Strategic Gas Plan for Nigeria

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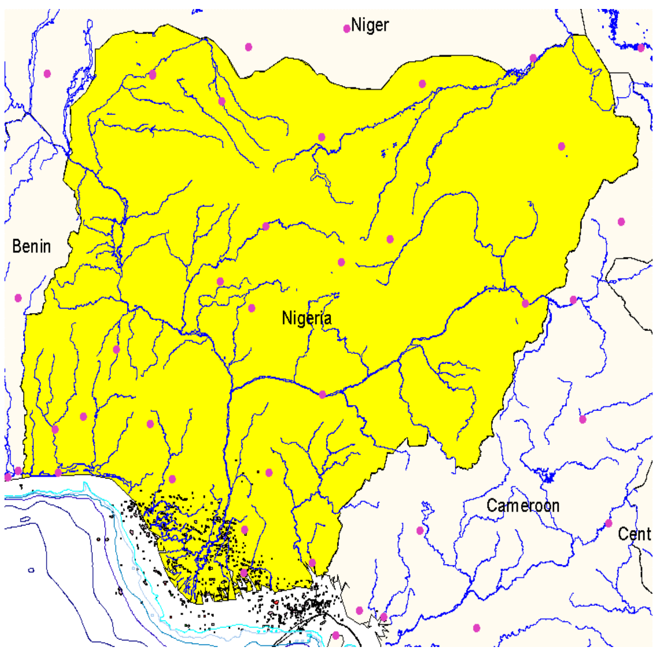

Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP)

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Acknowledgments

The study underlines the government's strategic role in promoting orderly and proactive gas development schemes and the drive for change in gas flaring reduction for better use of Nigeria's gas resources. The project was designed by Mourad Belguedj, Lead Energy Specialist at the Oil, Gas, Chemicals, and Mining Department of the World Bank who initiated this effort in response to the FGN's request and supervised the analytical work carried out by the IHS Energy Group in Washington, Houston, and London, competently lead by Charles Lucas Clements. The project is financed by The Public and Private Infrastructure Advisory Facility (PPIAF), and its publication has been possible thanks to the complementary funding by the Energy Sector Management Assistance Program (ESMAP), to which it relates directly. The study will also be useful to policymakers, industry, and practitioners, and in identifying projects, addressing key policy issues, and enriching the debate on energy sector reforms in Nigeria. The authors wish to thank all the colleagues who contributed to the review of this work and particularly Charles McPherson, Senior Advisor, Eleodoro Mayorga Alba, Lead Energy Economist, Akin Odouolowu, Lead Energy Specialist and Peter Law, Senior Energy Specialist and Adegbite Adeniji, Legal Advisor for the Team. Special thanks are also due to ESMAP, for helping with its publication and dissemination. The report was edited and formatted by a team consisting of Esther Petrilli, Carmen Pineda, and Fikerte Solomon, Oil and Gas Policy Division, Oil, Gas, Mining, and Chemicals Department, World Bank Group. Ms. Marjorie Araya from ESMAP supervised production, printing, distribution, and dissemination of this report.

Foreword

This study is an analysis and integration of seven independent proposals [1] from the International Oil Companies (IOC's) to the Government of Nigeria for gas utilization projects. The Study evaluates the elements and policy framework needed to formulate a consolidated development plan for Nigeria's gas resources through a series of viable projects. It covers the basic elements of gas supply, the uses for gas, the sequence involved in gas planning evaluations, the background issues for gas planning for Nigeria and the development of a stage 1 Gas Management Model.[2] The Study reflects the Government's strategic role in promoting orderly and proactive gas development and the drive for change in the reduction of flaring of gas resources and better utilization of gas.

The parties involved

The study was carried out by IHS Energy Group in Houston, in close cooperation with and under the supervision of the World Bank.

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[1] All project proposals from the International Oil Companies are covered under a strict confidentiality agreement

[2] The Gas Management model is based upon a dynamic supply and demand model and forms the essential core to investigate options and alternate strategies. A dynamic model an essential element in the system and should be continually updated to reflect the latest position and projections. IHS Energy has a proprietary gas planning system in which this study has been modeled.

Abbreviations and Acronyms

AG	Associated gas
AMPCO	Atlantic Methanol Production Company
API	American Petroleum Institute
CAPEX	capital expenditures
CCGT	Combined cycle gas turbine
CNG	Compressed natural gas
CPN	Chevron Producing Nigeria
DCF	Discounted cash flow
DME	Dimethyl ether
DPR	Department of Petroleum Resources
DRI	Direct reduced iron
E&P	Exploration and production
EAF	Electric arc furnace
EIA	Environmental impact assessment
ELPS	Escravos to Lagos Pipeline System
EPA	Environmental Protection Agency
EPZ	Export processing zone
ESMAP	Energy Sector Management Assistance Programme
EU	European Union
FCC	Fluid catalytic cracker
FGN	Federal Government of Nigeria
FLNG	Floating liquefied natural gas
FOB	Free on board (price)
FPSO	Floating, production, storage, and off-loading
FSU	Former Soviet Union
GDP	Gross Domestic Product
GEPS	Global exploration & Production service
GOR	Gas-oil ratios
GTL	Gas-to-liquids
HBI	Hot briquetted iron
HDPE	High density polyethylene
HSE	Health, safety, and environment
ICB	International competitive bidding

IDP	Industrial development plan
IHSE	IHS Energy Group (consultant)
IOC	International Oil Company
IPP	Independent power producers
IRR	Internal rate of return
JV	Joint venture
LDPE	Low density polyethylene
LME	London Metals Exchange
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
Midrex	A direct reduction process, developed by the Midrex Corporation
MIRR	Modified internal rate of return
MPN	ExxonMobil Producing Nigeria
MTBE	methyl tertiary butyl ether
MTO	methanol-to-olefins
NAG	Nonassociated gas
NGL	Natural gas liquid
NNPC	Nigerian National Petroleum Company
NPV	Net present value
OECD	Organisation for Economic Co-operation and Development
OPEC	Oil Producing and Exporting Countriec
OPEX	Operating expenditures
PEPS	Petroleum economics and policy solutions
PI	Profitability index
PP	Payback period
PSA	Production sharing agreement
PSC	Production sharing contract
RFG	Reformulated gasoline
RoR	Rate of return
SPDC	Shell Petroleum Development Company of Nigeria
Syncrude	Synthetic crude oil
Syngas	Synthesis gas (in natural gas reforming)
TAME	Tertiary amyl methyl ether
UAE	United Arab Emirates
UNDP	United National Development Programme

VAT	Value-added tax
VRA	Volta River Authority
WAGP	West African Gas Pipeline Project
WND	West Niger Delta
WTO	World Trade Organisation

Units of Measure

Bcf	billion cubic feet
Bcm	billion cubic metres
Bbl	barrel, barrels
Bn	billion
Bpd	barrels per day
GJ	gigajoule
GWh	gigawatthour
Kcal	kilocalorie
Kg	kilograms
Km	kilometres
km^2	square kilometre
KW	kilowatt
KWh	kilowatthour
MmBTU	million BTU (British Thermal Units)
Mmcfd	million cubic feet per day
Mmcmy	million cubic meters per year
Mmtpy	million metric tons per year
Mtpy	thousand metric tons per year
MW	megawatt
MWh	megawatt hour
Scf	standard cubic feet
Tcf	trillion cubic feet
Tcm	trillion cubic meters
Tj	terajoules
Toe	ton oil equivalent
Tpd	metric tons per day
Tpy	metric tons per year
TWh	terawatt hour
USD	US dollars

Conversion Factors

Energy, Work, and Heat

			To			
	J	*KJ*	*Btu*	*kcal*	*MJ*	*kWh*
From			***Multiply by***			
J	1	10^{-3}	9.5×10^{-4}	2.4×10^{-4}	10^{-6}	2.8×10^{-7}
KJ	1000	1	0.95	0.24	10^{-3}	2.8×10^{-4}
Btu	1065	1.055	1	0.252	1.055×10^{-3}	2.93×10^{-4}
kcal	4187	4.19	3.97	1	4.19×10^{-3}	1.16×10^{-3}
MJ	10^{6}	1000	947.8	238.8	1	0.28
kWh	3.6×10^{6}	3600	3412	859.8	3.6	1

1 Therm = 100,000 BTU

Volume

			To			
	Litres	*US Gal*	*UK gal*	*ft^3*	*m^3*	*barrel*
From			***Multiply by***			
liters	1	0.264	0.22	0.0353	1×10^{-3}	6.29×10^{-3}
US Gal	3.785	1	0.833	0.134	3.785×10^{-3}	0.0238
UK gal	4.55	1.2	1	0.16	4.55×10^{-3}	0.0286
ft^3	28.32	7.48	6.23	1	0.0283	0.178
m^3	1000	264.2	220.0	35.3	1	6.29
barrel	159	42	35	5.61	0.159	1

Crude Oil

		To		
	Metric tons	*kiloliters*	*barrels*	*US gallons*
From		***Multiply by***		
Metric tons	1	1.165	7.33	308
Kilolitres	0.86	1	6.29	264
Barrels	0.136	0.159	1	42
US Gallons	0.00325	0.0038	0.0238	1

Products

	To convert			
	Barrels to metric tons	*Metric tons to barrels*	*kiloliters to metric*	*Metric tons to kilolitres*
	Multiply by			
LPG	0.086	11.6	0.542	1.844
Gasoline	0.118	8.5	0.740	1.351
Kerosine	0.128	7.8	0.806	1.240
Gas oil/diesel	0.133	7.5	0.839	1.192
Fuel oil	0.149	6.7	0.939	1.065

Executive Summary

1. Nigeria is one of the world's best endowed and largest oil producing countries and it has an equally great amount of undeveloped gas resources in reserve. If oil has played a key role in helping develop Nigeria's economy, gas has yet to contribute its share. Instead, Nigeria is known as one of largest gas flaring countries in the world. In response, the Federal Government of Nigeria (FGN) has instructed all oil producers that gas flaring must cease by 2008 and has enlisted the World Bank to investigate the ways and means to help achieve this ambitious goal. The Oil and Gas Policy Division of the World Bank has been entrusted with the mission of carrying out a study to define (i) a realistic strategy and (ii) a plan of action to meet this goal, by reviewing first the several gas development plans that each oil company had prepared.

2. This project is the first comprehensive analysis and integration of corporate proposals[3] to develop gas resources prepared by the seven largest International Oil Companies (IOCs) operating in Nigeria, along with NNPC, the Nigeria National Petroleum Corporation. It integrates these proposals into one "Gas Master Plan" to develop a clearer gas strategy of viable and complementary gas use projects. The study evaluates, the resource base of the country and suggests all possible gas use options available in the domestic as well as the international market. The domestic power sector and export-oriented projects will lead this effort. The study also identifies which institutional changes and new policy framework are needed to formulate and implement a consolidated development plan for Nigeria's gas resources. It covers the basic elements of gas supply, gas uses, the sequence involved in gas planning evaluations, the background issues for gas planning for Nigeria, and the development of a dynamic gas management model.[4]

3. Nigeria is blessed with a large hydrocarbon resource endowment, both in absolute terms and relative to other petroleum-producing countries. This resource is of growing benefit, as gas has become, and continues to be, the fuel of choice in developed as well as developing countries. This in turn should allow Nigeria to develop its own internal market in a way commensurate with is resource base. It could also help it become a solid regional, as well as an international, gas supplier if this development is properly planned and administered.

4. In recent years it has become clear that Nigeria, already well known as a major quality oil producer, is just as much or perhaps more of a gas than an oil province.

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[4] The Gas Management model is based upon a dynamic supply and demand model and forms the essential core to investigate options and alternate strategies. A dynamic model an essential element in the system and should be continually updated to reflect the latest position and projections. IHS Energy has a proprietary gas planning systems in which this study has been modeled.

Gas reserves found while looking for oil, are conservatively estimated at more than 150 trillion cubic feet (tcf). The reserves represent over 5 percent of the world's total and the undiscovered potential is considered to be just as large. Compared to countries with similar or even smaller gas resources, Nigeria is only consuming a fraction of what it reasonably could, especially to meet its internal demand for energy and is therefore only on the first step of the gas development ladder.

5. The study found that if this resource base is properly developed and integrated into a realistic national strategy, supported by a sound applicable gas master plan, Nigeria has the necessary means to enable a potentially skyrocketing growth rate. The FGN has thus asked the World Bank to look at each IOC's gas development proposal and project, identify and mitigate possible duplication, and address preference for the more challenging route of building an integrated domestic gas and power market beside regional and international gas export projects. This will require that the FGN take full control of this process and manage it for results to realize all the expectable benefits.

6. The study has determined the need for a gas master plan to facilitate orderly sector development, give guidance to the IOCs as to what the desired goals are to target, and thus gain the FGN's acceptance and support. This integrated approach also enables maximization of the potential for secondary and tertiary development benefits in Nigeria, compounding the potential growth in the country. The basis for this master plan is that it primarily seeks to:

- Eliminate the wasteful practice of gas flaring in the short term but in any case by 2008
- Allow the refurbishment and more rapid development of the crippled power sector
- Make gas available at commercial and affordable prices to local markets, yet reflecting eventually its full economic value
- Widen the availability of gas to more of Nigeria's underserved regions
- Promote gas use investment to replace imported products (or release them for export)
- Allow for the widespread distribution of gas, LPGs, or even CNG to more remote areas, regionally and internationally
- Ensure and enhance the production of oil and LPG recovery, wherever possible
- Ensure supply continuity to meet major existing and future contracts
- Store gas for load balance and future use when markets or contracts are not ready/available
- Formulate a strategy that adds value for all parties and encourages beneficial gas usage both domestically and/or through capture and, where relevant, savings of foreign exchange
- Develop an integral industry development plan (relate options to a monetary benefit to Nigeria)
- Ease and facilitate the decision process to speed up the approval process

7. Up to now, Nigeria has only barely begun to benefit from its gas. Current production of 4.6 bcfd is largely wasted with nearly 55 percent or close to 2.5 bcfd being flared. The gross monetary value of this gas (equivalent to the total annual power generation of Sub-Saharan Africa) is on the order of US$2.5 billion per year. The adverse global environmental impact of Nigeria's gas flaring is on the same scale, resulting in roughly 70 million metric tons of CO_2 emissions per year. It is a large contributor to local and regional pollution as well as the emissions forming a substantial proportion of worldwide Green House Gas (GHG). This issue goes well beyond Nigeria's borders and its government wants to address it seriously.

8. Failure to harness its gas resources has had other negative consequences for Nigeria. This is particularly true in the power sector where unreliable or nonexistent gas supplies have contributed to a major ongoing crisis in power deliveries, crippling the economy for years, and seriously inhibiting new investment. Through either the power sector or direct supply to industry, natural gas has the potential to fuel rapid growth in Nigeria's nonoil economy, which is now lagging. A fully integrated approach to gas and power development will be the principal driver for fundamental economic stability and growth, enhancing employment opportunities. Further, once the basic pipeline transmission and distribution infrastructure is in place, gas represents an attractive possibility to provide disadvantaged rural and urban areas with access to a modern energy source, based on small-scale gas usage or gas turbine technology.

9. It is against this background that the FGN has requested World Bank funding to assist in assessing and recommending an appropriate national gas strategy, viable market structures, and in identifying options available to enhance private sector participation in rehabilitation and development of the downstream gas sector in Nigeria.

10. The study also determined that, as in most gas-producing countries, the expansion of domestic gas use would also benefit not only the global environment through reduced flaring but the local and regional environment as well through replacement of fuel oil, wood, and biomass, which are depleting rapidly, especially in the North causing desertification and general destruction of a sustainable agricultural environment. Furthermore, capturing all presently flared gas would greatly improve the quality of life for the wider population in the Niger Delta area.

11. With the exception of the Lagos metropolitan area, the entire country is badly underserved in terms of gas distribution, and most manufacturing and industrial activities have been using liquid fuels in lieu of gas. In response to this situation, over the past several years the FGN has paid more attention to gas issues. Key objectives for gas now include:

- Ending the massive gas flaring by 2008
- Capturing the economic value of this flared associated gas and of undeveloped gas
- Enhancing the quality of life contribution to the wider population

12. The obstacles to moving from generally expressed objectives to project implementation are many. The study found that the most important issues for the FGN to address include:

- A lack of a clearly stated, long-term "vision" for the sector and realistic policy goals to promote and facilitate gas use.
- A lack of a clear gas sector development strategy and implementation plan, covering both policy directions and integrated investment priorities.
- A lack of adequate legal, fiscal, regulatory, and contractual frameworks and institutions that are required to accommodate new investment proposals from international investors while protecting Nigeria's interests.
- A lack of capacity to evaluate, correlate, and prioritize proposals received from the private sector, together with growing reservations about the structure of current fiscal incentives.
- An inadequate or nonexistent infrastructure for the commercialization of gas in the Nigerian domestic market.

13. It is both relevant and important to recognize that this escalation in interest in gas sector reform is occurring in the context of a larger, economywide reform program, emphasizing a diminished role for the state in commercial operations, enhanced competition, and increased private sector participation especially from the major oil and gas companies, first upstream and increasingly downstream.

14. This study identified the following action sequence as necessary for success:

- Solidify and ensure backing, legislation, and funding for current, immediate-use projects, first in the power sector refurbishment and in independent power producer (IPP) development and second Nigeria LNG train 4 and 5 development.
- Instigate the necessary fiscal concessions and penalties to encourage good corporate compliance through the development of a dynamic gas management model to identify and match the future supply and demand, and allow the consequential reinjection/storage of gas for later use, where feasible, in a practical but short timescale.
- Develop coordinated fiscal incentives and a legislative framework to promote “initiation” projects that fit the plan to diversify into different low-risk market sectors and/or develop local benefits.
- Ensure that subsequent projects meet the common goal of providing a minimum critical plant size to meet the long-term goals (where possible develop one large project instead of two small projects) and provide for some element/portion of common access to the smaller or domestic players at a regulated price.

15. The study recommends that in order to develop a solid basis upon which a master plan can be prepared, the resource base remaining to be produced must first be

known. Within the context of the current Nigerian industry, the gas resources must be split into the following categories:

- Resources currently under production or associated with developments in place
- Resources presently under development and discovered (with proven and probable reserves)
- Resources likely to be found given the Nigerian oil and gas basin is relatively unexplored or undeveloped

16. The starting point for establishing the alternative uses and future development plans that best fit the flaring cessation objective is determining where current and projected gas production will occur.

17. Where no immediate utilization method can be found, reinjection or storage of currently flared gas should be promoted to save the gas for later monetization and designed to allow later export. Reinjection allows this resource to be produced later in the life of the field, when the reservoirs can be depleted once the maximum oil recovery has been attained. For planning purposes, it is useful to have a portion of the reserves recoverable in this way; during the blowdown period, the field will behave like a nonassociated gas (NAG) field, as it will be free from oil production although potentially rich in Natural Gas Liquids (NGLs). Also the current issue facing Nigeria is that there is too much associated gas for immediate use, but when the utilization projects and internal usage have grown, then this resource base will be balanced and thus available for use.

18. The challenge facing the operators is to justify adding reinjection facilities if no outlet is available yet. But when a stable gas market price is established, operators have a basis to factor in their economics, especially if tax holidays or credits are given to put in compression early (ultimately to be used for sales gas), then reinjection can be realized early. The tax credit can be returned to the FGN, minus any reasonable associated costs, when the operator finally sells his gas to the market. Given this environment, then a mandate to stop flaring can be realized. Exceptions then need a full justification and clear permission for a limited period. Tax holidays or grants from the Carbon Credit Mechanism, Global Environmental Facility (GEF), and the like could be brought into play to enhance these incentives.

19. The study confirms that future associated gas (AG) production will be controlled by the oil production policy in place. The reserves from the fields currently under production will be depleted using typical industry norms for declines and production-to-reserves ratios. Additional fields will have to be brought onstream to maintain production or to increase it further. These additional fields will further accentuate the problem of AG usage. The projections for each area or field are then entered into a dynamic gas management model to enable a range of outcomes to be visualized.

20. The role of the government is to provide a roadmap to guide the direction of development desired by the FGN and proceed by enacting the legislation and fiscal

framework that allows it to happen and rewards those companies that take risks in the initial building phase. If the FGN fails to accomplish these activities, then investors will take it that this issue is unimportant to the FGN and does not require FGN focus.

21. A thorough review of unmet energy demand by sector, helped define priority areas where gas would be absorbed in volumes large enough, to justify the heavy investments in gathering, transmission and distribution pipeline networks required for a balanced market growth. The study found that large users can essentially be classified into the following five categories, by order of consideration and ultimate consumption:

- Gas to Power
- Gas to LNG plants
- Gas to GTL
- Gas to pipelines for export
- Gas to chemicals, refineries, and other uses in the domestic, commercial, and industrial sectors of the economy.

22. Developing these sectors will require particular attention to the following:

- Building a framework or backbone upon which other options become possible (in principle this keeps the most options available as market conditions change over time).
- Establishing the driving principles (if the principle is to maximize domestic gas use, ensure that the first set of projects promote domestic usage until this demand is met) before moving forward with any other specific project(s).
- Spreading the risk in project selection.
- Not selecting projects based on their projected Rate of Return or net present value (NPV) alone; a full risk assessment and sensitivity to all areas and its ability to integrate with complete gas chains, should create a more balanced approach between domestic, regional, and international dimension of development.
- Working out all the peripheral benefits and opportunities for additional beneficial fallout, when considering a project.
- Developing an implementation plan that drives other industrial benefits, when a series of projects is decided upon.

23. Based upon the government policy of reorganizing the power sector to resemble the current international framework, that is a split into a generation sector, a transmission sector, and a distribution and supply sector, the ability to attract and regenerate the sector becomes possible. A new and growing sector will undoubtedly emerge as soon as a rigorous legal framework can be finalized to attract foreign direct investment (FDI) and private sector participation. This reorganization will enhance the prospect of a viable West African power pool and transmission system for neighboring countries, now under study in the World Bank, where gas, in essence, would be exported as electricity.

24. In addition to the major system, promoting the policy of using local LPG can broaden the benefits or piped-gas-based microturbines in the more remote regions, in parallel to major power hubs needed across much of the country. This option may both enhance and speed up the recovery and development of Nigeria's LPG and power sector as it prepares the future buyers to expect and manage to pay sustainable prices in the future.

25. The major IOCs have submitted a number of gas use export projects for consideration by NNPC and the FGN. These proposals have been reviewed in this study and analyzed in the context of creating an overall gas master plan.

26. In addition to these proposals a coastal international West African power and transmission system is proposed to balance the gas development. This proposal is not considered further here, as it is the subject of a separate study in the World Bank.

27. Nigeria's capability to produce LNG volumes under consideration is not in doubt. This volume would be in addition to supplying all of Nigeria's potential domestic needs in power, chemicals, LPG, and other sectors. The LNG plants, however, will not provide the infrastructure needed to promote the domestic market, except for LPG recovery and depending on the timing of the sales contracts, they do little to move the flare down policy forward in the near term.

28. Nigeria has a current overriding need to meet its flare down targets. Its gas-to-liquids (GTLs) potential to consume large amounts of gas on the one hand and produce useful and immediate products on the other far outweighs the concerns over immature technology. This status in maturity actually offers Nigeria an opportunity. In return for taking the risk to create a worldscale plant, it would be reasonable for Nigeria to take a stake in the chosen technology, generating a return in future years.

29. Nigeria is fortunate to have such a large and balanced reserves base. The issues facing the FGN are mostly time sensitive, and as such, solutions are needed to provide realistic plans to achieve a self-imposed 2008 flare down target and to implement a set of building blocks that achieve maximum overall long-term benefit to Nigeria. Key institutional and regulatory reform is needed to allow progress to be made, a program with strict timelines should be put in place as soon as is practical to ensure the sustainability of the proposed solutions herein.

30. In developing the solution for gas, the first step is to set the liquids production rate (oil and condensate) that meets FGN policy. Depending upon the ability and desire to keep these streams separate, the overall production can be manipulated to stay within reasonable bounds with respect to Nigeria's OPEC quota. However, there is a cost and time penalty. This goal becomes easier over time as more dedicated gas and condensate facilities are built.

31. Moving forward and putting the first steps together to decide which projects most effectively benefit the Nigerian people and economy, the study came to the following logical conclusions, that the first and most obvious priority is to reset the

foundation in the power sector. The refocusing of the National Electric Power Authority (NEPA) and privatization of generation and/or final distribution are, undoubtedly, better managed privately or at least in public-private partnership. The use of private, diesel-fired power generation by large numbers of the population and businesses, is a clear indication of the need for stabilization of the power supply and the ability of the population to pay for a service that is reliable at economically sustainable rates.

32. Government policies for high grading of projects can then be based upon a number of strategic objectives, particularly the following:

- Needing more power to meet the demands of normal population growth
- Promoting economic growth
- Increasing exports up to OPEC quotas
- Reducing flaring
- Generating and saving foreign exchange
- Diversifying the industry and increasing nonoil exports
- Creating employment
- Creating downstream added value (to domestic resources)
- Acquiring foreign technology
- Reducing in import dependency
- Attracting FDI in all sectors

33. To implement the process, government policy initiatives will be required to address the institutional framework needed for this gas development, including some, if not all, of the following elements:

- Developing policies via a policy and regulation framework
- Developing a project approvals procedure that is transparent and consistent, with a purpose-designed vehicle for good coordination (that is, a one-stop shop)
- Developing various framework elements (legal, fiscal, financial, and so forth)
- Promoting development projects, upstream and downstream, for domestic benefit
- Providing and applying a competitive investment climate
- Promoting and attracting private investors (including FDI)
- Fostering collaboration between upstream and downstream investors for the provision of infrastructure and gas markets
- Facilitating the establishment of downstream industries
- Determining the extent of government participation in investment in downstream ventures
- Developing human resources and training programs
- Defining a time bound implementation plan

34. While the government defines the policy with specific gas legislation, such as a Gas Code, a Gas Master Plan/Industrial Development Plan and a Gas Planning Methodology should be put in place. Most importantly, each project/utilization should be subjected to a rigorous standard screening and integration process early in the evaluation stage. In order to succeed, there should be a plan of action in time, devised on the basis of the recommendations above to:

- Give absolute priority to gas-to-power projects as they absorb much excess gas and help rapidly rebuild the deficient capacity in the Production side of the power equation.
- This would, in turn, generate both (a) an integrated gas gathering system upstream, and (b) a national network of gas transmission and distribution pipelines to the main consuming markets downstream, including Liquid Petroleum Gas (LPG). Once the proposed basic gathering and transmission infrastructure is in place, the availability of gas in most markets will "snowball" into substituting for less efficient and usually more expensive liquid fuels, and release those for the transport sector or for export.

35. In conclusion, as with most gas-rich countries, which have succeeded in developing a sustainable gas industry, the development of a sound and balanced gas sector in Nigeria must be based, first, on a solid domestic market, driven by Power and Industry, aimed at absorbing at least half of the available gas production and second, on exports, which will absorb the rest, as and where needed.

1

Scope of Work

Current Situation in Nigeria

1.1 The Strategic Gas Plan described here seeks to build upon the recent or ongoing initiatives in the gas or related sectors in Nigeria to assess and select the best market structure and public private infrastructure (PPI) options available to the downstream gas industry.

1.2 These previous initiatives include the following:

- The World Bank Group's Nigerian Petroleum Sector Review (PSR) completed in 2000 outlined in broad terms key gas sector issues and recommendations. The Nigerian Oil and Gas Reform Implementation Committee (OGIC) endorsed the findings of the review and, in particular, the need for a study of the kind described here.
- Private sector investors have prepared studies of gas sector development, but these are largely technical and focus on projects, rather than an encompassing strategy or investment framework. These private sector inputs would complement rather than replace the proposed study.
- The Nigerian authorities and the World Bank are preparing a power sector reform project, which will be funded out of a World Bank loan. As noted above, the gas and power sectors are closely linked and activity under this proposed activity would be closely coordinated with work on power reform.

