMBD worldwide. The Middle East will account for 30.7 MMBD, or 69% of this total.

The IEA also estimates that the rate of dependence on the Middle East will increase steadily after 2010 as other fields are depleted in areas where new resources cannot be brought on line. It estimates that 29 MMBD, or 94% of the total 31 MMBD increase in OPEC production between 2010 and 2030 will come from Middle Eastern members of OPEC.^{viii}

World energy supply and demand become very different in the high oil price case, and this EIA projection for a high oil price case now seems more likely to reflect future trends. In the reference case, the price per barrel was expected to be \$25-\$27 per barrel in constant US dollars, or range around \$51 per barrel in 2025 in current or nominal dollars. In the high price case, prices are projected to reach \$34 per barrel in 2013 and to be around \$35 per barrel in 2025.

In the high oil price case, world demand drops sharply as prices increase, and with it the amount of additional oil needed by importing countries. The leveling off in the high price case also results from a sharp increase in conservation, efficiency, and the projected

market penetration of alternative energy supplies that could become economically viable at that price (such as liquids from oil sands, natural gas, coal, biofuels, and oil shale).

This explains why the export levels projected for MENA countries are so much lower in the high oil price case, and this would be even more true if oil prices remained at the current level of \$40-\$50 a barrel in constant dollars. If the reference case is compared to the high price case, total global production capacity drops from 126.1 MMBD to 117.3 MMBD, and Persian Gulf capacity from 45.0 MMBD to 32.9 MMBD.

Almost all of the cut in increase production capacity is projected to come from the MENA region. The EIA estimates that OPEC will increase its oil production capacity in the high price from 27.2 MMBD in 1990, and 32.6 MMBD in 2001, to 31.6 MMBD in 2010, 33.3 MMBD in 2015, 39.6 MMBD in 2020, and 46.6 MMBD in 2025. The amount of OPEC oil coming from MENA countries is projected increase from 25.7 MMBD to 37.5 MMBD in 2025.

The EIA estimates that Saudi Arabia would account for 5.8 MMBD in the high price case versus 12.3 MMBD in the reference case by 2025, Iraq for 2.8 MMBD versus 3.8 MMBD. Kuwait for 1.0 MMBD versus 2.6 MMBD, and the UAE for 1.2 MMBD versus 2.5 MMBD.^{ix} These figures are far more credible in terms of the MENA country plans described earlier.

It is clear from these EIA estimates that it will be much easier for MENA countries to expect capacity to reach the levels of oil production capacity in the high price case than is the case for the reference case – where oil prices were in the \$25-\$27 per barrel range. This is not a minor issue since the International Energy Agency estimates that imports will rise from 63% of total OECD demand for oil in 2002 to 85% in 2030 in its low price reference case; that some \$3 trillion dollars must be invested in the oil sector from 2003 to 2030 to meet world demand for oil; and something approaching half of this total must be invested in the Middle East. It estimates that another \$234 billion will be required for tankers and oil pipelines, and again, a substantial amount must go to the MENA area.^x

While the cost of imports to the US and other Western countries will be much higher per barrel in this case, the demand for imports is projected to be much lower, and the rate of increase in conservation, energy efficiency, and alternative energy supplies is projected to be much higher. The EIA does not estimate net cash flows or economic impacts over time, but the high oil price case will have far less impact on US and world economic growth if markets prove to be elastic in reacting to oil prices and cost-effective alternatives become available over the next decade.

It must be stressed that such conclusions are extremely uncertain and are scarcely an argument for high oil prices. At the same time, they also are not necessarily an argument against them. Furthermore, barring massive new advanced in oil production technology or costs, and/ or equally massive new discoveries of oil reserves, cheap oil in the near term means more expensive oil in the long term as oil reserves are depleted.

Cheap oil may also well means the world faces a more abrupt, expensive, and potentially low economic growth "learning curve" in finding substitutes for oil imports once reserves begin to be seriously depleted. While high prices also mean a serious increase in the share of global GNP and RDT&E funds going to energy research and production, it is not clear

that this means a diversion from socially more useful uses of the same funds or lower overall growth and living standards as the global market adapts to a different mix of structural needs.

World Oil Production Capacity by Region and Country, Reference Case, 1990-2025

(Million Barrels per Day)

