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The upstream petroleum industry and local industrial development A comparative study

by

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PREFACE

This report is part of a study commissioned by the Norwegian Agency for Development Cooperation (Norad) and the Norwegian Ministry for Petroleum and Energy (NPE) under the custody of four oil-industrial related Nigerian government organizations: The Office of the Advisor to the President on Petroleum and Energy, the Department of Petroleum Resources (DPR), the Nigerian National Petroleum Corporation (NNPC) with its subsidiary, National Petroleum Investment Services (NAPIMS).

INTSOK was engaged to organize the study, and appointed the Institute for Research in Economics and Business Administration (SNF) to be in charge of the research. This comparative study will together with a study on Nigerian industry by Kragha & Associates, Lagos, and a technology assessment of upstream oil and gas in Nigeria, undertaken by Rogaland Research, form the basis for SNF's preparation of the final report from the project.

The main work on this comparative study was conducted during the period August 2002-February 2003. The authors appreciate comments to drafts of the report at different stages. The discussions in a reference group have been particularly useful. This reference group was made up of the following members:

Egbert Imomoh, Advisor to Shell International
H. Sola Oyinlola, MD Schlumberger Nigeria
Odd Godal, Statoil
Kjell Miskov, Aker Kværner
Tore Sandvold, Sandvold Energy

Furthermore, we are extremely grateful to comments from Per Hagen, INTSOK.

The authors are responsible for designing the study, and the conclusions that are drawn. Neither the reference group nor the custodians, the organizer of the study, or those who have commissioned the work are responsible for the content of this report.

Bergen, May 2003

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SUMMERY

This report analyses the prospect for generating industrial development linked to the petroleum sector in Nigeria, drawing lessons from five other oil exporting countries: Brazil, Indonesia, Malaysia, Mexico and Norway. Oil exporting countries, including Nigeria have often experienced problems related to macro-economic stability and competitiveness on the part of industries exposed to international competition. The report discusses the causes of such problems and how they might be addressed in the Nigerian context as a prerequisite for the development of a cost-effective local supply industry for the Nigerian upstream petroleum sector. Nigeria has been a significant oil producer for 40 years, and has had a policy objective and policy measures in place for the promotion of a local supply industry. Yet, local content in deliveries to the upstream sector is only estimated at about 5 percent in 2002. Therefore, there is a need for rethinking the policy framework and it is the objective of this study to contribute to the rethinking.

A general observation from the comparison of the six countries is that the technological challenges facing the petroleum industry together with increased focus on environmental sustainability have induced liberalization in all cases. Liberalization appears to have been motivated by the need to access state-of-the-art technology and the need to specialize in the market segments where the local industry has obtained competitiveness. In the countries with the highest local content (Brazil, Mexico and Malaysia) the local content share appears to be on a declining trend as a result of liberalization. Indonesia is arguably the country closest to Nigeria regarding level of development and industrial capacity. The industrial capacity gap between the two is nevertheless wide as Indonesia has a much broader and larger industrial base than Nigeria. It is worth noticing that Indonesia has not been able to reach its target local content of 35 percent, even when local content there is defined as value added in Indonesia, regardless of ownership of the supplying firms. Nigeria's policy objective of moving from 5 percent local content at present to 30 percent in 2005 and 60 percent in 2010 appears to be unrealistic.

It is also argued that local content requirements that are binding (i.e. set higher than existing levels) increase costs, reduce government revenue and most likely reduce the investment and production level in the upstream oil and gas sector. However, binding local content requirements are less costly when set in terms of local value added and/or local employment rather than according to ownership of the supplying companies. Finally, binding local content requirements are likely to attract oil companies and contractors with a less efficient international

supply chain than the most efficient operators and contractors, since the former have the lowest switching costs. Given the industrial capacity, regulatory capacity and general economic conditions in Nigeria, the least costly measure of promoting local content in the upstream oil sector is probably to impose a moderate (WTO-compatible) tariff on competing imports.

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"In one generation we went from riding camels to riding Cadillacs. The way we are wasting money, I fear the next generation will be riding camels again" (King Feisal, cited in Gylfason, 2001).

1 Introduction

This paper analyzes local industrial development related to the upstream petroleum sector in six selected oil-exporting countries. It focuses on local content in the supply industry, but also addresses indirect effects on industrial development at large where such effects can be identified, for example through government investment of the oil revenue in national industries. The selected case studies are Brazil, Indonesia, Malaysia, Mexico, Nigeria and Norway. The objective of the study is to draw lessons for Nigeria from the other countries' experience and Nigeria's own past experience. The six countries are at different development stages both at present and at the time when petroleum resources were first discovered in the country. Nigeria and Indonesia were poor, populous countries at the time when the first investments in the petroleum sector were undertaken.[2] They both had a GDP per capita between USD 220 and 250 in the early 1960s, far below the other countries in the sample. However, while Indonesia developed competitive industries, mainly outside the petroleum sector, and the economy grew rapidly, Nigeria's economy stagnated and industrial production likewise.

Nigeria's remaining oil reserves are mainly found offshore and deep offshore. Offshore production is more technologically demanding and capital intensive than onshore production. It is therefore useful to compare Nigeria to other oil producing countries where production is largely from offshore fields. This is why Brazil, Mexico and Norway are chosen for comparison. Indonesia and Malaysia are interesting comparisons also for their large-scale LNG industry, an industry, which is

[1] Thanks to Frode Kristiansen who has produced table 1 in the report.

[2] Population in Indonesia is, however, about 70 percent more than the Nigerian population (207 mill in Indonesia and 124 mill in Nigeria at present).

rapidly developing in Nigeria and is seen as a promising new area of industrial development.

There is ample empirical evidence of a negative correlation between endowments of natural resources and economic growth. This observation is coined as the resource curse. Natural resource wealth is hardly a curse as such, but it probably creates a demanding policy environment where windfall revenue easily triggers a spending spree that ends in tears when boom turns to bust. A recent study by Gylfason (2001) finds that among the 65 countries classified as natural resource rich, few have performed better in terms of investment and economic growth than average during the period 1965-98. GDP per capita has for example declined by an average of 1.3 percent per year during the period 1965-98 in the OPEC countries. Malaysia and Indonesia are among the few successful natural resource-rich countries, which is an important reason for including them in this study.[3]

The rest of the paper is organized as follows: The next section discusses the challenges of natural resource-based economic development. Section 3 presents the six case studies focusing on the success factors and pitfalls experienced by each country. The study focuses on industrial policy and the ability to create indigenous capacity in the upstream petroleum industry. Where data is available the study assesses local content in the industry, and linkages from the petroleum sector to the rest of the economy. Local content will be defined along three dimensions: local ownership, expenditure in the local economy and employment. To have a better understanding of the driving forces behind the oil companies' and major contractors' procurement policy and sourcing of inputs, we describe the structure of international supply chains in section 4. Local content in the petroleum industry is not an objective in itself, but a means to improve industrial capacity and welfare. Experience from other industries as well as the upstream petroleum sector suggests that local content requirements have not always had the desired effects. The possible undesired side effects and trade-offs between local content and overall industrial development are discussed in section 5. Lessons for Nigeria from the six case studies are drawn in section 6. These lessons also take into account the structure of the supply chains in the upstream petroleum sector and experience from local content requirements in developing countries.

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[3] The weakness of the Gylfason study is the way natural resource-rich countries are defined. They are defined by the share of raw materials in total exports. This measure is biased towards unsuccessful economies since a high share could simply reflect lack of industrial development.

2 Natural resources and development

What distinguishes the petroleum sector from most other sectors of the economy, bar other valuable minerals, is first that the earnings are mainly in foreign exchange. Second, the earnings mainly accrue on the government in terms of royalties, taxes and eventually dividends from the state-owned oil company. A common policy mistake during oil booms is to act as if the increased foreign exchange earnings and government revenue are permanent. Introduction of expensive infrastructure investment programs or welfare programs that cannot be afforded during slumps are examples of this. These trigger increases in future recurrent expenditure and public sector deficits during periods of low and even moderate oil prices. Large-scale government programs reallocate productive resources to non-traded sectors. This development is helped by an overvalued exchange rate and results in unsustainable current account deficits during periods of low to moderate oil prices. External debt problems consequently follow. Volatility in the exchange rate and domestic demand can by itself create uncertainty, higher risk and lower investment than what would otherwise be the case. Natural resource rich countries are therefore advised to establish revenue-stabilizing funds in order to smooth consumption over time.[4]

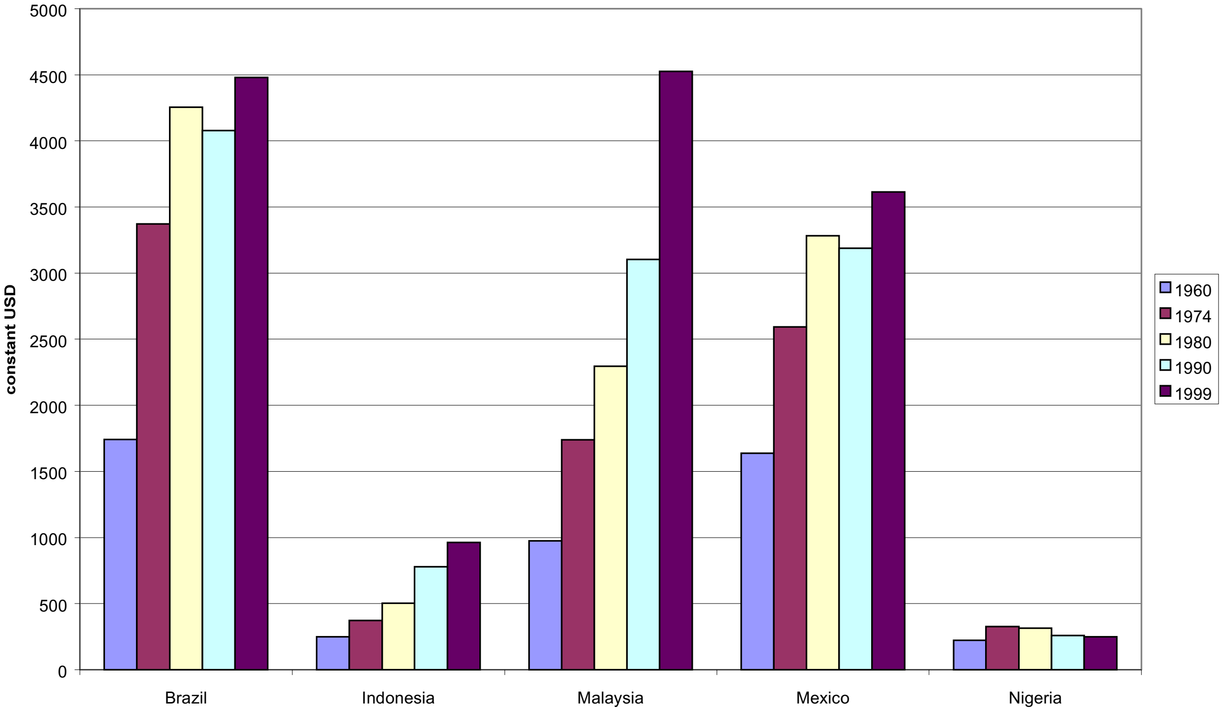
Natural resources provide “easy riches” and in most countries a massive pressure to spend the wealth on all kinds of good causes. Successful rent-seeking activities from interest groups ranging from industrial investors to NGOs are an additional contribution to ineffective allocation of resources both across sectors and over time in natural resource rich countries. These are popular explanations for an observed negative correlation between economic growth and endowments of natural resources. Other explanations relate to the misperception of a permanent increase in income followed by over-investment financed by borrowing and a resulting debt overhang that has increased the cost of capital in subsequent periods and thereby impeded investment and growth (Manzano and Rigobon, 2001). Closely related to this explanation is the theory of adjustment from above launched by Rodriguez and Sachs (1999). Their argument is that resource-rich countries are likely to live beyond their means during the booming years and that adjustment to a sustainable growth path[5] therefore implies a downward adjustment when the resource sector’s role as an engine of growth is exhausted.

[4] Both Mexico and Norway have such a fund, but Mexico only established the fund in 2000, so it has not had much impact yet, and certainly not during the booming years of the Mexican petroleum sector.
[5] This is referred to as the steady-state growth in the growth literature.

Gylfason (2001) finds a negative correlation between school enrolment and natural resource abundance and argues that this is an important explanation for the negative correlation between natural resources and economic growth. The reason for low investment in human capital in resource-rich countries in turn, is simply that education does not pay in an environment where protected and non-traded sectors dominate employment and some of the resource rent accrues on workers. In Nigeria during the 1980s for example, the unemployment rate was much higher among secondary school leavers than among people with no education or only primary education (Bevan et.al., 1999). Finally, Nordås (2000) argues that slow growth can be explained by lock-in of an industrial structure subject to substantial static economies of scale, but little dynamic economies of scale.

3 The case studies

Before we analyze each country in detail, we present an overview and comparison of key indicators for the six countries included in the study. Figure 1 shows GDP per capita in constant 1995 USD in 1960 (before the first oil price boom), then in 1974, (during the first oil price boom), in 1981 (during the second oil price boom) and finally the most recent comparable figure, which is for 1999. Since Norway's GDP per capita has been way above the others during the entire period Norway is not presented in the figure.

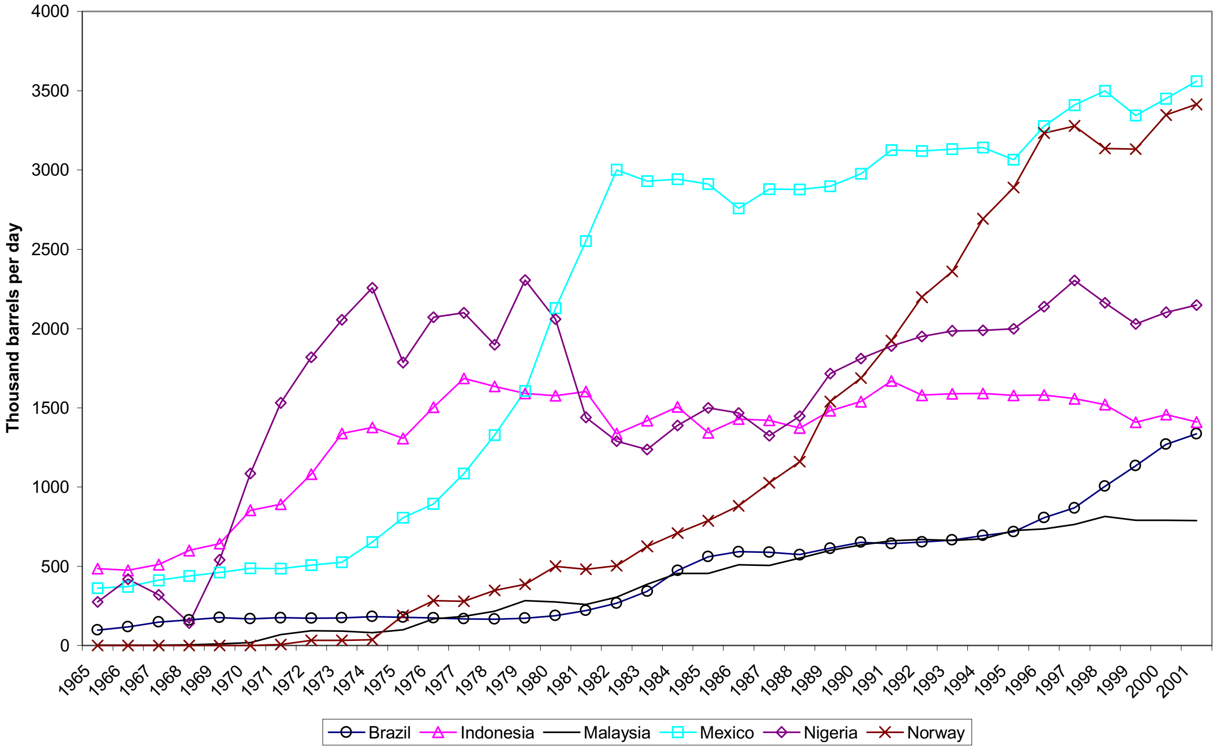


Source: World Bank: World Development Indicators (2001)

Figure 1. GDP per capita

We notice that Nigeria and Indonesia had similar levels of GDP per capita during the period 1960-74. But while Indonesia embarked on a sustained growth path after the first oil boom, (there was a setback during the Asian financial crisis in 1997 and its aftermath), Nigeria stagnated and was worse off in terms of GDP per capita in 1999 than it was in 1960. We also notice that the 1980s were a lost decade in terms of per capita income growth in Mexico and Brazil, while Malaysia has caught up with Brazil and become the second richest country in the sample by 1999.

Figure 2 below depicts oil production in the six countries from 1965 to 2001. Production is shown in terms of thousand barrels of oil per day.

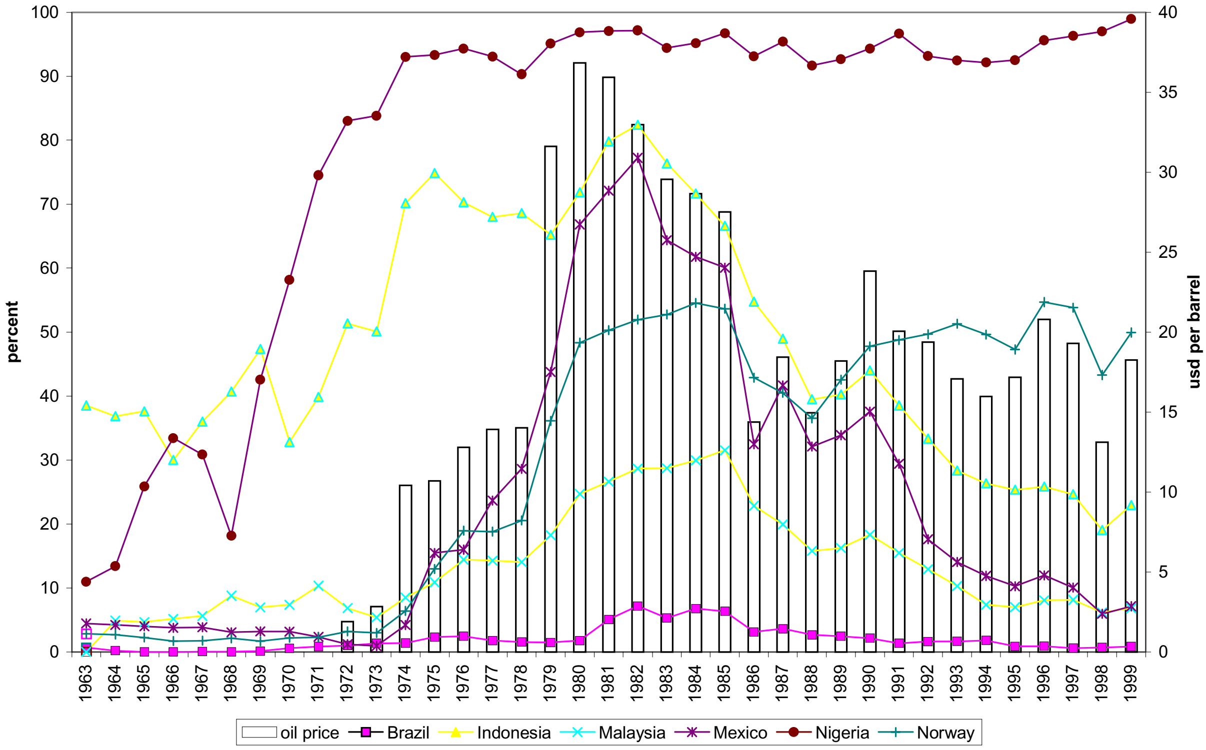


Source: BP (2002)

Figure 2. Oil production

We notice that Nigeria was the largest oil producer among the six during the 1970s, but was overtaken by Mexico in 1980 and Norway in 1991. These three are the large oil producers in the sample, while Indonesia's production is on a declining trend and Malaysia's production has leveled off. Brazil is a relatively small producer, but output has increased sharply recently, due to the opening of deep offshore fields. The increasing trend is expected to continue as new fields come on stream. It is also clear from figures 1 and 2 that the petroleum sector accounts for a much higher share of total national income in Nigeria than in the other countries. This is because Nigeria has been less successful in developing its non-oil economy.

Figure 3 depicts fuel exports as a share of total merchandise exports for the six countries during the period 1963-99. Fuel exports as a share of total merchandise exports are depicted on the left-hand axis, while the oil price in current USD per barrel is shown on the right-hand axis and oil prices are depicted by stars.