1.3 Furthermore, this study seeks to identify legal, fiscal, and regulatory reforms that are necessary to promote competition and attract private investors to the downstream sector. The FGN has assigned a very high priority to the preparation of a natural gas strategy to end massive flaring and maximize recovery of the economic value of Nigeria's gas through the promotion of export projects and development of the domestic gas market.

1.4 The foreign and domestic private sectors are similarly anxious to see a strategy put in place that would provide a framework for investment in gas. To that end, the FGN requested World Bank support to undertake a critical review of its gas sector and to make recommendations for the rapid design and implementation of a viable overall Strategic Gas Plan (SGP).

1.5 The SGP is derived from seven proposals received by the FGN from International Oil Companies operating in Nigeria. The following proposals were received by the World Bank and the Consultant:

Brass LNG Downstream Project
ExxonMobil Gas Project (Including electronic format)
AGIP-NAOC JV Strategy on meeting deadline on gas flaring
TotalFinaElf Gas and LNG development Project
NNPC/CNL JV Gas Utilization Strategy
Statoil/NNPC (ChevronTexaco) LNG export Projects
Shell Nigeria Gas Development Projects

1.6 This study is an analysis and integration of these projects, including essential inputs from IHS Energy Group's database and experience to design a dynamic SGP, which would fit with a National Gas Strategy aimed at the medium and long term.

1.7 As background information, the World Bank provided its recent mission's views and evaluation of the FGN's latest moves to see an effective end to gas flaring by 2008. To that end, the mission recommended first that all associated gas must either be reinjected in producing and/or in depleted reservoirs if no immediate outlet is available for it. It must also be monetized by providing it for small gas uses in urban and peri-urban commercial and diverse manufacturing and industrial processes. It also has a natural market in the chemical, petrochemical, and other energy intensive industries, including those which can be converted from liquid fuels to using natural gas. LPG extraction from liquid-rich associated gas has a niche of its own, both in the domestic as well as in the export market, including in the form of higher value butane, propane, isobutane, and so forth. The power sector also stands to become one of the largest gas users and could even contribute to exports by way of interconnection to the grid of power deficit neighboring countries. Finally recovered associated gas could contribute to diversify and increase foreign exchange earnings by way of exports as LNG, LPG, power or piped gas. This will require wide ranging and encompassing sector reform aimed at defining a clear and realistic gas strategy that the industry could adhere to in order to achieve gas-flaring elimination by 2008. This will include a full gas utilization plan as well as a clear "ban" on any new oil field development that does not respect the announced FGN goal of zero flaring for 2008. An independent institution, with no vested interests, will need to monitor the compliance of any ban and review on a case-by-case basis any variations. For instance, in the United Kingdom this is carried out by the Health and Safety Committee, which has the power to shut down any facility.

1.8 The FGN provided the consultant with paper copies of seven gas development plans (some in PowerPoint format) submitted by international oil companies operating in Nigeria. The consultant reviewed these documents and found them essentially to be a response to companies' corporate strategies to deal with their own associated gas rather than fitting into a national vision.

1.9 The oil company proposals are, on the whole, not integrated into one another or into a national gas plan. Gas-to-power which should emerge as the largest potential gas consumer, sometimes was not even mentioned as an option, because it is adversely affected by the issues of generation, billing, and collection which the Power Parastatal NEPA seems unable to master.

1.10 NGL extraction including LPGs fractionation for domestic, as well as international markets, were mentioned but have not developed to their true potential, at the dimension of Nigeria's capacity to produce them from associated gas streams. It also seems that industry is seeking clearer guidance from the FGN in meeting the 2008 zero flaring deadline and it is trying to "guess-out" true FGN intentions as meaning business this time or just another down the road deadline that this government would not live to see. To discard this perceived weakness in the government's message, a clear announcement should be made that it will no longer approve, as of today, any oil field development that includes any gas flaring possibility or does not include associated gas processing and monetizing.

1.11 This study identifies the need for the FGN to design and propose to the industry its gas strategy and an integrated and comprehensive National Policy for the gas sector in the earliest possible timescale. It is certainly realistic to have final recommendations for implementing this by yearend.

Driving Forces for Change in Nigeria

1.12 In 2000 Nigerian gas production amounted to some 4.6 Bcfd with some 55 percent being flared and the balance split between reinjection, NLNG feedstock, internal fuel usage, and a small percentage marketed as LPG.

1.13 There are a number of general factors driving the need to reduce the gas volumes being flared:

- flaring represents a significant economic loss (lost opportunity value estimated at some US$2.5 billion, based on LNG values)
- combustion products make a major contribution to environmental damage through production of greenhouse gases
- political scrutiny increases leading to antiflaring policies

1.14 A growing number of the large multinational energy companies are instituting policies to reduce or halt flaring. Some individual organizations are pushing the development of gas conversion technologies.

1.15 International organizations, such as the World Bank, the International Monetary Fund, and United Nations view gas development and consumption in emerging nations as a means of spurring employment while reducing deforestation and local air pollution.

Barriers to Development in Nigeria

1.16 Nigeria’s natural gas resources exploitation is limited by the following:

- resources are in a remote location (in bulk market terms)
- the major potential market of power is in a state of stagnation
- limited infrastructure to transport the gas beyond the current locations of Lagos and Port Harcourt
- high levels of initial investment required

Unlike oil, gas can rarely be used immediately after production. Consumption of each increment of gas production requires a large initial expenditure on a complete network of production, transmission, and distribution facilities.

- poor investment climate due to lack of a proper consistent legal, fiscal, and approval framework.

1.17 The realization of further gas projects in Nigeria will have to overcome these general barriers to development together with some specific Nigerian difficulties. In addition, domestic gas demand growth will depend on economic growth and stability.

2

The National Gas Strategy

General

2.1 Nigeria is blessed with a large hydrocarbon resource endowment, both in absolute terms and relative to other petroleum-producing countries. This gift is of growing benefit, as gas has become, and continues to be, the fuel of choice in developed as well as developing countries, allowing Nigeria to become a solid regional as well as an international gas supplier if its development is properly planned and administered.

2.2 In recent years it has become clear that Nigeria, already well known as a major quality oil producer, is just as much or perhaps more of a gas than oil province. Gas reserves found while looking for oil, are conservatively estimated at more than 150 trillion cubic feet (TCF). They represent over 5 percent of the world's total and the undiscovered potential is considered to be as big again. Compared to countries with similar or even smaller gas resources endowment, Nigeria is only on the first step of the growth ladder of gas development.

2.3 If this resource base is properly developed and integrated into a realistic national strategy supported by a sound implementable plan, Nigeria has the necessary stepping-stones to enable a potentially skyrocketing growth rate. Failure of the Federal Government of Nigeria (FGN) to take control and drive this process will result in a fraction of the potential benefit being realized. Just accepting the status quo and looking at each International Oil Companies (IOCs) proposal in isolation potentially results in undersized (and hence nonoptimum) projects, duplication, and a preference for export-only projects rather than the more challenging route of integral domestic, regional and international developments. It should be noted that in reality all the gas produced belongs to the Nigerian Government and thus it is the FGN that should decide what is the best coordinated common usage for that gas.

2.4 A **National Gas Strategy** can facilitate an orderly development of the sector, give guidance to the IOCs as to what the desired goals are and thus gain the Federal Government of Nigeria's (FGN's) acceptance and support. This integrated approach also enables maximization of the potential for secondary and tertiary development benefits in Nigeria, compounding the potential growth in country. The basis for this master plan is that it primarily seeks to:

- Eliminate the wasteful practice of gas flaring in the short term
- Allow the rapid development and refurbishment of the crippled power sector
- Make gas available at commercial and affordable prices to local markets
- Widen the availability of gas to more of Nigeria's underserved regions
- Store gas for load balance and future use when markets or contracts are not ready/available
- Where commercial, promote gas utilization investment to replace imported products (or release them for export)
- Allow for the widespread distribution of gas, LPGs or even CNG to more remote areas, regionally and internationally
- Ensure and enhance the production of oil and NGL recovery, where possible
- Ensure continuity of supply to meet major existing and future contracts
- Formulate a strategy that adds value for all parties and encourages beneficial gas usage both domestically and/or through capture and, where relevant, savings of foreign exchange
- Develop an integral industry development plan (relate options to a monetary benefit to Nigeria)
- Ease and facilitate the decision process to speed up the approval process

2.5 Up to now, Nigeria has only barely begun to benefit from its gas. Current production of 4.6 bcfd is largely wasted with nearly 55 percent or close to 2.5 bcfd being flared. The gross monetary value of this gas is in the order of US$2.5 billion per year to the economy, amounting to US$50 billion over 20 years. The adverse global environmental impact of Nigeria's gas flaring is on the same scale, resulting in roughly 70 million metric tons of CO_2 emissions per year. It is a large contributor to local and regional pollution as well as the emissions being a substantial proportion of worldwide Green House Gas (GHG). This issue goes well beyond Nigeria's borders and its Government is addressing it seriously.

2.6 Failure to harness its gas resources has had other negative consequences for Nigeria. This is particularly true in the power sector where unreliable or nonexistent gas supplies have contributed to a major ongoing crisis in power deliveries, crippling the economy for years and seriously inhibiting new investment. Through either the power sector or direct supply to industry, natural gas has the potential to fuel rapid growth in Nigeria's nonoil economy, which is now lagging. A fully integrated approach to gas and power development will be the principal hope for fundamental economic stability and growth in employment opportunities. Further, once the basic infrastructure is in place, gas represents an attractive possibility to provide disadvantaged rural and urban areas with access to a modern energy source, based on small-scale gas usage or gas turbine technology.

2.7 Finally, an expansion of domestic gas use would benefit not only the global environment through reduced flaring, but also the local and regional environment through replacement of fuel oil, wood, and biomass, which are depleting rapidly, especially in the North causing desertification and a general destruction of a sustainable agricultural environment. Furthermore the correct implementation would greatly assist the wider population in the Niger Delta area.

Government Policy

2.8 With the exception of the Lagos metropolitan area, the entire country is badly underserved in terms of gas distribution, and entire sectors have been using other fuels in lieu of available gas. In response to this situation, over the past several years the Federal Government of Nigeria (FGN) has paid more attention to gas issues. Key objectives for gas now include:

- An end to the massive flaring of gas by 2008
- Capture of the economic value of this flared gas and of unexploited gas
- Enhance the quality of life contribution to the wider population

2.9 Much of Nigeria's current gas production is associated gas but larger reserves of nonassociated gas remain unexploited. A more rapid development of domestic and regional gas markets, especially but not exclusively for power, and improved responsiveness to global and local environmental issues is clearly sought by the FGN. In pursuit of these objectives, Nigeria announced a 2008 target to totally eliminate gas flaring and at the same time introduced a series of fiscal incentives for the development and commercialization of gas.

2.10 These measures have attracted a broad range of private sector investment proposals, including more liquefied natural gas (LNG) projects, national, regional, and international pipelines dedicated to increasing domestic access to gas but also promoting gas export projects, gas-to-liquids (GTL) plants, power generation projects and gas consuming industrial projects. Only one such project has gone ahead, the multibillion dollar Nigeria LNG project, which had been under negotiation for over 20 years before the recent interest in gas and is subject to a very special regime.

2.11 The obstacles to moving from generally expressed objectives to project implementation are many. Among the most important issues for the FGN to address have been:

- A lack of clearly stated, long-term "vision" for the sector and realistic policy goals to promote and facilitate gas use
- An inadequate or nonexistent infrastructure for the commercialization of gas
- A lack of a clear gas sector development strategy and implementation plan, covering both policy directions and integrated investment priorities
- A lack of capacity to evaluate, correlate, and prioritize proposals received from the private sector, together with growing reservations about the structure of current fiscal incentives
- A lack of adequate legal, fiscal, regulatory, and contractual frameworks and institutions required to accommodate new investment proposals from international investors while simultaneously protecting Nigeria's interests

2.12 It is relevant and important to recognize that this escalation in interest in gas sector reform is occurring in the context of a larger, economywide reform program, emphasizing a diminished role for the state in commercial operations, enhanced competition, and increased private sector participation especially from the major oil and gas companies.

2.13 It is against the above background that the FGN has requested World Bank funding to assist in assessing and recommending an appropriate national gas strategy, viable market structures, and identifying options available to enhance private sector participation in rehabilitation and development of the downstream gas sector in Nigeria.

2.14 This study identifies the following sequence of actions as necessary for success:

- Solidify and ensure backing, legislation, and funding for current, immediate use projects; first, in the power sector refurbishment and in independent power producer (IPP) development and second, NLNG train 4 and 5 development.
- Instigate the necessary fiscal concessions and penalties to encourage good corporate compliance through the development of a dynamic gas management model to identify and match the future supply and demand, and allow the consequential reinjection/storage of gas for later use, where feasible, in a practical but short timescale.

- Develop coordinated fiscal incentives and a legislative framework to promote the first project in each favored sector that fit the plan to diversify into different low-risk market sectors and/or develop local benefits. For it is these "first mover" investors that are taking the risk as in the case of NLNG who should be rewarded with return commensurate for the level of risk taken.
- Ensure that subsequent projects meet the common goal of providing a minimum critical plant size to meet the long-term goals (where possible develop one large project instead of two small projects) and provide for some element/portion of common access to the smaller or domestic players at a regulated price.

2.15 The fiscal incentives should be specific to different sectors and reward "initiation project" stakeholders for their risk exposure. Subsequent projects, in the same sector, should have a corresponding lower concession, which corresponds to the lower risk. It is thus reasonable and advantageous to provide structured incentives that are holiday, time or rate of return dependent, rather than blanket concessions.

Resources

Current Oil and Gas Reserves

2.16 Oil and gas reserves data used in this report are from the IHS Energy Group's proprietary IRIS21 E&P database.

2.17 The Niger Delta Basin is primarily an oil province with original proven plus probable oil and condensate reserves found to date of 55 billion barrels. This compares to gas reserves found to date of 32 billion barrels oil equivalent (194 Tcf). four percent of these reserves lie in Cameroon's offshore waters.

2.18 More important than original reserves are the remaining and yet-to-find gas reserves, as this is the starting point for a national gas strategy. These resources are discussed in the context of the following categories:

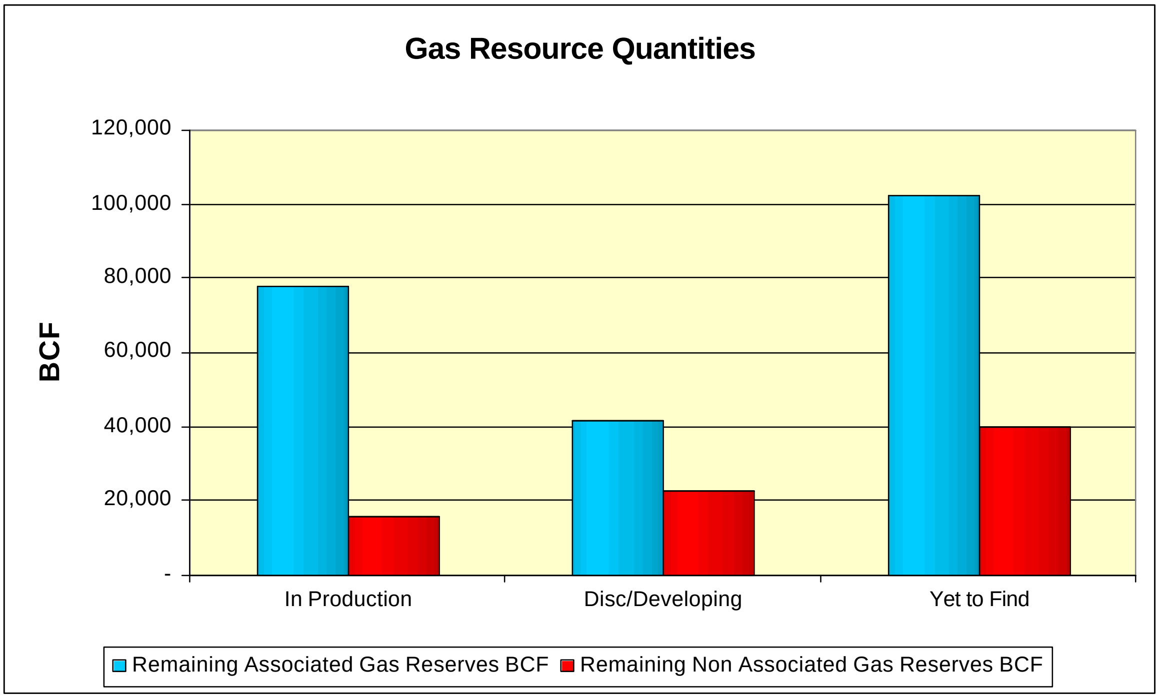
- Resources that have been found (proven plus probable). This includes:
    - Resources currently under production, some of which may be undergoing further development, and
    - Resources discovered but undeveloped or which are currently being developed but are not yet producing
- Resources that have yet to be found and are likely to be found given that the Niger Delta Basin is relatively unexplored

2.19 The first category is estimated to hold 158 Tcf of gas resources with 142 Tcf estimated to be in the second. The yet-to-be-found estimate is based upon a statistical method commonly used in the industry, it tends to be conservative as it only takes into account the plays or producing zones currently known. More details on the methodology are provided in the section on “Undiscovered (Yet-to-Find) Reserves”.

2.20 Under current production rates gas resources that have already been found would last for 108 years; the combined found and undiscovered resources would last for 205 years. Clearly, this is a long-term future. However, the opportunity also exists to increase current production rates if additional gas utilization and monetization methods are brought into the plan.

2.21 Figure 2.1 shows the quantity of gas resources available to Nigeria and the split between gas from oil fields (associated gas or AG) and gas from fields that contain no oil (nonassociated gas or NAG). It should be noted that this designation has more to do with the way the field is or will be developed than with actual oil or gas reserves. Typically, groups of fields are developed together as a combined production unit, and the liquids and gases are commingled. Therefore, a few fields that are technically gas or gas and condensate have been designated as AG because they are located with oil fields. This type of designation may result in different statistics from other analyses. However in this way, a dynamic plan can distinguish pure NAG fields from AG fields whose development and production are subject to restrictions, such as OPEC quotas. This allows the ability to include development of these pure nonassociated gas fields independent of the restrictions on oil fields, plus it provides the flexibility to also produce a marketable condensate stream if required.

Figure 2.1: Associated and Nonassociated Gas Resources

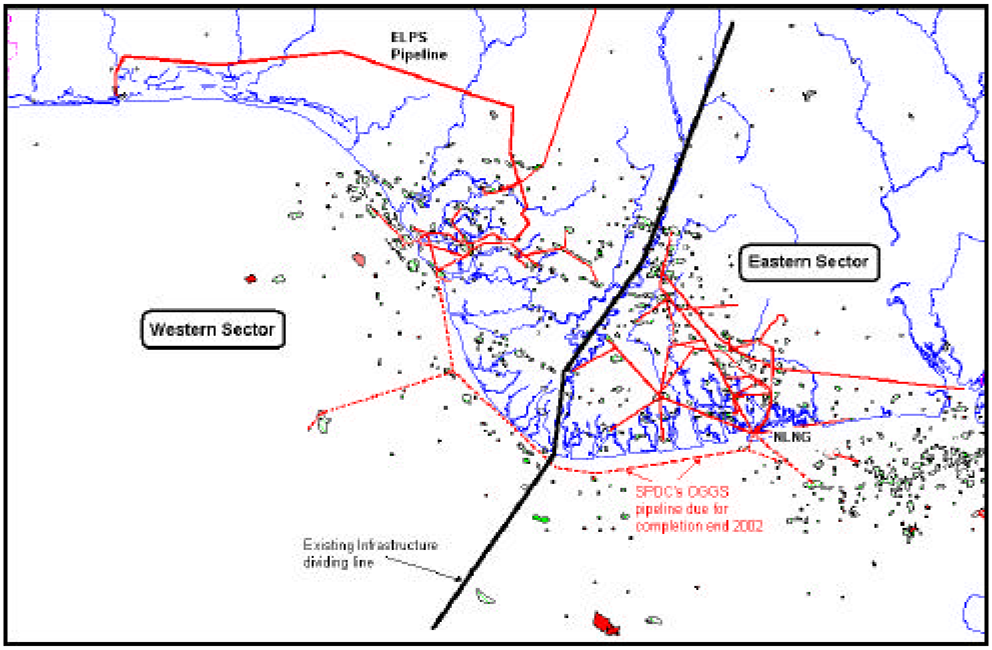


2.22 Additional benefit can be derived from this categorization of AG and NAG in that gas or gas products can be more easily guaranteed in any supply contract as the supplier can supplement their feed gas with NAG if the oil supply is interrupted or constrained. This is a superior basis for planning, particularly in terms of obtaining financing and meeting the objective of a continuous income flow into the treasury.

2.23 Of the remaining AG reserves, approximately two-thirds are in production and one-third are undeveloped or developing discoveries. However, for NAG, there are more nonproducing reserves than producing reserves. In part, this reflects that gas fields historically have been less likely to be developed. The AG-NAG split for the yet-to-find gas was estimated based on that split for known producing and nonproducing reserves determined separately for each geographic region. More detail is provided in the section below on "Undiscovered (Yet-To-Find) Reserves."

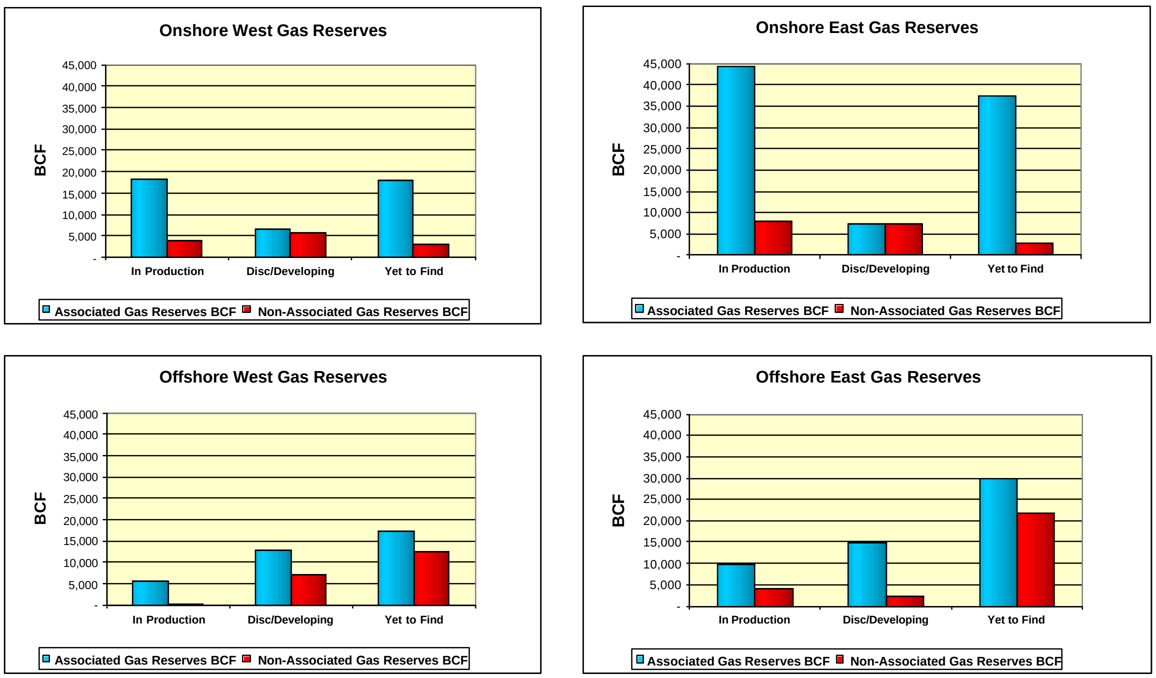
2.24 The geographic distribution of the gas resources (known and undiscovered) is also important, particularly since there is currently a split system of infrastructure in Nigeria as shown in Figure 2.2 below.

Figure 2.2: Gas Infrastructure Split in the Niger Delta



2.25 Figure 2.3 shows how these resources are split between east and west and between onshore and offshore. This geographic distribution of the gas resource indicates that the site and future growth of NLNG has been well placed in the East. However, the predominance of gas resources in the East will mean that additional substantial infrastructure will probably be needed to link East and West, both for the use by the remainder of Nigeria and for future export opportunities via pipeline to states to the west of Nigeria and to Algeria. This point will become more critical when the capability to increase NLNG will be limited by the ability to get more LNG ships in and out of Bonny. Thus, the East could potentially have supply available for pipeline export that is in excess of the supply that goes to NLNG. Given the potential growth for gas consumption in the power sector, this excess supply does have a potential future market (see section on the Power Sector in Domestic Consumption Projects).

Figure 2.3: Geographic Distribution of Gas Resources



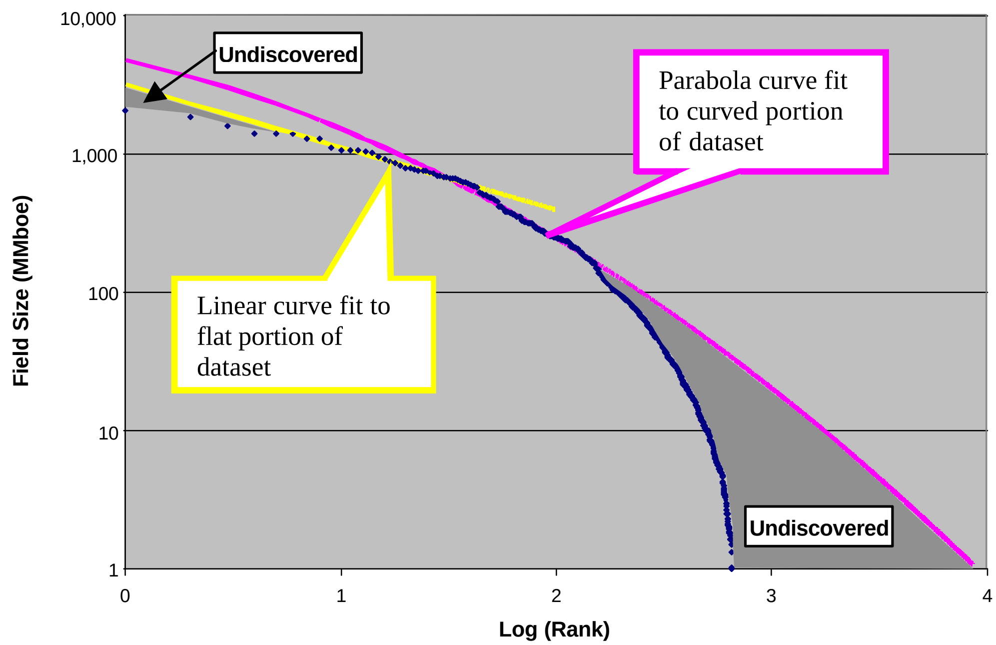
Undiscovered (Yet-To-Find) Reserves

Methodology

2.26 The methodology uses proven plus probable reserves data from IHS Energy Group's IRIS21 E&P database to extrapolate a trend from which the ultimate recoverable reserves for the basin are calculated. The reserves found to date are subtracted from the ultimate recoverable to get undiscovered, or yet-to-find (YTF), resources. The methodology used in this report for the Niger Delta Basin is a two-part statistical approach, which is modified from the standard calculation of YTF in the IHS Energy Group's proprietary software ProbE4.0. The standard YTF calculation assumes that the largest fields in a basin have already been found. This two-part statistical calculation takes into consideration that much of the deeper water portions of the Niger Delta Basin have not yet been explored, and thus there is a high potential for a field even larger than the largest existing field to be found. Nevertheless, this is a conservative estimate relative to the standard method of fitting only one straight line to the dataset—one which projects more smaller fields than the method used here.