	1990	2001	2010	2015	2020	2025
OPEC						
Persian Gulf						
Iran	3.2	3.7	4.0	4.3	4.7	4.9
Iraq	2.2	2.8	3.7	4.4	5.3	6.6
Kuwait	1.7	2.4	3.1	3.7	4.4	5.0
Qatar	0.5	0.6	0.6	0.7	0.8	0.8
Saudi Arabia	8.6	10.2	13.2	14.4	18.2	22.5
United Arab Emirates	2.5	2.7	3.3	3.9	4.6	5.2
Total Persian Gulf	18.7	22.4	27.9	31.4	38.0	45.0
Other OPEC						
Algeria	1.3	1.6	2.0	2.1	2.4	2.7
Indonesia.	1.5	1.5	1.5	1.5	1.5	1.5
Libya	1.5	1.7	2.0	2.2	2.6	2.9
Nigeria	1.8	2.2	2.6	3.0	3.4	3.8
Venezuela	2.4	3.2	3.7	4.3	4.9	5.6
Total Other OPEC	8.5	10.2	11.8	13.1	14.8	16.5
Total OPEC	27.2	32.6	39.7	44.5	52.8	61.5
Non-OPEC						
Industrialized						
United States	9.7	9.0	9.5	9.3	8.9	8.6
Canada	2.0	2.8	3.5	4.6	4.8	4.9
Mexico	3.0	3.6	4.2	4.5	4.6	4.8
Australia	0.6	0.7	0.9	0.8	0.8	0.8
North Sea	4.2	6.3	5.9	5.4	5.1	4.6
Other.	0.6	0.7	0.8	0.6	0.6	0.6
Total Industrialized	20.1	23.1	24.8	25.2	24.8	24.3
Eurasia						
China	2.8	3.3	3.6	3.5	3.5	3.4
Former Soviet Union	11.4	8.8	13.2	15.1	16.1	17.3
Eastern Europe	0.3	0.2	0.3	0.4	0.4	0.5
Total Eurasia	14.5	12.3	17.1	19.0	20.0	21.2
Other Non-OPEC						
Central and South America	2.4	3.8	4.7	5.7	6.3	6.8
Middle East	1.4	2.0	2.2	2.5	2.6	2.8
Africa	2.1	3.0	4.0	5.0	5.7	6.9
Asia.	1.7	2.5	2.6	2.8	2.7	2.6
Total Other Non-OPEC	7.6	11.3	13.5	16.0	17.3	19.1
Total Non-OPEC	42.2	46.7	55.4	60.2	62.1	64.6
Total World	69.4	79.3	95.1	104.7	114.9	126.1

Note: OPEC = Organization of Petroleum Exporting Countries.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004); and U.S. Department of the Interior, U.S. Geological Survey, World Petroleum Assessment 2000(Reston, VA, July 2000).

World Oil Production Capacity by Region and Country, High Oil Price Case, 1990-2025

(Million Barrels per Day)

	1990	2001	2010	2015	2020	2025
Persian Gulf						
Iran	3.2	3.7	3.5	3.6	3.8	4.3
Iraq	2.2	2.8	2.9	3.2	3.7	4.6
Kuwait	1.7	2.4	2.3	2.5	2.9	3.4
Qatar	0.5	0.6	0.6	0.6	0.7	0.7
Saudi	8.6	10.2	9.4	9.8	12.9	16.0
United Arab Emirates	2.5	2.7	2.7	2.8	3.3	3.9
Total Persian Gulf	18.7	22.4	21.4	22.5	27.3	32.9
Other OPEC						
Algeria	1.3	1.6	1.6	1.7	2.0	2.2
Indonesia	1.5	1.5	1.5	1.5	1.5	1.5
Libya	1.5	1.7	1.7	1.8	2.1	2.4
Nigeria	1.8	2.2	2.2	2.4	2.8	3.3
Venezuela	2.4	3.2	3.2	3.4	3.9	4.5
Total Other	8.5	10.2	10.2	10.8	12.3	13.9
Total OPEC	27.2	32.6	31.6	33.3	39.6	46.8
Non-OPEC						
Industrialized						
United	9.7	9.0	9.9	9.7	9.6	9.0
Canada	2.0	2.8	3.7	5.0	5.2	5.5
Mexico	3.0	3.6	4.4	4.8	5.0	5.2
Australia	0.6	0.7	0.9	0.8	0.8	0.8
North Sea	4.2	6.3	6.0	5.6	5.3	4.8
Other	0.6	0.7	0.7	0.7	0.7	0.6
Total Industrialized	20.1	23.1	25.6	26.6	26.6	25.9
Eurasia						
China	2.8	3.3	3.7	3.6	3.6	3.4
Former Soviet Union	11.4	8.8	13.9	16.2	17.4	19.0
Eastern Europe	0.3	0.2	0.3	0.4	0.4	0.4
Total Eurasia	14.5	12.3	17.9	20.2	21.4	22.8
Other Non-OPEC						
Central and South America	2.4	3.8	5.1	6.2	6.9	7.5
Middle East	1.4	2.0	2.4	2.7	2.9	3.1
Africa	2.1	3.0	4.6	5.5	6.8	8.2
Asia	1.7	2.5	2.8	2.9	3.0	3.0
Total Other Non-OPEC	7.6	11.3	14.9	17.3	19.6	21.8
Total Non-OPEC	42.2	46.7	58.4	64.1	67.6	70.5
Total World	69.4	79.3	90.0	97.4	107.2	117.3

Note: OPEC = Organization of Petroleum Exporting Countries.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division.