Source: World Development Indicators (2001) and BP (2002)

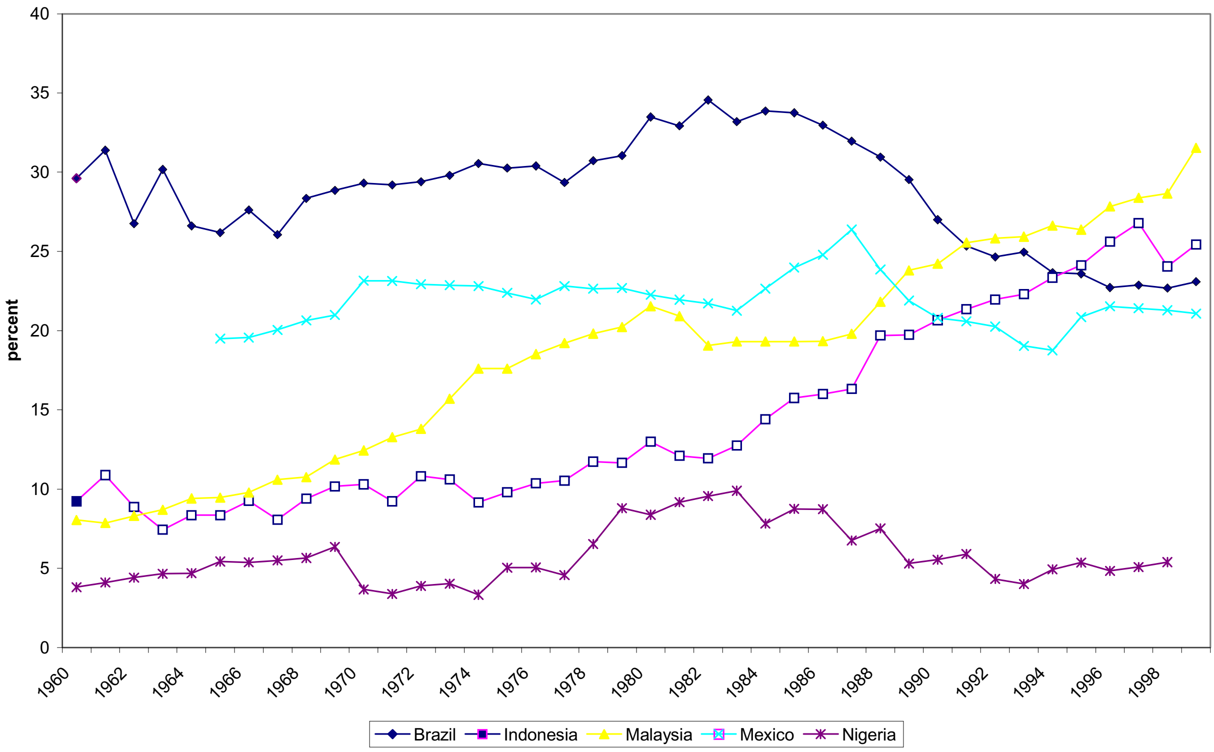
Figure 3. Exports of fuel as a share of total exports

What immediately strikes the eye is that fuel exports as a share of total exports is strongly correlated with the oil price in all the countries except Nigeria. This simply shows that the petroleum sector is the only significant exporting sector in Nigeria, while the other countries have a more diversified industrial base. We also notice from the figure that Brazilian production is largely for domestic consumption, which is also increasingly the case for Malaysia. In Mexico, the falling share of fuel in total exports is a reflection of a high growth rate of non-fuel exports, particularly during the period after the country joined Canada and USA in the North American Free Trade Area (NAFTA) in 1994.[6]

Developments in the industrial base in the five developing countries in the sample is further illustrated by figure 4, which shows developments of manufacturing value added as a share of GDP during the period 1960-99. We notice that Indonesia and Malaysia have experienced a period of rapid industrialization during this period. Industrialization was, however, not driven by local content and linkages to the petroleum industry. Rather, it was a result of low-cost, reasonably productive labor, competitive

[6] If exports by the in-bond industries (the so-called maquiladoras) are included, oil exports accounted for only about 10 percent of total exports in 2000 (OECD, 2002).

exchange rates and a relatively open and export-oriented trade and industrial policy, and not least improvement in the skills base. Brazil has experienced a stagnating and declining manufacturing share of GDP, but at a high level. Brazil's manufacturing share of GDP is still high compared to the average for middle-income countries. Mexico industrialized behind protective tariff walls in the 1950s and 60s, but as usual for these policies, the home market was not sufficient to develop the industrial sector beyond "light" consumer goods, and the industrial sector's share of GDP leveled off, but at a relatively high level. In Nigeria in contrast, the industrialization process appears to have been brought to a halt in 1983 and has not recovered since then. It was no higher in 1998 than it was in 1960.

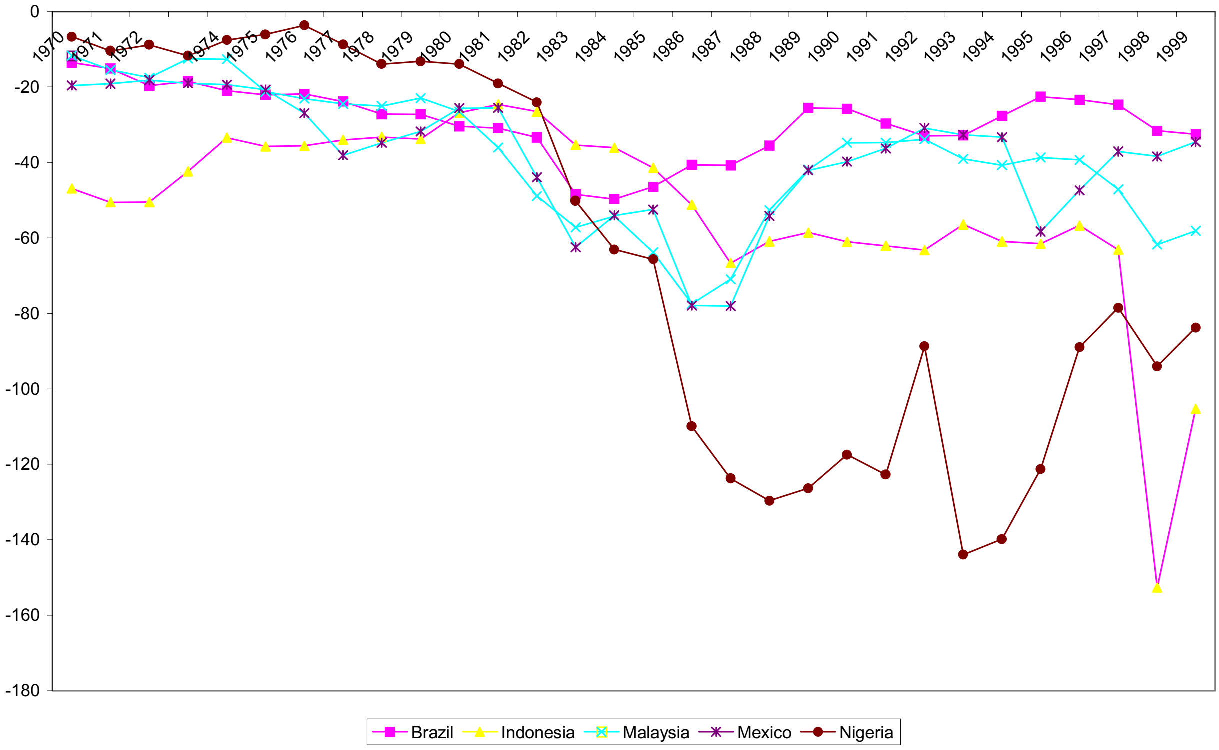


Source: World Development Indicators, 2001

Figure 4. Manufacturing share of GDP

We finally include a chart showing developments in external debt during the period 1970-99. Figures are given as a share of GDP. This makes them comparable and also gives an impression of the debt burden facing the country in question. The stock of foreign debt reflects the accumulated effects of current account deficits over time. Current account deficits in turn represent domestic expenditure over and above current domestic value added. A current account deficit opens if the government runs a budget deficit that is larger than the private sector savings-investment balance. In other words, countries with large government budget deficits and countries with a higher investment rate than the national savings rate (or both) will run current account deficits and accumulate foreign debt.

In periods of rapid industrialization or large-scale investments in the petroleum sector, significant current account deficits are not necessarily a problem. In Malaysia and Indonesia during the period from the early 1970s to the Asian financial crisis in 1997, the current account deficit financed an investment boom, which created additional export capacity and a sufficient flow of foreign exchange revenue to comfortably service the debt. However, the sustainability of the foreign debt position strongly depends on confidence in the country's economy and a reasonably stable exchange rate. To take an example, a foreign debt to GDP ratio of 50 percent turns into a ratio of 100 percent if the exchange rate depreciates from parity to the dollar to two units of local currency to the dollar. Depreciations on this scale happened during the Asian financial crisis and turned a financial crisis into a debt crisis in Indonesia. Malaysia has already recovered from the crisis and the debt to GDP ratio is declining towards a sustainable level. Also Indonesia is on its way to recovery, although the crisis was deeper there. Mexico and Brazil went trough a debt crisis in the early 1980s and Mexico again in 1995, while Brazil was at the brink of yet another financial market crisis in late 2002. We notice that debt crises can occur at relatively low debt levels if the maturity structure of the debt stock is unfavorable, and if turmoil in financial and currency markets undermine confidence in the economy. Nigeria has experienced a permanent debt crisis since the early 1980s. The improvements during the last decade are mostly due to debt rescheduling with the Paris Club and the London Club of commercial banks (EIU, 2002).



Source: World Development Indicators, 2001

Figure 5. External debt as a share of GDP

Turning to key indicators in the petroleum sector, table 1 below gives a snapshot of the structure of the six countries, focusing on the upstream petroleum sector and key economic and social indicators.

Table 1. Fact sheet

	Nigeria	Brazil	Indonesia	Malaysia	Mexico	Norway
1. Production 2001						
1.1 Oil (Thousand barrels daily)	2148	1337	1410	788	3560	3414
1.1.1 Offshore share	45%	83%	35%	100%	81%	100%
1.1.2 State owned company	55%	100%[7]	3,3/80%[8]	30%	100%	
1.1.3 Other domestic comp.	5%	-			-	
1.1.4 Foreign companies	40%	-			-	
1.2 Gas (Billion cubic meters)	13.4[9]	7.7	62.9	47.4	34.7	57.5
1.2.1 Offshore share	45%	65%	37%	100%	34%	100%
1.2.2 State owned company	55%	100%[7]	7.4/80%		100%	
1.2.3 Other domestic comp.	5%	-		0%	-	
1.2.4 Foreign companies	40%	-			-	
2. Reserves 2001						
2.1 Oil (Thousand mill. Barrels)	24.0	8.5	5.0	3.0	26.9	9.4
2.1.1 Offshore share (by 1999)	54%	96%	20%	99%		100%
2.2 Gas (Trillion cubic meters)	3.51	0.22	2.62	2.12	0.84	1.25
2.2.1 Offshore share (by 1999)	29%	72%	61%	99%		100%
4. National oil companies						
4.1 State owned company?	Yes	Yes[10]	Yes	Yes	Yes	Yes
4.1.2 Operator or financial?	Finance	Oper.	Oper.	Oper.	Oper.	Oper.
4.2 Other domestic companies?	Yes	Yes	Yes	No	No	Yes
4.2.1 Operator or financial?	Oper.	Oper.	Oper.	-	-	Oper.
5. Oil policy						
5.1 Member of OPEC?	Yes	No	Yes	No	No	No
5.2 Block auction or awarding?	Award.	Auct.	Award [11]	Award	na	Award
6. National economy 2000						
6.1.1 GNI per capita USD	260	3580	570	3380	5070	34530
6.1.2 GNI per capita PPP	800	7300	2830	8330	8790	29630
6.1.3 GDP Growth, annual %	3.8	4.5	4.9	8.3	6.6	2.3
6.1.4 Gross FDI, % of GDP	2.9	6.0	4.2	2.0	2.3	11.4
6.1.5 Gross inward stock FDI USD bill.	20.3	197.7	54.3	60.6	91.2	37.1
6.2 Sectors, VA as % of GDP						
6.2.1 Agriculture	29.5	7.7	17.0	8.6	4.1	1.8
6.2.2 Industry	46.0	37.5	47.0	51.7	27.9	42.9
6.2.3 Services etc.	24.5	54.8	35.9	39.7	68.0	55.2

[7] Brazil has deregulated the oil industry. As a result other companies than Petrobras will soon start producing.

[8] Indonesia's state owned Pertamina handles a small fraction of production as an operator, but has a 65 – 90 percent involvement in all fields trough production sharing contracts (PSC).

[9] Due to lack of utilization infrastructure, Nigeria flares 75 percent of the natural gas it produces, and re-injects 12 percent to enhance oil recovery. LNG-production is planned to end flaring by 2004 (EIA).

[10] In 1997 Brazil started a process of opening its petroleum industry to other domestic and foreign players. In august 2000, the government sold a 28,5% stake in Petrobras. Foreign companies entered JVs with Petrobras first in 1997, and have participated in bid rounds in 1999, 2000, 2001 and 2002 (EIA).

[11] The state owned Pertamina is a partner in all developments trough PSCs.

3.1 Brazil

3.1.1 Production of oil and gas

Oil production in Brazil has been on a steady increase the last ten years from 630.000 barrels a day (bbl/d) in 1990 to approximately 1.500.000 bbl/d in 2002. Still Brazil is a net importer of oil with national consumption now running at around 2.200.000 bbl/d (EIA, 2002). Brazil is not a member of OPEC and neither an important exporter as the country is primarily striving for self-sufficiency in oil production. This goal is unlikely to be met in the next few years. Oil was first discovered in 1939 and the first offshore discovery came in 1968. In the late seventies Brazil was producing 66 percent of its crude oil from onshore and 34 percent from offshore fields. Today most of Brazil's crude oil production is taking place offshore (87 percent) and 60 percent of the production is concentrated in the Campos Basin Southeast of Rio de Janeiro (FEI, 2002).

Brazil is the world's second largest producer of hydroelectric power and thereby heavily dependent on one source for the domestic energy supply. A recent national energy crisis and the exhaustion of new hydropower projects forced the government to introduce an energy-rationing program in 2001. One important part of this program is to convert some of the electricity consumption into alternative use of natural gas. From 1999 Brazil started to import gas from neighboring countries as the national production has not be able to keep up with national consumption. Brazil's production of natural gas has increased steadily in the last twenty years from 40 million cubic feet in 1980 to a rate running at 260 million cubic feet in 2001. 65 percent of the natural gas is produced offshore, basically from the Campos Basin. All gas produced is used domestically of which 80 percent are used in power generation (FEI, 2002).

3.1.2 Reserves

Brazil's proven reserves of crude oil are in the range of 8.1-8.4 billion bbl in 2001 (EIA, 2002). This makes the country the second largest container of oil in South America. Almost all of the proven reserves are located offshore. New explorations are now moving to ultra-deep (from 2000 meters) fields, but some onshore blocks have also been on offer.

The reserves of natural gas are in the range of a modest 7.8-8.2 trillion cubic feet in 2001. The largest reserves are again located offshore (72 percent) in the Campos basin and in the smaller Santos basin. Most of the past exploration activities have focused on oil. It is expected that the potential for a significant increase in the production of natural gas can come from under-explored offshore blocks in the Southeast part of Brazil.

These reserves most probably will keep Brazil as a net importer of both oil and gas in the next decade. Pipelines already connect southern part of Brazil to gas fields in Bolivia and Argentina. In the future one could expect construction of pipelines from Venezuela and LNG based supplies from Trinidad and Tobago. Oil imports to Brazil now arrive from Africa as the most important region, and from the Middle East, Venezuela and Argentina.

3.1.3 Technology

As most of the Brazilian oil and gas production is taking place in offshore fields and more and more from ultra-deep waters, the demand for sophisticated technology is strong. The country has a long history of an import substitution policy both related to commodities and technology. In 1953 president Vargas proclaimed that Petrobras, the national oil company should incorporate with solely Brazilian capital, technical know-how and workers. The country should strive for self-sufficiency in most petroleum products reducing the import and cost of by-products, build new refineries, and create a supply infrastructure with a transportation network and terminal installations. Upstream the nation should also lower the reliance on imported crude oil and increase domestic production. Another important challenge at that time was to develop a national technical know-how in petroleum production, first of all in the operation of upstream and downstream activities, but also in developing a national construction and equipment industry. In the fifties the Brazilian supply industry was not very sophisticated. As the substitution of imports and development of the country’s infrastructure was the most pressing goals, the government encouraged foreign construction enterprises to set up operation in Brazil in order to speed up the development. Most of the designs and equipment used in refining or petrochemical processing, pipelines and oil field production came from the North American supply industry. As a result the Brazilian petroleum industry was capable of operating modern technology, and to develop the capacity and capabilities needed to supply the country with most petroleum products (Bjørnstad, 2000).

Offshore exploration in Brazil started in 1968, the first commercial finding came in 1974 and the first production started in 1977 on 120 meters depth. In the early eighties the government promoted a more nationalistic development model. In addition to reduce imports and supply the whole country, Petrobrás was also given a responsibility to find and help developing a new national supply industry. As a part of this policy Petrobrás was allowed to choose its own way regarding the technological and industrial aspects of their business. Barriers to trade particularly in the construction industry helped develop domestic capacity and skills in platform construction, piping and shipbuilding. Some of this was based on technological assistance from abroad.

At the end of the eighties, several new laws were enacted in Brazil aiming at modernizing the domestic industry as a whole and make it more competitive. In this period new means were introduced to foster domestic, technological development in the petroleum business. As Brazil has moved into deeper and deeper waters, the country's petroleum related industry has been part of the technological frontier in deep water oil and gas exploration. By this Brazil also has taken part in the development of new, innovative and sophisticated technologies. Petrobrás is today regarded as one of the most experienced deep-water operators in the world and has developed, alone or in joint ventures with domestic or foreign enterprises, new technology in floating production and in subsea production systems. These new technological challenges in deep waters and a need to increase productivity in the sector encouraged the introduction of a new Industrial and Foreign Trade Policy and reduced restrictions on imports.

As in the rest of the international oil industry, Petrobrás has implemented partnership with the national and international supply industry to develop new technologies for ultra-deep waters and to stimulate better designs and better quality (Petrobras, 2002). Brazil is now a holder of the state-of-the-art technology in deep water operation, in offshore drilling and in telecommunications and information services between the operating units in the offshore scene.

3.1.4 Role of national petroleum company

As already mentioned Brazil has a long history of national control over the energy sector and the energy industry. As in most countries the supply of oil was regarded to be of strategic importance to the countries' independence from foreign rule and for the industrialization of the country. As a developing country the demand for petroleum products was small during the first part of the last century and import was the only source. For this reason foreign companies also dominated the distribution system.

In 1934 the regime under President Vargas established *the National Department of Mineral Production* (DNPM) with the purpose to explore for petroleum. The Mine Code from 1934 declared that the mineral resources in the ground belonged to the federal Union and that foreign as well as domestic firms interested in exploring and/or refining mineral resources needed permission from the federal government. The national control over the mineral industry was sharpened through the constitution of 1937 that required shareholders in the mineral industry operating on Brazilian territory, to be natives (Bjørnstad, 2000).

As a follow up of this nationalist legislation a new agency was established in 1938. *The National Petroleum Council* (CNP) was directly subordinated the president and had as its objective to develop a strategy for the establishment of a national oil industry. CNP was made responsible for the control of imports, transport of petroleum products and given authority to decide which and where new refineries should be established. At this time private firms could continue to operate, but foreign capital was excluded from operating in Brazil. From its inception CNP had a governing structure giving the central bureaucracy a strong influence together with a minority from the private sector outside the existing oil industry. As in many developing countries a representative of the armed forces was the first president. CNP discovered the first oil reservoir in 1939, but national production at that time was marginal and did not free the country from imported crude oil and refined products.

After the Second World War ended the Economic Commission for Latin America (ECLA) advocated an import-substitution strategy to economic development. This strategy also highlighted the necessity for all countries in Latin America to become self-sufficient in petroleum products. CNP on the other hand declared at that time that foreign capital was necessary to develop the refining industry, but national control should still be maintained over exploration of oil.

From the liberal oriented constitution of 1946 a Petroleum Statute followed proposing that the national oil industry should be developed as a joint project between the Federal Union and private industry. The Petroleum Statute never gained the support of the Congress. It was too liberal for the majority and too nationalist for a minority. Parallel to this congressional struggle the Department of the Administration of Public Services proposed a *plan to develop a national oil industry* without altering the existing legislation. This plan proposed to accelerate several oil projects, construction of a new refinery, and expansion of a state-owned refinery, all under the control of CNP. The plan also suggested purchase of several oil tankers. The approval of this plan created the judicial basis for establishing a *national oil shipping company* (FRONAPE) in 1949.

In the presidential election in 1950 the oil question was at the forefront of the political debate. National control over the resources was highlighted as well as the elimination of imports and the need to free foreign currency for other and more needed purposes. It was a question of short-term balance of payment problems as well as the long-term modernization of the Brazilian economy.

After the election it was suggested to create a state-owned holding company denominated *Petrobrás*. A long political struggle ended in a suggested model stating that the new company should be wholly owned by the federal Government and command monopoly power in exploration, production, refining and transportation of petroleum. All activities should be directly controlled, not organized as subsidiaries. This last SOE model achieved the support of the Congress and the nationalist-biased Petrobrás project was transformed to law number 2004 in 1953.