2.27 The YTF calculation is done for the entire basin (including those portions covering Cameroon and Equatorial Guinea) because the methodology is based on the assumption that the geologic basin, not political boundaries, is the controlling feature of the hydrocarbon accumulations. However, for the purposes of this report, all of the YTF resources estimated from this calculation are assumed to be in Nigeria. This assumption is based on the fact that 96 percent of the existing reserves of the basin are within Nigeria's boundaries, and the margin for error of the YTF estimate is certainly not less than ±4 percent.

Figure 2.4: Schematic Graph Illustrating the Technique for Calculating YTF



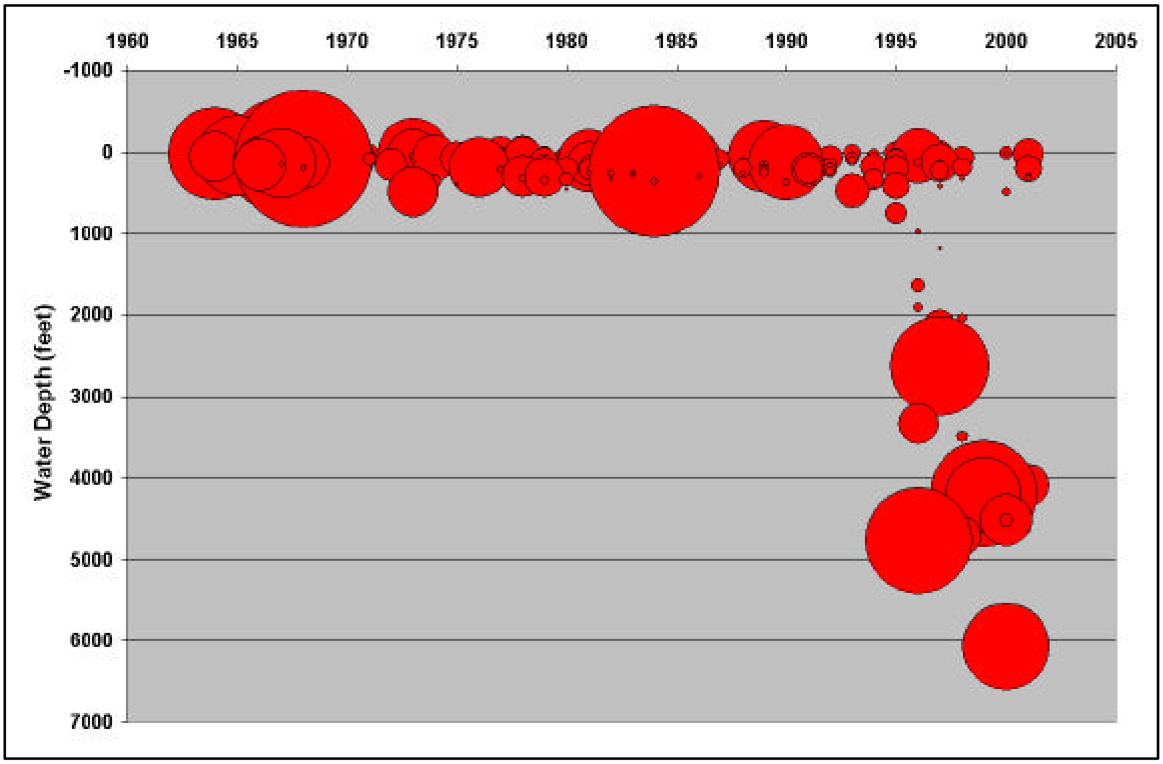
2.28 For both parts of the calculation, all of the existing fields and discoveries in the basin, amounting to 707 fields in total, are plotted on a log-log plot of field size (proven plus probable recoverable hydrocarbons in barrels of oil equivalent) versus rank. The largest field is Rank 1, the second largest field is Rank 2, and so forth. First, a linear trend was fit to the straight-line portion of the data and extrapolated back to the largest field (see Figure 2.4). Second, a parabolic trend was fit to the next smaller portion of the data that best defined the curvature of the remaining smaller fields. In all, 45 percent of the data were used in determining the curve fits as opposed to 40 percent used in the standard YTF calculation.

2.29 After the undiscovered resource for the basin was estimated, it was then allocated into onshore and offshore and into eastern and western portions of the basin. The hydrocarbon was further split back into gas and oil.

2.30 For the geographic allocation of the undiscovered resource, it was assumed that when the basin has been fully explored, the hydrocarbon resources would be evenly split between onshore and offshore as more and more exploration efforts are being directed offshore. This is a reasonable assumption based on two things. First, the offshore exploration drilling density is barely over half that of the onshore. Second, most of the current exploration activity is focused offshore. Ninety percent of the discoveries made in the entire basin in the last five years have been offshore, and 42 percent of those have been in deepwater (Figure 2.5). To make the final ultimate reserve split 50-50 between onshore and offshore, a larger portion (59 percent) of the future discoveries is assumed to be offshore. For the division between east and west, it was assumed that the total recoverable hydrocarbon would continue to follow roughly the same pattern as existing reserves. The same east-west split was applied to both onshore and offshore.

Figure 2.5: Gas Reserve Additions by Year and Water Depth for Offshore Fields

Bubble scale is relative to the largest field which is 5.5 Tcf.



2.31 After being split geographically, the YTF hydrocarbons, expressed in million barrels oil equivalent, were split back into oil and gas; the gas was further split into associated and nonassociated. For the onshore, the split was assumed to be the same as existing fields. For the offshore, the split was based only on the existing split in deepwater, the assumption being that more of the future exploration will be in deeper water.

Yet-to-Find Reserves Estimates

2.32 Nigeria's upstream potential is likely to remain extremely positive, and the potential yet-to-find resources may almost equal the remaining discovered reserves in the basin. Across the Niger Delta, exploration success, at 50 percent, is above global averages. The geology of the basin favors hydrocarbons accumulations. Source rocks of the Akata and Agbada formations are good quality and widespread. Although in portions of the basin, the source rocks are over mature for oil, they still have potential for gas generation in the deeper portions of the basin. The main reservoir is unconsolidated sandstones that have generally high porosity with permeability in the Darcy range. These are interbedded with the source rock and thus filling of the reservoirs is not limited by complex migration pathways. Much of the future of gas supply lies offshore in the deeper waters that are largely untested. Only 24 discoveries have been made in water depths greater than 400m; three of those were NAG.

2.33 The results of the YTF calculations are summarized in the table below. The total undiscovered hydrocarbons for Nigeria are estimated to be 63 billion barrels oil equivalent, which is split into 39 Bn bbl of oil and 142 Tcf of gas. For the gas, 40 Tcf will be in gas fields with the remainder being found in oil fields. Reserve additions are expected in most size categories, although few gains can be expected in the 500-2,500 million barrels oil equivalent size categories. Most of the reserve additions are likely to be in the 10-50 million barrels oil equivalent and >2,500 million barrels oil equivalent size categories.

Table 2.1: Yet-to-Find Hydrocarbons in Nigeria by Hydrocarbon Type and Geographic Area

	Oil (Bnbbl)	*Gas (Bcf)*	
		Associated	*Nonassociated*
Onshore			
East	8,522	37,364	2,812
West	6,761	17,971	2,926
Offshore			
East	15,264	29,878	21,636
West	8,830	17,284	12,516
TOTALS	39,737	102,497	39,892

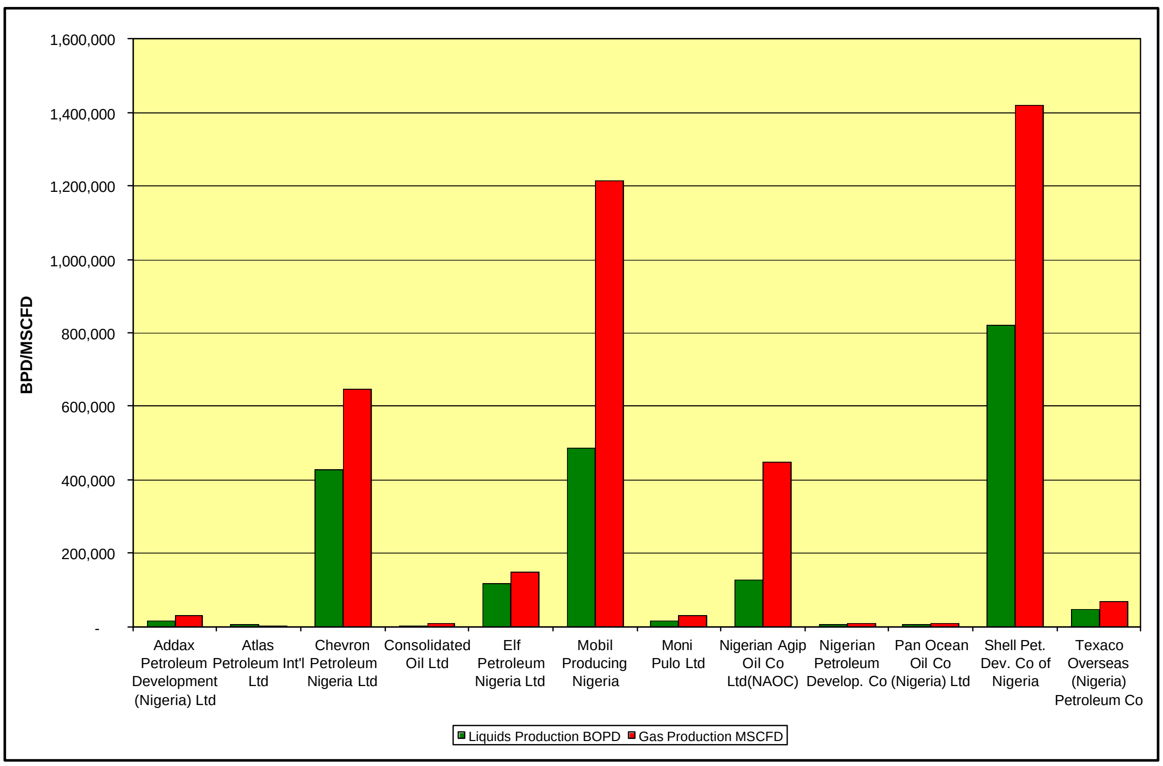
Production

Production by Operator

2.34 Figure 2.6 shows Nigeria oil and gas production by operator for 2000. Shell Petroleum Development Co. of Nigeria is the largest producer of both oil and gas with 820 thousands barrels per day and 1.47 Bcfd. Mobil Producing Nigeria and Chevron Petroleum Nigeria Ltd. are the second and third largest producers, respectively, followed by Nigerian Agip Oil Co. and Elf Production Nigeria in the fourth and fifth largest spots. These five players account for 95 percent of Nigeria's total production of both oil and gas. The Nigerian National Petroleum Co. (NNPC) owns between 55 and 60 percent of each of these companies. However, NNPC is not the operator on any of the contracts.

2.35 Gas production for each operator and region was estimated on a field-by-field basis using recorded or average gas-oil ratios (GORs) and multiplying by the oil production rate. Where NAG production was reported or declared by the operator then those numbers have been used in preference. Future production was estimated by producing the remaining reserves for each operator over typical industry production lives of 25 to 40 years (depending on the extent of the reserves). This approach is likely to slightly understate year 2000 gas production but when compared to the predictions given in the oil company's proposals, seems to give a reasonably consistent and matching gas profile.

Figure 2.6: Estimated Production by Operator



Current and Forecasted Production of Remaining Reserves

2.36 The oil production from the east and west sectors is approximately the same at 1,186,000 and 900,000 Bpd, respectively. However, gas production is substantially higher in the East than in the West. Daily gas production in the West is 1.495 Bcfd, whereas in the East it is 2.559 Bcfd (Figure 2.7).

Figure 2.7: Oil and Gas Production Rates

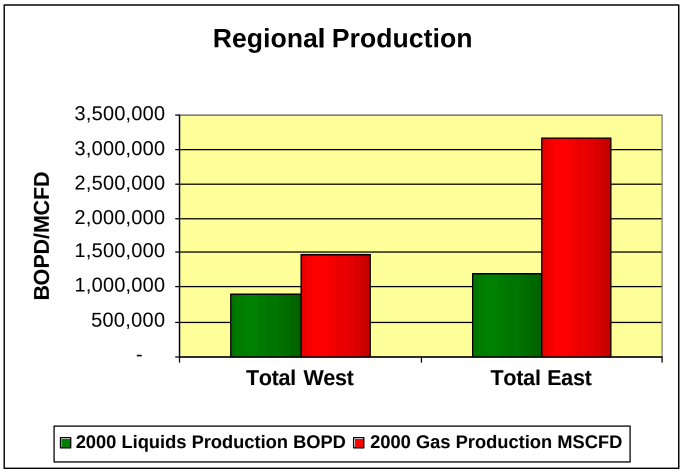
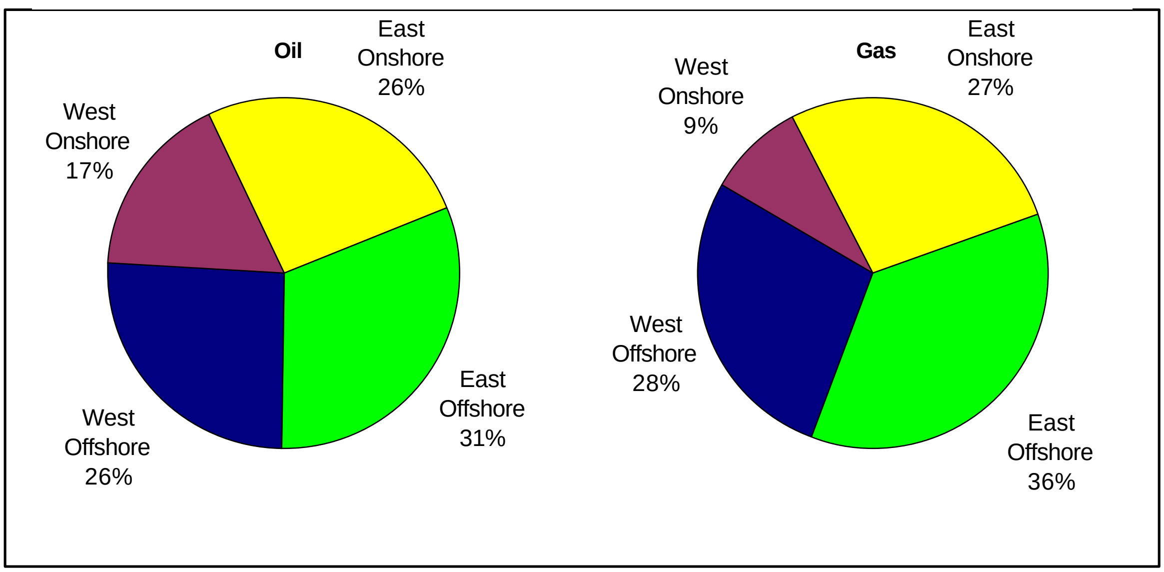


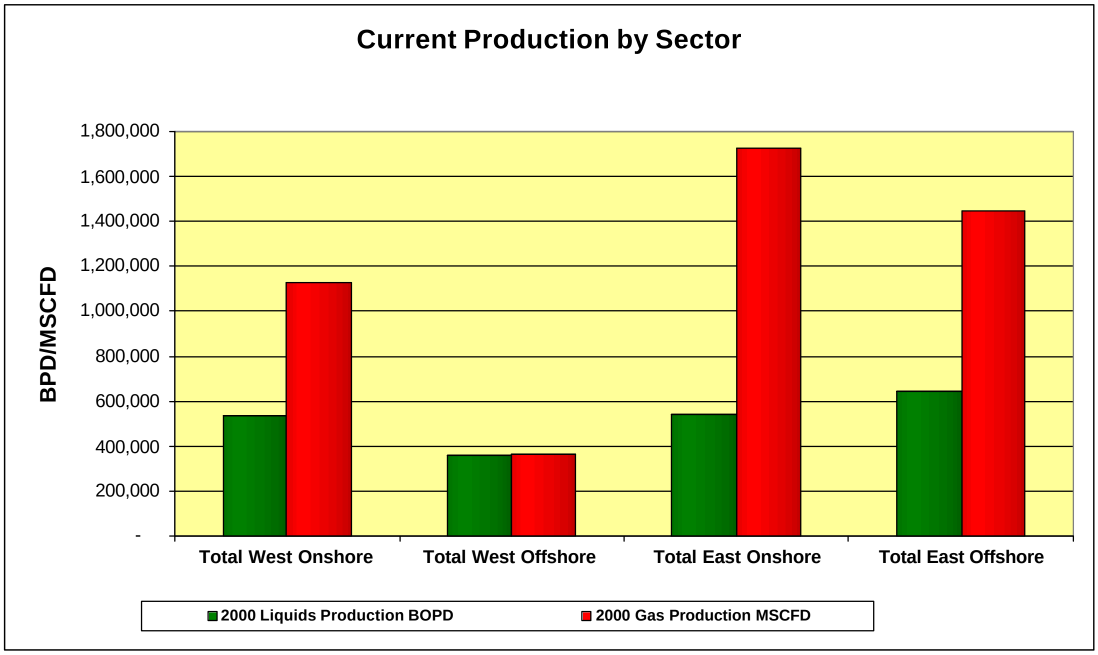
Figure 2.8: Oil and Gas Production Percent by Sector and Onshore/Offshore



2.37 Figures 2.8 and 2.9 show the additional breakdown of production between onshore and offshore. In both the East and the West, production of oil and gas offshore exceeds that onshore. Fifty-seven percent of Nigeria's oil production and 64 percent of Nigeria's total gas production, or 2.572 Bcfd, is from the offshore.

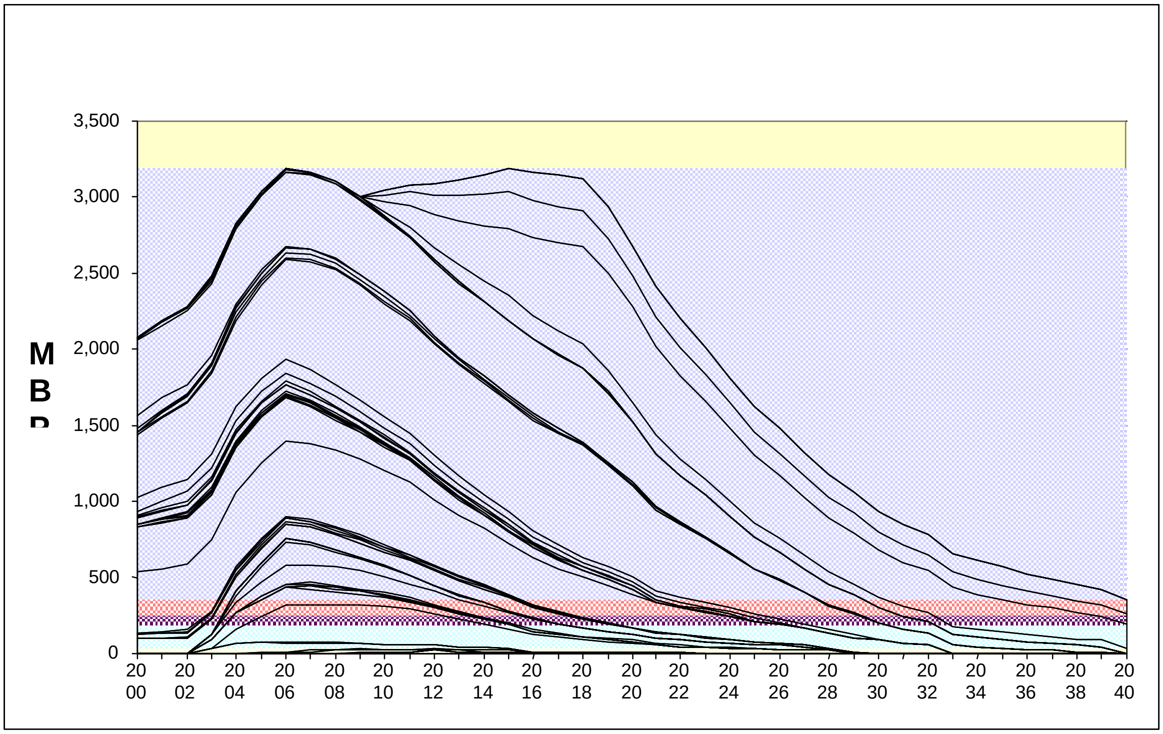
2.38 In developing the future gas profiles, the first step was to set a liquids production rate (oil and condensate) that meets FGN Policy. Depending upon the ability and desire to keep these streams separate, the overall production can be manipulated to stay within reasonable bounds with respect Nigeria's OPEC quota. However, there is a cost and time penalty. This goal becomes easier over time as more dedicated gas and condensate facilities are built.

Figure 2.9: Oil and Gas Production Percent by Region



2.39 For the purposes of this analysis and in line with projections from some of the oil and gas companies, a target liquids plateau rate of approximately 3 million bpd was chosen for five years hence. Looking at current fields and projects currently under development, Nigeria would have to slow development not to reach this target. Figure 2.10 shows this, with the lightly shaded elements representing fields discovered but with no set development date.

Figure 2.10 : Liquids Production Projections



2.40 Based upon the liquids rate in Figure 2.10, the AG and NAG production rates can be set to maintain the oil plateau and to provide sufficient NAG to maintain a balance on export commitments. Figure 2.11 shows the projected gas production, with the lightly shaded elements again representing fields discovered but with no set development date. Figure 2.12 shows the same volume split into AG and NAG, demonstrating the issue that if the overall utilization of gas is not addressed now the flaring will get worse as more AG is coming into play.

2.41 The production rate to support the liquids rate peaks at just under 12 Bcfd. This level of production is very reasonable for an extended and sustained period when taking account of the 142 Tcf of YTF gas that is likely to be present and discovered over the next 5–to 10 year period.

Figure 2.11: Gas Production Projections

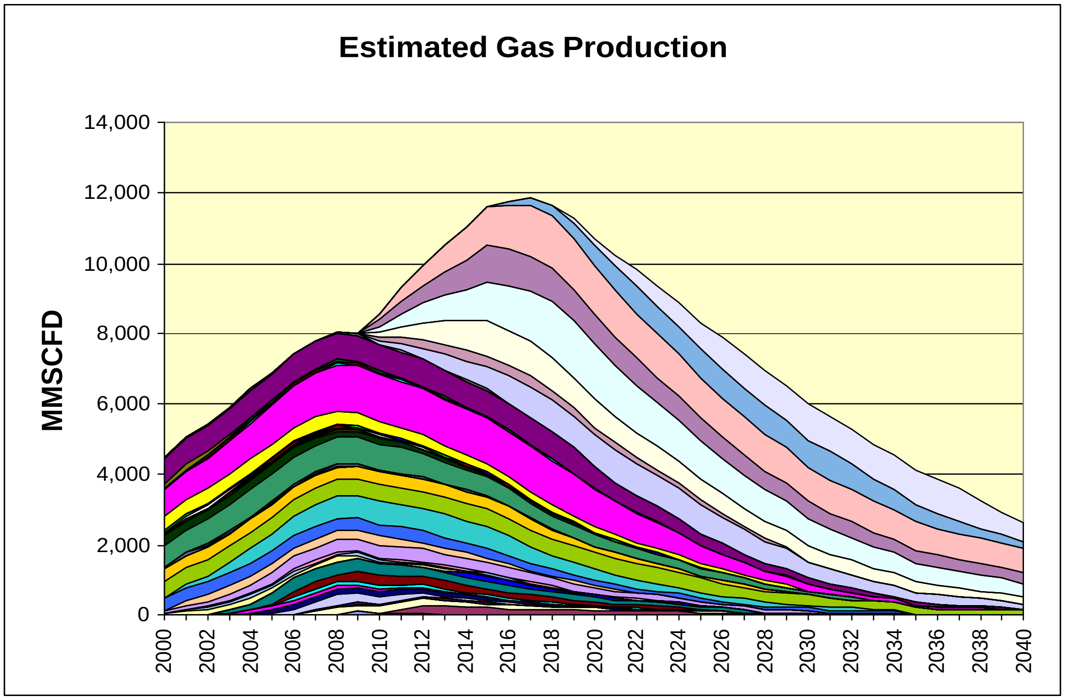
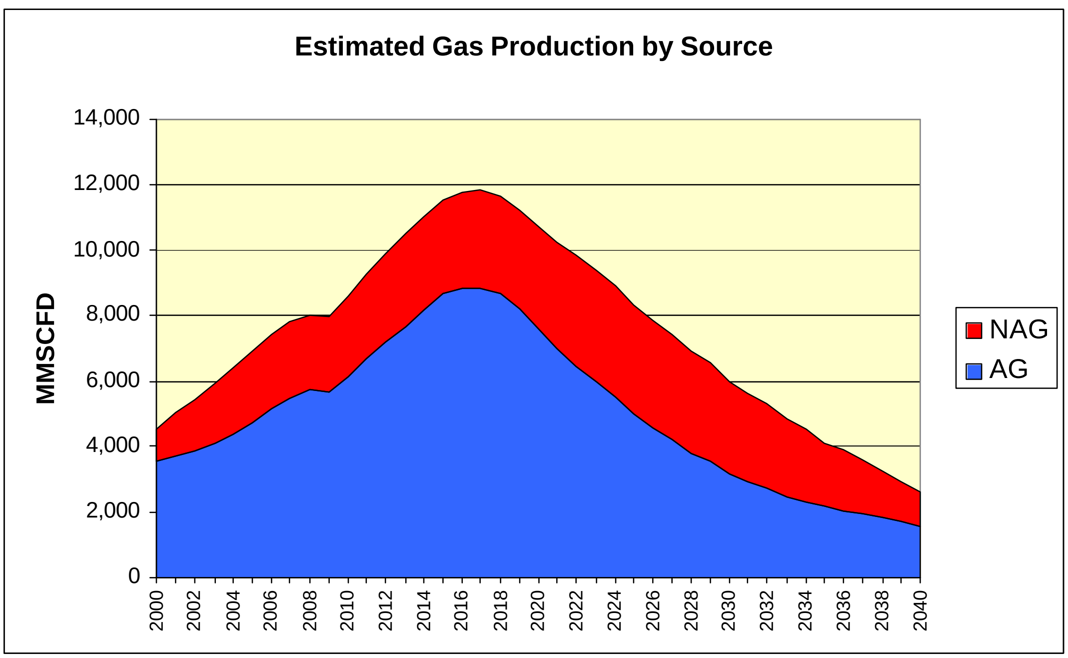


Figure 2.12: Gas Production Projections for Associated and Nonassociated Gas



Cost of Gas Supply

2.42 Gas resources can only be developed when the gas can be economically produced and transported to markets. In addition, providing the necessary flexibility to meet varying gas demand and gas contracts can be expensive. Consequently the price of gas varies considerably from region to region, determined by local costs of production and transportation distance.