Projections:

EIA, System for the Analysis of Global Energy Markets (2004); and U.S. Department of the Interior, U.S. Geological Survey, World

Petroleum Assessment 2000(Reston, VA, July 2000).

Changing Patterns in Import Dependence that Affect the US Role in a Global Economy

Neither the low or high oil price cases ease the challenge of maintaining strategic stability in the Gulf. The EIA provides the following assessment of the Gulf's strategic importance, and it is clear that even if major reductions do take place in the rate of future Gulf exports still leaves the world highly dependent on Gulf and MENA output :^{xi}

In 2001, industrialized countries imported 16.1 million barrels of oil per day from OPEC producers... Of that total, 9.7 million barrels per day came from the Persian Gulf region. Oil movements to industrialized countries represented almost 65 percent of the total petroleum exported by OPEC member nations and almost 58 percent of all Persian Gulf exports.^{xii}

By the end of the forecast period (2025), OPEC exports to industrialized countries are estimated to be about 11.5 million barrels per day higher than their 2001 level, and more than half the increase is expected to come from the Persian Gulf region.^{xiii}

Despite such a substantial increase, the share of total petroleum exports that goes to the industrialized nations in 2025 is projected to be almost 9 percent below their 2001 share, and the share of Persian Gulf exports going to the industrialized nations is projected to fall by about 13 percent. The significant shift expected in the balance of OPEC export shares between the industrialized and developing nations is a direct result of the economic growth anticipated for the developing nations of the world, especially those of Asia.

OPEC petroleum exports to developing countries are expected to increase by more than 18.0 million barrels per day over the forecast period, with three-fourths of the increase going to the developing countries of Asia. China, alone, is likely to import about 6.6 million barrels per day from OPEC by 2025, virtually all of which is expected to come from Persian Gulf producers.

North America's petroleum imports from the Persian Gulf are expected to double over the forecast period. At the same time, more than one-half of total North American imports in 2025 are expected to be from Atlantic Basin producers and refiners, with significant increases expected in crude oil imports anticipated from Latin American producers, including Venezuela, Brazil, Colombia, and Mexico. West African producers, including Nigeria and Angola, are also expected to increase their export volumes to North America. Caribbean Basin refiners are expected to account for most of the increase in North American imports of refined products. With a moderate decline in North Sea production, Western Europe is expected to import increasing amounts from Persian Gulf producers and from OPEC member nations in both northern and western Africa. Substantial imports from the Caspian Basin are also expected.

Industrialized Asian nations are expected to increase their already heavy dependence on Persian Gulf oil. The developing countries of the Pacific Rim are expected to almost double their total petroleum imports between 2001 and 2025.

Dependence on MENA Export Security

Even today, some 40% of all world oil exports now pass daily through the Strait of Hormuz. Both EIA and IEA projections indicate this total will increase to around 60% by 2025-2030 at low oil prices, and an examination of the EIA estimates indicate this figure will still be around 50% in the high price case.^{xiv}

Current IEA projections indicate that Middle Eastern Exports will total some 46 MMBD by 2030, and represent more than two-thirds of the world total. This means that the daily traffic in oil tankers will increase from 15 MMBD and 44% of global interregional trade in 2002, to 43 MMBD and 66% of global interregional trade in 2030. This means that the daily traffic in LNG carriers will increase from 28 BCM and 18% of global interregional trade in 2002, to 230 carriers and 34% of global interregional trade in 2030.^{xv} The IEA

does, however, estimate that these increases would be some 11% lower if oil prices remained consistently high in constant dollars.

US Import Dependence

US strategic dependence on the world, and the Gulf and MENA region, is shown in the tables below. Direct US petroleum imports increased from an annual average of 6.3 MMBD in 1973, and 7.9 MMBD in 1992 to 11.3 MMBD in 2002, and 12.9 MMBD in 2004. Some 2.6 MMBD worth of US petroleum imports came directly from the Middle East in 2002.^{xvi}

The economic impact of this increase in import dependence obvious varies with oil prices. According to March 2005 statistics from the EIA, the oil price collapse of late 1997 and 1998 cut U.S. net oil import costs during 1998 by around \$20 billion (to \$44 billion) compared to the previous two years. Increased oil prices since then have increased U.S. net oil import costs: to \$60 billion in 1999; \$109 billion in 2000; \$94 billion in both 2001 and 2002, and \$122 billion during 2003. For the first ten months of 2004, U.S. net oil import costs were running about 31% higher than during the same period in 2003. Oil currently accounts for about one-fourth of the total U.S. merchandise trade deficit.

US Dependence on the MENA Region and the Gulf

The US is only dependent on the Middle East for part of its imports and there have been no consistent trends in the percentage of imports the US gets from OPEC and the Gulf. If one looks at OPEC exports as a percent of US imports, these ranged from 47.8% in 1973, and 51.9% MMBD in 1992 to 39.9% MMBD in 2002, and 43.6% MMBD in 2004. If one looks at Gulf exports as a percent of US imports, these ranged from 13.6% in 1973, and 22.5% MMBD in 1992 to 19.7% MMBD in 2002, and 19.3% MMBD in 2004.