Assets under the control of CNP were transferred to Petrobrás including the tanker fleet. Brazil's state oil company initiated its operation in 1954. Private refiners established before the law was approved were allowed to continue, but not to expand. During the first years the development of Petrobrás was turbulent with many changes in the executive administration, confrontations with part of the central administration hostile to the company, and further debates in the Congress between nationalists and liberals. The co-operation between CNP and Petrobás soured with the result that CNP was marginalized (Bjørnstad, 2000).

The President supported Petrobrás in this period, but also intervened in the decision-making processes of Petrobrás. As an example he gave more power to the labor union, which ended dictating important parts of the operational decisions of the company. This disorganization led to inefficiency and a falling production. The political turmoil of these times ended with the military coup in 1964.

From now on Petrobrás had a more solid basis for its operation. The military had always regarded the oil question as crucial to the national security and therefore of paramount importance to preserve a centralized line of command over this industry and to defeat tendencies of the Brazilian populism. This dirigiste nature of economic policy was kept during the entire period from 1964 to 1985.

As in many other countries with an authoritarian rule, the state owned company was allowed to invest in other sectors of the economy. Petrobrás established a myriad of subsidiaries going into petrochemicals, fertilizers and sulphur, in distribution of fuel alcohol and in commerce. In this period Petrobrás also started its international activities through *Braspetro*. Also as experienced in other oil nations, the state oil company in Brazil developed into a state in the state supported by its self-financing capabilities and freedom to run the business as an insulated bureaucracy with the sanction of the military regime. Still it was formally under the jurisdiction of the *Ministry of Mines and Energy* established in 1964. In this period Petrobrás' strategic goal was to concentrate on refining and distribution of imported oil. This played down the role to explore and produce crude oil and undermined the government's objective to develop self-sufficiency in oil production. In this period subsidiaries of Petrobrás were also allowed to enter into joint ventures.

Partly due to this under-performance, the government introduced *risk contracts* in 1975. The aim was to increase domestic oil production through the participation of foreign firms. These where allowed to explore fields at their own risk, but if they were successful they had to sell the reserves to Petrobrás. Over 200 risk contracts are reported in this period. Most of the 38 companies entering into these contracts came from USA and only five of the contracts developed into commercial production.

The military regime ended in 1986. The following constitution of 1988 gave even stronger preferences to national companies at the expense of foreign companies already operating in Brazil. Further risk contracts were banned. This very nationalistic regime first terminated in 1997. As a consequence Petrobrás had a very strong position in the Brazilian economy during the eighties and early nineties.

In the late eighties The Brazilian 'economic miracle' was slowing. Inflation skyrocket starting in 1987, GNP growth was negative from 1989 and the crisis-ridden economy needed a new policy. The state apparatus was restructured, barriers to trade were lifted and a new free trade agreement with the neighboring countries installed. A national program for privatization was introduced in the early nineties. Large SOE's should be divested with no restriction on the nationality of the new owners. In this period a discussion of a restructuring of Petrobrás also started, but met opposition in the state apparatus, especially from the *National Fuel Department* (DNC), which had replaced CNP in 1990. In the political environment the conflict between nationalists and liberal modernizers was still sharp.

The first steps to dismantle the monolithic Petrobrás structure came in 1991 when two insignificant subsidiaries were divested. The national tanker fleet FRONAPE lost its monopoly and Petrobrás was free to sign contracts with other freighters. A reorganization of the company also started with the focus to improve performance, decentralize the organization and cut operational costs. From 1989 to 1999 the labor force was reduced from 60.000 to 39.000 employees.

The new President took office in 1994 and a reform process of the petroleum sector started. Two objectives guided the reform: to attract foreign capital to expand national oil production and to cultivate national private entrepreneurship. The reform suggested that the Federal Union still should own the resources underground, but could contract private enterprises in all aspects of the industry. Petrobrás should be kept as a national state owned oil-company but had to compete with private enterprises in all sectors. In addition Petrobrás was allowed to enter into joint ventures with national and foreign partners. The suggested oil reform of 1995 must also be seen as part of a policy to integrate Brazil into the wider global economy. The Congress approved the reform in 1995, but a regulatory framework had to be developed. This legislation was submitted to the Congress in 1997 and a new regulatory regime was at last approved. This will be discussed below.

The most controversial part of the political debate was not the deregulation, but the question if Petrobás should remain a state owned enterprise under control of the Federal Government or partly be privatized. The last policy was acclaimed. The real end to Petrobrás monopoly did not take place before June 1999 when the Government offered 27 blocks in an internationally open auction and competitors entered the Brazilian scene. In 2000 the government sold a 28.5 percent stake in Petrobrás of which half was sold to foreign investors (EIA, 2002). The company's shares were listed on the stock exchange the same year. In 2002 Petrobrás also lost its monopoly to import and refine oil products.

Today Petrobrás is the 12th largest oil company in the world. When it comes to reserves it is one of the largest. It still operates within the whole spectrum of activities upstream and downstream. The downstream activities are left to two subsidiaries: Transpetro (logistics) and Petroquisa (refining and petrochemical). International activities are left to Braspetro and the gas and power business to Gaspetro. E&P and technical services are under direct control of the holding company. In 2002 all of them are exposed to competition and have to perform as a commercial company. In 2001 the number of employees had decreased to 33.000 in the holding company and 5.700 in the subsidiaries. Net sales was 24.4 billion US $ and net profit 4.3 billion (Petrobras, 2002). This makes Petrobrás one of the more profitable oil companies in the world. As the opening of the Brazilian sector is of new date almost all Brazilian production is still under the control of Petrobrás. The company has an ambition to produce 1.800.000 barrels a day in the coming years, most of it in Brazil in deep and ultra deep water where Petrobrás has a technological advantage. In international exploration and production the company has concentrated on West Africa (Angola and Nigeria), Latin America and the Gulf of Mexico. It also has an ambition to lead the development of the national gas market and integrate into the electric power market.

3.1.5 Local content

With a nationalistic oil policy and at times almost totally closed for foreign enterprises, it is no wonder that the local content has been very high in Brazil. It is said that these policies combined with protectionism helped increasing the domestic capacity and capabilities to such an extent that the home market industry could meet 94 percent of Petrobras requirements in the late eighties (Petrobras, 2002). The negative effect of this policy was higher costs and lower quality and productivity than achievable using foreign technology.

As a result of the introduction of international bidding in the equipment and technical service industry the local share of purchases fell to 80 percent in 1993 and is still in this range for standard projects. In the more sophisticated projects offshore the local content is much lower.

The Brazilian market is still protected by import duties between 10 and 20 percent depending on the specific product and the existence of national production of goods and replacement parts (The REPETRO-list) (DoC, 1998a, 1999). Import of platforms or supply-vessels are punished with an 18 percent duty, but technologically sophisticated equipment not produced in Brazil could be imported without the imposition of import duty up to 2008 (Decree 378/2001). As a result many of the large multinational producers are moving into joint ventures with Brazilian yards and produce locally (Dagens Næringsliv, 2002).

As Petrobás still is the most important operator in the offshore sector, the procurement policy of this company is also defining the magnitude of local content. The market for investments in Petrobás was 6 billion US $

in 2001, 70 percent of these in the E&P sector, basically offshore (DoC, 2001).

The market for construction of heavy equipment for offshore exploration and production is large and growing. In the market for drilling rigs and production platforms approximately 55 percent was estimated to come from foreign imports in 1998. Singapore, South Korea and Spain have been successful in this sub-segment of turnkey projects. Portugal and the Netherlands are additional foreign sources. A combination of sophisticated technology, attractive financial terms, price and local representatives and agents in Brazil seems to be behind their success. ISO 9000 is required from all suppliers to Petrobrás (DoC, 1999). Most of the domestic offshore platform construction yards are located in the state of Rio. Out of sixteen yards active in this segment, the five largest are now under foreign control (Dagens Næringsliv, 2002). One can expect that more of the platform import will be replaced with domestic production, but under the control of the large multinational construction companies.

In the latest tenders all companies are asked to commit themselves to acquire local goods and services, the higher the local content the more points attributed to the company. In exploration 50 percent is treated as a maximum, in development 70 percent[12]. In the exploration phase the winning concessionaires have committed themselves to purchase between 15 to 50 percent of needed goods and services from Brazilian suppliers, in the developing phase between 10 and 70 percent. In complex ultra deep blocks the promised local content share from bidders is as low as 35 percent in the development phase. In smaller and simpler development project, local content is as high as 70 percent (ANP, 2002a).

Further, the more knowledge based the locally produced goods or services, the more it will count in the calculation. If the concessionaires, be it a foreign or Brazilian operator, do not fulfill the commitment for Brazilian participation in the project, a liquidated damage fee has to be paid to the National Petroleum Agency (ANP). Even with this ‘good will contracts’ in mind, it is the value of the Signature Bonus that is the principal criterion for the evaluation of the bids.

A minimum percentage required of Brazilian or a maximum of foreigner employed could also be part of the concession. There also exist

[12] Maximum means that the tender is not gaining further points if the local share is above 50 or 70 percent.

requirements for domestic R&D if the project moves on to develop fields that pay special participation.

3.1.6 Outline of industry structure

As already lined out, the Brazilian oil and gas scene has been and still is dominated by domestic companies. The monopoly still prevails in the sense that Petrobrás still is the absolutely dominating player.

From 1999 four bidding rounds have challenged this dominance. In the first round Petrobrás won the bid for one of 12 blocks solo and four others in joint ventures with major oil companies. Other international majors won blocks alone. In later rounds new, smaller international and national oil companies have arrived on the Brazilian scene. Slowly the structure is changing. The same is happening in other primary segments of the oil and gas industry. Also in the upstream segment new competitors are arriving and challenging the monolithic structure of Petrobrás that still controls 14 refineries and 7.800 gasoline stations.

In the oil and gas equipment and service industry the wholly owned Brazilian industry is competitive in the standard segments, but the multinational fabrication industry is on its way into the market, but mostly through local subsidiaries or joint ventures as mentioned already.

3.1.7 Present regulatory regime

Deregulation means that a system with one monolithic entity (Petrobrás) regulating the petroleum market; developing the national petroleum policy; and executing exploration, production and distribution, has come to an end.

With the privatization of Petrobrás two new agencies were created. The *National Petroleum Agency* (ANP) regulates and supervises the sector's activities. The *National Council for Energy Policies* (CNPE) acts as an advisory and consulting body to the President presided by the *Ministry of Mining and Energy*. This ministry is responsible for developing a national policy and specific measures for the national energy sector.

The role of Petrobrás in this new structure is to restructure its productive activities into a commercial actor performing as a normal, privately integrated oil company. All preferences should be removed and Petrobrás should compete on equal terms. In some areas Petrobrás market share is restricted. It is for example not allowed to control more than 40 percent of new gas transportation capacity or construction of pipeline expansions.

ANP is also reviewing the possibility to allow open access to the existing pipeline infrastructure.

3.1.7.1 Licensing

The new regime is based on contracts for concession or authorization. It follows bids held by ANP where new blocks, gas pipelines or refineries are subject to international competitive tenders. In this way ANP should raise capital for the Government through concessions and the sale of certain parts of the sector.

In the first round in 1999 very large blocks were on offer. Ten foreign firms purchased concessions and only 12 out of 27 blocks attracted bids. The second round was concluded in 2000. 23 smaller blocks intended to attract smaller oil companies were on offer. Pertobrás won many of the bids in partnership with foreign companies. Only two blocks did not receive any bid in this round (ANP, 2002a). The third bidding round came in 2001 offering 53 blocks, mostly in deep or ultra deep waters. A third of the blocks did not receive any bid. Many majors were attracted to these blocks. Lastly the fourth round ended in May 2002. 35 companies were competing for 39 offshore and 15 onshore blocks. Again Petrobrás was a big winner often in partnership with other international oil companies. All together Petrobrás is now involved in over 200 active partnerships with foreign companies (Petrobras, 2002).

To participate in these tenders a company must first submit an Expression of Interest, have a legal accredited representative in Brazil, be accepted as technically, legally and financially qualified and it must have paid the participation fee running from 10 000 to 187 500 US $ dependent on field and time. The companies must qualify as an ‘A’, ‘B’ or ‘C’ operator for dedicated blocks where the grading is according to capacity and proven capabilities. As already discussed the evaluation of the bids does not only look at the Signature Bonus but also attributes points and weights given for the company’s commitment to acquire local goods and services etc. The winning company must form a Brazilian company or delegate to an affiliated Brazilian company to sign the Agreement (ANP, 2002b).

The Brazilian Government benefits from exploration and development of the oil and gas resources through: 1) the Signature Bonus, 2) a Royalty in the range of 5-10 percent of the value of the production, 3) a Special Participation fee based on net income from production dependent on volume of production, location and year of production, and lastly 4) Rentals based on area surface. If the field is onshore there is also a property tax to be paid to the owner of the land. The rate is 0.5-1 percent of the value of production.

In addition, concessionaires should hire and train a minimum of Brazilian personnel and in case of payment of Special Participation fee to the Government they must also invest 1 percent of the production Gross revenue from the field in Research and Development expenditures.

3.1.8 Success criteria and caveats

As most of the South American countries Brazil has for long followed a nationalist, import-substitution policy with a proclaimed goal for self-sufficiency in energy supplies and a nationalistic industrial development plan. Basic industries as the oil and gas industry have for this reason for a long time been under the control of the Government and operated through SOEs. The Government has also had a longstanding technology policy to develop national capabilities and capacities in the supply industry by means of a protective trade regime and high barrier of entry for the international oil and supply industry. As a result Brazil has succeeded in developing a domestic oil industry and also to develop a national supply industry that has been able to develop new technology in certain areas. In this respect Brazil has been successful, but the cost has also been obvious. Without competition Petrobras developed into a bureaucracy more than an economically efficient producer of oil and gas. A protected domestic supply industry has also been rather inefficient and did not generate economic resources and technological know how to follow the exploration into ultra-deep waters. For such reasons the liberalization of the sector is wise and seems to have followed a path that has been able to take advantage of what Brazil has achieved under protectionism and convert this into competitiveness under open international competition. As this survey has shown the international supply industry is now locating some of its production in Brazil. This should be beneficial also for the national supply industry through sub-contracting, joint ventures, technological transfer and employment of Brazilian citizen. At the same time it is a challenge for national groups to operate in an international competitive market that hopefully will bring about a restructuring of the Brazilian supply industry and further develop an entrepreneurial and competitive spirit in the national industry.

3.2 Indonesia

3.2.1 Production of oil and gas

Indonesia has been an oil producer since 1890. In the period from 1990 to 2000 crude oil production has been within the range of 1.4 and 1.5 million barrels per day. In 2002 the production decreased to 1.24 million bbl/d. The recent downturn is due to natural decline in mature oil fields. As member of OPEC, Indonesia has a crude oil production quota. This is 1.125 million bbl/d in 2002. Estimated capacity in 2002 is 1.25 million bbl/d (EIA, 2002). Most of Indonesia's oil fields are still onshore in central and western parts of the country. Offshore production started in 1966 and covers an increasing share of the country's output. 20 percent of crude oil productions is produced offshore in 2001.

For some time Indonesia has been the world's largest exporter of LNG – 1.489 billion cubic feet in 2001. From 2001 Indonesia is also piping 32 billion cubic feet natural gas to Singapore via a newly built pipeline. The domestic infrastructure for distribution of gas on the other hand, is not developed and thereby slowing the domestic use of gas. Indonesia produced 2.807 billion cubic feet of natural gas in 2001, a 3 percent decrease from 1999. 67 percent of the natural gas was exported, the rest used primarily to generate electricity and produce fertilizers.

3.2.2 Reserves

Indonesia's proven reserves of oil are now 5 billion barrels, a 14 percent decline from 1994 (EIA, 2002). Much of the proven reserves are still to be found onshore in the large Duri and Minas oil fields in Central Sumatra. New exploration is moving to frontier regions in eastern Indonesia, offshore East Kalimantan and in the Natuna Sea, but also offshore northwestern Java. Three major projects are expected to come on stream in 2003 or 2004. In existing fields investment programs are underway to increase recovery rates. Due to the natural decline from mature fields one does not expect that the gross production of crude oil will increase in Indonesia. In a few years time it is a good chance that Indonesia will turn into a net importer of oil.

The reserves of natural gas are more significant, 92.5 trillion cubic feet in 2001. Much of the newly discovered reserves are located offshore, in the South China Sea (the Natuna project is one of the world's largest offshore gas development projects) and offshore and onshore Irian Jaya. Indonesia's proven gas reserves are also found in Aceh and in East Kalimantan. Many of these provinces are considered risky due to separatist activities.

3.2.3 Technology

Foreign oil companies operate most of Indonesia's petroleum fields. As a former Dutch colony it is not surprising that a for-runner of The Royal Dutch Shell was the first to produce oil in 1892. Standard Oil of New

Jersey through its Dutch subsidiary started exploration in South Sumatra in 1912 and Standard Oil of California opened a branch in 1930. In 1936 a joint venture between Standard Oil of California and Texaco formed Caltex, still the largest crude oil producer in Indonesia (Bevan et al., 1999). After independence it is basically American oil companies and a few European that have explored, developed and operated oil and gas fields in Indonesia. Most of these licenses are operated in partnership with the Indonesian State Oil Company Pertamina under Production Sharing Contracts (PSC). Pertamina as an operator is only responsible for 3.3 percent of the petroleum production in 2000 (US Embassy, 2001).

This dominance of US operators and US standards also means that most of the exploration, drilling and production technology in use in Indonesia is imported from abroad and basically from US oil, engineering and construction companies. Japanese energy companies have been investing extensively in the Indonesian gas and LNG industry. As a side effect Japanese technology and construction firms have delivered equipment, piping and turnkey plants to Indonesia. Depending of investment projects, USA and Japan together account for 60 percent of the imported oil and gas field equipment, with USA as the most important (DoC, 1998b).

As most of the fields still are located onshore or in shallow waters, the technology used is not very sophisticated and innovative. Lately there has been an increase in the use of enhanced oil recovery (EOR) equipment and more of the exploration and production-activities are taking place in deeper water. Some of the new frontier regions are lacking infrastructure and demands flexible and mobile design of equipment.

3.2.4 Role of national petroleum company

Indonesia's first president, Sukarno declared independence after the Japanese had surrendered in 1945. At that time oil fields under control of the Japanese Army were transferred to Indonesian authorities and formed the first national state oil company (PTMNRI) in north Sumatra. This was followed by PERMIRI in South Sumatra and Jambi. The former Shell fields in Central and Eastern Java were later expropriated and formed PTMN. After independence in 1949 an Indonesian style state capitalism developed under the Sukarno regime. Dutch assets in the country came under military supervision and were later expropriated and in the end nationalized (Bevan et al., 1999).

State ownership over important basic and exporting industries were part of the nationalistic policy for independence of that time. As part of the new Constitution article 33 also declares that; '*All natural resources in* *the soil and the waters of the country are the jurisdiction of the State and shall be used for the greatest benefit and welfare of the People*.' In this period the Indonesian Army, as the only managerial force in the country, also received a direct stake in the emergent state capitalism and in new state oil companies.

In 1957 PT PERMINA was formed to signify national ownership over national resources. This company was based on PTMNRI. The Oil and Gas Law no 44 of 1960 also ratified a new regime concerning oil and gas mining. In this law it was affirmed that only the Government could carry out oil and gas development projects and that these operations should be controlled by State Companies. Through this law the three incorporated companies changed to three state oil companies.

In 1966 the Sukarno regime was replaced through a military coup. The following 'New Order' regime of general Suharto started to reform an inefficient economy, including the oil sector, and the government opened up for direct foreign investments.. As a result the Government established one integrated state oil and gas company in 1968 under the name of PN PERTAMINA.

In the early phase of state ownership, significant influence of the operation of Pertamina came from the Armed Forces and the bureaucratic-nationalist group favored the company. Pertamina diversified into a very wide range of sectors as shipping, petrochemicals, fertilizers, steel and hotels. As the most important generator of state income, the company was used as and instrument in the industrialization of Indonesia, but also for personal benefits of an elite. Pertamina's independence in contracting external debt was early a problem for the Indonesian economy as the company developed into a state in the state (Bevan et al., 1999).

Law no 8/1971 (The Pertamina act) together with Law 44/1960 established the legal fundament, which has regulated the Indonesian petroleum activities up to 2001.This act closed this independence in 1972. From then on the company has been under control of a committee including representatives from Bappenas (The National Development Planning Board), the Ministery of Mining and Ministry of Finance.

Under this regulative regime Pertamina was responsible for all ventures in Indonesia in both upstream and downstream sectors of the petroleum industry. In consequence Pertamina has hitherto taken the major policy decisions concerning oil and gas production, investments, distribution and pricing in the domestic market. The Company has also supervised all petroleum activities, including bidding guidelines and had a final say in the decisions of large purchases. Pertamina is also legally responsible for securing supply of adequate petroleum products to the nation. This obligation is basically carried out through PSC's in cooperation with joint venture partners as already mentioned, particularly in the upstream segment. Pertamina currently supervises more than hundred domestic and foreign oil and gas contractors. These contractors produced 96 percent of the crude oil and 90 percent of the natural gas in 2000.