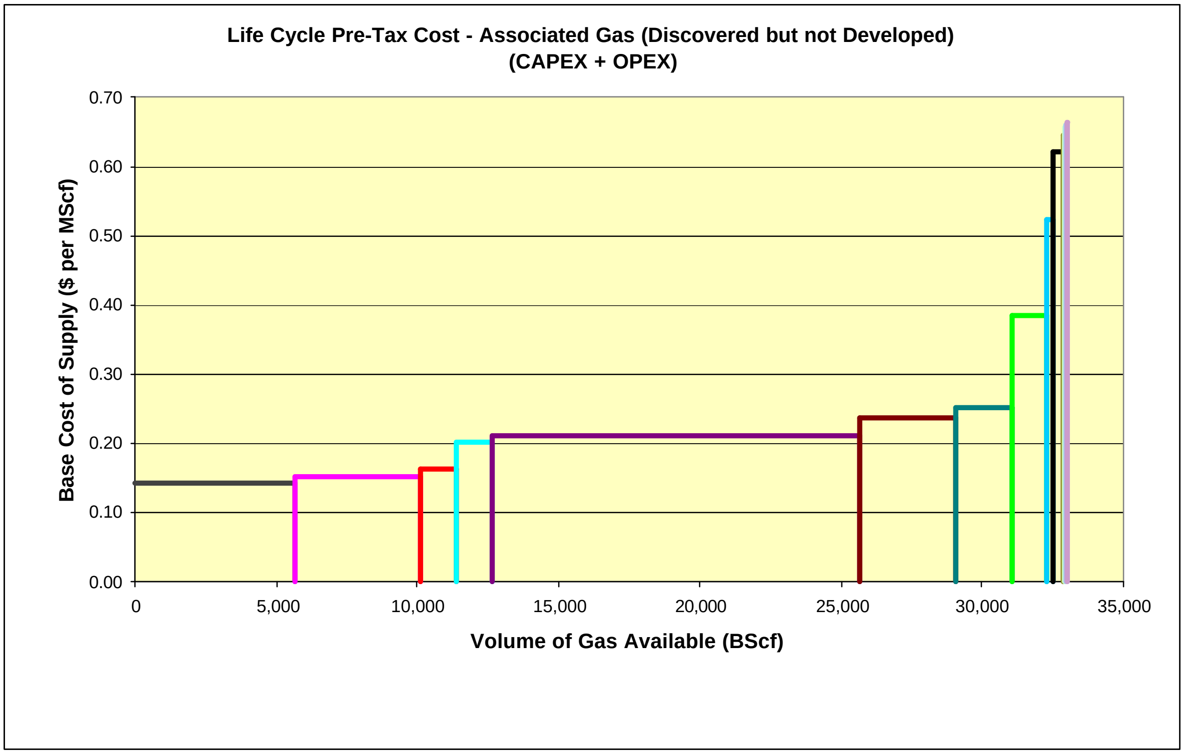
2.43 For export markets long-term relationships are all important while a gas industry is being developed. The contracts for selling and transporting gas tend to be very detailed, as they have to consider many eventualities. Each of the major contractual terms has specific commercial value and can affect the price agreed in a negotiation. The final price is for the service conditions for the gas supply and not just for the units of gas delivered.

2.44 A major question from the government's point of view is how the economic rent is apportioned; that is, how much could and should go to the government, to the producer, and to the individual commercial parties in the gas supply and consumption chain. The key element that must be considered, if the FGN wishes to fully open up to all producers including the emerging national companies, is what should be the tax taken in the upstream production contract, thus providing the supply cost, and what should be taken in tax for the transport and downstream activities (demand cost).

2.45 Nigeria is fortunate to have a substantial volume of low-cost gas. Figures 2.13 and 2.14 show the average cost of supply of discovered resources, to a point of delivery close to current gas utilization, Bonny in the East and Escravos in the West. The cost basis assumed is that each field requires its own gas-oil separation facilities (the most conservative option), thus if individual companies group the smaller fields into a gathering or pooling system, average unit costs per mcf for these fields could be substantially lower. However, for planning purposes, the more conservative approach is taken. This approach still demonstrates that ample low-cost gas (less than US$0.25/mcf) is available for many years in the future.

2.46 The costs included here include for a gathering flowlines of 3km onshore, 50km offshore shelf, and 100km in the deepwater areas. It is assumed that this is sufficient to get the gas to a major gas gathering system and from there into any nationwide transmission system, via a NGL or LNG extraction plant as appropriate.

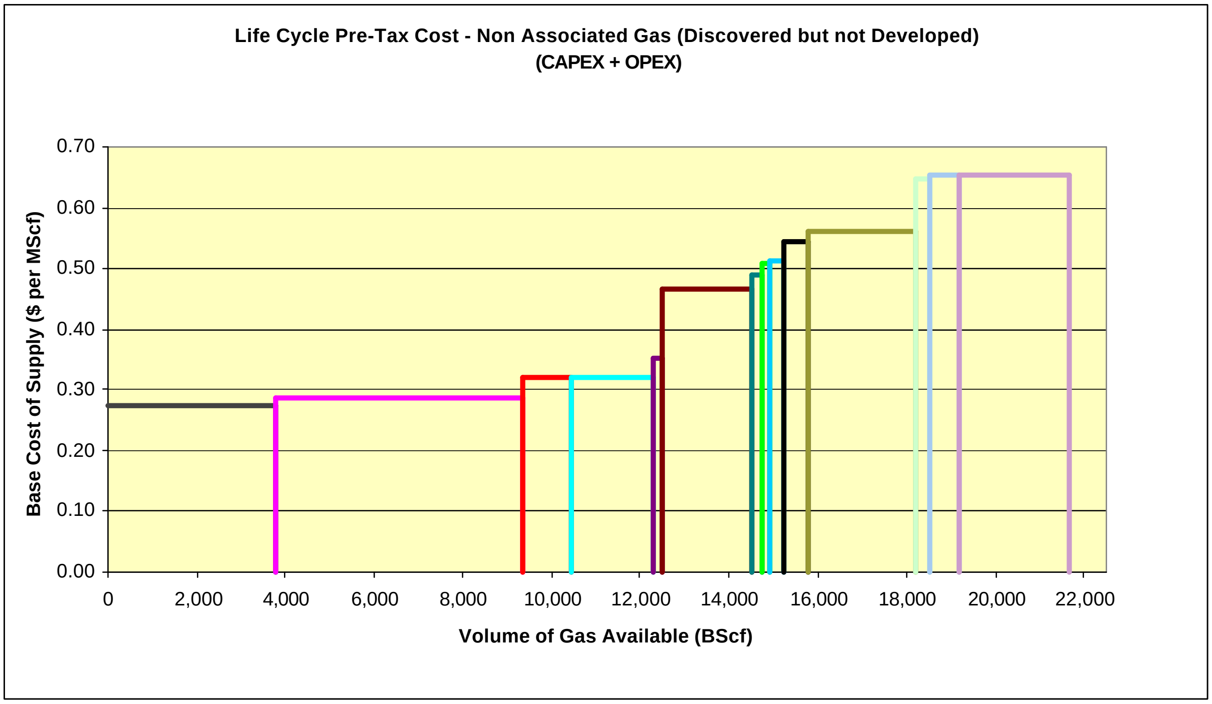
Figure 2.13: Bare (Pre-Overhead, Profit And Tax) Unit Cost of Gas Vs. AG Volume Available[5]



2.47 The graphs show that both AG and NAG, for those resources that have been discovered, can be developed to support virtually all utilization options, depending on the tax, overhead, and profit take. However it should be noted that supplying gas below the new development price is not sustainable and should be avoided in the planning of any new project.

[5] Associated Gas cost based upon full gas compression and a nominal export pipeline costs only

Figure 2.14: Bare (Pre-Overhead, Profit And Tax) Unit Cost of Gas vs. NAG Volume Available[6]

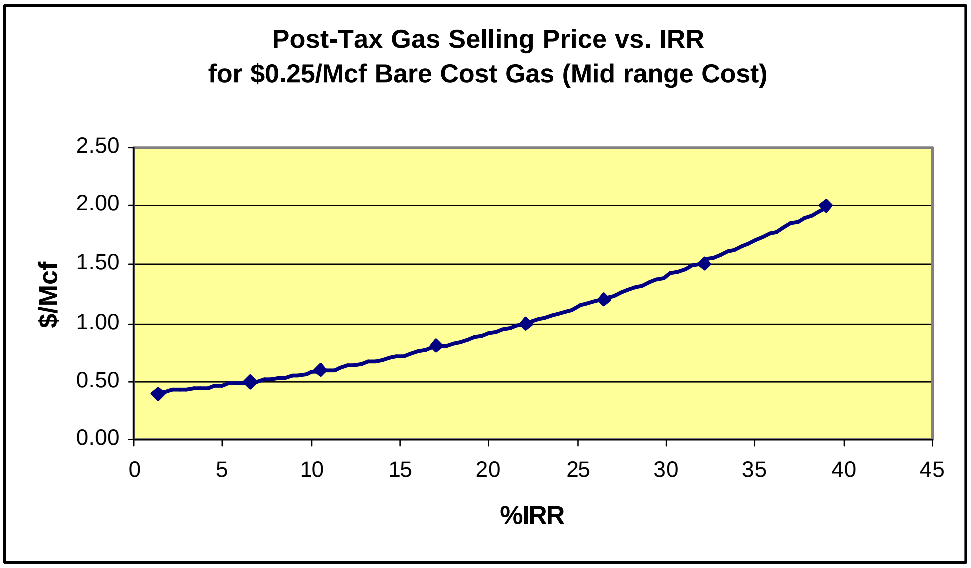


2.48 Figures 2.15 and 2.16 show a typical set of gas sales prices producing companies might make for a specified IRR on a post-tax basis under the current fiscal regime. When these numbers are compared to the gas netback downstream plants can afford to pay, it demonstrates that projects with netback above US$0.75/mcf are feasible under the current fiscal structure.

[6] Nonassociated Gas costs based upon a condensate credit at US$20/bbl with an LGR of 20 bbl/mcf

Figure 2.15: Post Tax Unit Cost of Gas vs. IRR for US$0.25/Mcf Gas

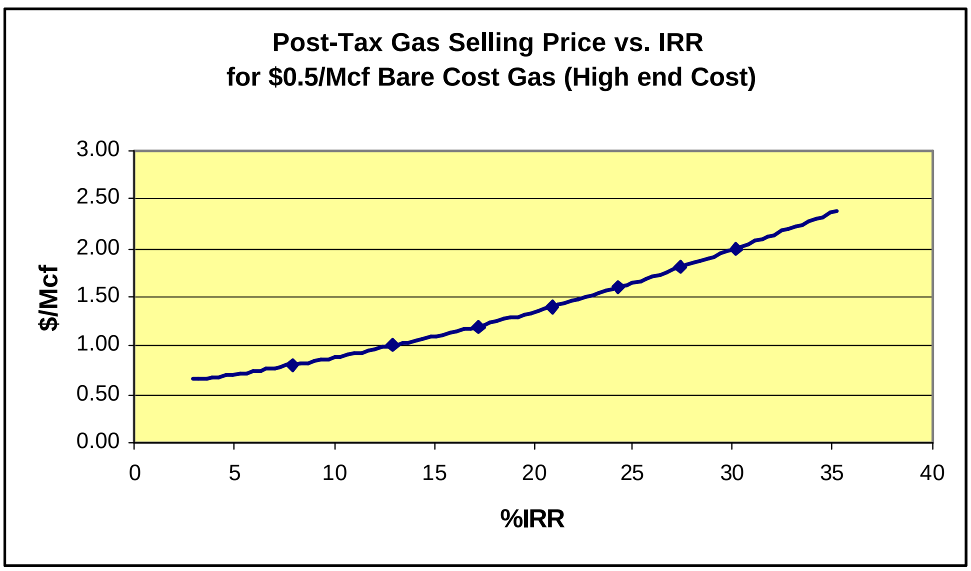
(Based upon 15 percent Local and Foreign Company Overhead Cost)



2.49 However netbacks above US$1.0/mcf or a little more would be needed for a substantial volume of NAG, or that NAG would need to be clustered to bring the development costs down to AG levels.

Figure 2.16: Post Tax Unit cost of Gas vs. IRR for US$0.50/mcf Gas

(Based upon 15 percent Local and Foreign Company Overhead Cost)



2.50 If gas is to be transported long distances then this transmission cost would need to be built into the equation to arrive at a commercial sales price at the City Gate, a transmission cost of around US$0.60/Mcf is estimated to be required to get full domestic distribution across Nigeria. (See Chapter 3, Gas Utilization Options an explanation of this calculation). Exception projects have to be managed on a case by case basis to bypass the system.

2.51 Key projects, that meet the objectives of the FGN, may need more favorable fiscal treatment. However, some of these projects may consider an increase in the planned throughput, if the market can justify it, to achieve the benefit of scale. Projects offered in the future may need a broader set of backers to achieve this size increase, or some element or percentage of "open access" may be desired in exchange for fiscal concessions.

Gas Pricing Issues

Social Policy

2.52 (i) *Social protection mechanisms*: In the case of smaller customers, the regulatory system will probably need to address any social concerns if the price of gas is unaffordable or is likely to be a significant financial burden on particular enterprises or households. If, however, it appears that social objectives are going to play a more significant role in the development of the Nigerian gas industry, then steps need to be taken at the outset to introduce appropriate policies. These policies need to go hand in hand with the Power Pricing Policy as the two are directly connected. Any disconnection of pricing between power and gas prices will ultimately hurt both industries and maintain the status quo of stagnation in perpetuity. Nonpower connected pricing policy for gas could include the provision of assistance to low-income consumers. In designing such mechanisms, the key objectives are that such mechanisms should:

- be targeted

  The mechanisms need to be targeted on those consumers in need rather than to subsidize wealthier consumers. This provides a lifeline for the poorer customers and ultimately allows them to climb out of the poverty trap.

- be low-cost operationally

  The policy should be low-cost to administer, both in the collection of funds and in their distribution.

- minimize distortions

  Any subsidy which moves prices away from costs will lead to movements away from allocative efficiency. Such efficiency occurs where the price of a good is set at least equal to its long-run marginal costs of supply. Therefore, consumption only takes place where the value of a good to a consumer is less than or equal to the cost of its replacement.

2.53 Ideally, any support that is required for low-income and other consumers should be provided directly by local or central government, either through the general tax and benefits system or through mechanisms such as vouchers. However, it is recognized that this is not a feasible option in many countries, either because of budgetary constraints or to the absence of a well-developed social security system able to identify poorer consumers and channel support to them.

2.54 It is important to note that prior to designing a social protection mechanism, an important decision must be made about who is responsible for social protection. Decisions on social welfare and the protection of vulnerable consumers are the preserve of governments rather than energy regulators.

2.55 Should a standard price across the country be employed wherever a consumer takes gas from in the main distribution system, then the main distortions between states can be eliminated, thus minimizing the need to subsidize directly.

2.56 (ii) *Partitioning:* One of the key aspects for successful development of a gas industry is to ensure each sector in the gas, power, and industry sectors are self sustaining, such sectors cover upstream, mid-stream and downstream. Partitioning will allow the FGN the greatest chance of success to encourage domestic and foreign direct investment and a consequential boom in all sectors. A problem arises; for example, if the government sets final tariffs lower than the costs of production, transportation, and distribution of natural gas to smaller customers. Historically this has been done with NEPA to the detriment of all parties. It also arises if the government incorrectly directs gas to nonprofitable industries; Alscon with aluminum production is potentially one example of that as without a serious domestic market it is either marginal or sub-marginal. For future downstream investments, the size and scale of plants installed should take into account the economies of scale if the domestic, regional, and international markets can take it, or at least be installed in a phased approach to fit more closely the growth in the markets, ending up with a worldscale plant at conclusion.

2.57 The issue of gas gathering needs to be addressed. Gas gathering typically falls into the remit and indeed the fiscal system of the upstream operator, whilst it is desirable that open access is possible, this may not be feasible. However, some form of hospitality rules or guidelines or negotiated access may be more workable.

2.58 (iii) *Revenue collection (incentives and penalties):* Avoidance or non-payment problems is a further issue that needs to be tackled. In a cash-poor system the most important feature of the structure should be to provide an incentive for distribution (or retail supply) companies to collect from consumers, allowing them to pay their suppliers and so on up through the chain.

2.59 A significant element in achieving cost recovery will be to provide consumers with strong incentives to pay the posted tariffs. Prepayment is the most successful option at the point of sale. This has been proven to work both in Nigeria and in the region, such as in the poorer parts of South Africa and so forth.

2.60 The disconnection or right not to supply utility services is a crucial weapon in the fight to ensure that utility companies cover their costs, as part of a wider program to tackle nonpayment and manage accounts receivable. Unless supplies can be refused or curtailed, consumers have little incentive to pay the required tariffs.

2.61 There are various obstacles to the introduction of a successful refusal to supply and disconnection policy—the most obvious being political resistance at either the national or local level to the notion of nonsupply or disconnection. To be a credible threat, a regulation to permit refusal and disconnection (and reconnection when debts are paid off unless there has been an unauthorized connection in the first place) must be accompanied by a series of actions by the government to affirm positively that it is serious about introducing a policy of total countrywide enforcement.

Price Regulation and the Institutional Role of the Regulator

2.62 The form and complexity of an industry for gas production and utilization means that the resulting gas market is unlikely to conform to economic efficiency if left to its own devices. For example, where there are changes in gas ownership any prevailing monopoly conditions are likely to lead to distortions in price negotiations unless there is some intervention to counteract large differences in bargaining power. In the overall chain between producer and ultimate customer whether direct gas or through power, the prospect of capturing resource rents could mean counterproductive arguments between the various participants at the expense of the success of the overall chain. One broken link in the chain means the whole system does not work. Under these circumstances (and others like it where there is no unencumbered market), some form of regulation is generally required. The issue of gas and power should be dealt with together, as even successful examples, such as Mexico, where power and gas distribution regulations have brought a huge influx of investment, the upstream supply was not fully addressed and the expansion of gas supply is suffering as a result. Besides the questions of regulatory intervention in any gas and power pricing system itself, there are many questions about the form of the institutional aspects; for example:

- Setting up the independent regulatory body for the gas and power, generation, transmission, distribution sectors (composition, appointment/dismissal of commissioners arranged, single versus multiutility function, and so forth
- Role, jurisdiction, and powers of the regulatory body
- Appeals process
- Establishing the regulatory body in law

2.63 The principal aspects of the regime that the regulator would be concerned with need to be spelled out in any concessions or licenses for the companies involved.

Approach to Setting the Gas Price Level

2.64 The lower limit to the price of gas is normally taken as the cost of the supply of gas (cost of service approach). This cost is influenced by the development costs, the level of contingencies set aside to cover the perceived risks in that particular locale, the quantities discovered, the proximity to the market and the discount rates assumed. In countries where there is not a surfeit of installed capacity, pricing at below the Long-Run Marginal Cost (LRMC)–that is, not taking full account of the capital employed but only the short-term additional marginal operating cost–cannot be a sustainable policy.

2.65 Alternatively, the gas price can be set at a level that reflects the gas value in the end use (market-price approach). This level is highly recommended to maintain a supportable and sustainable system.

2.66 If the price of delivered gas is too low, there is a serious risk that further investment will dry up and a gas shortage will result. If the price is too great, this can dampen demand for gas, drive consumers to other energy sources, and also create tensions between the industry and government on the split in revenue, which in itself can create undesirable instability for both sides.

Nonprice and Other Contract Clauses

2.67 Mandated clauses in the sale and purchase of gas are an essential element in defining contract terms. Guarantees properly formulated can speed gas penetration into existing and new markets by reducing uncertainties. Unless they are carefully designed however, they can also negate the incentive effects of pricing. These clauses typically include the following:

- Obligations to deliver (nondelivery penalties)
- Obligations to purchase (take-or-pay requirements)
- Escalation clauses (often with indexation)
- Currency convertibility
- Tariff structures
- Discounts and premiums (for example,. for interruptability and high swing respectively)

3

Gas Utilization Options and Competition

Introduction

Development of the Resource

3.1 The principal drivers for the development of natural gas are usually:

- Pressure to reduce flaring
- Desire for economic growth and general enhancement of populace quality of life
- Desire for industrial development

3.2 On the other hand, the principal barriers for the development are:

- Structure of investment—large investments in pipelines and distribution systems are needed
- Inappropriate domestic pricing policy—government policy may also heavily influence gas pricing, for example, through social or sector policies

Gas Utilization Options

Typical Gas Utilization Projects

3.3 Available and commercially priced gas can be the initiator to a real expansion in a multitude of domestic and export-based projects (excluding Pipelines). These options will include a cross section of facilities that once the larger and more strategic options have been put in place and initiated, can support that growth over a long period of time. Options relevant to Nigeria include:

Priority 1:

- Power Generation
- Gas-to-Liquids (GTL) manufacture

Priority 2:

- LPG processing

- Cement manufacture
- Steel (DRI) manufacture
- Fertilizer (Ammonia/Urea)

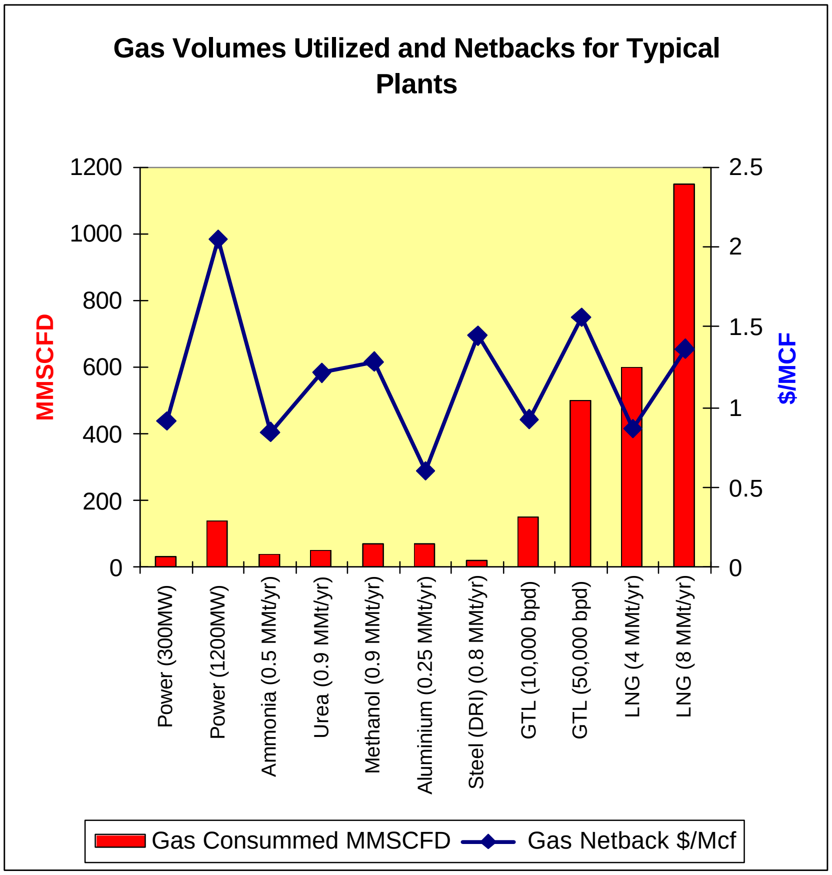
Priority 3:

- Further Liquefied Natural Gas (LNG)
- Methanol
- Aluminum smelting

Gas Usage of Typical World-Scale Plants

3.4 Based upon an independent look at gas utilization the following figures briefly explain the returns and netback gas price maximums needed to make any of the projects work. These should not be taken as absolute, but put the relative economic merits of each into perspective. The specific projects and their applicability to an overall plan are discussed later under the projects subsections. The netback gas value is the maximum price a downstream project can afford to pay to achieve a 15 percent IRR (pretax). These netbacks and the corresponding volumes required have been summarized to examine some of the comparisons between the commodities. A full assessment of each major Export Gas Utilization sector is included in Appendix 2 and details the options, competition, markets, and economics for each option.

Figure 3.1: Summary of Gas Utilization Project Feed Gas Netbacks[7,8]



3.5 Netback gas values for all the commodities investigated lie within the range of US$0.60 to US$2.05/MmBTU. If lower rates of return were acceptable, then theoretically a set of economic circumstances may exist for project evaluation.

3.6 A further analysis of the typical power olants demonstrates the sensitivity to the domestic prices paid; Figure 3.2 shows the sensitivity to both size and power prices attained.

3.7 The majority of plants being planned currently, according to ExxonMobil's study, are in the 600kW to 2400kW range with the majority greater than 1200kW. However, if power generation is to be encouraged in the more remote states, more 600kW plants are likely.

3.8 The power prices cannot be set in isolation; it must be a balance of the whole gas value chain. Given today's fiscal structure for gas taxation in the upstream

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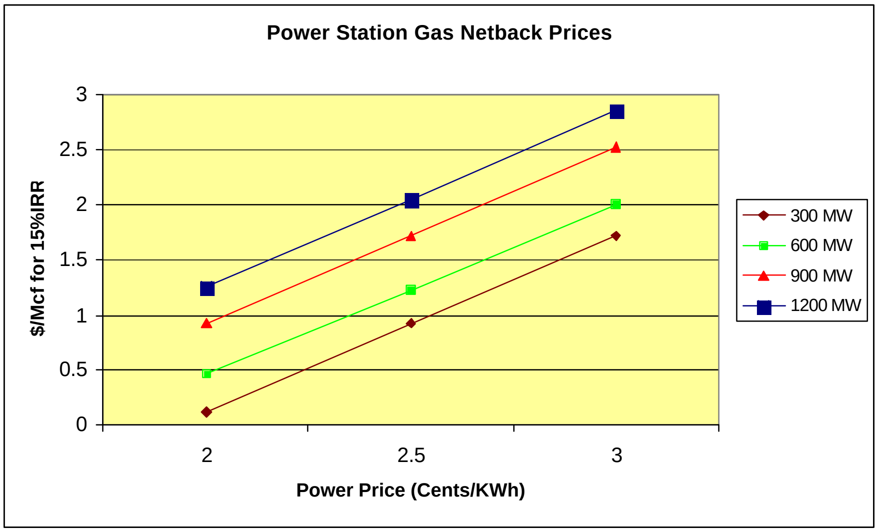
[7] All plants (except power) assumed to be at a port location with adequate infrastructure.
[8] Include the cost of shipping/transport of products to main overseas markets (except power).

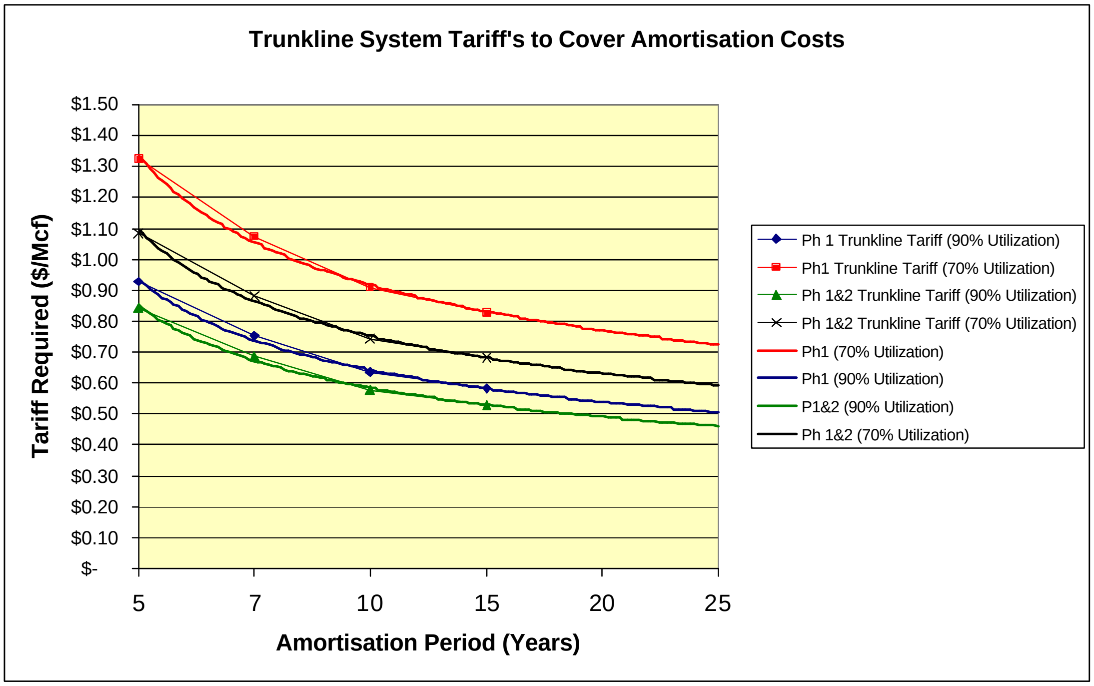
business and adding the cost of a national trunkline system will determine the cost of supply to any location. It is desirable to equalize the price each user will pay across the country to encourage a consistent and widespread growth.