Under most conditions, however, the areas and countries the US imports from, and the normal day-to-day destination of MENA oil exports, is strategically irrelevant. Oil is a global commodity, which is distributed to meet the needs of a global market based on process bid by importers acting in global competition.

With the exception of differences in price because of crude type and transportation costs, all buyers compete equally for the global supply of available exports, and the direction and flow of exports changes according to marginal price relative to demand. As a result, the percentage of oil that flows from the MENA region to the United States under normal market conditions has little strategic or economic importance. If a crisis occurs, or drastic changes take place in prices, and the U.S. will have to pay the same globally determined price as any other nation, and the source of US imports will change accordingly. Moreover, the U.S. is required to share all imports with other OECD countries in a crisis under the monitoring of the International Energy Agency.

The size of direct US imports of petroleum is also only a partial measure of strategic dependence. The U.S. economy is dependent on energy-intensive imports from Asia and other regions, and what comes around must literally go around. While the EIA and IEA do not make estimates of indirect imports of Middle Eastern oil in terms of the energy required to produce the finished goods, the US imports them from countries that are

dependent on Middle Eastern exports, analysts guess that they would add at least 1 MMBD to total US oil imports.

U.S. Petroleum Trade and Import Dependence: 1973-2004

	Imports in Thousand Barrels Per Day					Products Supplied (MBD)	Percent of Products Supplied				Percent of Total Imports	
	Gulf Imports	OPEC Imports	Total Imports	Exports	Net Imports		Gulf	OPEC	Imports	Net Imports	Gulf	OPEC
1973 Average	848	2,993	6,256	231	6,025	17,308	4.9	17.3	36.1	34.8	13.6	47.8
1974 Average	1,039	3,280	6,112	221	5,892	16,653	6.2	19.7	36.7	35.4	17.0	53.7
1975 Average	1,165	3,601	6,056	209	5,846	16,322	7.1	22.1	37.1	35.8	19.2	59.5
1976 Average	1,840	5,066	7,313	223	7,090	17,461	10.5	29.0	41.9	40.6	25.2	69.3
1977 Average	2,448	6,193	8,807	243	8,565	18,431	13.3	33.6	47.8	46.5	27.8	70.3
1978 Average	2,219	5,751	8,363	362	8,002	18,847	11.8	30.5	44.4	42.5	26.5	68.8
1979 Average	2,069	5,637	8,456	471	7,985	18,513	11.2	30.5	45.7	43.1	24.5	66.7
1980 Average	1,519	4,300	6,909	544	6,365	17,056	8.9	25.2	40.5	37.3	22.0	62.2
1981 Average	1,219	3,323	5,996	595	5,401	16,058	7.6	20.7	37.3	33.6	20.3	55.4
1982 Average	696	2,146	5,113	815	4,298	15,296	4.5	14.0	33.4	28.1	13.6	42.0
1983 Average	442	1,862	5,051	739	4,312	15,231	2.9	12.2	33.2	28.3	8.8	36.9
1984 Average	506	2,049	5,437	722	4,715	15,726	3.2	13.0	34.6	30.0	9.3	37.7
1985 Average	311	1,830	5,067	781	4,286	15,726	2.0	11.6	32.2	27.3	6.1	36.1
1986 Average	912	2,837	6,224	785	5,439	16,281	5.6	17.4	38.2	33.4	14.7	45.6
1987 Average	1,077	3,060	6,678	764	5,914	16,665	6.5	18.4	40.1	35.5	16.1	45.8
1988 Average	1,541	3,520	7,402	815	6,587	17,283	8.9	20.4	42.8	38.1	20.8	47.6
1989 Average	1,861	4,140	8,061	859	7,202	17,325	10.7	23.9	46.5	41.6	23.1	51.4
1990 Average	1,966	4,296	8,018	857	7,161	16,988	11.6	25.3	47.2	42.2	24.5	53.6
1991 Average	1,845	4,092	7,627	1,001	6,626	16,714	11.0	24.5	45.6	39.6	24.2	53.7
1992 Average	1,778	4,092	7,888	950	6,938	17,033	10.4	24.0	46.3	40.7	22.5	51.9
1993 Average	1,782	4,273	8,620	1,003	7,618	17,237	10.3	24.8	50.0	44.2	20.7	49.6
1994 Average	1,728	4,247	8,996	942	8,054	17,718	9.8	24.0	50.8	45.5	19.2	47.2
1995 Average	1,573	4,002	8,835	949	7,886	17,725	8.9	22.6	49.8	44.5	17.8	45.3
1996 Average	1,604	4,211	9,478	981	8,498	18,309	8.8	23.0	51.8	46.4	16.9	44.4
1997 Average	1,755	4,569	10,162	1,003	9,158	18,620	9.4	24.5	54.6	49.2	17.3	45.0
1998 Average	2,136	4,905	10,708	945	9,764	18,917	11.3	25.9	56.6	51.6	19.9	45.8
1999 Average	2,464	4,953	10,852	940	9,912	19,519	12.6	25.4	55.6	50.8	22.7	45.6
2000 Average	2,488	5,203	11,459	1,040	10,419	19,701	12.6	26.4	58.2	52.9	21.7	45.4
2001 Average	2,761	5,528	11,871	971	10,900	19,649	14.1	28.1	60.4	55.5	23.3	46.6
2002 Average	2,269	4,605	11,530	984	10,546	19,761	11.5	23.3	58.3	53.4	19.7	39.9
2003 Average	2,501	5,162	12,264	1,027	11,238	20,034	12.5	25.8	61.2	56.1	20.4	42.1
2004 Average	2,485	5,626	12,899	1,048	11,851	20,517	12.1	27.4	62.9	57.8	19.3	43.6