As seen, only a minor part of crude oil production activities are operated by Pertamina. In exploration and production activities the company is ranked number nine in Indonesia. In the gas sector Pertamina ranks number five (US Embassy, 2001). Most of Pertamina's active involvement in this industry is concentrated in downstream activities where Pertamina owns and operates nine refineries, owns or franchises gasoline stations all over Indonesia, and retails crude oil, gas or petroleum products abroad. In 2001 Pertamina's turnover was 17.250 million US$ ranking as number 48 among Asia's 1000 largest corporations. Profit was a modest 3.7 percent in the same year.

From this short survey it is clear that the Indonesian SOE for petroleum has been both a regulatory instrument for the government and a commercial operator. This contradiction has been faced, among others under the pressure from IMF. As a result a new law - 'the Law of the Republic of Indonesia no 22/2001 Concerning Natural Oil and Gas, passed the Indonesian Parliament in October 2001 and replaced the laws 44/1960 and 8/1971.

This law declares that Pertamina has to establish itself as a limited liability company within two years. Pertamina's regulatory and supervisory function will be transferred to two new agencies, one (Badan Peraturan) for *regulating* the sector, particularly in the downstream sector, and another (Badan Pelaksana) to *implement* policy and supervise, particularly in the upstream sector. Pertamina will also loose its monopoly over downstream activities, but must maintain its overall responsibility for the domestic fuel supply and distribution for another four years (Platts, 2002a).

This restructuring will alter the regulatory regime in the Indonesian oil and gas sector dramatically and transform Pertamina into a 'normal' state oil company concentrating its activities on the commercial side of the business. In the future privatization of the company is also part of the plan where the state will gradually divest its stake. Among other things this restructuring means an increase in Pertamina's exploration and production spending and a reduction of the manpower from today's 26 000 down to 18 000. Pertamina is also expanding its investments into other regions such as Vietnam, Burma, Iraq and Libya. In this transformation the company hopes to increase its production capacity extensively and to streamline and rationalize its refining and distributional operations.

3.2.5 Local content

As we have seen, Indonesia has chosen to secure national interests basically through Production Sharing Contracts (PSCs). This arrangement was introduced in 1966 as the first of its kind in the world (Yusgiantoro & Hsiao, 1993). Under this regime the Indonesian government owns the resources, but a contractor operates and share the production on output basis. In crude oil production 80 percent of the output nowadays is government property, 20 percent the property of the contractor and the return for the investment (earlier a 85/15 split was normal). In the gas business the share has been 70/30.

As this petroleum province has matured and competing oil-producing countries have arrived on the Southeast Asian scene, the incentives for foreign oil and gas companies to invest in Indonesia have been less competitive than before. The combination of new competitors, frontier development in less accessible regions, the financial crisis in Indonesia and the following political and ethnic unrest, has forced the Indonesian government to change this incentive structure. In recent projects a new sharing ratio as 65/35 for oil and 60/40 for gas has been applied (US Embassy, 2001). In this way the national share of the values of the petroleum resources has been high and important for the development of the Indonesian economy, but a trend towards decreasing shares can be observed.

When a foreign company acts as a production sharing contractor, it also has to compel to a policy asking contractors to buy a minimum of 35 percent of all goods and services from local suppliers. In reality the local content is not more than 10 to 20 percent in major investment projects (DoC, 1998). The reason is said to be the high quality standards set in this industry and the problem local businesses have to reach these standards. Anyway, if the 35 percent target is not met, the contractor has to send a request for exemptions to the Department of Industry and trade.

The market for oil and gas field equipment has been around 1 billion US $ a year in the late 1990's and 1.208 million US $ in 2000. The value of locally produced oil and gas field equipment that year was 459 million $ of which 161 was exported to Malaysia, Thailand, China and Brunei. The cost of imported equipment was 910 million of which 40 percent came from USA. Calculating local content from these figures should give an approximate share of 25 percent produced in Indonesia.

A manufacturer is regarded local if the production is taking place on Indonesian territory, regardless of whether it is controlled by domestic or foreign investors. Most of the domestic manufacturing is still under the license from a foreign principal. In this regard local content in the Indonesian context is more like local manpower than indigenous technology. As an example, rig platforms have been produced in Indonesia since the 1970's but it is PT McDermott Indonesia that produces 70 percent of all jacket platforms in the country. The rest is shared among smaller domestic manufacturers Doc, 1998).

3.2.6 Outline of industry structure

Currently, 26 foreign oil or energy companies are active in the Indonesian downstream oil and gas sector. Caltex is the largest oil producer, Total the largest gas producer. In the industry there also exist 12 – 15 domestic oil companies. Beside Pertamina, Medco Energy Corporation is the largest domestic producer operating fields in Sumatra and Kalimantan. Generally speaking, domestic oil companies are small and financially weak. Domestic companies also operate under PSC conditions (US Embassy, 2001).

At present there are more than 200 local oil service companies operating in Indonesia. The majority is small companies working in the low-tech end of the industry with limited experience and weak financial capabilities. Only the larger ones manufacture equipment and are able to provide the preferred full services for all stages in the developing process. Foreign owned service providers are generally larger compared with domestically owned suppliers and normally offer superior expertise and a broader range of services. This very often makes them the preferred service partner for the oil companies. In the drilling field foreign companies totally dominated the industry until the late 1970's. At that time the government introduced a policy requiring foreign companies to work together with locally owned firms as part of a policy to transfer knowledge to Indonesians. Today 48 drilling companies are registered, but still foreign drilling companies dominate the offshore drilling activities inside these joint ventures due to the requirement of large investment in offshore drilling equipment.

In upstream activities Pertamina's monopolistic position has hindered the arrival of strong competing companies, be it domestic or foreign. This will change under the new regulative regime lined out in the next paragraph.

There exist a duty in the range from 0 to 25 percent on imported oil and gas field equipment (DoC, 1998). In principle it should be duty free if the equipment is used for operational purposes. Until 1998 import/export, wholesale and retail distribution was reserved for Indonesian companies. Indonesian in this regard means that Indonesian citizens hold at least 51 percent of the equity. Today it is possible to obtain a foreign investment license to retail or wholesale, if so, one has to use an Indonesian firm to import. In practice, a partnership with an Indonesian distributor or service provider or even establishing a local company, seems to be necessary, both to meet regulations and to develop the best connections for lobbying in the tender process.

3.2.7 Regulatory regime

Indonesia was the first oil-producing country that made oil companies contractors and not concessionaries in 1960.

3.2.7.1 Licensing

Under the present regulations, foreign companies are invited to take part in the development of Indonesian petroleum resources most commonly through production sharing contracts (PSC). If Pertamina is acting as an operator itself, foreign involvement could come under technical assistance contracts (TAC), joint operating agreements (JOA) or as enhanced oil recovery (EOR) contractors (Platts, 2002a, 2002b).

The basic terms of a PSC is that (Pertamina, 2002):

- Pertamina (from 2003 a new Implementing Body reporting directly to the oil minister) is responsible for the management of the operations of the contractor;
- The contractor bears the risks and is responsible for the preparation and execution of the work program;
- The term of the contract is normally 30 years, including six to ten years exploration period;
- If no successful discoveries have been made after the exploration period, the contract is terminated;

- The contractor pays a bonus when the PSC is signed and this cannot be recovered as costs;
- The contractor provide all funds to conduct operations;
- Contractor recovers start up costs only after commercial production begins;
- The contractor is free to export its entitlement under cost recovery an production split, subject to fulfilling its domestic supply obligation;
- The sharing is made on production, not on profit and the share is split after deduction of cost recovery and tax;
- Contractors pay Indonesian income taxes, and Pertamina reimburses the contractors for other taxes paid in conduction of operation;
- In recent cases Pertamina shall also have the right to demand from contractors a ten percent undivided interest in the total rights and obligations to itself or a limited liability company to be designated by Pertamina.

The new law has adopted a more generic ‘Cooperation Contract’ term for agreements on petroleum exploration and production. This includes, but is not limited to the PSC. Under these new contracts the contractors also have to give a priority on the use of local products/services, take part in community development and give priority to the use of local manpower.

Under the new law the government revenue will come in the form of tax, import duty and regional taxes and retributions, and as non-tax revenue in the form of the government’s share of production, government levies in the form of permanent exploration and exploitation contributions, and bonuses. The *Implementing Body* will regulate and supervise the upstream activities.

Downstream business will open up as Pertamina lose its monopoly. To take part in this business an undertaking permit from the Government will be required in processing, transportation, storing and trading. Prices of oil or gas fuel are in principle left to the market. The *Regulatory Body* will supervise the downstream activities.

A new law on Regional Autonomy no 25/1999 regulates a new taxation regime of this sector. Before the reform 100 percent of the revenue went into the central government’s coffers. For many years oil rich provinces have disliked this arrangement. Increasing separatist activities in petroleum rich provinces like Aceh, Riau and Irian Jaya have forced the Government to fiscal decentralization. The new law split government revenues for the crude oil resources in three shares; 85 percent to the central government, 3 percent to the Province and 12 percent to the Regencies (US Embassy, 2002). For gas the shares are 70/6/24. The central government refrains from taxes or duties on land and buildings under the new law. As it stands now there seems to be conflicting views of the legality or size of local taxation. For investors in petroleum production this is therefore regarded as an uncertainty and a new risk.

3.2.8 Success criteria and caveats

With its production sharing contracts Indonesia has succeeded in a policy to capture most of the revenues on the hand of the owner of the oil and gas resources. As in many developing countries the state owned oil-company has been one of the big earners of foreign exchange and holder of large financial resources. Pertamina has in this respect been an important instrument in the government's financial and industrial policy. Over time Pertamina also has developed a national technological expertise, specifically in the downstream activities of this industry. In exploration and development activities most of the technological know how is still in the hands of foreign operators even if Pertamina has the ambition to expand its upstream activities. In general the oil and gas resources and its economic rewards have been an important part of the Indonesian "miracle" up to the financial crisis in 1997.

As a commercial actor on the other hand, the company has not been very successful in the past. One reason is of course its many obligations to serve both as a producer, a regulator and service provider in a strictly regulated domestic energy market. The Indonesian reputation as a stronghold of KKU (corruption, coalition and nepotism) is also an important explanation for Pertaminas' under-performance in commercial terms. To prepare for full international competition from 2006, the company is now restructuring, shedding labor and streamlining its operation. As a longstanding actor in the Indonesian market it should have a good chance to wind bids on commercial terms in its home market. Internationally Pertamina alongside Petronas also have a specific expertise and culture that will make it attractive in other developing regions, specifically in the Islamic world. For the supply industry the prospect for full foreign competition is not so bright as the domestic industry in many segments is not a holder of front technology. Still Indonesia has been able to develop some expertise in the standard part of this industry that could be rewarding in the future domestic and Asian markets.

3.3 Malaysia

3.3.1 Production and reserves

The Malaysian oil industry goes back to 1910 when an onshore well was developed. During the 1960s the oil majors entered the country exploring for oil and gas offshore. The first offshore field came on stream in 1968, and by 1973 four fields were producing about 90 000 bpd combined. During the 1980s production increased and oil exports accounted for about 30 percent of Malaysia's total export revenue at its peak in the early 1980s. Production continued to increase until it reached a plateau of about 800 000 barrels a day in the mid 1990s, which has been sustained to date. Malaysia is thus a relatively small oil producer. The country's oil reserves stood at about 3 billion barrels by the end of 2001. The reserves to production ratio (R/P) was estimated at about 11. EIA projections suggest that Malaysia will become a net importer of oil in about a decade (EIA, 2002). Proven oil and gas reserves are mainly found offshore, and exploration activities are now venturing into deep offshore waters. Malaysia has 53 producing offshore fields; 42 oil fields and 11 gas fields.

Malaysia's significance as an energy producer is increasingly in the gas sector. Gas production is currently about 4.4 billion cubic feet per day. Gas reserves were estimated at 75 trillion cubic feet by end 2001, and the R/P ratio about 45.[13] The Malaysian government recognized the potential for the gas sector at an early stage and introduced comprehensive and ambitious plans for the development of the gas resources. The strategy involved the utilization of the country's gas resources for domestic energy use, exports of gas to neighboring countries through pipelines (to Singapore, Thailand and Myanmar), exports of LNG, and at a later stage as feedstock to a petrochemical industrial cluster. The first Peninsular Gas Utilization project was introduced in 1984. The project consisted of sub-sea pipelines from the gas fields, an onshore gas processing plant operated by Petronas (the state oil company), and a trans-peninsular gas pipeline stretching from the border with Thailand to Singapore and from the east coast to the west coast of peninsular Malaysia. Malaysia exports about 150 million cubic feet of gas per day to Singapore through this pipeline (EIA, 2002). The first end-users were power plants and a steel mill.[14] In the year 2000 gas accounted for about 80 percent of Malaysia's electricity power generation. The government now considers this as excessive dependence on gas in the power sector and has encouraged diversification towards clean coal, hydropower and renewable energy

[13] Reserves and production data are taken from www.bp.com

[14] The state-owned national electricity board was reluctant to switch to gas, but the emerging private independent power producers were keen on using gas.

carriers (EIA, 2002). Besides, other uses such as petrochemicals and exports of LNG add more value to the gas than using it as fuel in the electricity sector.

The gas market as well as the gas deposits are regional in nature. A significant gas field is located in a previously disputed area between Malaysia and Thailand, now known as the Malaysia-Thailand Joint Development Area. This area is now being developed by Petronas Carigali, Amerada Hess and BP. The developments were planned to come on stream in early 2003 (EIA, 2002). However, protests over environmental concerns on the Thai side have delayed the building of the storage facilities and pipelines, consequently the offshore structures have to bee mothballed awaiting the storage facilities and pipelines to be finalized. Production is expected at the earliest in the first quarter of 2004 (Tradepartners UK, 2002).

3.3.2 Technology

Malaysia applies standard technology for offshore fields, which are mainly located in relatively shallow waters. The equipment is mainly platforms made of steel, and much of it is fabricated locally. The last couple of years, exploration has started in deep offshore. More challenging technical solutions will then be applied. The area where the oil and gas sector has advanced to the technology front in joint ventures with the leading multinationals is in petrochemicals. Malaysia has established a large-scale cluster in this industry, fed by offshore gas resources. The industry is still growing and in the financial year 2000/01, 6 new plants were completed (Tradepartners UK, 2002).

3.3.3 Outline of industry structure

The major players in the Malaysian upstream sector are the multinational oil majors, where the local subsidiary of ExxonMobil (ExxonMobil Exploration and Production Malaysia Inc., EPMI) accounts for about half of total crude oil production (EIA, 2002). More than half of production comes from one offshore field (Tapis), operated by EPMI under a production sharing contract (PSC) with Petronas. EPMI has a share of 78 percent in the PSC, while the remaining 22 percent is held by Petronas Carigali, the exploration and production arm of Petronas (EIA, 2002). Petronas Carigali is the operator of a few oil and gas fields, and has the right to hold at least 15 percent of the license in all fields in Malaysia. In the fields where Carigali is not an operator, it typically enters into a joint operating agreement with the operator. Other major players on the operating side are Shell Sabah (the local subsidiary of Shell), Nippon oil, Amerada Hess and other smaller, independent foreign oil companies. Murphy Oil holds the largest acreage available for oil and gas exploration. On the contractor side, the major multinationals are the most important. Most of the leading contractors are established in the region and a number of them has offices in Kuala Lumpur and fabrication activities in Malaysia. Malaysia has, nevertheless developed an indigenous subcontractor industry and shipyards that have diversified into the production of offshore equipment.

Malaysia is one of the world's largest exporters of LNG and accounted for 15 percent of the world's total LNG exports in 2000 (EIA, 2002). Malaysia's first LNG plant was developed as a joint venture "smart partnership" between Malaysia LNG, a subsidiary of Petronas (65 percent equity), Shell and Mitsubishi (15 percent equity each), using associated gas from an offshore field and exporting the LNG to Japan.[15] Shell was responsible for technical control and running the plant through a Technical Service Agreement, which gave the company managerial control, while Mitsubishi was responsible for marketing and sales in Japan and achieved a 20-year sales contract with the Japanese customer.[16] After the first plant followed a second and a third is about to be completed and is scheduled to begin operating in 2003 (Tradepartners UK, 2002).

3.3.4 Role of national oil company

The national oil company, Petronas, is a formidable player in the Malaysian petroleum sector. Petronas was incorporated under the Companies Act as a commercial company in 1974. It was established as a government instrument with the task to negotiate and manage the production sharing contracts with the oil majors. Petronas' operative businesses started with international oil trading in 1975. It continued with the establishment of the wholly owned exploration and production subsidiary Petronas Carigali in 1978, and Malaysia LNG the same year. Some of the regulatory responsibilities were transferred to government bodies when subsidiaries of Petronas became operative competitors to the multinational oil companies, although negotiating and managing PSC still rest with Petronas.

Caligari's first field as an operator was an offshore gas field (Duyong) where the company did exploration, development and production. The

[15] The Sarawak State Government holds the remaining 5 percent.

[16] Managerial control was a condition for entering the project as a minority share holder on the part of Shell (Bowie, 2001).

field came on stream in 1984. The first oil field (Dulang) for which Carigali was the operator was also offshore and came on stream in 1991.

Petronas moved downstream in 1983 when its first small-scale refinery came on stream. In the 1990s followed a more complex and larger scale refinery in a joint venture with Conoco and Statoil. Petronas owns two out of 5 refineries in Malaysia.

Several activities have grown out of the gas utilization project. First, Petronas has set up a wholly owned gas subsidiary operating the pipelines and gas processing plants. Second, the company has set up a technical services subsidiary delivering engineering and consultancy services for large-scale development projects, and exports its services both to the region and further afield. The company is for example involved in an Australian gas transmission network.

The relatively small size of the local resources and Petronas' ambition to become a world-class integrated oil company could only be reconciled through internationalization. International engagements started in 1990. One important strategy for internationalization was to extend the cooperation with the oil majors and independent international oil companies to joint ventures outside Malaysia. Successful internationalization had probably not been possible without these established relationships. Nevertheless, Petronas has chosen the strategy of a niche company producing in developing countries with a relatively small petroleum sector and in some cases where no one else dear tread (Sudan, Iran and Myanmar/Burma). In the latter cases, cooperation has been with the local national oil companies, where Petronas finds itself in the role as operator facing technology transfer requirements from the host government.

In spite of having a good education system, Malaysia has developed a skills shortage problem, mainly because of a more skills-intensive industrial structure than one would expect given Malaysia's level of income (Lall, 2001). Petronas has alleviated the skills shortage in the petroleum sector by offering numerous training programs and the company has even established its own technical university.

Petronas has developed into a fully integrated multinational oil company with a presence in 24 countries and 39 exploration and production ventures in 21 countries (Petronas, 2002). Petronas is ranked as the world's fourth largest multinational company from developing countries (UNCTAD, 2001), and it was ranked as number 254 in Fortune's global

500 in 2001. Moreover, Petronas ranked 10th on the Fortune global 500 ranking according to returns on revenues.

Petronas has chosen a high profile and its headquarters in Kuala Lumpur, the twin towers, are probably known all over the world. This is the world's tallest building, counting 88 stories. The towers were officially opened in 1999, at the 25-year anniversary of the company. Another high profile venture is the Red Bull-Sauber-Petronas Formula One Racing Team where Petronas develops and provides the fuel for the car. In addition Petronas participates in the R&D undertaken to develop the engine of the racing car through a subsidiary in Switzerland.

Petronas has about 20 000 employees and is organized as a group with 62 wholly owned subsidiaries, 19 partly owned subsidiaries and 47 associated companies. Among the group members are also non-petroleum companies such as shipping, car manufacturing and property development. Petronas holds 62.08 percent of Malaysia International Shipping Company Berhad, which has a large fleet of specialized LNG ships (13 vessels). Among the property development activities is the development of a new administrative capital of Malaysia built close to the Kuala Lumpur airport (Petronas, 2002).

Petronas' market share of the Malaysian retail market is about 20 percent and the company's entire product range accounts for about 30 percent of the local market. In the fiscal year 2002, crude oil accounted for 22 percent of net revenue, petroleum products 34 percent, gas including LPG and LNG 29 percent and other activities 15 percent. The foreign operations accounted for about 30 percent of gross revenue (Petronas, 2002).

Petronas' non-oil sector activities have raised some controversy. The company has in fact bailed out firms that the government considers strategically important. The first strategic rescue operation came in 1985 when the company took an 80 percent stake in Bank Bumiputra.[17] More recently Petronas bailed out the national carmaker in the aftermath of the Asian financial crisis. Although Petronas argues that these are commercial investments, the company has incurred losses on them and the claimed synergies related to these acquisitions are not obvious.

[17] A bank owned and run by indigenous Malays, a population group targeted by the government's new economic policy aiming at a more equal distribution of income and wealth between indigenous Malays and the Chinese population.