Figure 3.2: Sensitivity of Power Project Feed Gas Netbacks to Price and Size



3.9 Figure 3.3 shows the tariffs needed for a national trunkline system shown in Figure 3.4 and based upon a 3 Bcfd throughput for Phase 1 and 5 Bcfd for Phase 2, shows that a tariff around US$0.5 to US$0.6/Mcf is achievable.

Figure 3.3: Countrywide Trunkline System Tariff Requirements



3.10 The cost and pipeline lengths used for this analysis are shown in Table 3.1 below and assume that the entire system is covered in Phase 1 and the capacities increased through loop lines along the busiest corridors. This is a high level analysis that has been calculated using IHS Energy Groups cost estimating software, QUE$TOR, and thus is in line with the likely costs that can be expected.

Table 3.1: Countrywide Trunkline System Costs, Lengths and Diameters[9][10]

Nigerian Pipeline Backbone and Trunkline System Basis

Basis for trunkline	**km**	**Phase 1**	CAPEX	OPEX	**Phase 2**	CAPEX	OPEX	**Phase 3**	CAPEX	OPEX
Name	length	Line size	MM$	MM$/yr	Line size	MM$	MM$/yr	Line size	MM$	MM$/yr
East West Connector	225	36			36			36		
East to Ajaokuta via Enugu	340	36								
Enugu to Makurdi	305	24								
ELS to Akure	75	24								
ELS to Ibadan/Abeokuta	135	24								
Ajaokuta to Kaduna	325	42			36			36		
Kaduna to Kano	205	42			36			36		
Kaduna to Yola	630	24								
Kano to Maiduguri	530	24								
Kano to Katsina	150	36			36			36		
Katsina to Bimin Kebbi	415	24								
ELS loop	400				36			36		
ELS to Ajaokuta	250				36			36		
		km	**MM$**	**MM$/yr**	**km**	**MM$**	**MM$/yr**	**km**	**MM$**	**MM$/yr**
Length of 42 inch	km	530	994	10						
Length of 36 inch	km	715	880	10	1005	1340	14.4	1005	1340	14.4
Length of 24 inch	km	2090	1780	20						
		3335	**$3,654.00**	**$40.00**	**1005**	**$1,340.00**	**$14.40**	**1005**	**$1,340.00**	**$14.40**
System Capacity (approx)		**3 Bcfd**			**5 Bcfd**				**7 Bcfd**	

3.11 If lower average power prices are desired by FGN, then the FGN requires a shift from taxing upstream to collecting downstream profits and sales/consumption taxes.

Population

3.12 The main driver for wealth generation and provision of socioeconomic stability in Nigeria is a rapid growth of GDP relative to the population level. The population of Nigeria in 2000 was estimated to be 116.7 million based on government projections of an earlier census. The population is shown by state in Table 3.2. The northern province of Kano is the most populous province with 7.6 million people, followed by the coastal province of Lagos, which is home of Nigeria's Capital, with 7.5 million people.

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[9] See Figure 2.15 for basis.
[10] See Figure 3.2 for basis.

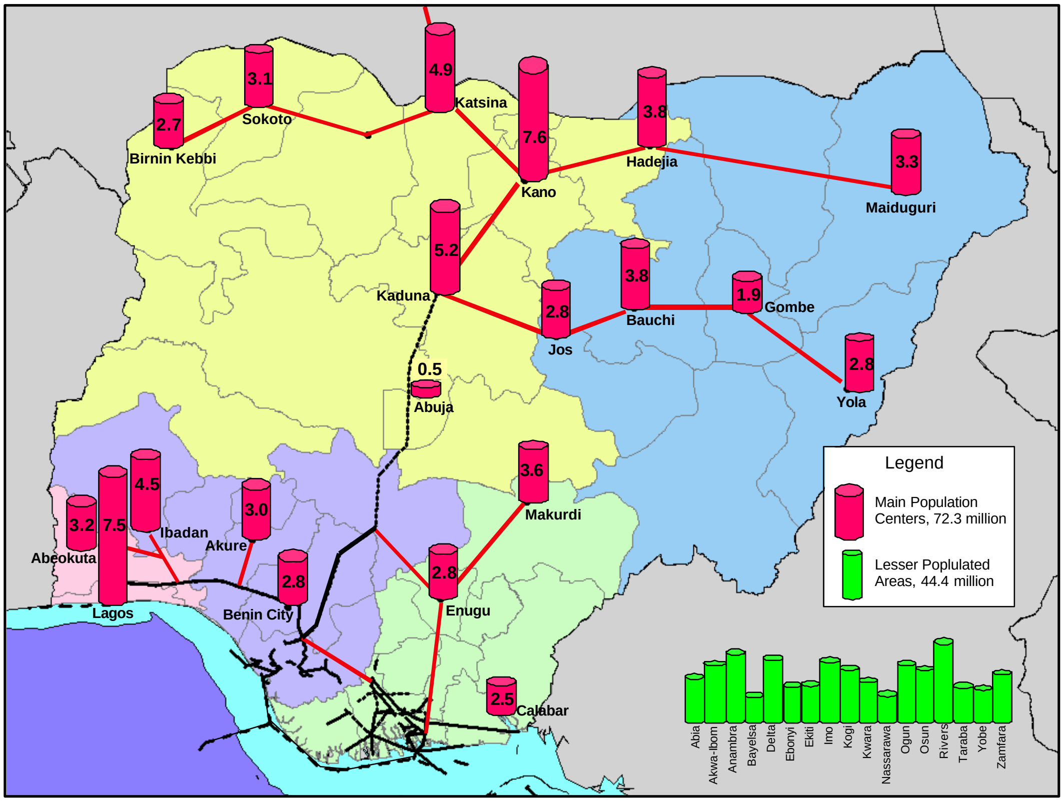
Table 3.2: Distribution of Population in Nigeria by State

(2000 figures, millions)

State	*Population Millions*
Abia	2.5
Adamawa	2.8
Akwa-Ibom	3.2
Anambra	3.7
Bauchi	3.8
Bayelsa	1.5
Benue	3.6
Borno	3.3
Cross River	2.5
Delta	3.4
Ebonyi	1.9
Edo	2.8
Ekiti	2
Enugu	2.8
FCT	0.5
Gombe	1.9
Imo	3.3
Jigawa	3.8
Kaduna	5.2
Kano	7.6
Katsina	4.9
Kebbi	2.7
Kogi	2.8
Kwara	2
Lagos	7.5
Nassarawa	1.5
Niger	3.2
Ogun	3.1
Ondo	3
Osun	2.8
Oyo	4.5
Plateau	2.8
Rivers	4.2
Sokoto	3.1
Taraba	2
Yobe	1.8
Zamfara	2.7
Total	**116.7**

Source: World Bank

Figure 3.4: State Populations and Proposed Trunkline in Nigeria



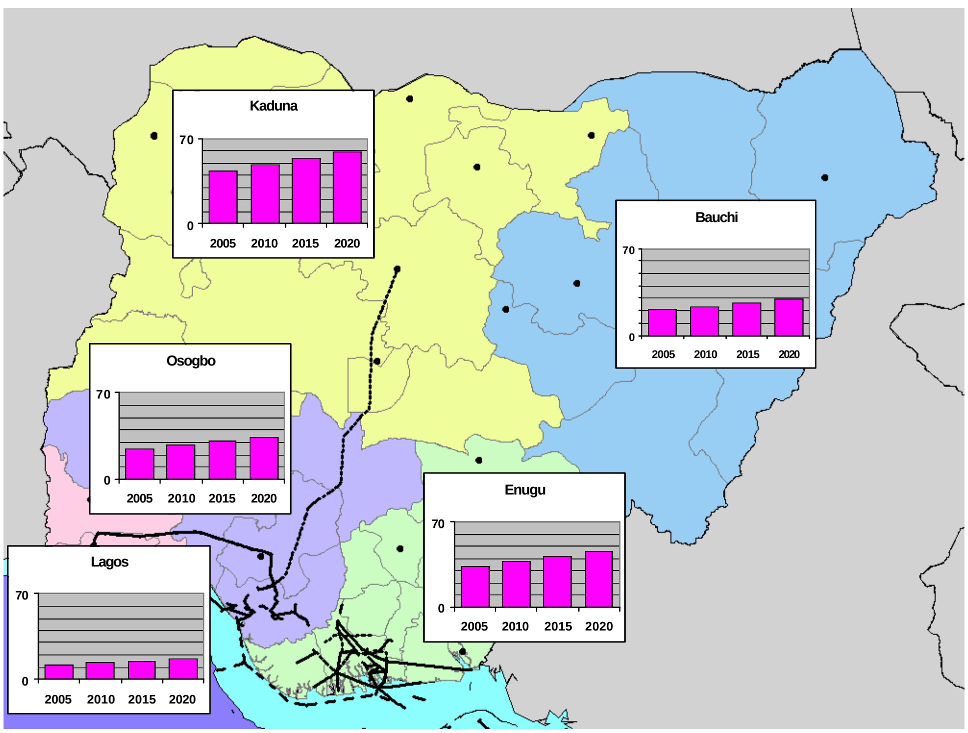
3.13 The recent annual growth rate for population in Nigeria is 2.83 percent. The recommendation of the Vision 2010 Committee is that Nigeria reduce its rate of population growth to under 2 percent by 2010. Using this projected rate, the future population of Nigeria through 2025 was estimated. These projected figures by region are shown in Figure 3.5 and illustrated in Table 3.3. By 2025, the population of Nigeria is expected to increase to 204 million, an increase of 75 percent from that of 2000. The implications of the population increase on the projected demand are covered under the section on Domestic Consumption Projects. The population has been segregated into four regions as shown in Figures 3.4 and 3.5. These four regions are understood to be the NEPA designated zones. Of the zones, Kaduna has the most population of the regions with 37.2 million people, followed by Enugu with 29.2 million (Figure 3.4).

Table 3.3: Projected Nigerian Population

(in millions) Growth for Period 2000–2025

Year	*2000*	*2005*	*2010*	*2015*	*2020*	*2025*
Bauchi Region	18.4	21.1	24	27	29	32
Enugu Region	29.2	34	38	42	46	51
Kadunas Region	37.2	43	48	54	59	65
Lagos Region	10.6	12	14	15	17	19
Osogbo Region	21.3	24	28	31	34	37
Total	**116.7**	**134**	**152**	**169**	**185**	**204**

Figure 3.5: Projected Population Growth by NEPA Power Region (in millions)



3.14 The growth in the above region further demonstrates the need to get gas and power to the northern parts of the country, as a substantial part of the population will be from there.

Nigeria's Competitors

3.15 Each of the following countries has been reviewed as a likely competitor to Nigeria in one or more of the gas use markets. The strength and characterization of this competition differs from country to country but is highlighted in each description. On review, some countries offer little competition but these have been retained for visibility. Each contains a summary description of the relevant elements of the country's background.

Angola

3.16 Angola potentially is a competitor to Nigeria in that its recent end to over 20 years of civil war puts it on the same time scale to develop its gas business.

3.17 Angola's proven plus probable oil reserves have risen from a little under 4 billion barrels in 1990 to some 13.3 billion barrels at the end of 2001. The equivalent gas reserve figures over the same period are 7.5 and 15.4 Tcf.

3.18 Since oil was first discovered in 1955, Angola's oil and gas industry has grown to a point where the country is sub-Saharan Africa's second largest oil producer, behind Nigeria. Crude oil production has quadrupled since 1980 to levels in excess of 750,000 Bpd. Another milestone was reached in the latter part of 1999 with the start of production from Kuito in Block 14, Angola's first deepwater field. In the latter part of 2001, production commenced from the Girassol field. Once the production plateau of 200,000 Bpd from Girassol and 100,000 Bpd from Kuito are reached, crude oil output in Angola will approach the 1 million Bpd mark.

3.19 Virtually all of Angola's oil and gas production is derived from offshore operations with only a little over 2 percent produced onshore.

3.20 In 1999, Angolan gas production amounted to 226 Bcf with some 80 percent being flared and the balance split between reinjection, internal fuel usage and a small percentage marketed as LPG.

3.21 A growing number of the large multinational energy companies are instituting policies to reduce or halt flaring. Some individual organizations are pushing the development of gas conversion technologies.

3.22 One such proposal by ChevronTexaco for an LNG project, certified expectation reserves of gas (for Blocks 1, 2, 3, and 17) are put at 9.5 Tcf with ranges from 4 Tcf (proven) to 25 tcf (proven, probable and possible). They do not take into account fields discovered in the ExxonMobil-operated Block 15 and BP-operated Block 18.

Equatorial Guinea

3.23 Traditionally, Equatorial Guinea has relied heavily on its agricultural sector for its economy. However the oil sector has grown rapidly in recent years and the country produced an average 186,000 Bpd of hydrocarbon liquids and an estimated 350 Mmcfd of gas in 2001. Proven and probable reserves were estimated at 1430 million bbls of oil and 5.3 Tcf of gas. Around two thirds of the gas produced is currently being flared or reinjected.

3.24 The Atlantic Methanol Production Company (AMPCO), a consortium comprising CMS Energy Corporation (45 percent), Samedan Oil Corporation (45 percent), and the Equatorial Guinea government (10 percent) completed installation of a 2,500 Tpd methanol plant at Punta Europa on Bioko Island in the Gulf of Guinea in 2001. The US$400 million plant will process gas from the Alba field into commercial methanol for export on the world market. Construction began in mid-1999 and start-up occurred during the second quarter of 2001 The methanol plant consumes around 115 Mmscfd of feed gas. Alba field reserves are now estimated at 4.2 Tcf (proven plus probable) having more than doubled in 2001. This project is thus a direct competitor to prospects for a similar development in Nigeria.

Gabon

3.25 Gabon is sub-Saharan Africa's third largest producer and exporter of crude oil. In 2001, the country's crude oil production averaged some 255,000 Bpd, down over 25 percent from the 1998 average of some 350,000 Bpd. Proven and probable reserves were calculated to be at around 1,86 Mmbbl of oil and 1.54 Tcf of gas at the end of 2001.

3.26 Gabon relies heavily on crude oil exports, which account for some 80 percent of total export revenues and there is some government concern about the longer-term trend of diminishing reserves.

3.27 Natural gas production is of the order of 260 Mmcfd and is used for power generation, refinery fuel or reinjected in the offshore fields for pressure maintenance. Gabon provides little competition as an alternative supplier.

Democratic Republic of Congo

3.28 The Democratic Republic of Congo produces a small amount of oil 24,500 Bpd and gas (32 Mmcfd), mainly offshore. Remaining reserves are 110 Mmbbl oil and 88 Bcf gas, mostly situated offshore. Reserves and production in Nigeria are far in excess of this, and therefore DRC does not provide competition as an alternative supplier.

Congo Brazzaville

3.29 Both oil and gas reserves and production in Congo Brazzaville are almost entirely offshore, and smaller than those of Nigeria. In 2001, oil reserves stood at 1.63 billion barrels remaining, with production of 230,000 Bpd. Production is about one-tenth of that in Nigeria, whereas remaining reserves are about one-twentieth of those cited for Nigeria. The situation for gas is similar, with production in Congo Brazzaville of 360 Mmcfd and remaining reserves of 2.9 Tcf.

3.30 Congo Brazzaville's economy is dominated by oil, and foreign expertise is relied upon for development and production. TotalFinaElf is the major producer, with Agip taking an increasing role in exploration and production. Interest from oil majors is based on the possibility of deepwater offshore potential similar to that being discovered in Nigerian waters.

3.31 Under present circumstances, Congo Brazzaville does not provide much competition as an alternative supplier.

Cameroon

3.32 Oil and gas reserves and production are offshore, at levels significantly below those in Nigeria. Remaining reserves are 480 MMbbl oil and 4.6 Tcf gas, and production in 2000 was 120,000 Bpd and 216 MMcfd gas. Under present circumstances Cameroon provides little competition as an alternative supplier. Current production is offshore, a long way from any infrastructure and especially in the Rio de Oro area are flaring virtually the entire gas produced, only using approximately 5 percent for fuel.

Mozambique

3.33 Mozambique has had political stability since the cessation of the civil war between the government and Renamo in 1992. Following the 1994 elections, the democratically elected government has achieved a stable and responsible record, including a role for the opposition. During the 1990s, the country achieved strong economic growth with a series of agricultural reforms that significantly improved the exports of agricultural commodities. The government has also reformed the economy and introduced privatization with over 700 of its 1000 or so state-owned enterprises transferred to the private sector.

3.34 The country has considerable natural resources not least of which is its low-cost hydroelectric power. It borders South Africa, a potentially large market in future years if that country's economy continues to grow strongly.

3.35 Apart from Temane and Pande fields, there are offshore exploration plans in the Sofala Bay and M-10 concession, near the city of Beira. SASOL has tentative plans to build a GTL plant there if sufficient gas can be found. This would be a similar project to that due onstream in Nigeria in 2005.

3.36 Mozambique's favorable geographical proximity to markets in South Africa and its likely supply of gas to that country is a competitive factor against Nigeria's prospects of supplying gas or power to this market. In addition, other gas monetization projects (such as its new aluminum smelter) provide a competitive element to potential Nigerian plans in this area.

Namibia

3.37 Namibia has examined the feasibility to pipe gas ashore from its southern offshore Kudu Field to feed a power plant located at Oranjemund to supply Namibia and South Africa. The forecast capacity of the plant, originally 750 MW, may have been reduced to 500 MW. Peak Namibian demand is around 350 MW and such a plant should be big enough to cover Namibia's electricity needs for the foreseeable future. Shell and Cape Area Metropolitan Local Authorities (CAMALA) are also jointly conducting feasibility studies into a 700 km pipeline to feed a power plant at the Cape as well as to provide fuel for industrial plants at Saldanha.

3.38 In addition, Shell is investigating the potential of using an offshore floating LNG facility at Kudu. If it proceeded, then this would compete for the LNG market, however, currently it is not seen as viable.

Saharan Africa (Libya and Algeria)

3.39 Both of these countries are potential competitors as gas suppliers (LNG and pipeline), particularly into southern Europe. More discussion on the issues involved here is presented in the LNG demand-side sector analysis in Appendix 2.

Egypt

3.40 Since exploration for natural gas began in the early 1990s, a number of significant gas deposits have been found in the Nile Delta and the Western Desert. Proven plus probable gas reserves have been rising rapidly in recent years from 25 Tcf in 1995 to almost 63 Tcf in 2001, with possible reserves based on initial offshore seismic analysis considerably in excess of this figure. Currently Egypt consumes all the gas it produces (510 Bcf in 2000). Its domestic demand, growing at some 5 percent per year, is used predominantly in thermal power plants (some 65 percent of total consumption). Natural gas is also being used in heavy industrial plants, including a world-scale ethylene plant at Sidi Krier, a large fertilizer plant in Suez and several major new steel plants. However, even with high projected growth, there is a limit to the amount of gas that can be absorbed in the domestic market and approximately 1 Tcf/year could be available for export in the next few years unless the gas is intentionally not developed.

3.41 Plans for gas exports include both pipeline gas and LNG to countries such as Turkey, Israel, Jordan, Western Libya, and Palestine. Plans for exporting the gas have been complicated by pricing concerns; Egypt is insisting that it sells gas at crude oil price parity. There are a total of four LNG schemes under discussion backed respectively by Union Fenosa (Spain), BG Group/Edison, BPAmoco/Eni and Shell.

3.42 In addition, Shell is examining a 75,000 Bpd GTL plant.

Chile

3.43 Cabo Negro is the site of Methanex Chile, the world's largest methanol complex with three trains producing a total of 8,500 Tpd.

3.44 The complex uses gas from both Chile and Argentina—indeed the third train uses Argentinean gas feedstock exclusively, and Argentinean shipments are the main reason for the recent capacity increases at the complex. Cabo Negro's location, protected from the strong winds and its ability to handle vessels up to 90,000 dwt, means that it is expected to be the main loading terminal for both Chile and southern Argentina. There is also interest in expanding gas processing capabilities to produce ammonia-urea, polyethylene and normal paraffins. Justification for an LNG plant has been discussed.

Venezuela

3.45 Venezuela has the seventh largest gas reserves in the world (some 149 Tcf) but gas production has taken a back seat compared to oil. The intention is to double gas production from a current 5 Bcfd to 9-10 Bcfd by 2010. Petroleos de Venezuela (PDVSA) is hoping that increased production and an expanded transport and distribution network will help to develop a market with gas-fired power plants and a gas-based petrochemicals industry.

3.46 By 2009, Venezuela plans to increase exports to 1Bcfd and 370,000 Bpd of NGL's. The country has revived its LNG export project (historically known as Cristobel Colon) with a single 4 Mmt train plant in proposed production by 2005 targeting the U.S. eastern seaboard and the Caribbean. The timing of this is unlikely given the current political situation, but could easily be fast tract given a different economic environment.

Trinidad and Tobago

3.47 Trinidad and Tobago has two purpose-designed major industrial sites for its gas downstream industry—Point Lisas on the west coast and Point Fortin in the southwest. Ammonia and methanol are the main methods of gas monetization and the country is already the world's biggest exporter of these two basic nonoil petrochemicals. Eight ammonia plants at Point Lisas produce 3.5 Mmtpy and a ninth, currently under construction, will boost production to over 4 Mmtpy. There is also a urea plant exporting 530,000 Tpy.

3.48 Also at Point Lisas, five worldscale methanol plants export some 3 Mmtpy to world markets. Methanol Holdings, which owns four of the five plants, is also planning a further unit that is thought to be the world's largest at 1.7 Mmtpy.

3.49 Once the expansion at Atlantic LNG is completed, Trinidad and Tobago will be the sixth largest exporter after Algeria, Indonesia, Qatar, Malaysia, and Australia. At Point Fortin, Train 1 is in operation and Train 2 is expected to be ready at the same time as the Dominican Republic's receiving terminal (2002). Train 3 is expected to come onstream in 2003. The new plants will raise capacity from 4 to 13 Bcmy. More than half of the additional capacity is earmarked for the Spanish market (3 Bn to power plants, 1 Bn to gas supply and 1 Bn to Gas de Euskadi). The remaining 4Bbn is destined for the US market.

3.50 Trinidad and Tobago is also believed to be investigating (with Noranda of Canada and BPAmoco), the feasibility of an aluminum smelter of 237,000 Tpy capacity, utilizing gas for power generation.

3.51 At the end of 2001, Trinidad and Tobago's proven plus probable gas reserves were put at 36.1 Tcf. Two of the major IOCs active in the country have carried out studies that suggest reserves could be in excess of 60 Tcf. Development of the country's gas resources are likely to need cooperation with Venezuela, since some fields straddle the maritime boundary. Trinidad's Energy Minister believes that Venezuela can only monetize the gas in waters north of the Paria Peninsula and on the Venezuelan side of the maritime boundary in the Atlantic only if it accepts that gas will have to be landed in Trinidad for liquefaction or other industrial use.

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3.54 There are two other projects for gas monetization at the planning stage:

a. Nova Chemicals (Canada) US$1Bn 500,000 Tpy ethylene plant

b. Reema International (US) £300 Mm GTL plant using about 100 Mmcfd gas

3.55 Shell is also interested in a GTL plant currently at feasibility study stage.

North America

3.56 The timing and scope of natural gas production from the U.S. Alaska North Slope and Canada's Mackenzie Delta/Beaufort Sea region remains a potential baseline competitor. Proven reserves are estimated at 30 Tcf with a possible further 100 Tcf undiscovered on the North Slope and 150 Tcf unproven in Canada.

3.57 Plans to monetize stranded gas from this area have included LNG, GTL, and a pipeline (although the latter is likely to need 3-4 Bcfd to be economic). BP is a leading player in this region, but they believe converting the gas into LNG for the Asian market faces major obstacles. If a pipeline is approved and enabled through tax and various other political concessions, it would put a substantial dent in the U.S. LNG requirement in the 2007—2015 time frame. They have unveiled plans for a GTL plant (cost US$86 million) on the Kenai Peninsula, using 3 Mmcfd to produce 300 Bpd of diesel and jet fuel. The plant is currently on hold.

3.58 It is possible that smaller projects might be initiated in the short term until the bigger decisions are made.

3.59 The Canadians are investigating a purely Canadian resources project to tap the Mackenzie Delta and Beaufort reserves of 12 Tcf with a pipeline of 800 Mmcfd to 2 Bcfd.

3.60 Canada has long been a key factor in U.S. energy supplies (it currently exports more than half of its oil and gas output to the United States). The United States has indicated its desire to reduce dependence on Middle East oil imports by relying more on imports from Canada and Mexico. However, indications are beginning to emerge that Canada is becoming concerned about the volumes of oil, natural gas, and power moving into the United States, especially as Canada's domestic users have seen escalating gas prices recently as a result of a squeeze on supplies.

4

Current Gas Utilization Project and Plans

Existing Projects

Nigerian LNG Project

4.1 The NLNG project is the first gas utilization project of any substance in Nigeria. Production of LNG started in September of 1999 with the first LNG cargo lifting in October. When fully complete NLNG will have 5 trains, consume around 2.5 Bcf/day and produce 16.7 million metric tons of LNG for export. In addition it will produce in excess of 2 MMtpy of NGL's depending upon the AG and NAG split in the feedstock. Trains 1 and 2 are currently producing, train 3 is under construction and due for completion in late 2002 and trains 4 and 5 have been approved for expenditure and are due to be completed in 2005 and 2006 respectively. Figure 4.1 shows the build up of gas usage over the projected life of the facilities.

4.2 NLNG's ownership is reflected as follows:

NNPC	40%
Shell Gas BV (SPDC)	25.6%
Elf Cleag Ltd (Elf)	15%
Agip Int BV (NAOC)	10.4%

4.3 The IOCs, having provided the financing for the facilities, each have an allocated commitment to supply gas to the plant generally in proportion to their equity holding for the life of the project. These supply agreements are exclusive to the equity holders, thus precluding nonequity holders from contributing or benefiting from the facility. Figure 4.2 shows the volumetric commitment of each of the IOC's.