a. Gulf = Bahrain, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates.

b. OPEC = Organization of Petroleum Exporting Countries. See Glossary.

c. Petroleum = crude oil, lease condensate, unfinished oils, petroleum products, natural gas plant liquids, and nonhydrocarbon compounds blended into finished petroleum products.

d. Beginning in October 1977, petroleum imported for the Strategic Petroleum Reserves is included.

e. Annual averages may not equal average of months due to independent rounding.

f. U.S. geographic coverage is the 50 States and the District of Columbia. U.S. exports include shipments to U.S. territories, and imports include receipts from U.S. territories.

Source: Energy Information Administration, **Monthly Energy Review**, February 2005, Web Page: <http://www.eia.doe.gov/emeu/mer/overview.html>.

US Crude Oil Imports, Total Supply and Disposition, 1973 - Present

(Thousand Barrels per Day)

US Field Production Year/Month	Imports		Total	Unaccounted for		Oil
	Domestic	Alaskan		SPR	Other	
1973 Average	9,208	198	3,244	--	3,244	3
1974 Average	8,774	193	3,477	--	3,477	-25
1975 Average	8,375	191	4,105	--	4,105	17
1976 Average	8,132	173	5,287	--	5,287	77
1977 Average	8,245	464	6,615	21	6,594	-6
1978 Average	8,707	1,229	6,356	161	6,195	-57
1979 Average	8,552	1,401	6,519	67	6,452	-11
1980 Average	8,597	1,617	5,263	44	5,219	34
1981 Average	8,572	1,609	4,396	256	4,141	83
1982 Average	8,649	1,696	3,488	165	3,323	71
1983 Average	8,688	1,714	3,329	234	3,096	114
1984 Average	8,879	1,722	3,426	197	3,229	185
1985 Average	8,971	1,825	3,201	118	3,083	145
1986 Average	8,680	1,867	4,178	48	4,130	139
1987 Average	8,349	1,962	4,674	73	4,601	145
1988 Average	8,140	2,017	5,107	51	5,055	196
1989 Average	7,613	1,874	5,843	56	5,787	200
1990 Average	7,355	1,773	5,894	27	5,867	258
1991 Average	7,417	1,798	5,782	0	5,782	195
1992 Average	7,171	1,714	6,083	10	6,073	258
1993 Average	6,847	1,582	6,787	15	6,772	168
1994 Average	6,662	1,559	7,063	12	7,051	266
1995 Average	6,560	1,484	7,230	0	7,230	193
1996 Average	6,465	1,393	7,508	0	7,508	215
1997 Average	6,452	1,296	8,225	0	8,225	145
1998 Average	6,252	1,175	8,706	0	8,706	115
1999 Average	5,881	1,050	8,731	8	8,722	191
2000 Average	5,822	970	9,071	8	9,062	155
2001 Average	5,801	963	9,328	11	9,318	117
2002 Average	5,746	984	9,140	16	9,124	110
2003 Average	5,681	974	9,665	0	9,665	54
2004 Average	5,430	908	10,038	0	10,038	189
2005 January	PE 5,433	PE 923	E 10,088	E 0	E 10,088	E 16

Source: Energy Information Administration/Petroleum Supply Monthly, Table S2.

US Dependence on the Flow of Exports to Other Importers

Moreover, the US and other industrialized states are increasingly dependent on the health of the global economy. With the exception of Latin America, Mexico, and Canada, all of America's major trading partners are critically dependent on Middle Eastern oil exports. In 2002, the Middle East and North Africa supplied 5.0 MMBD of 11.9 MMBD of European imports (42%). MENA exporters supplied 4.0 MMBD of Japanese imports of 5.1 MMBD (79%). While MENA countries supplied 0.8 MMBD out China's imports of 2.0 MMBD (39% and growing steadily in recent years), 0.2 MMBD of Australia's imports of 0.6 MMBD (33%), and 6.5 MMBD of some 8.6 MMBD in imports by other Asian and Pacific states (76%).^{xvii}

As has already been discussed in detail, the EIA and IEA project that the global economy will also grow far more dependent on the Middle East and North Africa in the future. The EIA's **International Energy Outlook 2004** projects that North American imports of MENA oil will increase from 3.3 MBD in 2001 to 6.3 MMBD in 2025 – an increase of 91%, almost all of which will go to the US. The increase in exports to Western Europe will be from 4.7 MMBD to 7.6 MMBD, an increase of 62%.