3.3.5 Regulatory regime

The upstream petroleum sector is regulated by the Petroleum Development Act of 1974 and the Petroleum Tax Act. The law vested the country's ownership of petroleum resources in Petronas, and the company was assigned the exclusive right of exploration and production of oil in Malaysia (i.e., the company is the only entity with legal title to Malaysian oil and gas deposits). This right is exercised through production sharing contracts (PSC) with the oil majors. The Act represented a significant change in the policy regime facing the oil companies operating in the country. Previously they had operated under Concessions Agreements with the State governments.[18] The objective of the Petroleum Development Act was to make available the nation's petroleum resources to the local market at reasonable prices, to form the basis for capital and energy-intensive industries such as petrochemicals, and to ensure Malaysian participation and control of both the upstream and downstream activities. In addition shipping and insurance related to the petroleum sector are mentioned as an area of Malaysian participation.

It took two years to negotiate the first PSC between Petronas and Shell (Bowie, 2001). From Petronas' point of view the negotiations were a battle on two fronts: the multinational oil companies on the one hand and the state governments on the other. The first PSC provided a maximum cost recovery of 20 percent of oil production, 25 percent for gas (the cost oil or gas), and a royalty of 10 percent to government. The remaining 70 percent of oil production was split on a 70/30 basis between Petronas and the operator. The first PSC became a standard in the industry and all the terms and conditions related to the contract were made public knowledge (Bowie, 2001). A considerable share of the nation's oil revenue in other words accrued on Petronas and the responsibility of managing and reinvesting these resources consequently rested with Petronas. This responsibility partly explains Petronas' diversification, as discussed above. It also partly explains why Petronas has a relatively high ranking on profitability in the Fortune 500.

The legislation left considerable discretion to Petronas in negotiating the terms of the PSCs. After the oil price bust in 1985/86, it was realized that the terms of the PSC were a disincentive to deep offshore exploration. The terms were therefore made more favorable for the PS contractors from the late 1980s. The revenue over cost concept was introduced as part of the PSC in 1997. This type of contract transfers a higher share of the downside risk to Petronas and provides incentives for cost cutting on the

[18] Malaysia is a federal state.

part of the operating company. The PSC partner is allowed to accelerate cost recovery if cost performance is within a specified range. At present the procedures for awarding the PSC contracts are as follows:[19]

1. Continuous block promotion;
2. Company shows interest and requests for data review;
3. Preparation of data package and data review arrangements;
4. Company conduct data review at Petronas premise in Kuala Lumpur;
5. Company submit report on block assessment and/or proposal for block;
6. Internal approval process (Management Committee);
7. Negotiation on PSC document between Petronas, production sharing contractor and Petronas Carigali. Negotiation between production sharing contractor and Petronas Carigali on joint operating agreement;
8. Internal approval process (Petronas Board) for award of block;
9. Letter of PSC award to PS contractor;
10. PSC signing ceremony (Petronas President);
11. Transfer of existing data to Company.

Technology transfer to Carigali is a mandatory part of the joint operating agreement. There are in other words no block auctions or competitive bids for the PSC.

The Petroleum Development Act was mainly concerned with national control of the petroleum resources through the establishment of a national oil company. The petroleum resources were first and foremost seen as an essential input into the local economy in a period of turbulent world energy markets. Security of supply at as low costs as possible was therefore the major consideration for the legislators. In order to encourage local refining of crude oil, an export tax on crude oil of 25 percent was introduced.[20] Company taxes are 28 percent in Malaysia. The Petroleum Tax Act, however, imposes a company tax rate of 38 percent for the petroleum sector (US department of state, 2001).

3.3.6 Local content

Turning to local content in the supply industry, Petronas requires PS contractors to procure inputs locally. PS contractors have to secure

[19] Information given by Sharifah Soraya, Corporate Information and Research Unit, Petronas, in e-mail 10.10.02.

[20] The export tax was reduced to 20 percent in 1993 (Malaysian Government, 1995).

equipment, facilities, goods, materials and services locally unless approval is given by Petronas to source internationally. PS contractors are also required to fill positions with suitable Malaysian personnel, and are only allowed to employ expatriates upon written approval by Petronas.[21] According to the Malaysian Plan (1996), 74 percent of total value of contracts to the upstream activities was granted to local companies in 1995. The Malaysian Plan does, however, not say how much of this was value added produced by locally owned firms, and how much was delivered by multinationals established in Malaysia. As in Norway, there were shipyards with idle capacity in the 1970s and 80s, and some of these have restructured and entered the market for building offshore platforms, topsides and equipment for petrochemical plants. It seems, however, that internationalization and the movement into deep offshore and the Malaysia/Thailand Joint Development Area (JDA) have increased the foreign share in deliveries. For example, in the ongoing gas field development in the JDA, the 3 drilling platforms were fabricated in Thailand, the riser/compression platform was fabricated in Malaysia and the jacked and topside of the central processing platform were fabricated in South Korea (Tradepartners UK, 2002).

In Petronas' present mission statement there is a general commitment to enlarge the country's industrial base, without specifying. Contractors and suppliers who whish to do business with Petronas are required to register with its Licensing and Registration Department. Registration forms and tender documents can be downloaded from the company's website.

3.3.7 Contribution to the Malaysian economy

As figure 3 above indicates, the petroleum sector has never been the major engine of growth in Malaysia. The sector has nevertheless been the driving force for the establishment and development of an industrial cluster with petrochemicals at its core on the east coast (the Eastern Corridor), a previously underdeveloped region in Malaysia. The LNG plants were also built in this area. The projects involved complementary investments in roads, a port, electricity supply and so on. The Eastern Corridor has attracted the leading world chemical and petrochemical multinationals forming joint ventures with Petronas and providing technology and marketing channels. Construction of these highly sophisticated plants was awarded to renowned multinational firms.

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[21] Information from Sharifah Suraya, Corporate Information and Research Unit, Petronas, by e-mail 10.10.02.

The petroleum sector's contribution to the Malaysian economy can thus be summarized as follows:

- The gas resources have provided reasonably clean and low cost energy to the economy at large;
- The gas resources form the basis for an industrial cluster in petrochemicals and other heavy industries in a previously underdeveloped area;
- The sector has earned the economy foreign exchange which has allowed the imports of state of the art machinery and equipment for both the petroleum sector and the industrial sector at large;
- The sector has contributed to government revenue, which in turn has made a relatively high investment level in social and economic infrastructure affordable;
- The sector has fostered the country's largest company, which has made it to the Fortune 500, and is seen as a well-run and profitable fully integrated multinational oil company.

3.3.8 Success factors and pitfalls

The Malaysian petroleum sector development has undoubtedly been a success. Not only has Malaysia developed comprehensive local competence in both upstream and downstream activities, it has also established a multinational fully integrated oil company. The development of the petroleum sector is part and parcel of Malaysia's general development success as figures 1 and 4 above clearly illustrate. Since the early 1970s the country has led an export-oriented industrial policy welcoming foreign direct investment while developing infrastructure and local skills through heavy investment in infrastructure, education and health. In addition the country has had a stable policy environment, a competitive exchange rate and a reasonably prudent macroeconomic policy. Thus, except for relatively short spells of excesses, the Malaysian government has not let the petroleum sector drive up costs and wages in the economy. As a result, rapid non-oil industrialization has taken place in parallel with the expansion of the petroleum sector, an unusual achievement indeed.

There have surely been excesses and mistakes. One of them being the massive investment in protected heavy industries such as petrochemicals, steel and cement in the early 1980s. These investments were largely state-driven and Petronas played an important role in them. Moreover, they were motivated by the desire to re-inject the windfall petroleum revenues into downstream processing activities and energy-intensive industries that were initially protected from foreign competition. This industrial policy led to a deep economic crisis in the mid 1980s.[22] The large-scale investments required foreign borrowing and the foreign debt stock increased sharply (see figure 5 above). The policy was reversed during the second half of the 1980s, returning to an export oriented industrial policy and also exposing the heavy industries to market discipline. The continuing use of Petronas as an industrial policy instrument by the government and Petronas' and the less than strict separation of regulatory and operating responsibilities are still potential problems.

The perhaps most important success factor is the checks and balances embedded in the Malaysian institutional setting. Although this has not prevented powerful interest groups and individuals from throwing their weight around, it has prevented such groups from jeopardizing the country's economic development for their own benefit. Thus, Malaysia has demonstrated an ability to adjust and rethink policy measures when they have turned out not to have the desired effects, or when unfavorable unintended side effects have arisen. In the absence of market discipline and checks and balances, Malaysia's and Petronas' ambitious investment projects (the twin towers, the LNG and petrochemicals developments, and the property developments related to the new administrative capital) could easily turn into white elephants.

Malaysia has also been lucky, being a natural resource rich country located in the midst of the most dynamic but resource-poor region in the world. The gas and LNG projects thus had a ready and rapidly growing market in Japan, South Korea, Taiwan and Singapore.

3.4 Mexico

3.4.1 Production and reserves

Mexico started exporting oil in 1911, and soon became the world's largest oil exporter. Its oil production was second only to the US in the 1920s. The petroleum sector has experienced its ups and downs, largely as a result of nationalization of the industry and Mexico's frequent balance of payment problems. The urgent need to generate export revenue led to focus on short-term expansion of production at the expense of exploration and a more careful management of the reservoirs. Exploration programs were only implemented when it became apparent that production would stagnate if new reserves were not found and developed. Once implemented, however, the exploration programs were very

[22] See for example Kind and Ismail (2001).

successful and large new fields were discovered first onshore and next offshore. Mexico was a net importer of petroleum during the 1960s and early 1970s. Discoveries and development of substantial offshore reserves in the early 1970s made Mexico a significant oil exporter again from 1975.

Mexico's proven reserves by the end of 2001 were estimated at about 27 billion barrels, while average oil production during 2001 was about 3.5 million barrels per day. This gives a reserves to production ratio of 21.7. Due to limited exploration activities recently, the reserves are on a declining trend. Furthermore, due to lack of investments, production has leveled off (EIA, 2002). Gas reserves by the end of 2001 were estimated at 29 trillion cubic feet and production in 2001 was 3.4 billion cubic feet per day giving a reserves to production ratio of 24 (BP, 2002). The reserves are mainly found in shallow waters in the Gulf of Mexico and onshore. It is, however, believed that the deep offshore fields entail significant reserves waiting to be explored. Hitherto the structure of the Mexican petroleum industry has discouraged such exploration. The national oil company lacks financial and technological capacity to venture into deep water, while the oil majors have very limited access to the Mexican part of the Gulf of Mexico. Currently the deepest field is located at a water depth of 103 meters.

3.4.2 Technology

Mexico has been an oil producer for almost a century, and it is seen as a mature market. Most development expenditure is on modifications to existing fields (Douglas-Westwood, 2002). Such investments may, however increase output substantially. A nitrogen injection project on Mexico's largest oil field (the Cantarell field) for example, has increased output by 60 percent from that field (EIA, 2002). Nitrogen injection commenced in August 2000. Currently this field produces 2.3 million barrels a day, almost 65 percent of total production.

3.4.3 Outline of industry structure

Private companies are not allowed to operate Mexican oil fields. In the gas sector, private companies are only allowed to provide services to Pemex and until very recently multiple services contracts were not allowed. Foreign participation in the upstream sector is limited to services and performance contracts and turnkey drilling contracts (US Department of Energy, 2002).

Gas development has not been prioritized until very recently. Associated gas was largely flared. Mexico has invested in a gas pipeline network which is connected to the US network, and in recent years net flows have been from the US to Mexico, and Mexico is expected to be a net importer of natural gas until 2015 (US Department of Energy, 2002). Gas is used for household and business consumption and electricity generation. There is currently a program to increase the use of gas in electricity both through the building of new combined cycle power plants and the conversion of existing power plants to natural gas. Lack of investment in pipelines has been the major obstacle to the utilization of the nation's considerable gas resources. Gas is mainly produced in the south of the country, while demand is highest in the North to which US gas is imported. At present, an investment program in a northern non-associated gas field (the Burgos field) is being implemented. The field has been in production since 1945 and reached its peak production in 1970. Remaining reserves are, however considerable and new drilling techniques are expected to increase production substantially.

The Mexican Petroleum Institute (IMP) is a training, research and engineering consulting organization established in 1965. It grew rapidly and soon became a sophisticated R&D center employing 3000 persons, including 1200 professional staff. IMP provides design and engineering services to Pemex and conducts hundreds of courses. It publishes a leading technical scholarly journal and it holds a number of patents.

3.4.4 Role of national oil company

The oil industry was nationalized in 1938 and the 100 percent state-owned company Petroleos Mexicanos (Pemex) was established in order to operate the Mexican oil industry. The company took over existing operations from the oil majors that had operated in the country since the turn of the century. Pemex became the only operator and gained a monopoly position in exploration, production, refining and distribution of oil and natural gas and the manufacture and sales of basic chemicals. The company was not a commercial company with the objective of maximizing profits. The objective was rather to provide subsidized fuel to the economy, and foreign exchange to finance industrialization through import substitution.[23] These two objectives turned out to be incompatible during the 1960s and early 1970s when domestic demand for cheap fuels increased faster than supply and Mexico became a net importer of hydrocarbons. In addition the company had a social mission of paying

[23] At an early stage of import substitution capital goods and intermediates need to be imported, but are supposed to be replaced by local supplies as the industrialization process gets under way.

high wages to its workers and to build schools, roads and other facilities in the oil producing areas.

The other major player in the Mexican petroleum sector is the Union of Oil Workers of the Mexican Republic established in 1935. The Union holds 4 positions out of 9 on Pemex's board of directors. The union runs construction activities, credit unions, farms, supermarkets and had the exclusive right to serve as contractor for pipelines, refineries, offshore drilling, roads, schools or any other project which Pemex itself did not execute. This exclusive right was abolished in the 1980s and replaced by the right to award 40 percent of drilling contracts to private companies through its committee on contracts. Further, the Union has the right to hire workers, except the "empleados de confianza" (the professional workers at middle management levels). The Union receives 2.5 percent of members' wages and 2 percent of the contract value negotiated with private firms. Union membership is mandatory for Pemex employees. The Union has played a pivotal role in skills development and the social development of the oil producing areas. However, the organizational structure of Pemex and the role of the Union have also provided fertile ground for corruption and diversion of resources from productive activities.

During the late 1970s and 1980s it became increasingly clear that Pemex was inefficient and highly overstaffed. Following the inauguration of a new president (Salinas) and a disastrous explosion in a Pemex gas pipeline that killed 200 people in 1992, Pemex was restructured. Four commercialized divisions were created. These were Pemex Exploration and Production, Pemex Gas and Basic Petrochemicals, Pemex Refining and Pemex Petrochemicals. Petrochemicals are split into two subsidiaries because Pemex has a constitutional monopoly in the production of some petrochemicals, classified as basic, while private sector participation and competition is allowed in other petrochemicals sub-sectors. Each unit became a semi-autonomous profit center. Pemex's labor force was reduced from 210 000 in 1989 to 116 000 in 1992.

Pemex is a fully integrated oil company with capacity for exploration, development and production in the upstream sector as well as refining, petrochemicals, gas processing and distribution and sales. The first years after nationalization were somewhat chaotic, but the company over time developed into a technically proficient company. However, its assigned role in Mexico's development has prevented it from becoming a cost effective oil company.

3.4.5 Regulatory regime

The Mexican Constitution of 1917 (article 27) prohibits private ownership of all hydrocarbon reserves as well as concessions in the oil industry. The constitution replaced mineral regulations that gave landowners the right to exploit minerals under the soil. International mining and oil companies were allowed to buy land in Mexico and foreign companies owned substantial areas containing valuable minerals, including oil. These existing rights were deemed by the Mexican supreme court to remain in perpetuity. Foreign companies created enclaves, protected by their home governments and the perception was that the companies exploited Mexico's resources and left little value added or wealth creation for Mexico. This perception led to the nationalization of the petroleum industry in 1938. The issue of private participation in the sector, let alone foreign participation is still a sensitive issue in Mexico.

The government policymaking units in the petroleum sector are National Energy Commission (CRE) and the Office of the President. The Secretariat of Energy, Mining and Parastate Industry (SEMIP) is responsible for the management of the energy sector, and the head of SEMIC is the chairman of Pemex's board of directors.

Pemex pays 12 percent of gross income in taxes starting in 1960.

Following the restructuring of Pemex in 1992 the monopoly of the Pemex trade union was broken, and Pemex was allowed to seek the lowest bidder for maintenance, transport, and other work formerly reserved for the official oil workers union. The reforms also allowed limited foreign participation in the petroleum sector. US exploration companies received permission to drill under contract and foreign partnerships were authorized (US Government, 1996).

After more than 70 years in government the PRI government was voted out of office and a conservative government headed by Vincente Fox took office. The new government has made several attempts to open the oil and gas sector to private companies, both local and foreign. Such reforms require constitutional amendments for which a two third majority in the Mexican Congress is needed. Since the PRI is against such reforms and holds more than a third of the seats in the Congress, privatization and private participation have not been possible. It has nevertheless been possible to open parts of the downstream gas sector to private companies as a matter of interpretation of article 27 of the Constitution. The same goes for the petrochemical industry, where chemicals have been reclassified as non-basic in order to allow the private sector to produce them.

Although the gas sector is the most liberalized in Mexico, private participation is still highly controversial. For example, invitations to tender for gas development contracts in Northern Mexico have been announced, but the process has been postponed to 2003 because of controversies whether the contracts will amount to concessions to foreign companies, which is prohibited by the Constitution. The planned contracts will allow private companies greater operating independence and the contracts will be renewable for 20 years. The produced gas will, however, belong to Pemex.

The Mexican Energy Regulatory Commission (CRE) regulates the gas industry according to the 1995 Natural Gas Law, which opens to private sector participation in the downstream gas sector; i.e. transportation, storage and distribution of gas. The private sector also includes foreign companies. Pemex retains the monopoly in upstream gas production. The gas market is thus the least regulated energy market in Mexico. Companies are awarded 30-years licenses through competitive bids administered by CRE. Nevertheless, so far private participation has been limited, and only in the distribution of gas has there been any significant private sector involvement.

Pemex is widely seen as being inefficient, and the present Mexican government is pushing for reforms and modernization, something that has been met with opposition in the Mexican Congress (US Department of Energy, 2002). Pemex is allowed to retain and re-invest very little of its profits. Most of it is siphoned to the government, which depends on the oil revenue for its operations. Pemex thus claims that production will decline by a third unless considerable funds for exploration are made available by 2006.

Pemex has a monopoly also in the downstream refining of crude oil and production of eight basic petrochemicals. It has not invested in sufficient refining capacity to meet domestic demand and Mexico imports about a quarter of its gasoline and diesel consumption.

3.4.6 Local content

The petroleum industry played a major role in Mexico's industrialization strategy. First, oil revenue financed subsidies and protection of the industrial sector at large. Second, Pemex (as well as other state enterprises) was required to purchase capital goods from domestic producers provided that the price of these goods did not exceed that of comparable imports by more than 15 percent. This regulation was part of an industrial strategy to promote a number of selected industries, including capital goods. Pemex was also required to prepare and publish detailed acquisition programs.

The interpretation of the regulations has differed with the leadership of Pemex. During investment booms resulting in scarce local capacity, Pemex has contracted out drilling, technical services and even the operation of single platforms to foreign companies. These moves have, however, been controversial and typically reversed by subsequent administrations.

3.4.7 Contribution to the Mexican economy

The upstream petroleum sector's relative importance to the economy has declined gradually, mostly as a result of growth in other sectors. The petroleum sector's contribution to GDP was only about 2 percent in 2000, but still accounted for about a third of government revenue and 10 percent of export revenue (OECD, 2002).[24] Mexico exports around 1.6 million barrels of oil per day, most of it to the US.

Mexico spent its oil windfalls during the late 1970s on infrastructure and industrial development projects. A number of parastatals were established, including steel plants, fertilizer plants and capital equipment plants and producers of pipes. Many of these became loss making and a drain on public sources of income (Tornell and Lane 1994). Moreover, oil revenue was spent on bailing out struggling private firms. The oil sector has therefore most likely not created much income over and above its direct contribution to the economy, although its large share of government revenue may have contributed to higher government expenditure than what would otherwise be possible. Government expenditure following oil price booms was, however, unsustainable and Mexico ran into the debt problems and financial crises that we described in section 2.

Mexico established an Oil Stabilization Fund in November 2000. In the event of higher than expected oil revenues, the extra funds are used first to replenish budget cuts made earlier in the year, next to amortize public debt and 40 percent of the remaining resources are used to build up the fund. In this way government expenditure becomes less vulnerable to fluctuations in the oil price. At the same time Mexico has increased other

[24] Total exports include exports from in-bond factories.

taxes, notably introduced VAT, reducing government dependence on oil revenue (WTO, 2001).

3.4.8 Success factors and pitfalls

Mexico has had a reasonably successful economic development during the past 10-15 years more in spite of its petroleum sector policy than because of it. The state monopoly and the nation's protectionist policy in the upstream as well as the downstream sector has lead to lower output, less exploration and a weaker technology base than one would expect of a country of Mexico's size, industrial base and its location close to the US Gulf of Mexico upstream sector. The trade union's privileges created an incentive to overstaff the company, which made it even less efficient. In spite of the largely mismanaged petroleum sector, Mexico has developed a sound and competitive industrial base outside the petroleum sector. Here local producers and foreign investors have taken advantage of Mexico's trade liberalization and free trade agreement with the USA and Canada (NAFTA), while the protected petroleum sector struggles to raise funds for necessary investments in order to retain production at the present level.