Figure 4.1: Projected Gas Consumption of Nigeria LNG

Trains 1 to 5

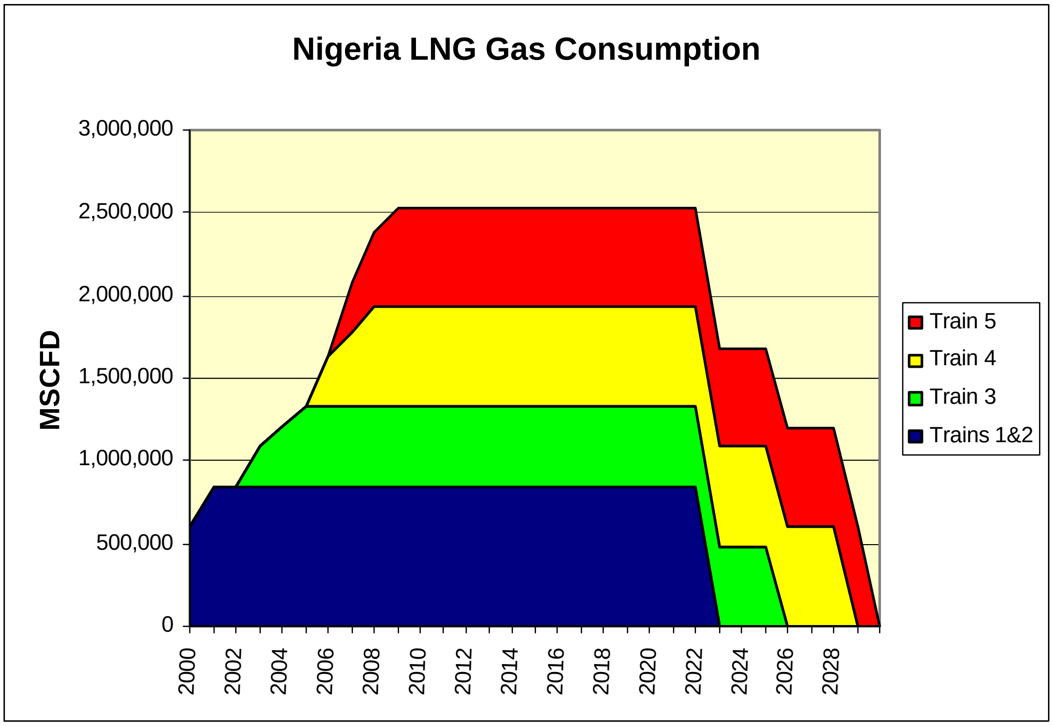
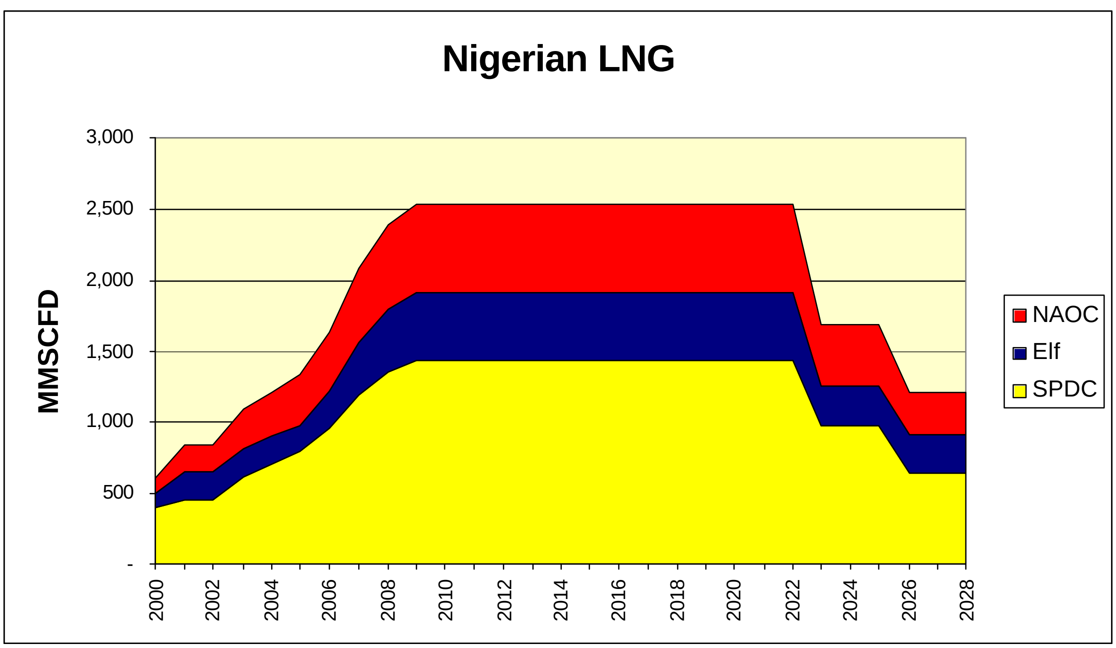


Figure 4.2: Allocation of Gas Supply to Participating Companies



4.4 It should be noted that all five trains will be capable of processing rich AG and thus contribute to a significant reduction of currently flared gas in the Eastern Sector. The facilities also have the ability to process NAG should oil production be curtailed (by OPEC agreement) with the resulting diminishment of AG. This flexibility is important in ensuring the security of supply in the future.

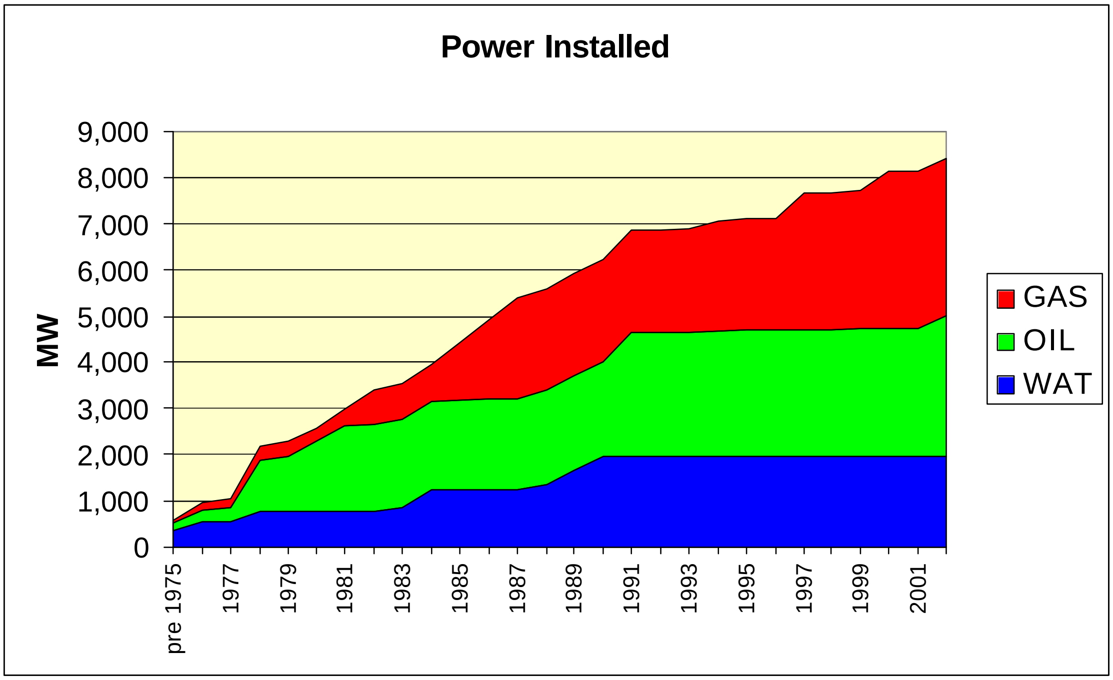
Domestic Consumption Projects

4.5 Domestic consumption projects range from major potential gas consumers such as the power sector to the much smaller ones in residential and small industry applications. This study attempts to identify each consumer category and where possible, quantify current and projected usage. Additionally, import replacement categories are pointed out. It is important to realize that domestic market information and projections have been gleaned from various sources and are considered valid as to order of magnitude for the purposes of this study, however a more detailed analysis of each sector/project will need to be carried out during the implementation phase of the NGMP. In some of the areas, particularly import replacement, only minor quantities of gas may be required, but as national interest entities, different evaluation criteria will undoubtedly apply in the NGMP.

Power Sector

4.6 The known installed operating capacity in Nigeria is 7923 MW. Of that, NEPA owns 6029 MW. The remainder are private plants associated with government buildings, various manufacturing plants, large office buildings, and universities. Gas-fired plants generate the largest portion of electricity with 41 percent (2932 MW) of the total power generation. Oil-fired plants are next at 36 percent, and hydroelectric plants are third with 23 percent of total power generation. Figure 4.3 shows the historical and current commercial power installed in Nigeria. The figure includes both NEPA and private plants but does not include small privately owned diesel generators used for back-up when the NEPA system fails.

Figure 4.3: Historical Commercial Power Installed in Nigeria



4.7 NEPA owns 68 percent of the gas-generated power capacity with three of its four thermal powered plants (Afam, Egbin, and Delta). Of the 2535 MW of oil-generated power capacity, approximately one quarter of that is capable of using gas as an alternate fuel. See Figure 4.4. These plants are therefore able to use gas as of today, this could be increased by upgrading existing oil fired plant to dual fuel, thus saving or making available oil for export. All four of NEPA's thermal plants are on or near the coast, situated near supply centers and the population center of Lagos (Figure 4.5).

Figure 4.4: Current Commercial Power Installed in Nigeria

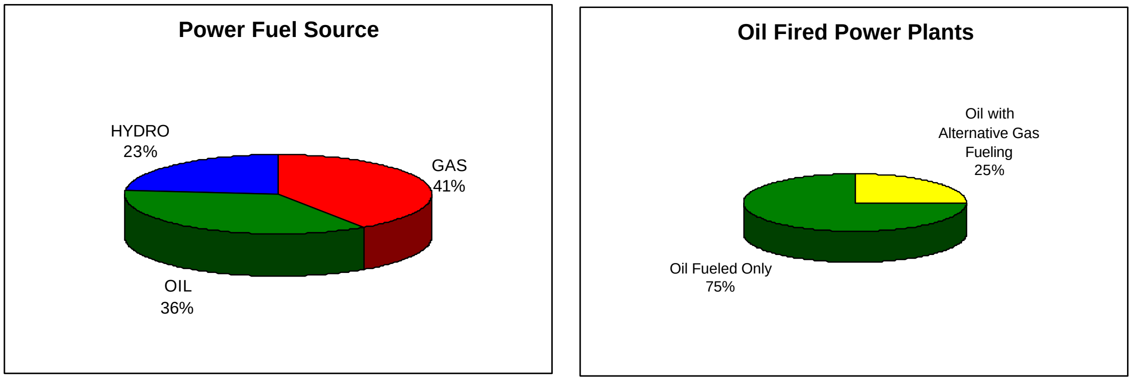
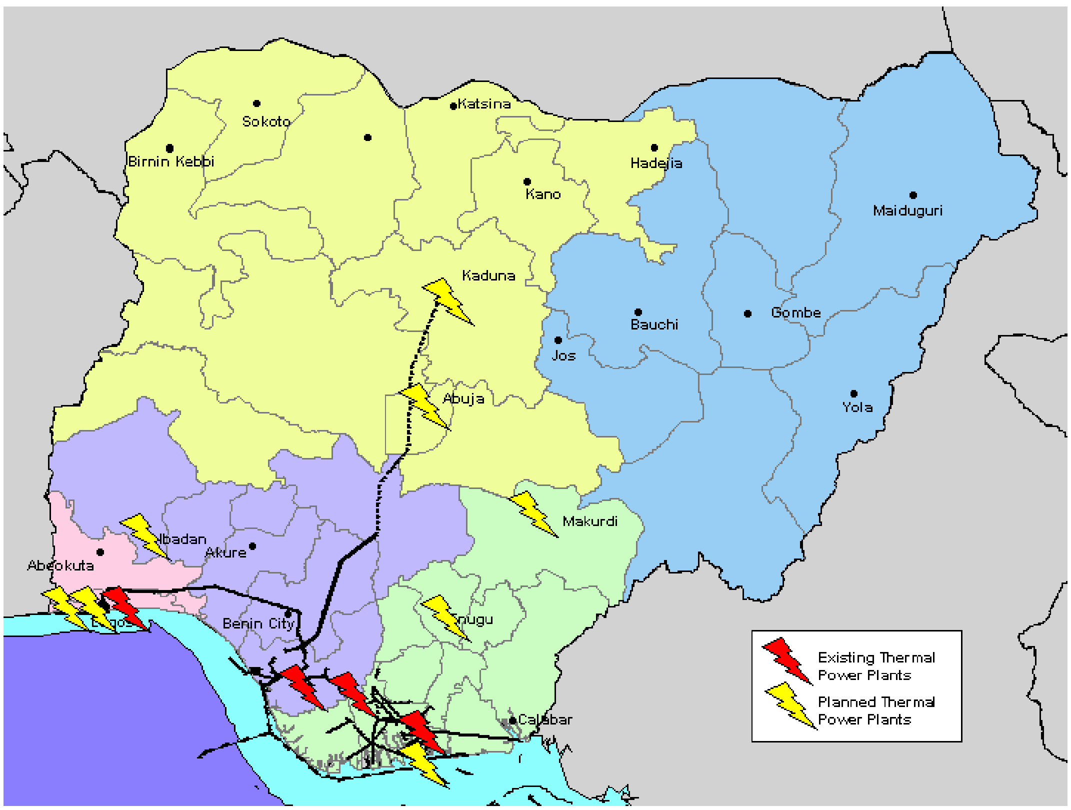


Figure 4.5: Map of Nigeria Showing Location of Existing and Planned Thermal Power Plants



4.8 NEPA's installed capacity for currently operating plants (all fuels) is 6029 MW, which is 76 percent of total installed operating capacity in Nigeria. However, according to ExxonMobil, in 1998 NEPA's working capacity was only 4528 MW. In 2000, NEPA reported their plants operating at only 2257 MW. Further loss in transmission and distribution resulted in NEPA selling, in 1998, only 11,241 MWh or a delivered capacity of 3122 MW. This translates into a 31 percent transmission loss; a percentage which is estimated to be even higher today at 40 percent. NEPA cannot meet current demand, and many diesel power generators provide back-up power when the NEPA system is down. Because of NEPA's inability to meet demand and the proliferation of private generators, the actual demand is unknown and must be estimated in order to have a realistic basis from which to project future demand.

4.9 Shell Petroleum Development Company estimates the total private liquid fuelled backup generator capacity in Nigeria as being between 3000 and 4000 MW. Using the more conservative of the two estimates, assuming the generators operate at 100 percent of installed capacity, and assuming that these private liquid fuelled generators lose 20 percent in delivery, this gives a delivered capacity of 2400 MW. Adding this to NEPA's 1998 delivered capacity of 3122 MW and to the known capacity from other non-NEPA plants gives a total delivered power capacity of 6663 MW for all of Nigeria. This translates into a per capita consumption of 152 KWh when only the power generation from known operating plants (NEPA and non-NEPA, all fuels) are considered. This compares well to the same figure (142 KWh/capita) calculated using Nigerian electricity production reported by the World Bank.

Table 4.1: Current Power Balance in Nigeria

	Current Installed Capacity MW	*Current Working Capacity MW*	*Current Delivered Capacity MW*	*Current Delivered MWh*	*Required Installed Capacity (if system losses lowered to a typical 25% benchmark) MW*
NEPA, all fuels (known power plants) [11]	6029	4528	3122	11,239,200	4163
Non-NEPA nonliquid (known power plants)	1426		1141	4,106,880	1426
Non-NEPA liquid					
Nondiesel (known power plants)	411		329	1,183,680	411
Diesel (known power plants)	57		46	164,160	61
Additional private diesel generators (back calculated from SPDC estimate)	2532		2026	7,292,160	2701
Non NEPA liquid total (estimated by SPDC)	3000				
TOTAL Known + Estimated	**10455**		**6663**	**23,986,080**	**8761**
NEPA, if NEPA replaced very private generators and known diesel power plants			5193		6924
estimated real per capita consumption, all Nigeria				218 MWh/cap	
estimated per capita consumption, NEPA only				152 MWh/cap	
per capita consumption calculated from 2000 NEPA production (from World Bank)				142 MWh/cap	

4.10 Assuming NEPA could take back the power delivery from the private diesel generators, that it ran at 100 percent installed capacity, and that it reduced transmission loss to 25 percent, NEPA would require an installed capacity of 6924 MW to meet the estimated current real demand. This is only slightly more than NEPA original installed capacity of 6029 MW. Therefore, if NEPA could reinstate its whole power system to original capacity and improve its transmission and distribution losses to 25

[11] Numbers from Platts Power Station Database, ExxonMobil report and NEPA presentation Powerpoint.

percent from its current 40 percent, then Nigeria would have a firm basis for future growth.

4.11 With that basis and with proposed new power plants identified by ExxonMobil as coming online through 2020, the authors have projected the power demand growth through 2040 (Figure 4.6). This projection equates to a 6 percent compound growth, which is easily sustainable and gives an installed capacity of around 77,000 MW. Mexico's growth of power has followed a very similar curve, with a very similar population level.

Figure 4.6: Power Demand Projection for Nigeria

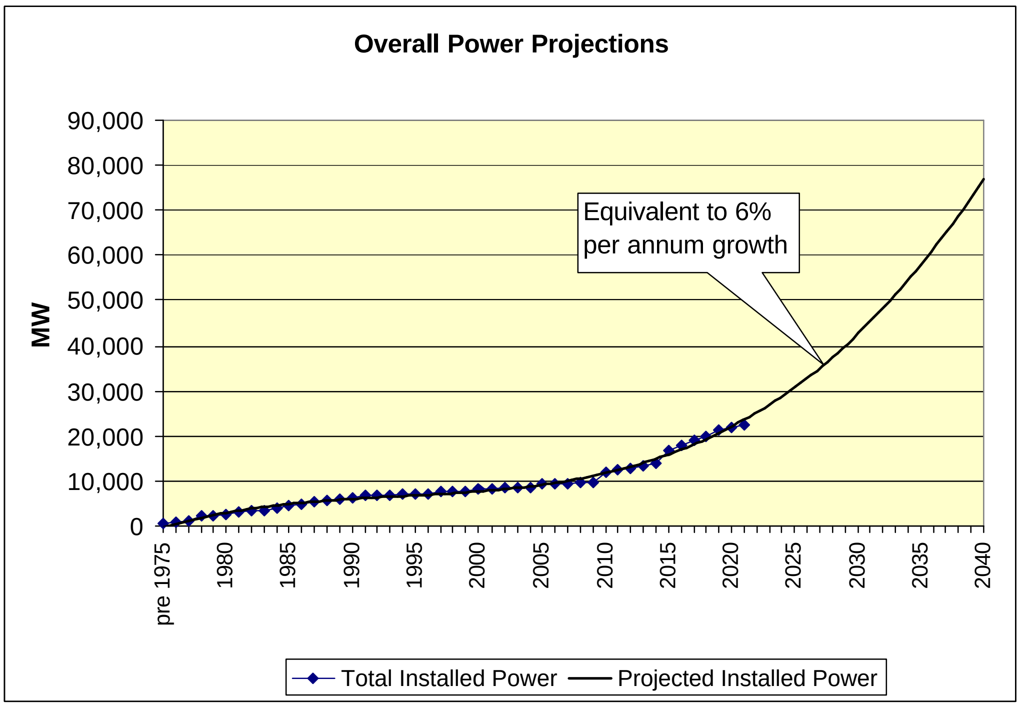


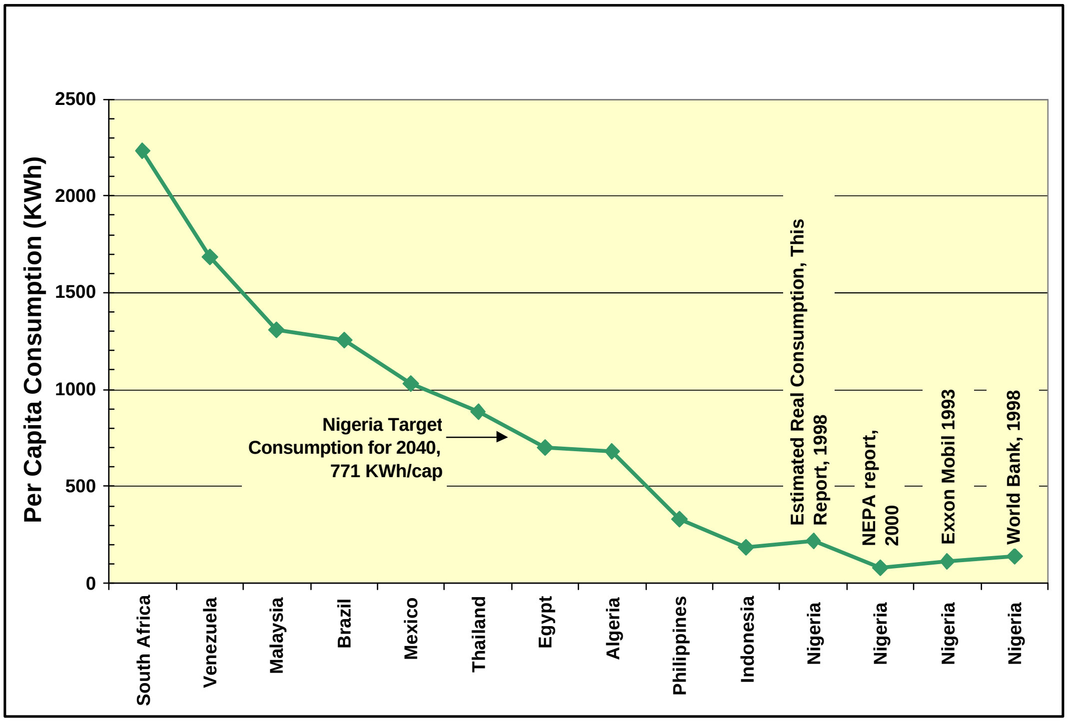
Table 4.2: Gas Power Plants added as per ExxonMobil Study

MW - New Power Installed *Location*	*Region*	*Sector*	*Ultimate MW*	*Year Start*	*Year Full Capacity*
Abuja	Kaduna	West	2420	2005	2021
Enugu	Enugu	West	1760	2010	2019
Ibadan	Osogbro	West	1760	2010	2019
Ikeja	Lagos	West	2200	2010	2021
Alagbado	Lagos	West	1980	2015	2020
Kaduna	Kaduna	West	1210	2015	2021
Makurdi	Enugu	West	1320	2015	2020
Afam 5	Enugu	East	660	2010	2014
Bonny	Enugu	East	880	2050	2014

4.12 To cross check that these projections were reasonable, the per capita usage in the year 2040 was calculated (Figure 4.7). The per capita consumption would rise from today's value of 218 KWh to 771KWh in 2040. This per capita calculation takes into account a growth in population of 2.8 percent today and dropping to below 2 percent in 2010 in line with Vision 2010 projections. It also assumes a 25 percent transmission and distribution loss. Figure 4.6 shows current per capita consumption for several countries similar to Nigeria, and it shows that the projected consumption for Nigeria in 2040 would place it roughly equivalent to Thailand, Egypt, Algeria, or Mexico today. Thus these projections are reasonable targets for Nigeria.

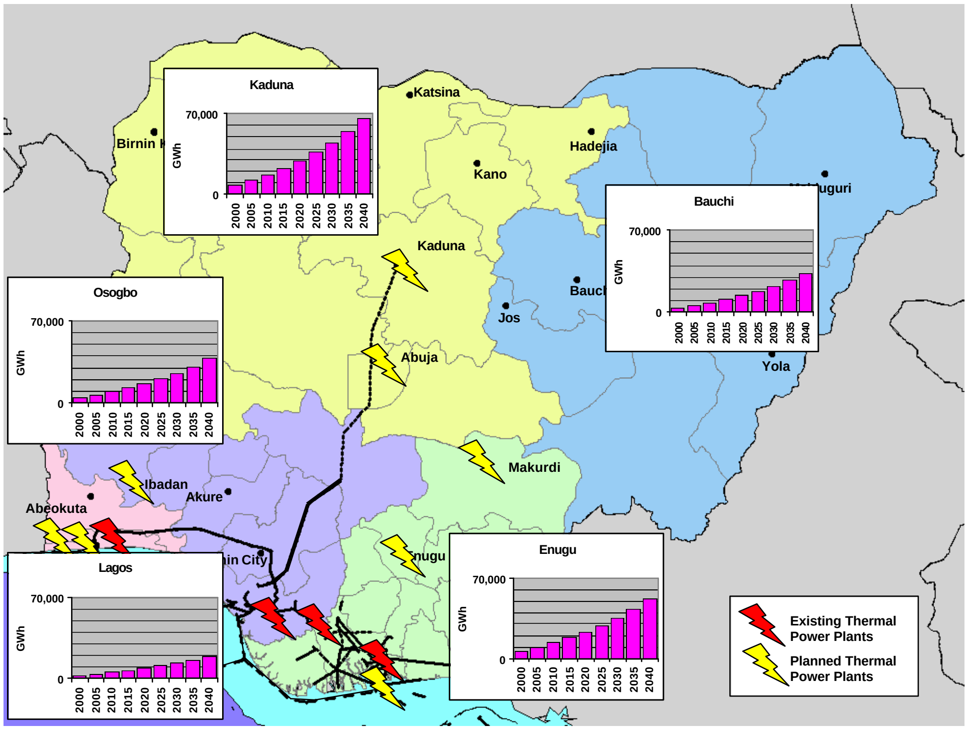
4.13 The future power needs discussed above were estimated based upon an even population growth across the country and an even usage within Nigeria. These power projections are split into NEPA regions as identified in the ExxonMobil study. To assist in seeing where future power distribution may be required, these regional consumption forecasts are displayed on a map of Nigeria (Figure 4.8). NEPA's planned thermal plants appear to be well placed to meet power needs for the next 20-25 years. However, if population growth is relatively even throughout the country, then the Bauchi region and the northern most part of the Kaduna region may require additional power resources by the year 2040.

Figure 4.7: Projected Power Consumption in Nigeria Compared to Similar Countries' Current Consumption



4.14 Given Nigeria's abundant gas resource and attractive netbacks for power supplied in the price range of US$0.02 to US$0.025/KWh, it is hugely advantageous that the vast majority of future power generation should be gas fired. Greater efficiencies are achieved by burning gas rather than oil or diesel in a single-cycle system. Combined cycles are unlikely to be feasible across the majority of the country, as the use of hot water or steam is difficult to coordinate in the short timescales needed. The basis for planning should thus be gas single-cycle systems. Combined cycles may be feasible but are likely to be the exception. The need to have substantial power generation come on line as quickly as possible is highly desirable, especially in a phased manner. Gas-fired power generation can be put on stream in a little over a year rather than the alternative hydroelectric plant that take many years to even clear the environmental approval let alone the commissioning of power.

Figure 4.8: Projected Power Consumption in Nigeria by Region



4.15 The consequences of future gas power generation on gas demand are shown on Figure 4.9. The gas consumption from gas-fired power plants would ultimately rise to 7000 Mmcfd by 2040 from the current level needed for the existing plants of 392 Mmcfd.

4.16 The emergence of IPPs, BOTs (Build Operate, and Transfer), and ROTs (Refurbishments, Operate, and Transfer) is making this sector look more credible and the future targets achievable. However, until the problem of charging and collecting monies owed on a realistic power price basis and the reinstatement of a credible country credit rating is achieved, no sustainable progress will be made. Mexico has made a remarkable transformation in this area both allowing private ownership in generation, including developing a legal and regulatory framework for it to operate in, together with raising prices to realistic levels acceptable to their customers.

4.17 Based upon government policy of reorganizing the power sector to resemble the current international framework, regeneration can start, that is. a split into three subsectors as follows:

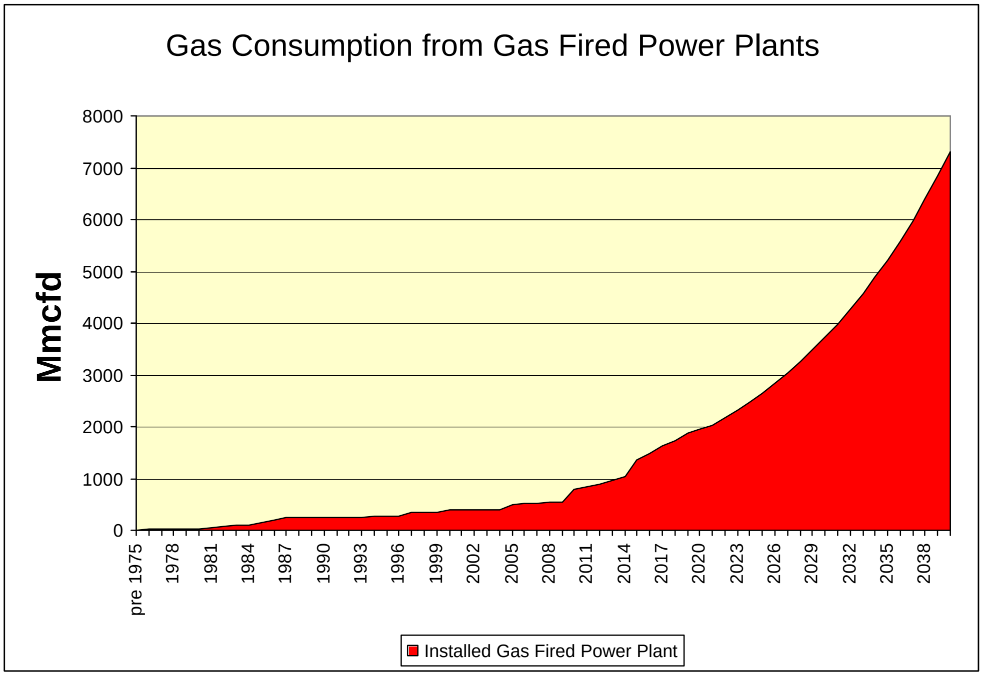
a. Generation Sector

b. Transmission Sector

c. Distribution and Retailing Sector

4.18 With this split, implementation becomes possible, provided it is done in parallel with a proper prepayment and disconnection system framework. A new and growing sector will undoubtedly emerge as soon as a rigorous legal framework can be finalized for the infusion of foreign direct investment and private sector participation.