This estimate is based on \$25-\$27 per barrel oil, but it also assumes major increases in oil exports from the FSU and conservation will limit the scale of European imports from the Middle East. Industrialized Asia – driven by Japan – will increase its imports from 4.1 MMBD to 6.0 MMBD, or nearly 50%. China will increase its imports from 0.9 MMBD to 6.0 MMBD, or by nearly 570%; and Pacific Rim states will increase imports from 5.0 MMBD to 10.2 MMBD, or by 104%.

Projected Increases in US Direct Imports

It is important to note that neither the Bush energy policy, nor any recent Congressional energy bills, are projected to have any meaningful strategic impact on US import dependence even if they are ever passed into law and transformed into action. The best case for the output from the Alaskan Wildlife Reserve, for example, is peak production of 1.0-1.5 MMBD. This may have considerable economic benefits for the US, but like virtually all of the measures proposed in recent legislation, it does not affect US strategic dependence on imports.

It takes truly massive shifts in US energy consumption and supply over extended periods of time to accomplish this and there are good reasons that the Bush Administration, Kerry energy policy, and Congressional advocates of different policies have either failed to make meaningful analysis of the impact of their proposals on US import dependence or have provided “blue sky” estimates that are little more than political posturing.

If one turns to the EIA estimates made since the Bush Administration came to office, it is also clear that realistic models of US energy needs have led to steady increases in the Department of Energy's estimate of US dependence on imports:

- For example, the EIA's 2003 Annual Energy Forecast reports that net imports of petroleum accounted for 55 percent of domestic petroleum consumption in 2001. US dependence on petroleum imports is projected to reach 68% in 2025 in the reference case. This is a rise in US net imports from 10.9 MMBD in 2021 to 19.8 MMBD in the reference case (+82%). In the low oil

price case, net imports would rise to 21.1 MMBD. They would be 18.2 MMBD in the high oil price case, 17.8 MMBD in the low economic growth case, and 22.3 MMBD in the high economic growth case.^{xviii}

- In contrast, the EIA's annual US energy forecast for 2004 predicts that imports will be even higher. It reports that net imports of petroleum accounted 53 percent of domestic petroleum consumption in 2002. U.S. dependence on petroleum imports is estimated to reach 70 percent in 2025 in the reference case, versus 68 percent in the 2003 forecast. Imports are expected to be 65 percent of total consumption. In the low oil price case this number is estimated to be 75 percent.^{xix} (The AEO2003 report indicated that estimated imports as a share of total oil consumption would be 65 percent in high price case in 2025, and 70 percent in the low price case.)

As has been discussed earlier, estimates vary according to oil prices and the growth of the US economy, and EIA contingency forecasts badly need to be updated to examine higher oil price cases. Nevertheless, they are almost certainly correct in estimating major increases in imports between 2002 and 2025. The latest estimates, based on a reference case with \$25-27 oil, are shown in the table below:^{xx}

Projected US Oil Imports: 2002-2025

Year and Projection	Product Supplied	Net Imports	Net Crude Imports	Net Product Imports
2002	19.8	10.5	9.1	1.4
2025				
Reference	28.3	19.7	15.7	3.9
Low oil price	31.1	23.3	18.2	5.1
High oil price	25.6	16.6	14.3	2.2
Low Growth	25.9	17.6	15.0	2.6
High Growth	30.6	21.8	16.4	5.4

As has been shown in previous tables, net US imports of petroleum accounted for 53 percent of domestic petroleum consumption in 2002. The EIA projects dependence on petroleum imports will reach 70 percent in 2025 in the reference case.

Oil prices affect domestic production as well as imports, however, and high oil prices do not affect the percentage of dependence on imports as much as might be seem probable if only reductions in imports were considered. The EIA projections of import shares of total US consumption in 2025 are still expected to be 65 percent in the high oil price case, and to be 75 percent in the low oil price case

Continuing US Import Dependence

In short, the practical problem for the foreseeable future is that no meaningful near and mid-term options that will allow the US to reduce dependence on MENA energy exports in any meaningful strategic sense. The US must shape its security policies accordingly, regardless of what happens in Iraq. It must also shape them in light of US dependence on a global economy – not simply direct US dependence on oil imports.