3.5 ***Nigeria***[25]

Since drawing lessons for Nigeria is the purpose of this paper, we analyze Nigeria in some more detail than the other countries in the study.

3.5.1 Economic development since independence.

Nigeria became an independent country in 1960. By then the petroleum sector was already established in the country. The first production came on stream in 1958, produced by Shell-BP.[26] During the first decade of independence, investments in manufacturing and the petroleum sector increased substantially and the economy was growing at a rate of 5 percent on average during the 1960s. The mining sector, which mainly consists of the petroleum exploration and production had reached about 12 percent of GDP in 1970/71, just before the first oil price boom in 1973. During the booming years 1973-81, petroleum revenues became the driving force in the economy. Estimates by Bevan et. al. (1999) indicate that more than 90 percent of the windfall oil revenue during this

[25] Thanks to George Max Raccah (managing partner, Star Oilfield supplies) Mfon Ekong Usoro (drafting the cabotage bill), Caroline Ola Abu, Ronke Ibrahim and (head of procurement, human resources in Statoil Nigeria), for useful information.

[26] The operator was Shell/D'Arcy Petroleum Development Company of Nigeria, a company owned by Shell and BP (Atsegbua, 1999).

period was saved and invested, most of it in domestic assets, but also foreign assets were accumulated. Nevertheless, the windfall oil revenue had only a minor impact on non-oil GDP levels and private consumption, indicating that the returns to these investments were low and/or had a long gestation period.

Even thought the level of non-oil GDP was little affected by the injection of oil revenue in the economy, the *composition* of non-oil GDP changed dramatically. Agriculture stagnated and prominent exporting sectors such as cocoa, rubber and palm oil declined sharply. Manufacturing increased, largely driven by government investment in large-scale heavy industries, such as steel and petrochemicals. These investments turned out to incur heavy financial losses. Food production in contrast, grew rapidly behind protective tariffs and quotas.

The manufacturing industry was established largely through foreign direct investment during the 1960s. Foreign investors faced generous tax incentives and protective tariffs and found the Nigerian expanding market attractive (Bevan et.al., 1999). In Nigeria as in most other newly liberalized countries, it was an important industrial policy objective to ensure that indigenous entrepreneurs controlled the commanding heights of the economy. Industrialization was seen as the road to development, and self-reliance. Employment generation and regional dispersion of industrial activities were seen as important objectives to ensure that industrialization benefited the population at large. Later the industrial policy measures came to include direct government intervention in credit allocation and public ownership of some large-scale strategic industries.

The Nigerian Enterprise Promotion Decree of 1972 scheduled 22 industrial activities that were reserved for Nigerians and another 33 activities that required at least 40 percent Nigerian ownership, including most industrial activities. In spite of these policy measures manufacturing output growth was anemic. Existing regulations were therefore replaced by even stricter restrictions on foreign investors in 1977. The sectors reserved for wholly indigenous firms were maintained and some industries for which 40 percent ownership was allowed were transferred to the Schedule I regulations where only indigenous companies were allowed. In addition a schedule III was introduced. This encompassed all industries not listed in Schedule I and II, and a maximum foreign ownership of 60 percent was allowed under this schedule. Again the regulations did not produce the desired results. To the contrary, investments declined after 1977, and it was decided that the restrictions should be lifted, beginning in 1981. In 1989 the indigenization decree was amended such that there was only schedule I left, but applied only to small and medium size enterprises. Foreign investors were from then on permitted to own 100 percent of any unscheduled enterprise except in the banking, insurance and petroleum sector where a 40 percent limit remained in place (Gidamo, 1999). In spite of these industrial policy measures, manufacturing output grew less rapidly than the average growth rate of the economy, and manufacturing accounted for only about 5 percent of GDP in 1998 (World Development Indicators, 2001).

The period 1981-87 was characterized by a bust in the petroleum sector. According to Gidamo (1999) the decline was due to conservation considerations and adherence to the OPEC quota that had been set to 1.6 million barrels a day since 1973.[27] The decline in oil production was accompanied by a fall in domestic expenditure, mainly investment expenditure, but also private consumption declined by 25 percent during the period 1981-86. The public sector budget balance went from surplus to deficit. The deficit could first be financed through depletion of reserves that had accumulated during the oil boom. But as these funds ran out and the deficit remained high, the government turned to foreign borrowing to finance the deficit (Bevan et. al., 1999). Soon after Nigeria experienced a full-blown balance of payment crisis and a public sector debt crisis resulting in an IMF stabilization program.

Turning to the promoted industries, the steel mills established during the 1970s had excess capacity compared to local demand, and only about 20 percent capacity utilization was obtained. However, even at a capacity utilization of 40 percent the mills' cost per ton was significantly above the world market price of steel. The steel projects were funded by oil revenue. In fact the oil companies paid about 80 000 barrels a day into a London bank escrow account reserved for the payment of the steel mills (Bevan et. al., 1999). Yet the giant steel mill on which construction started in the 1970s is yet to be completed.[28]

Government spent a large portion of the oil windfall on infrastructure, utilities and heavy industries, but expenditure on education also increased substantially and the primary school enrollment rate increased from 37 percent in 1970 to 79 percent in 1978, and 91 percent in 2000. Nigeria

[27] Yet, as shown in figure 2 above, actual output fluctuated between 1.8 and 2.3 million barrels a day during the period 1973-79.

[28] During recent discussions with the World Bank regarding new credit facilities, it has been suggested that the steel mill project be converted to an industrial park, but the Nigerian government has been reluctant to bring the steel project to a halt. Furthermore, developing the local steel industry is mentioned in the recent Report from the Committee on Local Content in the Nigerian Upstream Petroleum Sector, as a measure of increasing local content.

should therefore have a reasonably well educated labor force. The Nigerian history of industrial development and industrial policy suggest that heavy-handed government regulation and direct intervention have not given the desired results. Below, we discuss the lessons from these experiences for the suggested local content legislation before the Parliament in 2002 and 2003.

3.5.2 Production and reserves

At the end of 2001 Nigeria had proven oil reserves of 24 billion barrels of oil. The country produced an average of 2.148 million barrels a day in 2001 (BP, 2002). Nigeria is a member of OPEC since 1971, and subject to OPEC production quotas. At present the production capacity in the country is 2.3 million barrels a day, about the same as in 1979, while the OPEC quota is set at 1.787 million barrels a day (Petroleum Economist, July 2002). The Nigerian government plans to expand production capacity to 3 million barrels a day in 2003 and to 4-5 million barrels a day by 2010 (EIU, 2002). Utilizing such capacity would, however require a significant extension of the OPEC quota, and the required investment will probably depend on the ability to secure such quota increases. The production costs were estimated at an average of $3.5per barrel onshore and $5 per barrel offshore in 1997 (NNPC, 1998). The reserves to production ratio stood at 30.8 at the end of 2001. Nigeria also has considerable gas reserves. The proven reserves are estimated at 124 trillion cubic feet at the end of 2001 (BP, 2001). Most of it is associated gas.

Hitherto the gas sector has been developed only to a limited extent. According to Petroleum Economist (July 2002) 63 percent of associated gas is flared.[29] Flaring is, however, banned from 2008.[30] Another 12 percent of the associated gas is re-injected in the field in order to improve oil recovery, but according to SPDC, few of the reservoirs are suitable for this technology. Particularly in the Niger delta the water table is so high that gas injection could compromise well stability. The remaining 25 percent is being produced, partly for power generation in Nigeria, partly as feedstock to a fertilizer plant and partly for exports in the form of LPG and LNG. Due to limited domestic demand compared to the quantity of associated gas being flared, the zero flaring policy can only be

[29] The quoted share of associated gas being flared depends on the source. Douglas-Westwood quotes the figure 78 percent, EIA quotes 75 percent and EIU 54 percent.

[30] According to Mbendi (2003), president Obasanjo has announced that the end of flaring is pushed forward to 2004. This is only one year down the line and is not obtainable according to current gas investment plans. As late as late 2002 the largest producers stated that they are on track to end flaring in 2008.

implemented through increased exports of gas. For this purpose, new LNG, LPG and gas converted to liquids (GTL) projects are being developed or planned. In addition there are plans for piping of gas to neighboring countries (the West African gas pipeline to Benin, Togo and Ghana). The West African Gas Pipeline has, however, been on the drawing board since 1982, and the economic viability of the project is still uncertain.[31]

An LNG processing plant (the Bonny Island LNG Facility) with two LNG production trains was completed in September 1999 at an investment cost of USD 2.5 billion and production capacity of 2.95 million tons per year. A third train is coming on stream in 2002 at an investment cost of USD 1.3 billion, increasing capacity by 50 percent. (Douglas-Westwood, 2002). Two additional trains are planned and contracts for construction of the fourth train was awarded the first week of 2003. A consortium of a US and a German company was awarded the contract (Mbendi, 2003).[32] The fourth train will have a production capacity of 4 million tons per year and is expected to come on stream in spring 2005. The operating company is Nigeria Liquefied Natural Gas Corporation (NLNG) where the national oil company, NNPC, holds a 49 percent stake, Shell holds 25.6 percent and is responsible for the operations and management of the plant, and TotalFinaElf and Agip hold 15 and 10.4 percent respectively. NLNG has entered long-term contracts on the sales of most of the capacity of the plants, including the last two trains.

ChevronTexaco has invested in an LPG project at Escravos. The plant processes associated gas and has currently a capacity of processing 285 million cubic feet per day. The first phase came on stream in 1997, the second in 2000. A third phase extending capacity to 400 million cubic feet per day is planned. In addition to the LPG plant, a gas-to-liquid project is being planned close to the Escravos plant. It will use technology developed by the South African company Sasol and ChevronTexaco. It is expected to come on stream in 2005 (ChevronTexaco 2003). Also Statoil plans to install an offshore LNG plant at block OPL218 (Petroleum Economist, July 2002). Nigeria encourages gas-processing projects through tax incentives. It is estimated that Nigeria will have a world market share of LNG exports of 8 percent by the end of 2005.

[31] Benin and Togo are very small markets, while Ghana has considerable hydro-power resources.
[32] Chicago Bridge and Iron Company and Bilfinger Berger AG.

The Nigerian petroleum sector has not always been on good terms with the local communities in the Niger Delta and the relations are still tense. The communities claim a higher share of the benefits from oil production and there are accusations of human rights abuses and environmental damage. Further, local communities expect the oil majors to provide a number of services such as schools, roads, clinics, hospitals, potable water and so on as compensation. Petroleum companies have been plagued by vandalism, sabotage and outright theft. It is estimated that $4 billion of oil revenues was lost due to vandalism in 2001 and that about 300 000 barrels were illegally freighted out of the country (EIA, 2002).

3.5.3 Technology

Production technology in the onshore sector as well as the shallow offshore is standard off the shelf technology. Yet, little of it is produced locally. Oil services are mainly delivered by foreign companies' local affiliates. Nigeria has recently opened the Niger Delta deep and ultra-deep offshore fields for development. The oil majors have shown great interest in the fields and several are already under development. Floating production storage and offloading vessels (FPSO) combined with sub-sea structures have been the preferred technology in deep offshore. The first oil from deep offshore is expected in February 2003. It will come from Agip's Abo field located in water depth of 200 – 1000 m (Mbendi, 2003).

3.5.4 Outline of industry structure

Oil production is undertaken by multinational oil companies, mainly in joint ventures with the Nigerian National Petroleum Company (NNPC). Fields for which the multinationals are operators account for about 95 percent of total production, while the last 5 percent is undertaken by local firms operating marginal fields and tale production. Shell is the dominant multinational oil company producing about half of Nigeria's oil (EIA, 2002) through its subsidiary Shell Petroleum Development (SPDC), which operates a joint venture on behalf of the NNPC. Other major oil companies operating joint ventures with NNPC are TotalFinaElf, ExxonMobil, ChevronTexaco and Agip.

There are at present 16 indigenous Nigerian oil companies that have made commercial discoveries and 7 of them are currently producing oil ranging from 800 - 35 000 barrels a day (Douglas-Westwood, 2002). The government provides incentives for indigenous firms participating in the upstream sector, but sets an upper production limit of 35 000 barrels a day for eligibility for such incentives. During the 2000 licensing round it was required that in order to be awarded a license, evidence of at least USD 10 million of financial resources must be presented. This is seen as a barrier to entry for local firms. The indigenous companies with few exceptions have engaged an established international oil company as a technical partner in their operations. The government has launched a licensing round of 116 marginal onshore fields suitable for indigenous operators (EIU, 2002).

Turning to the supply industry, the major oil service firms and contractor firms (Schlumberger, Halliburton, ABB) have subsidiaries in Nigeria. There are also local subcontractors in a number of oil services such as wellhead services and wellhead fluids. In addition there is a plethora of small local firms with a turnover of less than 0.5 mill $ per year, and the local industry thus appears to be fragmented and without the sufficient scale to carry out significant contracts (K&A, 2003).

3.5.5 Role of the national oil company

As a consequence of Nigeria joining the OPEC in 1971, the government acquired a 35 percent stake in the oil majors operating in the country in 1973. These share holdings were increased to 55 percent in 1974 and later to 60 percent. The government holds only 55 percent of the shares in the joint venture with Shell, however. The government ownership of the petroleum resources is vested in NNPC. It was established in 1977 when the existing national oil company, NNOC was merged with the Ministry of Petroleum Resources in order to concentrate the management of the nation's resources in one institution. The national oil company's mission statement asserts that its objective is to become a commercial international corporation engaged in oil and gas activities, utilizing skilled manpower and current technology. The company's upstream activities are organized as follows:

1. National Petroleum Investment Management Services (NAPIMS) is the operating arm of NNPC in the upstream oil sector. It engages in joint operating agreements, production sharing contracts and service contracts with the oil majors. At the same time it manages the nation's hydrocarbon resources, encourages local content and skills development.
2. Crude oil sales division
3. Nigerian Petroleum Development Company
4. Integrated data services Ltd.
5. Nigerian Gas company

Among downstream activities are refineries with an installed capacity for refining 445 000 barrels of oil per day. The capacity utilization has, however, been by far below this for the most of its existence and the refineries have recently been overhauled in order to improve capacity utilization. NNPC has also engaged in petrochemicals and distribution through pipelines and depots.

3.5.6 Regulatory regime

The Petroleum Act of 1969 and the 1979 constitution assign the exclusive ownership of petroleum and mineral resources to the government. The Ministry of Petroleum Resources has the following responsibilities (Ministry of Petroleum Resources, 2002):

- Administration of government joint venture interests in all aspects of the petroleum industry;
- Administering all concession policies;
- Formulating all policy matters relating to the marketing of petroleum and petroleum products;
- Conservation, control and inspection of the Nigerian oil industry;
- Development of hydrocarbon industries including natural gas processing, refineries and petrochemical industries;
- Fixing of prices for crude oil, natural gas, petroleum products and their derivatives;
- Licensing of all petroleum operations activities;
- Overall supervision of the Nigerian oil industry.

The ministry does not have a minister and is therefore directly under the president's office where a special adviser plays a central role.[33] The Minster, i.e. the president is the chairman of the NNPC's board.

The major regulatory body is the Directorate of Petroleum Resources (DPR), which sorts under the Ministry. It sets standards for exploration, prospecting and mining operations and controls and supervises these activities. It enforces safety and environmental regulations and advises the government and relevant agencies on technical matters. Registration and accreditation of contractors is also the responsibility of DPR. Another important task of the DPR is to issue permits, licenses and giving authority and approvals as required under the various acts governing the petroleum industry, including the downstream activities. DPR stores data and, finally, it is responsible for ensuring timely and adequate payments of royalties and rents from the oil companies (Minsitry of Petroleum Resources, 2002). The Federal Inland Revenue Services collects the profit

[33] This structure has developed following the establishment of NNPC as a merger between the then existing NNOC and the Ministry of Mineral Resources. It was realized that the sector needed a Ministry that was then reestablished as an entity embracing both NNPC and DPR, but with no Minister.

taxes from the oil companies. International oil companies can apply for the following licenses:

1. Oil exploration license, which gives the licensee a non-exclusive right to carry out aerial and surface geological and geophysical surveys, excluding drilling below 91.44 meters. The licensed area must not exceed 12 950 square km. The license expires 31 December in the year when it was awarded, but could be extended for one year if the licensee had satisfied the conditions of the license award.
2. Oil prospecting license, which gives the licensee the exclusive right to explore and prospect for petroleum within the area of the grant, which must not exceed 2590 square km. The duration of the prospecting license should not exceed 5 years, and the licensee has the right to dispose of the petroleum won during the license period.
3. Oil mining lease, which gives the licensee the exclusive right to search for, win, work, carry away and dispose of all the petroleum discovered and won in the area covered by the lease. Only the holder of the oil prospecting license for the area in question can apply for an oil mining lease, but being awarded an oil prospecting license does not give the right to a subsequent oil mining lease. An oil mining lease has a duration of 20 years, but may be renewed.

The Nigerian National Petroleum Company (NNPC) has the exclusive right to exploit the hydrocarbons of Nigeria. This right is exercised through joint ventures with the oil majors where NNPC holds a 60 percent equity stake (55 percent in joint ventures with Shell). The joint venture partner is the operator of the fields. However, the joint venture agreement typically entails a joint operations agreement as well between the operator, NAPIMS and other partners in the license, if any. The joint venture arrangement implies that the partners split the investment costs and profits according to the equity shares. Each party also markets its share of the produced oil. The parties have voting rights according to the share holdings, and NNPC has the majority vote in all the licenses in the country.

Due to shortages of financial resources, NNPC has had problems with raising funds for its share of the investment costs since 1993 and substantial arrears have accumulated. This has been an impediment to the development of new fields in Nigeria. An alternative to joint ventures, which solves this problem is production sharing contracts (PSC). The arrangement here is that the operator incurs all the exploration, investment and operating costs. The oil produced is then split into cost

oil, tax oil and equity oil. Cost oil accrues to the operator as a compensation for its costs, revenue from the tax oil covers the tax obligations, while the profit oil is shared between the PSC partners according to an agreed formula. PSCs were first introduced in 1993 and are increasingly used in new deepwater areas (Douglas-Westwood, 2002).
The petroleum profit tax is 65.7 percent for joint ventures and 50 percent for PSCs. After 5 years of operation the profit tax increases to 85 percent. The royalty rate varies with location of the field (onshore, offshore and sea depth) and the nature of the contract (JV or PSC). The royalty rates range from 0 to 20 percent, the lowest for PSCs deep offshore and highest for onshore joint ventures. There is an investment tax credit of 5 percent in joint ventures onshore and between 10 and 50 percent in PSCs offshore, increasing with the water depth (Douglas-Westwood, 2002). The objective of utilizing associated gas and thus stop the flaring is followed by tax incentives for investments in equipment separating oil and gas, and utilizing the gas for usable products. The profit tax on gas production is the same as the company profit tax (Sote 1998).

The tax rates are specified in the Memorandum of Understanding (MoU) between NAPIMS and the oil majors. Apparently the most recent MoU becomes the regulatory regime for the sector as a whole. The objective of the MoU is to obtain high production volumes and a high level of exploration and development activities. The present MoU guarantees the operator a profit margin of $2.5 per barrel for projects with capital expenditure less than $2 bill., and a profit margin of $2.78 for projects with capital expenditure above $2 bill., based on a cost per barrel assumption of $4. A specific incentive to encourage exploration is a reserves addition bonus, where a financial bonus is offset against profit tax in a given year when the company in question has added to the country's reserves. Finally, the MoU obliges the operating companies to lift the NNPC crude that NNPC is unable to lift. The MoU is signed by the Ministry and NAPIMS.

The downstream sector is heavily subsidized. The NNPC refineries pay a price by far below the world market price for their crude inputs, while their products are also heavily subsidized in the local market. Consequently, the products are smuggled to neighboring countries and resold there, while Nigeria imports about 80 percent of local demand for petroleum products (Douglas-Westwood, 2002).

A condition for being awarded new production licenses is a credible strategy for zero flaring. Environmental regulations have been in place since 1988 when harmful toxic waste became a criminal act. In 1992 the

Environmental Impact Assessment Decree was passed which mandates a prior environmental impact assessment (EIA) of any investment project in the upstream sector.

3.5.7 Local content

Following the first structural adjustment program with the IMF, a new industrial policy regime was introduced in the late 1980s. Import substitution was replaced with trade liberalization, privatization of state enterprises and commercialization of remaining state-owned enterprises, including the NNPC. Oil marketing companies (Unipetrol, National Oil and Chemical Co. Limited and African Petroleum Limited) was partly privatized. The new industrial policy emphasized the objective of increased local content in Nigerian industrial output in general, not only the petroleum sector, and introduced a number of incentives in order to encourage industries to establish backward linkages to the local economy. These include pioneer status (5 years tax holiday on corporate income) of such industries that the government considers beneficial to Nigeria. There are additional tax concessions for companies that develop local raw materials and increases local value added.