Figure 4.9: Gas Consumption Projections for Future Gas Power Plants



4.19 The process of developing power can be enhanced by promoting the policy of using local LPG, or piped gas based microturbines in the more remote regions, in parallel to major power hubs needed across much of the country. This option may both enhance and speed up the recovery and development of Nigeria's power sector as it prepares the future buyers to expect and manage to pay sustainable prices in the future.

LPG Sector

4.20 LPG penetration in the Nigerian economy has grown steadily during the last few years to a figure of about 56,000 metric tons in 1998 based on a study commissioned by The World Bank and World LP Gas Association in 1999. There is some conflict in other source documentation, with ExxonMobil indicating a domestic utilization of 194,000 metric tons in the same year. This indicates the requirement to confirm existing levels of domestic consumption prior to any implementation scheme that envisages major LPG market expansion. Even at the higher current level Nigeria would appear to be an excellent candidate for expansion in this area.

4.21 Accepting the above utilization anomalies, LPG will still play a substantial role in implementing the NGL rich (including LPG) AG disposal/flare down policy. Currently Nigeria's refineries are expected to supply the domestic market, but because of chronic operating problems have proven to be an unreliable source of supply. Indeed, although Nigeria is a net exporter of LPG, it has to resort to importing of the product on occasion to assure adequate domestic supplies. While the majority of the LPG production will continue to be exported, both from the refineries and from current/proposed NGL/LNG projects, the domestic market should be aggressively addressed in both the industrial and residential sectors.

4.22 The industrial market in Nigeria consumes approximately 60 percent of the current domestic LPG according to the World Bank/World LP Gas Association Study. In the absence of any other denoted split in usage this would indicate a residential consumption of 40 percent, or approximately 23,000 metric tons per year. This is set out in a comparative form extracted from the WB/WLPGA study in Table 4.3 below.

Table 4.3: West Africa LPG Consumption

	Total LPG Consumption (MTonnes)	*Percent Res/Comm (%)*	*Res/Comm LPG Cons. (M Tonnes)*	*Population (MM People)*	*R/C LPG Cons. Per Capita (Kg/Year)*
Cameroon	28	95	27	14.9	1.8
Cote D'Lvoire	50	85	43	15.7	2.7
Ghana	40	85	34	19.2	1.8
Senegal	100	98	98	9.5	10.3
Subregional Average	**218**	**92**	**201**	**59.3**	**3.4**
Angola	50	90	45	11.7	3.8
Congo, Dem. Rep.	1	90	1	49.6	0.0
Congo, Rep.	4	90	4	2.7	1.3
Gabon	17	90	15	1.2	12.8
Nigeria	**58**	**40**	**23**	**125.1**	**0.2**
Other Countries	13	90	12	65.8	0.2
Total West Africa	**361**	**83**	**301**	**315.4**	**1.0**

4.23 While not a rigorous comparison, due to some distortion by subsidies, it is obvious that there is a substantial market available in Nigeria when compared to Cameroon, Cote d'Ivoire, Ghana, and Senegal. Nigeria's consumption of 0.2 Kg/year per capita versus and average of 3.4 Kg/year for the foregoing countries is a solid indication of an immature market sector. Even adjusting the total consumption figure to that shown by ExxonMobil should be sufficient incentive to address this sector in an aggressive manner. It should be reiterated at this point that the utilization of LPG for the residential sector has many socio-economic benefits including:

- Mitigation of massive deforestation for fuel,
- provision of a relatively nonpolluting energy source and
- contributes to a quality of life improvement, particularly when economies of scale bring the price of the product into reach of average populace

4.24 The industrial sector will benefit in some of the same ways as the residential sector. It will, in addition, help to generate a market which may grow in size and importance to the point that a natural gas feeder/reticulation system can be justified when users are located near a backbone line. Obviously, price and reliability of supply are keys to the further penetration of this market.

4.25 As indicated earlier, more market data in both the residential and industrial areas will be required prior to the progressing of an expansion effort and potential sizing and construction of any piped LPG infrastructure to main distribution points.

Cement Sector

4.26 The cement sector is one that fits easily in the category of a national interest entity. Although not currently a substantial gas user (+/-25 Mmscfd in 1999), it is projected to require 85 Mmscfd in 2010 and 270 Mmscfd in 2020 according to the ExxonMobil Utilization Study. The latter consumption figures are predicated on a presumption of import phase out by 2020. Total import/foreign exchange savings at the later stages are difficult to predict, but Table 4.4 provides figures for 2000 per ExxonMobil tabulations.

Table 4.4 : Current Cement Imports

Cement Imports Estimation	
Year	2000
Consumption (million metric tons)	6.16
Existing Plant Production (million metric tons)	3.28
Import Requirements (million metric tons)	2.87
Current Import Cost (US $ million)	224
% Imported	46.7

4.27 Using this historical data and setting an aggressive but attainable existing plant utilization and build-up of new facilities it is possible to at least visualize what the potential foreign exchange savings could be over the foreseeable future. With an unescalated import cost of US$78 per metric ton and ExxonMobil's projection of a doubling in cement consumption every ten years, coupled with the above aggressive program to totally phase out imports by 2020 one arrives at savings shown in Table 4.5.

Table 4.5: Potential Cement Import Reduction and FOREX Savings

	2000	*2005*	*2010*	*2015*	*2020*
Consumption, million Tpy	6.2	11.6	16.4	23.2	32.8
Import Displacement, %	0	25	50	75	100
Import Displacement, million Tpy	0	1.8	5.0	10.6	20.1
Annual FOREX Saving, US$million	0	140	390	827	1568

4.28 The figures in Table 4.5 do not take into account the additional benefits of monetizing the gas requirements for this sector. However over the next 18 years the cumulative savings would amount to over US$11bn.

4.29 It is obvious that bringing existing cement plants up to capacity and adding required plant to meet projected growth, combined with a reliable, reasonably priced energy source will result in major exchange savings and a measurable contribution to the GDP, this should be phased in conjunction with the additional requirements that will be brought about by the expansion of the gas business as a whole and on sustainable development thereafter.

Fertilizer Sector

4.30 The Fertilizer Sector currently relies almost completely on imports. The only nitrogenous fertilizer plant in Nigeria came on line in 1985 under the name of NAFCON, a joint venture between the government and M. W. Kellogg. The plant ceased operations in 1995. Attempts are currently underway to resuscitate the operation with the sale of the government shares and an injection of new capital.

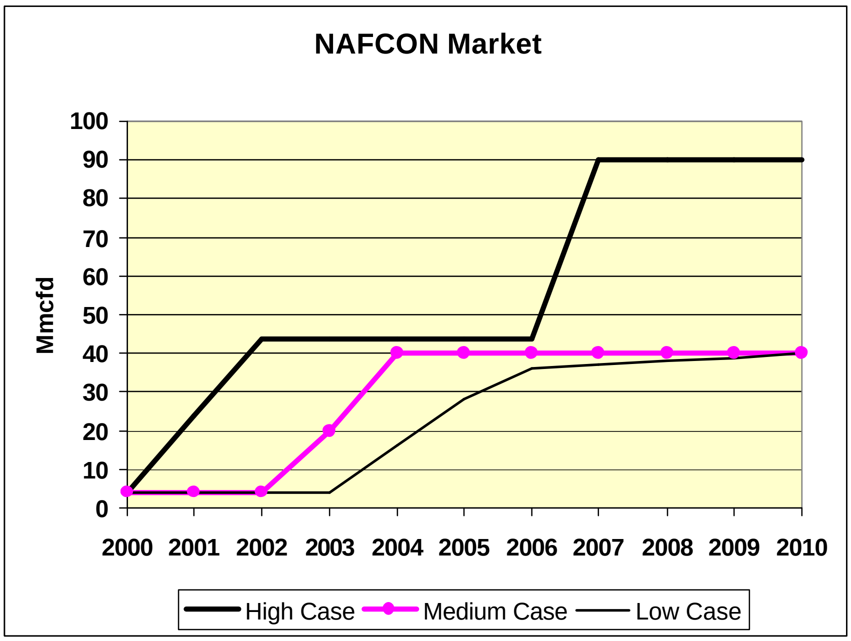
4.31 It is obvious that the replacement of fertilizer imports provide an opportunity for foreign exchange savings that, while not great in today's dollars ($US 24 million - 2000), will grow in volume and importance to the agricultural/food sector in the future and as more affluence is imparted to the general population. It should be noted that the manufacturing process for urea is very sensitive to the feedstock price. The possibilities for the re-establishment and indeed the expansion of this facility have been enhanced by the Nigerian Government statements that it intends to remove fertiliser subsidies and deregulate procurement.

4.32 Should the industry be restarted, it could, according to SPDC estimates, result in a gas consumption of some 55MMscfd at current capacity increasing to about

90MMscfd in 2007-2008 with the doubling of capacity to near 1400mtd. This is illustrated in Figure 4.10.

4.33 In addition to the direct savings by import substitution, a less visible but tangible savings in the food sector itself will result with increased fertilizer utilization. Currently imports of Food and Live Animals run at about US$US 1 billion annually, so any significant lessening of this figure will be noticeable.

Figure 4.10: NAFCON Gas Requirement



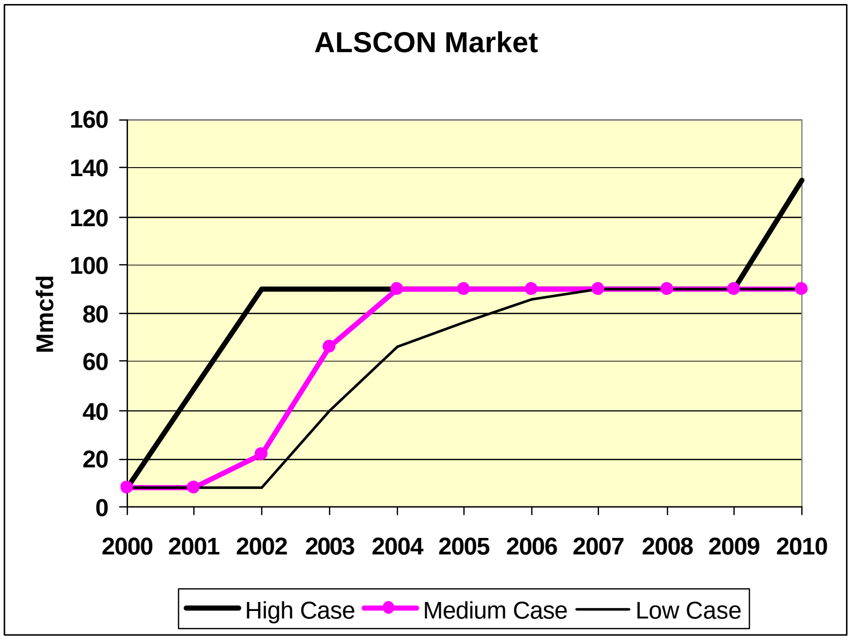
Source: SPDC Gas Planning Study

Aluminum Sector

4.34 The aluminum industry in Nigeria is centered around the Aluminum Smelter Company of Nigeria (ALSCON) facility which is currently in a care and maintenance status. The facility was initially commissioned in 1996 but ceased operations in 1999 due to lack of working capital and other issues. The facility was built primarily as an export project (140,000 metric export/ 40,000 metric tons domestic) and requires a very low cost fuel which may be available in an extended gas contract, but is the subject of ongoing negotiations with to SPDC. If an agreement cannot be made, then ALSCON's future does not look good as a going concern

4.35 A potential scenario for gas consumption based on an early restart for the facility is shown in Figure 4.11.

Figure 4.11: ALSCON Gas Consumption



Steel Sector

4.36 Steel production by DRI will be a relatively small user of gas in the future, whatever the expansion plans put in place - requiring only about 22Mmscfd for an 800,000 Tpy plant. Current plans are to de-mothball existing facilities to meet what is likely to be a growing demand resulting from an aggressive overall expansion plan by the Nigerian government.

4.37 If supported the by internationally credited steel producers, this and future plants can play a major plant in supplying the steel plate and line pipe needed for the gas industry expansion, as was the case in Algeria and Egypt.

4.38 The direct requirement from the coordinated expansion of the gas business is likely to require the complete capacity of the current plant as well as many new plants. In fact the steel demand required will enable the complete refurbishment of the current plant whilst still operating and further expansion provided the product produced is of international standard and at a commercial price. Given that the current plant is there and connected to the gas system, this should be feasible.

4.39 Both Venezuela and Mexico along with Algeria are examples where the oil and gas business kick started their steel business. Latin America, of which Mexico, Venezuela and Brazil are virtually the entire productive capacity, currently produces 14 Mmtpy showing the potential for Nigeria.

4.40 It is difficult at this stage to project overall gas consumption and should be based on an integrated gas and industrial development plan, but the ability to supply any possible gas usage by this industry is unquestioned.

Small Industry

4.41 Numerous small industries are scattered across Nigeria. These include glass, brick, ceramic, textile, food/beverage and other facilities which require energy in their manufacture. These industries at present generally use fuel oil to fire boilers and furnaces and are candidates for conversion to gas fuel. The conversion of these facilities will generally require that they be in the proximity of a large base load gas user as a reticulation system based solely on these small users will be costly and uneconomic.

4.42 If the plan to build backbone projects goes ahead, the quantities required by these industries may be easily accommodated, both as to quantity and ability to transport. No realistic estimate of usage can be projected at this time, although SPDC estimated this demand in the order of 50—500MMcfd, and is considered to be included in the general industrial numbers.

Commercial, Residential and Other Sectors

4.43 The domestic residential market for natural gas in Nigeria is likely to be relatively small. Due to the tropical location of the region, no space heating demand exists. Apart from the main population centers and food refrigeration and preservation needs, the remaining cooking and water heating demand of individual consumers is likely to be too small to justify the costs of a natural gas distribution and supply network for purely domestic consumers. This is demonstrated by the situation that the only tropical or subtropical cities that have natural gas distribution and supply networks for their domestic markets either had such a system installed in the late 19th or early 20th century, which was fairly early in the era of gas plants from coal and coke (like Johannesburg) or are extremely high in population density, with high rise buildings (like Hong Kong).

4.44 There are however occasional examples (like the very wealthy Pudong area of Shanghai, China) where, for prestige reasons, new gas distribution is being introduced, primarily to supply the commercial sector but also to some apartments and large houses.

4.45 In the future, it is possible that there are sections of the domestic market in and around the major cities, which might conceivably be supplied by natural gas especially with regard to food processing and storage.

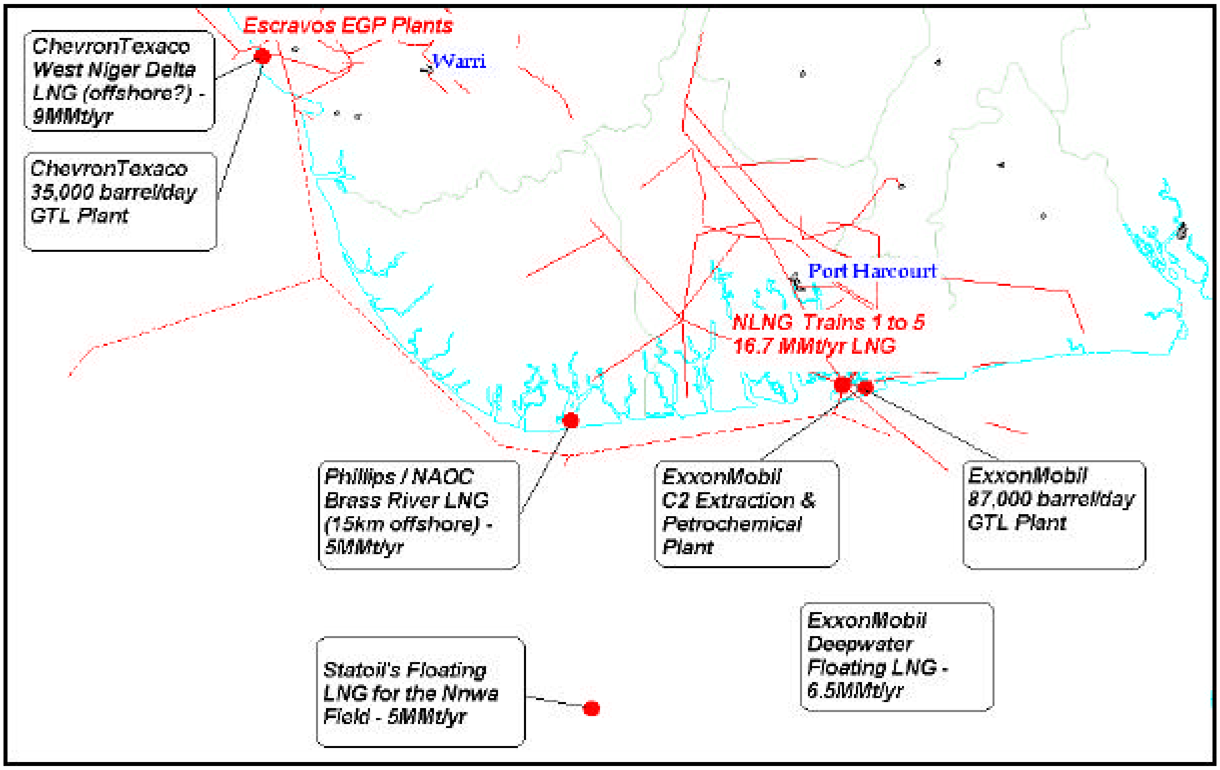
4.46 A more likely scenario in the provision of natural gas to the Residential and Commercial Sectors is in the form of LPG or compressed natural gas (CNG). The CNG market will probably at some stage gain a share of the vehicle fuel market. This will likely be in the commercial vehicle area initially, as expensive conversion from traditional fuels (petrol and diesel) will impede private utilisation.

Proposed Export Projects

Proposed Major Nonpipeline Export Projects

4.47 The major IOC's have put forward a number of gas utilization export projects for consideration by NNPC and the FGN. These proposals have been reviewed in this study and analyzed in the context of creating an overall Strategic Gas Plan. These proposals are as follows and shown in Figure 4.12:

Figure 4.12: Location of the Proposed Major Export Projects (nonpipeline)



4.48 In addition to these proposals a coastal International West African Power and Transmission System is proposed to balance the gas development. This proposal is not considered further here, as it is the subject of a separate study in the World Bank.

Proposed Additional LNG Projects

- Four LNG green field Projects have been proposed in addition to the existing 5 train NLNG project. (When all NLNG trains are complete, they are expected to produce 16.7 Mmtpy from Bonny Island by 2006) The new Greenfield proposals are:
- ChevronTexaco's (CPN) West Niger Delta (WND)- 9 Mmtpy LNG Plant at/near Escravos. Supplied by ChevronTexaco,

ExxonMobil (West) and Conoco Reserves (Consuming 1.5 Bcfd of feed gas)

- Phillips/NAOC Brass River—5 Mmtpy LNG plant based on a GBS 15km offshore
- Supplied by NAOC/Phillips reserves (Consuming 0.85 Bcfd)
- Statoil's Nnwa—5 Mmtpy Floating LNG plant on location near the Nnwa/Doro fields (Consuming 0.8 Bcfd)
- ExxonMobil (MPN)—Deepwater 6.5 Mmtpy Floating LNG - Possibly Erha NW of Escravos or in deepwater Eastern sector, south of Brass River and Bonny (Consuming 1.0 Bcfd)

4.49 The total production for all proposed new LNG Plants amounts to 25.5 Mmtpy looking for a market that is probably not that big, especially when taking non-Nigerian projects into account.

4.50 Statoil's and ExxonMobil's Floating LNG proposals are substantially based upon Non Associated Gas and Condensate reserves and therefore are independent of the oil plan and unable to solve any associated gas flare down needs. The decision to proceed on these FLNG projects can only be based upon their return and the need of the FGN to receive additional foreign exchange and income from their exploitation. These projects will compete for LNG market share if they are approved in a timescale that conflicts with other projects that perhaps fit more with immediate needs and objectives of the FGN, i.e. maximizing income from AG whilst meeting flare out by 2008. Thus, for these two projects, it is purely a question of the right timing subsequent to other more beneficial projects going ahead.

4.51 For WND and Brass River LNG Plants their proposals are premised on two factors:

- Export from the 5 trains of LNG at Bonny and export of NGLs and LPG's will completely load the shipping channel to its perceived limits
- Because of wet feed gas the location of the LNG plant should be close to existing infrastructure and should be substantially supplied by the promoting parties.

4.52 Both the WND and Brass River locations suffer from a lack of sufficient draft for the large LNG carriers likely to be needed to make the projects viable. Thus, to proceed, either a large channel must be dredged or the facility will need to be placed where sufficient draft exists (around 15km offshore). Both proposals state that economically the offshore location has greater returns on investment and are preferred by them.

4.53 This would be the first time such plants of this magnitude and complexity have been placed offshore, greatly adding to the risk of running into technical problems and hence cost and timing problems. Whilst it is believed the technology and designs are potentially feasible, solving any problems that are bound to arise as the design develops may result in substantial unplanned additional costs. If alternative, less risky uses or locations can be identified, they should be considered first and preferred.

4.54 Two issues ought to be answered with the interested parties prior to any decision being made to ensure a critical mass is achieved, these being:

- Could these projects be combined into one, producing a more viable entity?
- Could the LNG part of the project be located at a more optimal location for shipping (say where deeper water exists east of Lagos or to the west of Bonny Island) leaving NGL extraction at the proposed or existing major site locations and commingling dry gas to the final LNG plant location?

4.55 In any event, the market will drive the timing of this (these) project(s). Whilst the USA will have a growing influence on the LNG market, it currently operates on a spot basis only. There is no mechanism or perceived need to change that concept into the long-term market purchasing that would be needed to get a new LNG facility off the ground and financed.

4.56 The author believes the only long term contracts possible in the USA will be initiated by the major gas trading operators and stakeholders who have substantial asset value. (e.g. Shell, BP, El Paso, Duke Energy or Sempra and possibly ChevronTexaco through Dynegy). These players are unlikely to move in this direction until the last possible moment. If they do, the volumes are likely to be quite small and not enough to finance a new LNG plant. If players like Shell and BP can develop and sustain a spot market over time from the LNG plants they either partially or fully own, then a substantial long term market is not likely to be achieved for at least another 10 years. The only other option would be for the current proposers to guarantee the finance in total and enter the spot market themselves, currently seen as unlikely.

4.57 For this reason any new LNG Plant planned must develop an initial market (first two trains) based upon either Europe or the Far East, the latter region being more economical to serve from the Middle East, SE Asia and Australia.

4.58 Thus these LNG plants will be constrained by both import volume into Europe and the consumption in Europe. All previous new projects have taken many years to secure the first 5 Mmtpy sale of LNG on a long-term basis, for a delivery often 8 to 12 years away.

4.59 The capability of Nigeria to produce the volumes of LNG under consideration is not in doubt. This volume would be in addition to supplying all Nigeria's potential domestic needs in Power, chemicals, LPG and other sectors. The LNG plants, however, will not provide the infrastructure needed to promote the domestic market and depending on the timing of the sales contracts do little to progress the flare down policy in the near term.

4.60 As part of a long-term strategy they are seen as attractive and relatively low risk projects.

Proposed GTL Projects

4.61 There are currently two projects proposed as follows:

- Chevron Producing Nigeria (CPN)—35,000 bpd GTL Plant at Escravos (Consuming 0.35 Bcfd)
- ExxonMobil (MPN)—87,000bpd GTL Plant on Bonny Island (Consuming 0.82 Bcfd)

4.62 The Chevron proposal promotes early sanction, whilst ExxonMobil's proposal is timed to coincide with the blow down of their offshore fields and thus will be of little use to meet 2008 flare out.

4.63 A GTL plant could start development immediately, as it is not dependent on selling its products prior to starting, thus it is feasible for these projects to meet more of the immediate objectives of the FGN especially in relation to the flare down policy. They have the additional benefit of potentially lowering the imports of diesel and LPG's in the process thus earning and saving substantial amounts of hard currency. However, these projects still do not increase the domestic usage, with the possible exception of LPG should it be part of an LPG distribution and dispatching center.

4.64 Ideally the first plant built should be in the order of 50 to 90,000 bpd as the gas resources are available. This would mean that the main IOC's might need to cooperate and join forces to achieve this and guarantee supply. The only note of caution is the fact that plants of the scale proposed are new, potential delays and cost overruns are probable, and thus for the first project the FGN will probably need to offer very favourable fiscal term treatment and fiscal support. But once proven GTL will undoubtedly offer a good future option.

4.65 There are a relatively few groups of companies with credibility in the technology. For the three players with commercial experience (Shell, Sasol and ExxonMobil) the potential for the development of individual GTL projects is linked with their global strategic positioning in GTL products and in their E&P in the country/region concerned. These three generally indicate 50,000 bpd as being the lower end of economically viable projects (gas netbacks around US$1.50/MmBTU).

4.66 Syntroleum, who unlike the three above license their technology, have less commercial experience than their rivals. They claim economic viability down to smaller plant capacities (20,000 bpd or lower with netbacks around US$1/MmBTU). However as gas is not in short supply and due consideration is taken in Syntroleum's lack of track record in anything but a small scale pilot plant, caution in using this vendor ahead of others would be prudent.

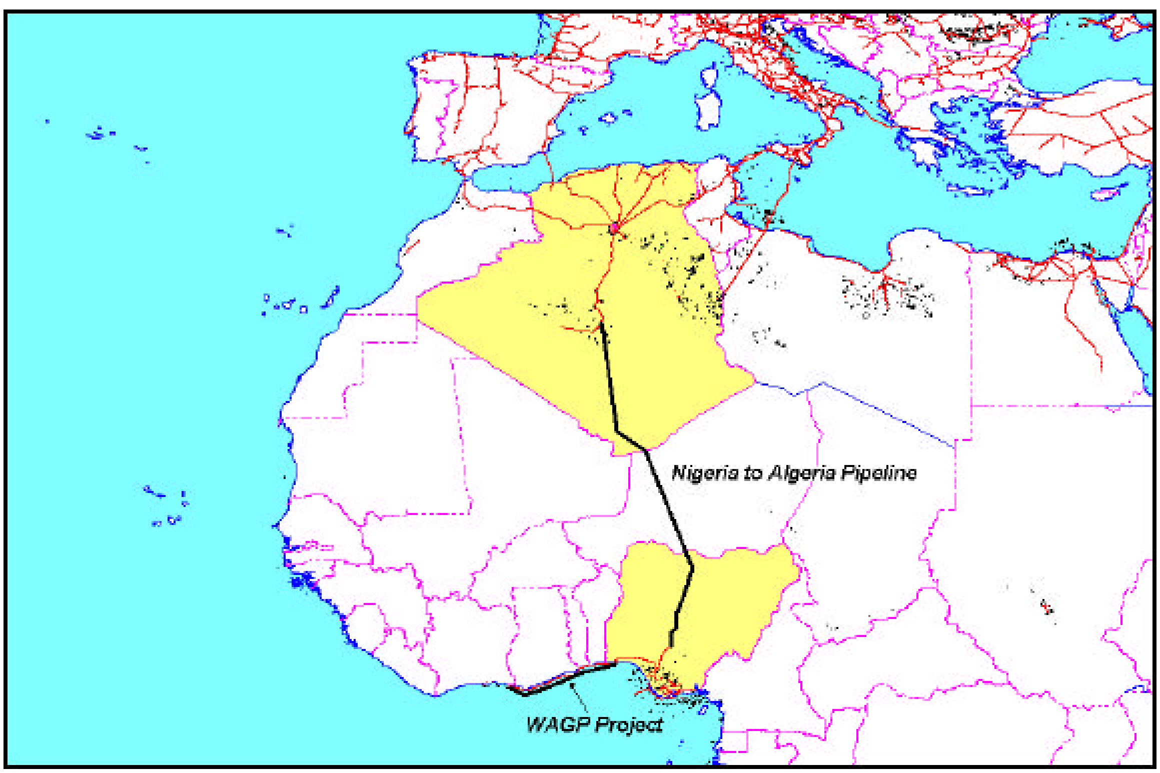
4.67 The main driver for GTL is the fact that the market for its products is huge, impacting less than 1 percent of the market volumes. As an upside to this, GTL products are attractive to a number of clients as non-sulphur, high grade blending stock. Since they increased their environmental standards, the current squeeze on US and European refinery capacity increases the potential premium. However, if it is to be sold in this manner, then dedicated white product shipping is required, potentially lowering the return for that premium.