ⁱ See <http://www.eia.doe.gov/emeu/cabs/pgulf.html>, DOE/EIA estimated in September 2004 that the Persian Gulf contains 715 billion barrels of proven oil reserves, representing over half (57%) of the world's oil reserves, and 2,462 Tcf of natural gas reserves (45% of the world total). Also, at the end of 2003, Persian Gulf countries maintained about 22.9 MMBD of oil production capacity, or 32% of the world total. Perhaps even more significantly, the Persian Gulf countries normally maintain almost all of the world's excess oil production capacity. As of early September 2004, excess world oil production capacity was only about 0.5-1.0 MMBD, all of which was located in Saudi Arabia.

According to the Energy Information Administration's International Energy Outlook 2004, Persian Gulf oil production increased from 18.7 MMBD in 1990 to 22.4 MMBD in 2001. It is expected to reach about 27.9 MMBD by 2010, and 38 MMBD by 2020, and 45.0 MMBD in 2025. This would increase Persian Gulf oil production capacity to over 33% of the world total by 2020, up from 28% in 2000.

The estimate does, however, change significantly in the high oil price case: It is expected to reach about 21.4 MMBD by 2010, and 27.3 MMBD by 2020, and 32.9 MMBD in 2025.

ⁱⁱ EIA, OPEC Revenues Fact Sheet; <http://www.eia.doe.gov/emeu/cabs/opecrev.html>

ⁱⁱⁱ These points are taken from the EIA short term forecast for March, 2005.

^{iv} The following excerpts come from the oil sections of the countries shown as current in the EIA web page, Country Analysis Briefs, at <http://www.eia.doe.gov/emeu/cabs/cabsme.html> on March 16, 2005.

^v Estimates differ according to source, The last comprehensive USGS analysis was performed in 2000, and was seriously limited by the fact many countries were affected by war or internal turmoil and declared reserves without explaining them or provided data by field. Standard estimates of reserves by non-USG sources like those in the *Oil and Gas Journal* and *World Oil* do not adjust reported data according to a standardized methodology or adjust for the large number of countries that never alter their estimates of reserves for actual production.

For example, six of the ten nations with the largest proven reserves are in the MENA region. An IEA analysis shows a range of 259-263 billion barrels for Saudi Arabia, 105-133 billion for Iran, 66-98 billion for the UAE, and 31-29 billion for Libya.. The figure of 115 billion for Iraq is consistent only because it is a figure announced in the past by the Iraqi government and there are no accurate, verified estimates. To put these figures in perspective, the range for Russia is 60-69 billion, 25-35 billion for Nigeria, 23-21 billion for the US, and 52-78 billion for Venezuela. (International Energy Agency, "Oil Market Outlook," World Energy Outlook, 2004, OECD/IEA, Paris, October 2004, Table 3.2.)

Estimates alter radically if an unconventional oil reserve like Canadian tar sands are included. The Middle East has only about 1% of the world's known reserves of oil shales, extra heavy oil, tar sands, and bitumen. Canada has 36%, the US has 32%, and Venezuela has 19%. The rest of the world has only 12%. The cost-effectiveness of producing most of these reserves, and the environmental impact, is highly uncertain, however, even at high oil prices. (International Energy Agency, "Oil Market Outlook," World Energy Outlook, 2004, OECD/IEA, Paris, October 2004, Figure 3.13.)

Reserve estimates also change radically if ultimately recoverable reserves are included, and not simply proven reserves. Some estimates put the total for such reserves at around 2.5 times the figure for proven reserves. For example, the IEA estimate for the Middle East drops from around 60% to 23%. Such estimates are speculative however, in terms of both their existence and recovery price, and do not have significant impact on estimates of production capacity through 2025-2030. They also ignore gas and gas liquids. The Middle Eastern share of undiscovered oil and gas resources rises to 27% based on existing data.

Such estimates are also heavily biased by the fact that so little experimental drilling searching for new fields occurred in the Middle East between 1992 and 2002. The IEA estimates that only 3% of some 28,000 wildcat explorations for new fields worldwide took place in the Middle East. Recent exploration in

key countries like Iran, Iraq, and Libya has been minimal. Some 50 Saudi fields, with 70% of the reserves that are proven, still await development. (International Energy Agency, "Oil Market Outlook," World Energy Outlook, 2004, OECD/IEA, Paris, October 2004, Figure 3.15.).

^{vi} Guy Caruso, "US Oil Markets and the Middle East, DOE/EIA," October 20, 2004.

^{vii} Guy Caruso, "US Oil Markets and the Middle East, DOE/EIA," October 20, 2004.

^{viii} IEA estimate in the World Energy Outlook for 2004, Table 3.5, and analyzed in Chapter 3.

^{ix} Guy Caruso, "US Oil Markets and the Middle East, DOE/EIA," October 20, 2004.

^x International Energy Agency, "Oil Market Outlook," World Energy Outlook, 2004, OECD/IEA, Paris, October 2004, Chapter 3.

^{xi} The DOE/EIA, International Energy Outlook for 2004, can be found at <http://www.eia.doe.gov/oiaf/ieo/download.html>.