A bill that makes provision for Nigerian content in the upstream sector is currently being prepared for the Nigerian parliament. The proposed bill categorizes supply industry activities according to technological impact (low-medium-high) and supply industry firms according to ownership (category "A" 100 percent local ownership through category "E" 100 percent foreign ownership). The proposed bill has five elements:

- The establishment of a Joint Qualification Committee (approved by the Directorate of Petroleum Resources, DPR) whose tasks are to establish and operate a system for joint qualification of contractors, and the establishment and continuous updating of a national databank that contains available capabilities;
- Systematic tracking of local content in upstream projects by (DPR) and mandatory submission of quarterly reports on local content in procurement and employment;
- DPR and National Petroleum Investment and Management Services (NAPIMS) shall implement the Act with a view of ensuring a measurable and continuous increase in the market share of category A companies and in the direction of high technology impact among oil services companies within category A. For low-technology impact services non-category A companies can only be included in the bid list of a project if the NNPC is satisfied that there are no category A companies left that are capable of providing the goods or services. There shall be allowed a price

premium of 10 percent for category A companies when bidding against non-category A companies;

- A labor clause mandating that all contracts awarded in excess of USD 100 mill. use a minimum percentage of Nigerian labor (the percentage to be determined by DPR in each case);
- Employment of Nigerian citizen in multinational oil companies and oil service companies having operated in Nigeria for 10 years or more. At least 95 percent of those employed in managerial, professional and supervisory grades shall be Nigerian citizens while 60 percent of board members shall be Nigerian citizens.

The proposed act leaves it to the DPR to set specific targets for local content, but the report of the National Committee on Local Content Developments in the Nigerian Petroleum Industry (January 2002) suggest a target of 30 percent market share of category A companies in 2005 and 60 percent in 2010 in the supply industry.

Figures on local content at present vary widely from one source to another. The report of the National Committee estimates that the local content is 5 percent at present (presumably only the value added of category A firms are included in this measure), while SPDC claims that about a third of their procurement contracts are awarded to local category A firms (Imomoh, 2002). Whether the differences are due to differences in how local content is measured or due to poor quality of data is not clear.[34]

A coastal and inland shipping (cabotage) bill is currently being discussed in the Nigerian National Assembly. It reserves the exclusive right of Nigerian owned and Nigerian built vessels operated by a Nigerian crew to provide transport services within Nigeria. The legislation also applies to transport of goods and personnel to the offshore oil installations. At present there are hardly any company that satisfies these criteria in the transport services for the offshore sector. It takes time to develop local capacity in this sector, particularly in the shipbuilding industry. Waivers will therefore have to be permitted for almost all contracts in this market segment for the foreseeable future. While awaiting local content to develop, new bureaucratic procedures for granting waivers are likely to arise. To the extent that such procedures cause delay, they will contribute to less efficient upstream operations, and possibly the temptations to offer

[34] Since SPDC has about 50 percent of total output, a rough estimate suggest that local content should be at least 15 percent even if no other operators buy anything from local suppliers. Differences in estimates could nevertheless be due to differences in time period measured, and whether or not the multinational's internal production of supplies to the project is included.

bribes in order to avoid delays. Finally, since delays are very expensive in the upstream offshore sector, some of the transport will probably be diverted to air transport. This will make the Nigerian offshore sector less cost efficient and competitive if such a situation arises.

Lack of long-term finance is one of the main obstacles for local investors in any sector. This is because the local banks' deposits are mainly short-term. Long-term lending would imply a mismatch of the maturity structure of assets and liability, which in turn implies excessive risk-taking in an environment of volatile financial markets and a failure to stabilize the inflation rate at a reasonably low level.[35] In order to assist local suppliers overcoming the financial obstacle SPDC recently joined the International Finance Corporation (of the World Bank Group) in a program aiming at increasing the involvement of local contractors (Petroleum Economist, 2002). The procedures to access these funds are, however, seen as bureaucratic and time-consuming by representatives for the local industry, and it is yet not clear whether the program will open the financial bottleneck for local suppliers.[36]

Turning to the production of oil, marginal fields are seen as an entry point for indigenous firms. Some of the operating oil majors decided to farm out marginal fields within their concession area to local, indigenous firms in the mid 1990s. Such agreements had to be approved by the Ministry. In recent years the Ministry has taken charge of the allocation of farmed-out marginal fields to indigenous firms. These are fields in which the first discovery well was drilled more than 10 years ago and reasonable amounts of seismic data is available. As mentioned above, a licensing round of such fields was under way in 2002 and the pre-qualification round was completed in November.

3.5.8 Contribution to the Nigerian economy

Depending on the price of crude oil, the petroleum sector's contribution to gross domestic product in Nigeria has varied between 10 and 15 percent during the 1990s. It accounts for more than 90 percent of the country's export earnings. As indicated in the introduction to the Nigeria section, it can also be argued that the petroleum revenue has contributed to the typical Dutch disease syndrome. The spending of the petroleum revenue, mainly by government, has driven up costs, rendered industrial production in sectors for which Nigeria used to have comparative

[35] The inflation rate has occasionally come down to single-digit figures. but currently the inflation rate is around x percent.

[36] Interview with Mr. Roccah, Chairman of Star Petroleum Services, a local firm providing wellhead services and equipment to the petroleum sector. The firm represents Aker-Kværner in Nigeria.

advantage uncompetitive and created excessive dependence on oil revenue. This makes the country's income volatile, adding to the difficulties facing investors in Nigerian manufacturing industry and commercial agriculture.

3.5.9 Success factor and pitfalls

Nigeria has introduced several measures with the objective of increasing local value added, employment and ownership in the petroleum sector as well as the industrial sector at large. In the petroleum sector, early policy measures aimed at local ownership and employment rather than sourcing of local inputs. While ownership in the upstream sector itself is indeed vested in NPPC and employment in both NNPC and the majors' local subsidiaries are reasonably high both at unskilled, skilled, professional and managerial levels, the objective of developing an indigenous supply industry has been less successful. Furthermore, the considerable oil revenues flowing into Nigeria over the past four decades have failed to provide the nation with an adequate infrastructure, social services and a conducive environment for industrial development.

A number of paradoxes are apparent when analyzing the Nigerian economy in general and the upstream petroleum sector in particular. For example, even though the banking sector is the fastest growing sector in the economy, lack of long-term investment funding is stated as one of the most important obstacles facing local actual and potential suppliers to the petroleum industry (K&A, 2003). Second, while the government is heavily involved in industrial activities both within the petroleum sector in other industries, there is a lack of capacity for providing basic government services such as health, education and infrastructure. Furthermore, in the major oil-producing communities and States, the oil majors have to a significant extent substituted for local and state governments in providing such services.

We argue that one pitfall in Nigeria's industrial policy is to aim at too much too soon, given the present situation. The objectives in the proposed National Content Bill as well as the cabotage bill set very ambitious targets for local content. Obtaining them would require a more rapid industrialization and a steeper learning curve than seen anywhere in the world to date. Even if the expenditure level in the upstream sector was constant during the next 3 years, the local supply industry would have to grow by 60 percent per year the next 3 years and 14 percent each year between 2005 and 2010 to obtain the targets set in the local content report. Most likely it will be impossible to obtain them. This means that waivers, exemptions or worse will be the order of the day from day one.

This undermines the legislation from the very start and breeds an environment of rent seeking and the emergence of a large number of short-term companies hunting for opportunities. More realistic objectives combined with coherent policy measures that can be effectively implemented given the capacity of the regulatory and implementing bodies and a more stable macroeconomic, political and social environment are required in order to succeed in increasing local content.

Another pitfall is lack of clear legislation and regulatory framework. The petroleum act is outdated and largely ignored, while current regulation is largely spelled out in the MoU between an oil major and the Ministry/NAPIMS. The legal status of this document and the role of the legislators, i.e. the Nigerian Parliament are unclear.

3.6 Norway

3.6.1 Production and reserves

All oil and gas in Norway is located offshore. Exploration for oil and gas started in the mid-1960s, and the first field came on stream in 1971. In 2001 oil production, including NGL, was 3.4 million barrels a day, or 198 million standard cubic meters of oil equivalents, whereas natural gas production according to the same measure was 53.

Almost all of Norway’s oil and gas are exported, making Norway the third largest oil exporter in the world, and a significant gas supplier on the European scene. Gas has played a role in Norway’s commercial upstream activities since the early 1970s as a ban on flaring of gas was enforced.

The R/P-ratio for oil is close to 20, and above 100 for natural gas. Increasingly unexploited oil and gas are found in deep sea areas. Norway is a high-cost producer, where the break-even price for new independent field developments is assumed to be 12-15 USD/barrel.

3.6.2 Major players

When oil and gas activities started, the major oil companies like Exxon and Shell, as well as independents like Phillips, were awarded licenses to explore for and produce crude oil and natural gas.

After petroleum was discovered, Statoil was established as a state-owned oil company in 1972, to take an active part in the industrial activities. Since then, Statoil has developed to become the major player on the Norwegian shelf. Statoil was established as a 100 per cent state owned company, and stayed so until 2001. Then a process of privatization started. Currently the state holds 80 per cent.

The other major oil company on the Norwegian shelf is Norsk Hydro, where the state currently holds a 44 per cent ownership interest. Besides, the large international oil companies, as Shell, Exxon Mobil, TotalFinaElf and BP, always have been, and still are, playing a substantial role.

The largest player on the Norwegian shelf, however, is Petoro, a 100 percent state owned company, which is not operating as an oil company industrially. Petoro handles the economic interests of the Norwegian state, stemming from the state's direct financial involvement in the oil and gas activities in Norway. This arrangement means that the state holds a share in the gross capital flows related to oil and gas, both inflows and outflows.

The major contractors assisting the oil companies in the handling of wells and field development, are partly the large multinationals, as Haliburton and Schlumberger, partly engineering competence that has been developed in Norway with the assistance of McDermott and Brown & Root, as in Aker/Kvaerner and ABB.

It has been a deliberate policy from the Norwegian authorities to take industrial advantage of the challenging task linked to the extraction of oil and gas, meaning that there politically has been significant attention to the issue of local content. Today, roughly 50 per cent of the value added related to offshore oil and gas takes place in Norway. This is partly due to the competitive advantage of geographic proximity. But it is also due to international competitiveness among companies offering goods and services for offshore oil and gas. The larger Norwegian based firms are increasingly serving upstream oil and gas in other regions of the world.

3.6.3 Regulatory regime

3.6.3.1 *The licensing procedure*

Norway has all through her history of oil and gas, followed a system where oil companies are awarded exclusive rights for a limited period of time to oil and gas that are found in specific geographic areas. The time limit encourages exploration, as a certain share of the area has to be returned to the state if commercial discoveries cannot be documented. If such discoveries are made, the exclusive right is normally extended for 30 years, and may be extended further if extraction still can take place. This concession is granted according to a negotiated procedure, where the oil companies present their plans to explore the area, and their policy regarding field development. Auctions based on financial payments have never been used as an instrument.

When the first licenses were granted in 1965, Norway did not possess much negotiating power with regard to the oil companies. However, in the early 1970s, as the large international oil companies were excluded from many of the petroleum regions in the world, the oil price rose, and Norway proved more and more promising as a petroleum region, the negotiating power of the Norwegian government increased tremendously, and it continued to do so throughout the 1970s and early 1980s. The, the concessionary procedure was used as an instrument to enforce the participation of the international oil companies to engage in technology transfer and local content development.

3.6.3.2 *Local content requirements*

Norway has never made specific requirements as to the share of local content. Norway, however, stated that Norwegian based firms should be chosen when they are competitive in price, quality and delivery. Nevertheless, the oil companies never doubted that the Norwegian government and politicians appreciated the choice of local firms to supply the oil and gas activities with goods and services, and they were pretty sure that this would be honored in negotiations for future licenses. Thus, during the late 1970s and early 1980s local firms probably were chosen even if they were not the most cost effective. After all, the oil and gas activities at that time were taxed 85 per cent on the margin, meaning that additional cost were mostly paid by the Norwegian state as tax revenues were reduced.

Specific requirements were made in domestic capacity building concerning the domestically based oil companies, Statoil and Norsk Hydro, and also Saga Petroleum, which later has been merged with Norsk Hydro. As newcomers, these companies did not possess the competencies needed to take the responsibility as fully operating oil companies. Nevertheless, they were granted the task of being the operator in production licenses, and foreign oil companies volunteered to become their technical assistants, and to contribute with all the necessary technology transfer.

In some sense, technology transfer also took place through agreements with the foreign oil companies to locate research and development to Norway, and to have research cooperation with universities and research institutes in Norway.

The Norwegian authorities also required that the operator presented the firms on its bidders list for the Ministry before a tender, and that the Ministry could add Norwegian based firms on the list. In this way, local firms were not excluded because they had no previous experience as a part of the supply chain of the foreign oil companies. The Ministry should also be informed about which firm that had been chosen for the contract, before the firm was notified. The purpose was to give the Ministry a right to change this decision. Only once, however, the Ministry has found it worthwhile to change the decision of the oil companies at this final stage. More frequently, however, soft influence was enforced at earlier stages to promote local content.

Despite these policy measures, which easily could have led to a very protected industry development, Norway never really departed from the prerequisite of international competitiveness. Thus, there was never an issue to substitute all imports that technically could be replaced by domestic suppliers. Ambitions were to have domestic suppliers that could defend their competitive positions by international standards.

3.6.3.3 Taxation

The issue of government take has been important in relation to offshore oil and gas in Norway. During the 1970s, government take was strengthened, by introducing a sector specific tax system. On the margin, oil companies' profits were taxed 85 per cent.

In addition, Statoil was granted positions to increase government take besides taxing profits. However, due to this position, Statoil grew to become very dominant in Norway's oil and gas, and the state participation was reorganized in 1985. The role of Statoil changed, and since then Statoil has been supposed to operate as any other oil company. At the same time, substantial shares of Statoil's ownership positions were transferred to the state's direct financial involvement, which later has been organized as Petoro.

The drop of oil prices in 1986 also triggered revisions of the tax system, reducing the tax base as well as the tax rate. However, even today oil and gas in Norway is taxed in order for the state to grasp as much as possible of the land rent without destroying the incentives of the oil companies.

3.6.4 Local content and contribution to Norway's economic development

3.6.4.1 The effectiveness of local industry in international comparison

Local content to cover the demand for undertaking upstream oil and gas activities offshore in Norway, is roughly speaking at 50 per cent when measured according to value added. Over the last 15 years, it has become increasingly necessary for the local firms to be competitive by international standards. Nevertheless, a significant number of the local firms are still competitive mainly due to geographic proximity. Some figures, based on Heum et. al. (2000) and Kristiansen et. al. (2002), illustrate this:

- Firms based in Norway supplying goods and services to the Norwegian oil and gas sector, has on the average one third of their turn-over to petroleum regions in other parts of the world;
- Roughly 50 per cent of the domestically based supplying firms have some sales outside Norway;
- Nevertheless, only one of five firms have more than 20 per cent of their turn-over in other parts of the world than Norway, indicating that they really have established market positions internationally;
- These internationally oriented firms are larger on the average than the whole group of petroleum-related firms in Norway, and they grow more rapidly.
- There are no estimates as to the share of value added among local firms that takes place in firms that are internationally oriented, or in firms which only serve the domestic market. A guesstimate will be 50/50.

3.6.4.2 The contribution of oil and gas to Norway's economic development

With the current high volumes of oil and gas production in Norway, and the high oil price, upstream oil and gas make up a substantial share of the Norwegian economy. In 2001, more than 22 per cent of Norway's GDP originated in upstream oil and gas, 35 per cent of state revenues came from taxing oil and gas and from the state's direct financial participation in Norway's oil and gas, while the share of oil and gas in Norway's exports was 45 per cent.

These figures, however, fluctuate with the oil price. In 1998, for instance, the GDP-share was 12 per cent and the export share 30 per cent.

Less than 1 per cent of Norway's employment is in upstream oil and gas. Oil and gas related industrial activities are more labor intensive. However, employment directly related to upstream oil and gas and oil and gas related industries, does not amount to more than just above 3 per cent of total employment in Norway.

Due to the integration of industrial activities related to oil and gas in Norway's industry, and the conscious spending of petroleum revenues domestically, Norway has so far been able to avoid severe and damaging crowding out effects of the traditional exposed sector of the domestic economy. It has been reduced, but not eroded.

3.6.5 Success factors and pitfalls

Norway has been quite successful in developing domestic industrial capacity of reasonable high international standards in relation to offshore oil and gas. In this respect, it has been decisive that Norway hosted relevant industrial competence with a high international standing in areas that were relevant for offshore oil and gas. This relates to

- Shipping, ship equipment and ship yards, whose competence was useful for offshore operations in general, and where the firms in shipping already had developed customer relations with the major oil companies in the transport of oil;
- Operating capital intensive process industries in general, which is directly relevant for extracting oil and gas;
- Geological competence from the mining industry, which was relevant for mapping and interpreting the geology on Norway's continental shelf.

Besides hosting relevant industrial competence, there was a technological window of opportunity when it all started in Norway, because the oil companies also were relative newcomers in offshore oil and gas production in other areas than shallow water close to shore. Thus, local firms, and the domestic knowledge base, could be engaged and contribute to the technological development in offshore oil and gas on the world scene.

Thus, the challenge for Norway's government was

1. To create institutions, which could promote sound business practices and which could provide industrial dynamics;
2. To attract the interest of the relevant industrial base in Norway, which also meant that Norway did not try to cover all goods and services that technically could be provided domestically;

3. To get the commitment from oil companies and major players of the international oil industry to contribute to technology transfer

This was done by encouraging the development of domestic oil companies, and by having sharp attention on the opportunities for domestic firms to participate, which in some instances led to quite obvious protection of local firms. With lucky timing, this proved quite successful. The oil companies, and the large engineering companies, were more than eager to contribute throughout the 1970s and early 1980s, when the build up of domestic capacity took place, as Norway was one of the few promising petroleum regions where they could operate. However, as protection no longer was needed, or justified according to an infant-industry-argument, Norway avoided the pitfall of destructing value by making the protection permanent. This was not deliberately decided as the free will of politicians. Rather, it was forced upon the system. Firstly, as the oil price collapsed in 1986, the oil companies were forced to stress cost effectiveness. Secondly, with the Single Market in Europe, and Norway's participation in the European Economic Area, the politicians had to abolish all laws that could imply some kind of protection of the domestic petroleum related industry.

Norway avoided another pitfall in the strategy that was chosen, by allowing for the participation and rivalry between domestic oil companies, and between oil companies of Norwegian and foreign origin. Similarly, Norway never stressed the ambition of local content development as far as to disregard economic considerations completely. World market prices have been a guiding principle, even though it has been violated at times. But it was never violated to the extent that the domestic gasoline price has been set lower than the world market price, simply because Norway is an oil producing country.

3.7 Summary, success factors and pitfalls drawn from the case studies

The policy measures related to ensuring national control with the upstream petroleum sector and embedding the sector in the domestic economy have been surprisingly similar in the six countries across time and space. All six countries established a national oil company, which has had the role of managing the petroleum resources, and all six countries have introduced local content requirement, requirements for the training of local staff and technology transfers. The countries have, however, differed significantly in policy design, policy transparency and ability to enforce regulations. The countries have also differed in the openness towards the international oil industry and the degree of protecting local suppliers. A general observation is that the technological challenges facing the petroleum industry together with increased focus on environmental sustainability have induced liberalization in all the case studies. Liberalization appears to have been motivated by the need to access state-of-the-art technology and the need to specialize in the market segments where the local industry has obtained competitiveness. In the countries with the highest local content (Brazil, Mexico and Malaysia) the local content share appears to be on a declining trend as a result of liberalization. Indonesia is arguably the country closest to Nigeria regarding level of development and industrial capacity. The industrial capacity gap between the two is nevertheless wide as Indonesia has a much broader and larger industrial base than Nigeria. It is worth noticing that Indonesia has not been able to reach its target local content of 35 percent, even when local content there is defined as value added in Indonesia, regardless of ownership of the supplying firms. We discuss the success factors and pitfalls related to three policy issues: i) the role of the national oil company; ii) the relation between the national oil company and the oil majors; iii) industrial policy with the focus on local content in section 6 below. But before we summarize the lessons from the case studies we need to take into account the structure of the market that the local supply industry aims at entering and the experience from local content requirements in developing counties at large.

4 Supply chains in the oil industry

The supply chain is a linear sequence of activities organized around the flow of materials from source of supply to finished products, after-sales services and often also recycling. Activities are only justified when they add value to the overall process, and may shift between organizations or being enhanced or eliminated depending on market conditions, technology and firm strategy. The supply chain also involves transport, communication, finance and other specialized support functions. The primary supply chain driver's approach to supply chain management typically involves the following steps (Schary and Skjøtt-Larsen, 2001):

i. Segmenting the potential suppliers based on strategic importance (level of dependence on the suppliers' product);
ii. Evaluate suppliers according to quality, delivery, lead-time and cost performance, and often also financial stability, capacity, design capability, capability to manage materials and subcontractors and ability to implement continuous improvement;

iii. Rationalization of the supplier base – choose the set of suppliers to enter closer relationship with from the base of qualified suppliers;
iv. Enter long-term contracts with the chosen suppliers.

The long-term contracts with the chosen suppliers typically entail objectives of cost-cutting, mainly on the part of the supplier. This has sometimes led to the squeezing of suppliers' margins. Experience with the supply chain approach has thus been mixed and the supply chain driver has often benefited more than suppliers in the upstream oil and gas industry (NORSOK 1995, DTI 2000). Nevertheless the supply chain management approach will probably characterize the business environment facing Nigerian suppliers and an understanding of this environment is necessary in order to design strategies for increasing local content.

The long-term contracts typically entail agreements on capacity building, cooperation on process and/or product innovation, promises of increased sales for the supplier and sometimes an agreement on sharing the benefits that the buyer gets from the suppliers' cost-cutting innovations. Procurement is often outsourced to the first-tier suppliers (e.g. the major contractors in the oil industry) and quality control is typically expected to take place at source. According to Douglas-Westwood (2002), there is a growing proliferation of long term contracts (of 7 years or more) in the maintenance, modification and operations market in the upstream sector. Furthermore such contracts, as well as contracts related to exploration and development, are increasingly awarded by the oil majors' Houston offices to which procurement is centralized.

Further out in the supply chain, arms-length market exchange is more common for standardized products and activities, but even here automated procurement processes using the Internet is becoming common in the upstream petroleum sector. The oil companies have been the drivers for introducing e-commerce in the upstream oil and gas industry. The oil majors have jointly introduced portals for e-commerce, the most significant being Trade Ranger, owned by 15 oil and petrochemical companies including BP, Shell, TotalFinaElf and Statoil, and it has at present more than 1000 supplier members. It provides catalogue services such as standards, trading and invoicing and value added activities such as auctions and investment recovery. Another major portal is PetroCosm, which was founded by among others Chevron and Texaco.

E-commerce is most widespread in low-cost, high-volume transactions, the market segment in which Nigerian suppliers might be competitive. E-commerce is also increasing in the market segments providing standardized and well-tried technologies such as drilling and routing drilling supplies. In markets where customization is more common e-commerce is less widespread. A combination of widespread use of framework agreements and e-commerce could introduce significant barriers to entry for small and medium-sized enterprises (SME) in the supply chain. Participation in e-commerce requires investment in the necessary ICT equipment, and training. A considerable trading volume is probably necessary to recover such investment.

As already mentioned, the upstream offshore petroleum industry is a global industry and the same goes for the oil services companies that are the main contractors during exploration, field development and production. A recent British study (DTI, UK, 2002) argues that the supply industry is being polarized: suppliers must either be able to offer full service engineering-procurement and construction (EPC) contracts or they must specialize in niche segments. But even the niche producers must be able to supply their products globally. Thus, the British study argues that some of the largest contractors prefer to work with global companies who have local subsidiaries in the oil-producing region in question in order to ensure quality. Local content, where such requirements are present can then be obtained either by using local sub-contractors further out in the supply chain, or local affiliates of global companies when these are counted as local.

In the light of this discussion, the local content policy being developed needs to address the following questions:

- Where in the supply chain/ value chain does Nigeria have firms with the capacity for timely delivery of the required quality, at a competitive price?
- What are the obstacles for such companies to enter the market?
- Which measures should the government take in order to improve local companies' access to the supply chain?
- How can such measures be designed in order to provide incentives for a safe, environmentally sound and cost-effective upstream petroleum sector?

5 Local content: preconditions and contribution to development

Local content requirements have been popular in developing countries in order to improve industrial capacity. It is anticipated that when foreign investors are required to purchase a certain percentage of total intermediate inputs from local firms, they will also transfer technology to their local suppliers in order to improve the quality and reduce the cost of local content. Thus, there are two positive effects of local content requirements; the employment effect and the technology transfer effect. There are, however, also costs related to local content requirements. First, local content requirement usually leads to higher costs of intermediate inputs in addition to significant switching costs when the investors have established international supply networks. This affects the investor's profit margin and leads to lower FDI flows than would have materialized without such local content requirements (Hackett and Srinivasan, 1998).

Foreign investors facing local content requirements are inclined to minimize the cost of meeting the terms. One possibility is to reduce intermediate purchases and produce some of the intermediates in-house. This would increase the investor's demand for labor, which could be hired locally or internationally, depending on the supply of adequately qualified workers. Another possibility is to bring the first-tier investor's international suppliers into the host country. In industries characterized by international supply chains and where the supply chain driver is a multinational company focused on its core activities and with long-term relationships with suppliers, this is commonly observed. The multinational oil companies largely fall into this category. Wherever the oil majors are present, the major contractors are also found.

In small markets or industries subject to economies of scale, local content requirements are strongly anticompetitive. Local suppliers would have a captive market and significant market power. In some cases a local supplier would have a monopoly for inputs produced subject to economies of scale. Experience from the car industry, which is subject to significant economies of scale, indicates that local content schemes have been very costly to consumers, government budgets and the economy in general. Moreover, in most cases it has not advanced indigenous technological capabilities. The upstream petroleum sector has in common with the car industry that the supply industry is specialized and subject to significant economies of scale both due to fixed costs in production and due to R&D expenditure. Thus, local content requirement would

constitute a setting where a few local providers would gain market power, and the cost of extracting oil and gas would increase.
Local content requirements may have an adverse effect on what kind of companies that are attracted to the market. It is the foreign investors with the least efficient supply chain that will be the least affected by local content requirement, since the difference between their costs before and after having complied with local content requirements are smaller than for more efficient companies (Qui and Tao, 2001). In the Nigerian upstream sector this may imply that oil companies with a relatively high cost structure will be more attracted to the Nigerian offshore sector than low-cost companies that have established an effective international supply chain.

Government revenue from profit taxes on foreign investors will suffer from local content requirements. The operating profits will inevitably be reduced as a consequence of the enforcement of local content requirements over and above what the oil companies would have purchased in the local market in a free trade setting. When the marginal tax rate on profits is high, the host government will bear most of the cost related to local content requirement. The petroleum rent will in this case be partly shifted from government (and the beneficiaries of government expenditure) to the local supply industry.

There are no systematic studies published on the determinants of local content in the upstream petroleum sector. There is, however, a recent study of determinants of local content in Japanese multinational electronics firms (Belderbos et.al. 2001).[37] The electronics sector has in common with the offshore petroleum sector that it is a relatively high technology, capital- and skills-intensive industry, and that multinational firms with established international supply chains dominate the industry. Some of the findings of this study should therefore be relevant to the upstream petroleum sector.

The study finds that local content is larger the less R&D-intensive the investing firm's activity, an effect that disappears with investment in developed countries. Further, it finds that availability of local suppliers and good infrastructure, particularly telecommunications, in the host country are important for local content. The study also finds a "vintage" effect. It takes time to establish a local supplier base, and local content increases over time for a particular investor. This vintage or experience

[37] The study covers 272 Japanese electronics manufacturing affiliates in 24 countries, including Brazil, Indonesia and Malaysia.

effect peters out after about 10 years.[38] It was also found that affiliates of Japanese parents that belong to a kereitsu with strong intra-kereitsu supplier relationships have a higher local content in host countries than independent firms. This effect is entirely explained by the investor bringing in the kereitsu affiliates in the host country. Applied to the petroleum sector this should imply that the oil majors with an established international supply chain are likely to induce additional investments by its supply chain partners in the host country.

Turning to the impact of the host country's trade and industrial policy, the study found that FDI motivated by circumventing trade barriers were less likely to establish linkages to local suppliers. The explanation for this is that such investments are only partly determined by the host country's cost competitiveness and resource endowment, and since trade policy changes faster than resource endowments, investments circumventing trade barriers are less committed to the host country and thus more footloose. Finally, the study finds that local content *requirements* have a modest positive impact on local content, but not on procurement from locally owned firms. Local content regulations in other words induce the foreign investor to bring in its supply chain suppliers to the host country, or the foreign investors will produce the inputs themselves in the host country. The study concludes that local content requirements are not very effective in developing the host country's indigenous supplier base.

The lessons from this discussion are:

- Local content requirements that are binding (i.e. set higher than existing levels) increase costs, reduce government revenue and most likely reduce the investment and production level in the upstream oil and gas sector;
- Binding local content requirements are less costly when set in terms of local value added and/or local employment rather than according to ownership of the supplying companies;
- Binding local content requirements according to ownership are likely to attract oil companies and contractors with a less efficient international supply chain than the most efficient operators and contractors, since the former have the lowest switching costs.

Local content requirements related to investment expenditure are prohibited under the WTO agreement on trade-related investment

[38] Entry mode is important for this effect. Local content is much higher at an early stage when the foreign investor enters through merger, acquisition or joint venture than if he enters through a greenfield investment. In the former cases he can build on existing supplier networks.

measures (TRIM). Least developed countries have been allowed a longer time (7 years) to eliminate regulations that violate the TRIM agreement. The transition period for least developed countries expired 01.01.2002, although there is the possibility of applying for an extension of the transition period. Apparently, Nigeria has not done so, and the TRIMs regulations under the WTO in principle already apply to Nigeria. Least developed countries are allowed to introduce measures that violate the TRIM regulation for balance of payments purposes and temporarily for infant industry protection, and thus have some, but limited flexibility in their investment policy. Also subsidies contingent on the use of domestic goods are prohibited under the WTO Agreement on Subsidies and Countervailing Measures. This rule applies to least developed countries from 01.01.2003. Least developed countries are, however, exempted from the WTO prohibition of subsidies contingent on export performance. Neither the TRIM nor the subsidies and countervailing measures regulations apply to the services sector.

6 Policy implications for Nigeria

We are now ready to draw the lessons and policy implications for Nigeria. We organize the discussion under three headings: the role of the national oil company; the relation between the national oil company and the oil majors; and industrial policy.

6.1 Role of the national oil company

Petroleum is seen as a strategic commodity creating wealth to an extent not seen in any other sector. A national oil company has therefore been established in all countries in order to ensure national control of the resources. Statoil, Petronas, Pertamina and NNPC were all established as non-operating companies with the objective of managing the nation's petroleum resources on behalf of the nation. They all had the objective of becoming operating oil companies when established and they all entered into technology transfer agreements with the oil majors in order to acquire the necessary capacity to become operating upstream oil companies. Pemex in contrast was established as an operating company right away, taking over the operations of the oil majors when the industry was nationalized. Petrobras took an intermediate position starting with refining and distributing imported oil. Statoil, Petronas and Petrobras have later developed into multinational fully integrated oil companies, Pemex has become a local fully integrated oil company while Pertamina and NNPC remain national oil companies with limited activities outside the national borders.

The technological capacity, cost effectiveness and environmental and health standards of the national oil companies depend strongly on the industrial base and pool of skills in the home country, the regulatory setting and the extent to which the companies have faced competition both in the market for inputs and outputs. A sufficient pool of skills is a necessary condition for developing a cost-effective and environmentally sound operating oil company. Given a critical mass of technical, organizational and financial skills, the specific skills for an operating oil company can be acquired through technology transfer agreements with the oil majors. It appears that joint operation of fields using proven technology is the best first step in developing local capacity as Petronas' experience shows. Pemex, in contrast chose to go it alone, and has had problems with technological capacity, environmental standards and cost effectiveness. Petrobras and Statoil could not rely on proven technology as they ventured into areas and conditions where no proven technology existed. In both cases technology was developed in cooperation with local and foreign suppliers. It should, however, be noted that both Norway and Brazil had a relatively sophisticated industrial base to build on, particularly in the maritime industries.

Technological capacity and skills are not sufficient to establish an efficient and sound operating oil company. There also needs to be the right incentives in place to utilize the capacity and skills in an optimal way, given the national objectives for the industry. The regulatory framework determines the incentive structure to a large extent. We argue that the case studies show that facing the discipline of the market after a relatively short period of protection will provide the needed incentives for efficiency. Further, it also seems important to design the contract with the oil majors in such a way that both parties gain from technology transfer. This is crucial for avoiding a situation where the oil major carries the national oil company financially and technically in perpetuity.

The six oil companies differ in the extent to which regulatory powers are vested in the companies. All six have had some regulatory powers in the early days and all six have had privileges as state-owned companies. However, over time it has become clear that regulatory powers should be strictly separated from operating activities, in order to ensure transparency and to avoid creating a fertile ground for rent-seeking and outright corruption. All countries have introduced reforms to that effect, but to a differing extent. Nigeria still has a long way to go before regulations and operations are strictly separated.

6.2 Relation between national oil company and oil majors

The oil majors have played a crucial role in five of our six country studies. They have undertaken the first exploration and development of fields in all cases. The relations between the oil majors and the national oil company have varied both between countries and within countries over time. The contractual relations between the national oil company and the oil majors can be divided into five broad categories: Joint ventures, joint operating agreements, production sharing contracts, service contracts and other risk contracts. The optimal contract depends on the financial and technological capacity of the national oil company relative to the challenges related to the particular field development. Joint ventures and joint operating agreements are the contractual forms most common when the national oil company has the adequate capacity. Joint operation agreement is an agreement between an operator and non-operating shareholders in a license. The parties divide the costs and profits according to the percentage they hold in the license. One, usually (but not always) the company that holds the largest share is the operator and prepares and proposes programs of work and budget for the expenditure. This is the most common contract in Norway. In Malaysia, Indonesia and Nigeria joint operating contracts are used in combination with a joint venture or a production sharing contract (PSC). In these the national oil company typically holds the majority share and the majority vote on major decisions, while the major is the operator. PSCs are common in E&P activities that require substantial upfront investment and where the national oil company aspires to acquire the technological capacity but lacks the financial capacity (or its strategy is not to expose itself to such financial risk). Service contracts leave the technological responsibility and cost risk to the contractor who operates the field for a fixed fee. Finally, there are risk contracts that leave exploration and prospecting to the contractor, who sells the field to the national oil company if a commercial field is discovered.

It is not possible to draw any firm conclusions on what is the optimal contractual relation between the oil majors and the national oil company when the objective is to transfer technology and develop the national oil company's competence. It is, however, clear that joint ventures are not a good idea when investments are substantial and the national oil company is financially weak. It is also clear that the less exposed the national oil company is to financial and technological risk, the less incentives will it have to choose the lowest cost and technologically sound solutions when these are in conflict with other objectives such as increased local content. A protected state owned oil company with a mission to develop the local supply industry runs the danger of creating an inefficient upstream industry throughout the supply chain.

6.3 Industrial policy including local content

All six countries have had a policy for developing a national supply industry. The measures for increasing local content can be classified into three categories. The first is to use the process of approving a production and development plan to promote a technology for which local companies have a comparative advantage or where the production equipment has to be constructed close to the fields (e.g., large-scale concrete structures). An important consideration when such a policy is conducted is the permanent income from the field (e.g. the revenue net of costs discounted over the entire life span of the project). It may well be the case that production technologies with high initial investment costs have low operating costs and perform well in a cost perspective over the life span of the project. If the technologies with the highest projected net value are the ones for which local suppliers have a competitive advantage, there is a good reason for choosing this technology. If local technology neither has the lowest initial costs nor the lowest life-span cost, there is a trade-off between foregoing some permanent income from the field and promoting a local supply industry. If local technology is chosen under such circumstances, there is the risk that the supply industry eats from the oil wealth instead of adding value to it. Furthermore, there is a risk that it will crowd out other industries for which the country has a comparative advantage and which have larger potential for employment creation than the upstream petroleum industry and its supply industry, which is relatively capital intensive.

A second strategy for increasing local content is legislation setting a minimum local content requirement in terms of contract value, value added or employment. Alternatively regulators have required that operators purchase inputs locally if local suppliers are competitive on price, quality and delivery or that the price of the product is not more than a given percent (10-15) higher price that the lowest bidder. If the minimum level is far beyond the actual capacity of the local industry, waivers will be necessary. This may easily create a situation of bureaucratic delays of operations as applications for exemptions are being processed. It may also prepare the ground for increased corruption aiming at avoiding such delays. Furthermore, it may create a plethora of local short-lived and inefficient companies that thrives on the imperative for local content.

A local content requirement is equivalent to an import quota on the product in question. WTO members have agreed to get rid of both local content requirements and import quotas (with a few exceptions). Preference of local firms that are no more expensive than a given premium over import prices (say 10 percent) is equivalent to a tariff on similar imports. Such tariffs do not violate the WTO agreement as long as the tariff rates do not exceed Nigeria's bound rates. The reason why the international community has agreed on replacing quotas with tariffs is that the latter is more transparent and less distortive. This is a good reason also for Nigeria to consider moderate tariffs instead of local content requirements. In the end of the day they have the same effect on the competitive position of local firms, but are easier to administer and have less undesirable side effects.

The experience from local content requirement indicates that developing a local supply chain may be successful if combined with exposing the local suppliers to the discipline of market competition after a relatively short period of protection. Malaysia for example, has encouraged local content without distorting local suppliers' incentives for cost effectiveness. Lack of competition, insufficient competence and/or weak regulations on the other hand have led to high costs, brought environmental damage, and sub-standard technology. Mexico is an example of this. Brazil has to some extent developed a cost-effective and technologically sophisticated national supply chain within a protective regime. But even in Brazil protection has given way to opening up the petroleum sector to international competition and partly privatization of the national oil company in order to keep abreast with the technology frontier and develop the nation's ultra-deep fields.

Finally, measures to develop the local supply industry through R&D programs where the oil majors also contribute with funding and expertise have been employed in Norway and Malaysia in combination with one or more of the above mentioned measures. These are programs aiming at narrowing the technology gap from both ends and have been relatively successful when there is an industrial base to build on. Research from other industries suggests that supplier development programs supporting R&D, training, product development, testing and factory auditing have been successful when there is a sufficient supplier base to build on. Government can encourage such programs in several ways: providing information through listings or databases of potential local suppliers, or expenditure on supplier programs could be tax deductible under given conditions.

Research from other industries concludes that local content requirements are not very successful of developing an indigenous industrial base, but somewhat more successful in bringing in the primary foreign investors' international suppliers to the host country. We therefore suggest that local content should be defined in terms of value added in Nigeria by local staff, rather than in terms of ownership of the company performing the value added activities. In a globalized industry a local subsidiary of a multinational can be just as effective in using local inputs and developing capacity and competence in the Nigerian community as a company for which Nigerians hold a majority of the shares. This has clearly been the case in Norway and Malaysia where local content has been high and local content has been defined as value added in the host country rather than in terms of ownership of the supplier.[39] One side-effect of local content requirements identified in other industries is that such an environment is most attractive to high-cost, less efficient suppliers, since these have the lowest switching costs.

As the discussion of the supply chains in the upstream petroleum sector suggests, there probably is a case for government intervention in order to lower local industries' barriers to entry. Closely knit international supply chains combined with widespread use of framework contracts, long-term service contracts and centralized procurement may constitute a formidable barrier to entry for local suppliers. When such contracts are anti-competitive, there is a case for regulations limiting the scope and duration of the contracts and opening for more competitive practices. This does not mean that framework contracts and bundling of contracts should be banned altogether. The supply industry must have sufficient scale and scope to be efficient and a balance must be found between sufficient competition and sufficient scale and scope. It appears from a recent study by Kragha and Associates (2003) that the Nigerian supply industry is very fragmented and a majority of companies has an annual turnover that is less than the average contract of the supply industry elsewhere. A consolidation of the industry is therefore likely in a more competitive market.

Other market imperfections relate to lack of information and switching costs for the oil majors or the major contractors who already have established relationships with suppliers that provide goods and services to the multinationals globally.

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[39] The measure of local content in Norway was contractual value going to firms incorporated in Norway, and Malaysia favored companies with Bumiputra ownership.

Barriers to entry of a local origin are lack of or poor infrastructure, inefficient business licensing procedures, slow and inefficient pre-qualification and certification procedures, skills shortages and strict regulation on labor migration and lack of access to credit. These are shortcomings that increase costs of local companies enormously and these are areas where government clearly has a role to play. Focusing on providing and maintaining the necessary infrastructure, improving education and health services and having a transparent regulatory framework would help making the local supply industry more competitive and well as being useful in their own right.

Malaysia, Brazil and Indonesia have used the national oil company as an instrument for industrialization in more or less related industries. The national oil companies have ventured into petrochemicals, fertilizers, steel, transport, and in some cases totally unrelated business such as car manufacturing, financial services and hotels. This has in most cases turned out to be a financial disaster and the policy has therefore been abandoned in all countries except Malaysia, where such policies have been combined with competitive export-oriented strategies. Nigeria does not have the industrial capacity, competitive environment and the checks and balances as Malaysia had. The lessons from the other case studies and not least Nigeria's own past experience with state-owned heavy industries indicate that further experiments with channeling the oil revenues into new such ventures are unlikely to create value for the nation.

Given Nigeria's weak industrial capacity, it is finally of utmost importance to have a macroeconomic policy framework that prevents costs from escalating and the exchange rate from appreciating to a level where non-oil industries are rendered uncompetitive. It should also be born in mind that the petroleum industry is a highly cyclical industry. Promoting oil-related industries runs the danger of putting all one's eggs in one basket, making the economy even more vulnerable to the ups and downs of the global petroleum market. Therefore Nigeria should ensure that the measures it takes to increase local content in the upstream petroleum industry do not crowd out other industries.

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