^{xii} See <http://www.eia.doe.gov/emeu/cabs/pgulf.html>. In 2003, Persian Gulf countries had estimated net oil exports of 17.2 MMBD of oil (see pie chart). Saudi Arabia exported the most oil of any Persian Gulf country in 2003, with an estimated 8.40 MMBD (49% of the total). Also, Iran had estimated net exports of about 2.6 MMBD (15%), followed by the United Arab Emirates (2.4 MMBD -- 14%), Kuwait (2.0 MMBD -- 12%), Iraq (0.9 MMBD -- 9%), Qatar (0.9 MMBD -- 5%), and Bahrain (0.01 MMBD -- 0.1%).

U.S. gross oil imports from the Persian Gulf rose during 2003 to 2.5 MMBD (almost all of which was crude), from 2.3 MMBD in 2002. The vast majority of Persian Gulf oil imported by the United States came from Saudi Arabia (71%), with significant amounts also coming from Iraq (19%), Kuwait (9%), and small amounts (less than 1% total) from Qatar and the United Arab Emirates. Iraqi oil exports to the United States rose slightly in 2003, to 481,000 bbl/d, compared to 442,000 bbl/d in 2002. Saudi exports rose from 1.55 MMBD in 2002 to 1.77 MMBD in 2003. Overall, the Persian Gulf accounted for about 22% of U.S. net oil imports, and 12% of U.S. oil demand, in 2003.

Western Europe (defined as European countries belonging to the Organization for Economic Cooperation and Development -- OECD) averaged 2.6 MMBD of oil imports from the Persian Gulf during 2003, an increase of about 0.2 MMBD from the same period in 2002. The largest share of Persian Gulf oil exports to Western Europe came from Saudi Arabia (52%), with significant amounts also coming from Iran (33%), Iraq (7%), and Kuwait (6%).

Japan averaged 4.2 MMBD of net oil imports from the Persian Gulf during 2003. Japan's dependence on the Persian Gulf for its oil supplies increased sharply since the low point of 57% in 1988 to a high of 78% in 2003. About 30% of Japan's Persian Gulf imports in 2003 came from Saudi Arabia, 29% from the United Arab Emirates, 17% from Iran, 12% from Kuwait, 11% from Qatar, and around 1% from Bahrain and Iraq combined. Japan's oil imports from the Persian Gulf as a percentage of demand continued to rise to new highs, reaching 78% in 2003.

^{xiii} OPEC data are labeled confidential but are very similar. The IEA does not provide country-by-country estimates, but uses very similar models with similar results. It estimates total world production was 77 MMBD in 2002, and will increase to 121 MMBD in 2030. If one looks at the data for the Middle East, the latest IEA estimate in the World Energy Outlook for 2004, Table 3.5, is:

	2002	2010	2020	2030	Ave. Annual Growth
OPEC Middle East	19.0	22.5	37.4	51.8	3.6%
Other Middle East	2.1	1.8	1.4	1.0	-2.7%
Total	21.1	24.3	38.8	52.8	
Non-Conventional					
Oil (Worldwide)	1.6	3.8	6.1	10.1	6.7%

World	77.0	90.4	106.7	121.3	1.6%
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^{xiv} See <http://www.eia.doe.gov/emeu/security/choke.html#HORMUZ>. The Strait is the narrow passage between Iran and Oman that connects the Persian Gulf with the Gulf of Oman and the Arabian Sea. It consists of 2-mile wide channels for inbound and outbound tanker traffic, as well as a 2-mile wide buffer zone. The EIA estimates that some 13 MMBD flowed through the Strait in 2002. The IEA puts the figure at 15 MMBD in 2003. Both agencies indicate that the amount of oil moving by tanker will increase steadily as Asian demand consumes a larger and larger share of total exports.

Closure of the Strait of Hormuz would require use of longer alternate routes (if available) at increased transportation costs. Such routes include the 5 million-bbl/d capacity Petrolina (East-West Pipeline) and the 290,000-bbl/d Abqaiq-Yanbu natural gas liquids line across Saudi Arabia to the Red Sea. Theoretically, the 1.65-MMBD Iraqi Pipeline across Saudi Arabia (IPSA) also could be utilized, more oil could be pumped north to Ceyhan (Turkey), and the 0.5 million-bbl/d Tapline to Lebanon could be reactivated.

^{xv} International Energy Agency, "Oil Market Outlook," World Energy Outlook, 2004, OECD/IEA, Paris, October 2004, Table 3.7 and 3.8.

^{xvi} BP/Amoco, BP Statistical Review of World Energy, London, BP, 2003, p. 17.

^{xvii} BP/Amoco, BP Statistical Review of World Energy, London, BP, 2003, p. 17.

^{xviii} EIA, Annual Energy Outlook, 2003, pp. 80-84.

^{xix} Energy Information Administration, Annual Energy Outlook 2004, p. 95.

^{xx} EIA, Annual Energy Outlook, 2004, Table 26