Proposed Pipeline for Export from Nigeria

4.68 There are two pipeline proposals identified so far, both of which have a huge potential to provide gas to local markets in addition to their final destinations. These are:

- West African Gas Pipeline (WAGP) - Consuming 0.45 Bcfd (0.140 Bcfd initially)
- Nigeria to Algeria Pipeline (and thence to Europe)—Undefined but likely to be between 1 Bcfd to 2.5 Bcfd

Figure 4.13: Locations of the Proposed Major Pipeline Projects



The West African Gas Pipeline

4.69 The West African Gas Pipeline (WAGP) is a joint proposal between ChevronTexaco and Shell (SPDC) as well as NNPC, NGC, Societe Beninoise de Gas, Societe Togolaise de Gas and Ghana's National Petroleum Corporation.

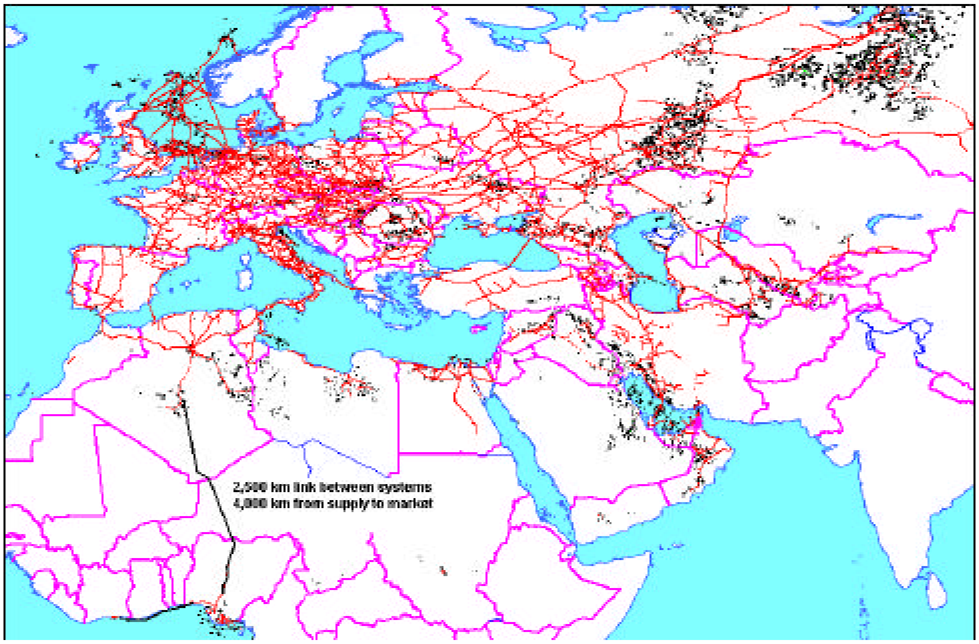
4.70 The WAGP is proposed to be the extension of the Escravos to Lagos Pipeline System which would need expanding from its current capacity of 300 Mmcfd to around 600 to 1000 Mmcfd to cope with demand from the WAGP and users in and around Lagos. The use by the WAGP clients will grow gradually over time, thus the expansion of ELPS should not restrict the timing of the WAGP. It is the intention of WAGP to supply Ghana in principal and in the process, Benin, Togo and Cote d'Ivoire with secure, predictable gas supply for their power stations and release variable and valuable fuel oil for either export or to avoid imports. Ghana is seen as the largest market here. In essence, the economics are as for Power as this is primarily a power generation driven project, provided the gas sale agreements can be made to the satisfaction of the sellers. Not only has the existing legal and regulatory framework delayed this project but also the issue of power prices in Ghana and the viability of the Volta River Authority (VRA), the main purchaser, is still in question. This project is undoubtedly beneficial for all concerned.

4.71 It should be noted that although the WAGP is basically supplying gas to Power stations, the proposed West African Power Pool and transmission project would compete initially, but within a short period of time the dual system will allow back up and expansion. This duplication on the market would probably not much delay the project. In any event, the same amount of gas will be used, as it will be sourced from Nigeria.

The Nigeria to Algeria Pipeline

4.72 The 2,500 km Nigeria to Algeria pipeline is an initiative driven directly by the governments of the respective countries. In essence it would connect the current pipeline in Ajaokuta in Kogi State, via Niger, to the In Salah development area gas pipeline currently under construction by BP and Sonatrach in Southern Algeria.

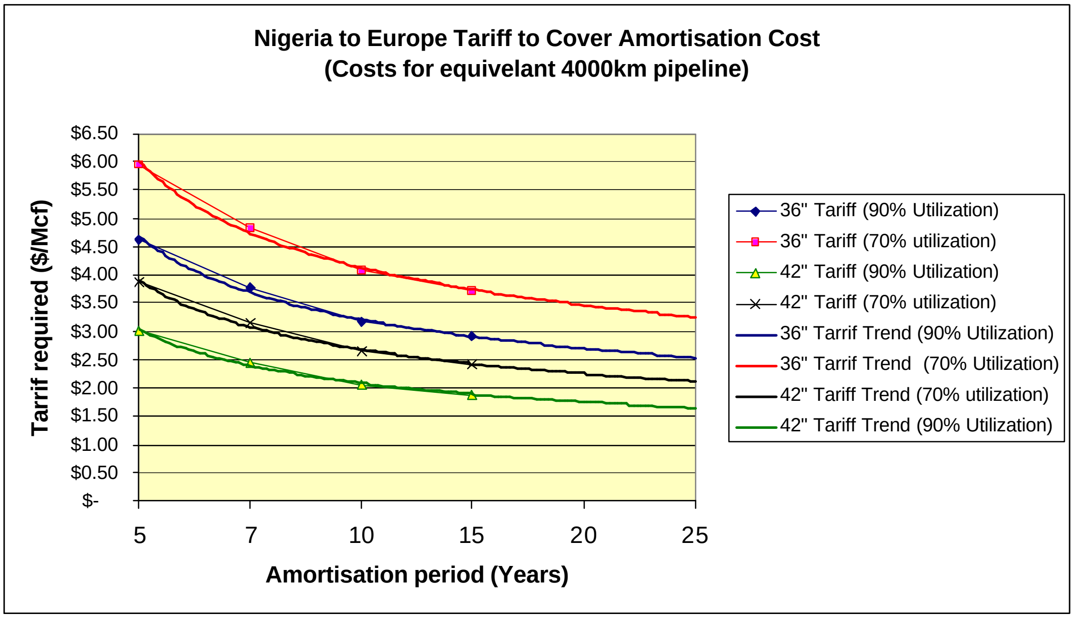
Figure 4.14: Nigeria to Algeria Pipeline in Relation to other European Supply



4.73 The supply from Nigeria to the market would be approximately half that of the distance from Western Siberian fields and only 25 percent longer than the northern most offshore fields in Norway, such as Snovhit. Thus, Nigerian gas should be able to compete in the European market, shown in Figure 4.14 above. Nigerian LNG is already in the European market and is accepted as a stable source of supply. This project makes even more sense when thought of in conjunction with an integrated backbone transmission system to satisfy the domestic markets throughout Nigeria. The key issue in setting the final tariffs will be deciding if these projects are financed together or separately. Both domestic and export projects are basically financable and economic independently, though a little marginal, they would be eligible for assistance from the World Bank and similar agencies as these are structural projects. If done together then the economics become much stronger and should encourage the participation of private investment from the major oil and gas companies as well. Similar projects such as the Tarim Basin to Shanghai Pipeline have included such combinations with Shell and ExxonMobil both taking a 15 percent interest in the 4,000 km pipeline.

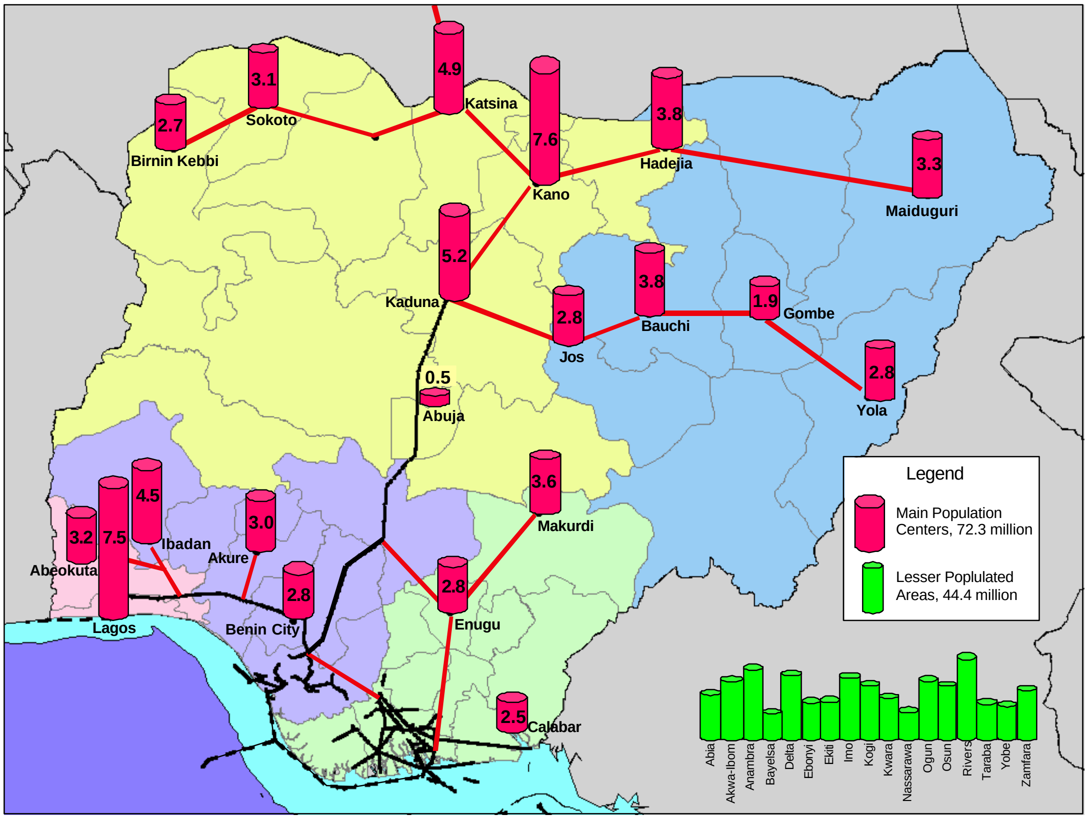
4.74 Based upon very preliminary estimates, the 2,500 km pipeline is likely to cost around US$3 bn for throughputs of around 1 Bcfd and US$3.6bn for a throughput of 2 Bcfd. Ultimate capacity could reach 2.5 to 3 Bcfd. With an overall distance of 4,000 km to the markets in Europe, a preliminary look at the required tariff seems to place it initially around US$1.60-3.20/mcf to transport gas from the Niger Delta to delivery in either Spain or Italy, based upon a 12 percent ROR for new and existing infrastructure. See Figure 4.15. Tariffs of this level and below would allow adequate netbacks to the producers at a market price around US$3.0 to 4.0/mcf and allow for a number of years of build up to full capacity. This is a critical advantage over LNG, which allows demand to pick up over time in Europe. Serious consideration should be made in future studies to use a 48" Pipeline at a slightly lower pressure, however current calculations are based upon 42"and 36".

Figure 4.15: Overall Tariff Estimated for Delivery to Europe (1 Bcf/day)



4.75 The advantages of this pipeline system to Nigeria are numerous. It can be initiated in stages and developed in a manner to feed domestic power projects and industrial consumers across Nigeria and throughout the region. Niger and Southern Algeria, albeit a small market are potential 'right of way' markets. As a secondary phase, extensions or spurs can be added to the backbone to feed all the major population centres that are not served by hydroelectric power plants (Kware, Niger and south Kebbi States) and supply the projected Power Station needs estimated to be up to 7 Bcf/day countrywide. Figure 4.16 shows this potential.

Figure 4.16: Gas Pipeline Backbone with Extensions to Major Population Areas (State population in millions)



4.76 Certain questions need to be answered with regards to who gains and who looses, these being:

- Why should Algeria allow competition through their country and system
- Why would BP co-operate.
- What is in it for Niger

4.77 Firstly the market in Europe is large, Algeria only holds a certain percentage. Typically it is the buyers who determine who supplies the market, based upon both the security of supply and the price. The security of supply is particularly relevant, as Europe does not want to become too dependent on any one source, so volumes from Russia, for instance are held and controlled.

4.78 Algeria will be able to exact benefits through cooperation, such as getting gas supplies to the deep south of the country, economically in assisting and participating in the project and in other general bilateral relations.

4.79 BP’s interests in the In Salah project are already looked after, on the most part, and thus additional gas in the early years will increase their and their JV partners Sonatrach’s economics. If there is no additional capacity then a parallel line can easily be accommodated. Sharing of operations, management and security for this line, improves BP’s position and returns on the existing system, thus, cooperation is in their direct interests.

4.80 Niger wins by getting both transit fees and a source of gas to develop a power system and local businesses.

4.81 The more significant question is *what happens if Nigeria does not use this opportunity* to develop their domestic infrastructure. This is quite simply answered. The historic stagnation will persist and the Nigerian market will not occur, little or no benefits and increase in the wealth of the general population will take place. Export projects will be the only survivor, at best bringing a little benefit to those people who are closest to the supply as the economics for power and industrial projects are strongest there. The capture and use of gas will be the last real opportunity to plan and implement a sustainable, stabilizing and lasting step up to the industrial world, spreading the effect not only round Nigeria but the whole sub-region. *To achieve it both power and gas must be planned and implemented together, separation of these two industry plans will result in the failure of both.*

5

Implementation Issues

Observations: Perspective of Participants in Gas Developments

General

5.1 These differences between gas industry and oil industry development are governed by the practical issues of linking upstream and downstream activities in projects and the perspective of the various players involved. For example:

- project coordination is often needed through the complete chain from wellhead to ultimate user
- the economics are linked through this chain.
- time frames to profitability are generally longer for gas compared with oil projects
- producers are dependent on customers connected to pipeline
- consumers cannot generally choose their supplier

5.2 Because of this nature of gas projects the partnership between producer nation governments and the companies involved needs to be clear and durable. There are differences here from oil developments, which tend to be more transitory, with more of an arm's length relationship.

5.3 In most circumstances (and specifically in Nigeria's case) the government, as sovereign power, ultimately owns the gas and expects to earn rent on its exploitation. It may in some scenarios become a customer. Government are by definition primarily politically motivated and their aims and objectives are much wider that those of the commercial companies. Whilst they will share concerns about economic viability, this is inevitably mixed with other political priorities. Besides differences in aims and objectives, there can also be differences in the nature of the businesses upstream and downstream. The planning of upstream activities in conjunction with those downstream often means bringing together different business approaches. In this context it is important therefore that all sides understand each other's position.

Contractual Rules for Gas

5.4 Oil and gas companies, whilst undoubtedly having some short-term interests, have the ultimate straightforward aim of earning corporate profits. Companies need to understand the principles being proposed for gas development is order to establish the ground rules. Traditionally, exploration contracts have contained detailed provisions for oil but often only outline mention of those for gas - usually along the lines that terms will be discussed once the gas has been found. Whereas the price for oil is determined on international markets there is no such forum for gas. Clauses for gas pricing therefore need to state clear principles for determining producer prices. Similarly, the principles of taxation should be laid out following a simple progressive system. Companies also need to see that there is scope for them to benefit from the upside potential of a project in high-risk ventures (i.e. the potential for earning a higher rate of return than if it merely earns the minimum return on costs).

5.5 For their part, governments rightly object to company negotiators who make unreasonable demands or who are insensitive to the political implications of their proposals. Companies also need to be aware that they may well be perceived as being in a position of power when negotiating contracts. Inevitably expertise and knowledge of gas matters can be very concentrated within the companies. It is in their interest to share their technical knowledge and information, as this is more likely to foster trust and goodwill. However, there is a strong case for government being separately well informed in gas monetization practices to protect their own negotiating position and for them to continually keep abreast of industry developments. With this aim in mind, it is strongly recommended that the Government Ministries and National Oil Company own or have constant access to a dynamic gas model to investigate the consequences of the many changes, variations, concessions and delays that they may need to effect as they implement their National Gas Strategy. It is usual the Master copy of any plan is held in the upstream sector as this is where most of the changes and variances occur, typically this may be the DPR, input can then be fed in at regular intervals from the other ministries or the regulatory or approving authority.

5.6 Although companies look upon establishing the extent of hydrocarbon reserves and their value as being part of its private business, in reality determination of commerciality for gas resources depends on upstream and downstream considerations. Sound decisions therefore require the sharing of information and ideas.

Gas and Project Planning—Government Policy and Framework

5.7 The institutional framework set up by government to oversee the process should include some form of the following elements:

- policy development via a Policy and Regulation Working Group
- project approvals procedure that is transparent and consistent

One key factor is that decisions must be taken by appropriate authorities and not all treated as special cases requiring government intervention.

- a purpose-designed vehicle for good co-ordination

  Gas projects tend to involve a wide range of interests within government ranks often with different points of view and some degree of bureaucracy. There is a strong need to present a unified face to companies. Co-ordination of government policies and the negotiation and approval process will be aided by some form of 'one-stop shop' with the specific role of reconciling the various views, presenting a unified government policy and framework to negotiators and generally to reduce bureaucracy levels.

- transparent procurement policy incorporating National incentives acceptable under ICB rules
- development of various framework elements (legal, fiscal, financial, etc)
- program for human resources

Efficient functioning of any institutional framework requires the necessary numbers and capabilities of officials with the relevant expertise to handle the evaluation process. It is likely that some priority will need to be directed at further professional development, training and capacity building. This is an area where Multi-national institutions can help prepare competency requirements, participate in implementation and monitor progress and forms part of the overall energy strategy and plan. Assistance in the latest techniques, software tools and hardware in this area are available.

5.8 The policy initiatives should include the following aims:

- promotion of exploration and development projects that tie into the desired gas infrastructure
- provision and application of a competitive investment climate
- promotion and attraction of private investors
- fostering collaboration between upstream and downstream investors for the provision of infrastructure and markets for gas
- facilitating the establishment of downstream industries
- determining extent of government participation in investment in downstream ventures

Legal

5.9 The legal framework should be clear and consistent, complying with international norms and provide for the principles of :

- enforceability
- consistency of interpretation
- preservation of sanctity of contracts
- openness and fairness in any adjudication process
- access to international courts

5.10 Some review of existing legislation is likely to be needed to ensure it is consistent with the incorporation of aspects involved in gas development. It is expected that such a review might need to examine the following areas:

- Petroleum Law
- Land Law
- Gas (and Power) Codes and Law
- Labor Code
- Company Law (including, protection of investors capital, confiscation and nationalization, entry and repatriation of capital, remittance of profits)
- HSE Law (including environmental regulations, government commitment and leadership, standards to be followed in practice)
- Intellectual property rights legislation

Fiscal

5.11 Many governments recognise that the economics of gas field development are different from those for oil. Gas developments typically have a longer lifespan and slower investment payback compared to most oilfield developments. It is not unusual for the upstream contract to provide for the operator and the government to enter into negotiations to agree fiscal terms appropriate for gas field development in the context of finding gas markets and agreeing terms of sales. To date Nigeria has been one of these. Rather fewer countries have accepted the need to establish fiscal incentives for gas in advance of exploration and appraisal, some uncertainty exists whether future projects will be given the same terms as that granted to date, thus this needs to be clarified and set in the future Gas Codes and Laws.

5.12 A study carried out by IHSE in early 1998 identified some fifteen countries in a survey of over seventy in which fiscal incentives were available for gas field development from day one (i.e. available prior to project specific bilateral negotiations). Analysis of these fiscal regimes demonstrated that the resulting state take (the proportion of net project profit claimed by the state in tax) was typically between 5 and 25 percentage points lower for gas than for an equally profitable oil field on a pre-tax basis. There is in these cases, a corresponding improvement in the returns available to investors. By comparison, the standard terms in most fiscal regimes do not differentiate between oil field and gas field development.

5.13 The inclusion of the Carbon Credit Fund, the Global Environmental Fund, etc. are possible additional avenues and resources available to assist and complement Nigeria's final terms laid out to investors.

5.14 Candidates for generating incentives to gas development are often described as those "increasing efficiency" such as:

- extra cost recovery (e.g. to include financing costs and insurance, uplift of cost recovery, or enhanced depreciation allowances)
- lower tax, royalty rates, etc. (royalty in particular often seen as a penalty for high cost fields and is considered "regressive"; i.e., one where the effective rate gets higher as profit gets lower)
- royalty or profit share taken as a function of actual daily production (on a field by field basis)
- ability to offset the expenses of failed exploration for other licenses against profitable operations elsewhere in country; e.g., Vietnam (relaxation of ring fencing)

5.15 On the other hand illustrations of disincentives include:

- excessive tax rates
- nonprogressive tax charges (such as turnover tax) especially if this means that the amount of tax depends on to which sector the gas is sold
- restrictive cost allocation rules (e.g., where the contractor is not allocated all the production for cost recovery purposes, which means that the contractor has less incentive to hold down costs)
- rules hindering full depletion of reservoirs (e.g,. high royalty rates, additional profit taxes etc)
- use of export taxes (i.e., potential use or not, and level on any major gas export project, needs to be made clear so that those planning such projects know where they stand. Any retrospective application of taxes or tariffs could have very negative effects).
- import taxes (e.g. duties on imported materials and equipment for construction, raw materials for process manufacture)

- inability to credit in-country taxes against home country taxation arising from requirement to explore through an incorporated JV; generally overcome by double taxation treaties between countries

5.16 The table below presents some examples of countries in which the government offers favorable fiscal terms for gas as a standard arrangement. A specific, more in depth and wider, study in this area would be warranted, as Nigeria moves forward with its strategy, to investigate the effect, and lessons learnt, of these variances and the losses and gains that each country has achieved by following these policies.

Table 5.1: Country Examples of Fiscal Incentives for Gas Development

Country	Bonuses	State Participation	Royalty	Cost recovery, Tax Depreciation	Cost Recovery Ceiling	Contractors Profit Share	Income Tax Rate	Tax Holiday	Other Taxes
Nigeria Upstream	S, P	60%	7% Onshore, 5%Offshore	CRC 5 yrs	99%	-	30%	-	EDT 2% VAT 5% PPT 67.5%
Nigeria Downstream		50%	-	CRC 90%	90%	-	30%	3 yrs	EDT 2%
Angola - Standard	S	20%	-	CRC 4 Yrs	50%	30-60%	50%	-	-
Angola - Deepwater	S	20%	-	CRC 4 Yrs	50%	20-80%	50%	-	-
Egypt	S, P	60%	-	CRC 5 yrs	30%	20%	PBS	-	-
Indonesia - Standard	S, P	60%	FTP at 20%'	CRC & Tax 100%/25%ddb	100%	62.50%	30%	-	DSO 6.7%
Oman	S, D	60%	-	CRC 100%	60%	60%	PBS	-	-
Trinidad & Tobago Offshore >600BCF	S, P	0%	-	CRC 4 Yrs	50%	15-45%	PBS	-	Training & Admin Fees
Vietnam - Standard	S, D, Oil P	60%	0-10%	CRC 100%, Tax 3-5 yrs	55%	50%	50%	-	Training Fee WH Tax

Source: IHS Energy Group's Petroleum Economics & Policy Solutions (PEPS)
S - Signiture Bonus, D - Discovery Bonus, P - Production Bonus PPT - Petroleum Profits Tax
FTP - First Tranch Petroleum, EDT - Education Tax, DSO - Domestic Supply Obligation, WH Tax - Withholding Tax

5.17 Table 5.1 shows that Nigeria assumed terms are reasonably equivalent, but not over generous.

5.18 For example Trinidad's standard fiscal package for downstream energy-based investments on which of the fiscal framework for the Trinidad Atlantic LNG project was based are understood to be as follows:

- Tax holiday (5 - 10 years)
- Relief from taxes on dividends and other distributions
- VAT exemptions on imports, including capital imports
- Concessions on import duties
- Relief on with-holding tax

Oil and Gas Sector Framework

5.19 In developing a framework for the growth of a gas business in Nigeria the following issues should be considered

Upstream

- Role and function of state (e.g., carry/participation rights, conflict of interests such as regulatory vs. commercial role)

  Where there is a desire for state participation, it is important that the capability of and the terms on which state company will invest (either on its own behalf as a future commercial entity or on behalf of the State) is made clear to the IOCs. If the financing for various elements of the gas business chain is indeed to be "carried" by the IOCs then this will be factored into their economics and their consideration of the likely rewards from investment when judged against the risks. Carry usually has a very negative effect on the investment economics of potential projects and is usually worsened by an inconsistent application of when it will happen and when it will not.

- Prices for nonassociated and associated gas

  In some instances of countries embarking on gas development, IOCs have expressed concerns about low prices for associated gas being taken as a precedent for determination of prices for non-associated gas. If a standard economic price is available for all gas whatever its source, then by default, associated gas will be preferred as it generally can be produced more cheaply. In setting the price, in Nigeria's case this must be done in conjunction with setting power prices, if Nigeria is to make the most of the immediate opportunities available to them. A rushed and disconnected approach will damage both industries in the long run.

  By setting a feasible and credible pricing structure across the industry, private and public entities will automatically steer towards the correct solutions and ultimately solve the flaring goals of the FGN with little additional input.

Midstream

5.20 The paramount need is to encourage the development by the private sector of what will be a highly capital intensive offshore infrastructure. This will need to address such questions as:

- degree of separation of the pipeline development from upstream and downstream elements

- over sizing of the infrastructure to cater for future gas developments and potentially open access for a certain percentage of capacity
- capability to expand offshore processing and compression
- pipelines capacities, including questions of pre-investment for line over sizing
- pipeline access (including issues of non-discrimination, fair pricing, common carriage, etc)
- pre-investment to facilitate future tie-ins
- configuration and expandability of the onshore facilities
- coordination of onshore pipelines (where relevant)
- coordination within country of the necessary legal, regulatory and institutional changes.

Downstream

5.21 The areas for concession in downstream activities depend in some part to the extent of the development of domestic markets as well as those for export. Development of the former will raise such questions as:

- the degree of separation of transmission/ distribution and gas marketing
- single gas purchasing organization vs. a series of bilateral gas and gas transportation contracts
- purchasers' size and bargaining power vs. that of IOCs (i.e. number of smaller purchasers rather than one large buyer)

5.22 The following points are applicable, regardless of the extent of domestic market development:

- ringfencing of flagship projects

  Ringfencing of any special terms introduced for flagship projects to help launch the industry are especially appropriate. This means that non-core project terms should be developed ahead of time to reverse or negate the position of concessions given for the selected flagship projects (i.e. Nigeria to Algeria pipeline and the first GTL projects).

- consistency of industrial development plans

  Plans for gas and indeed power development and any associated regulatory regime may need to take account of any other industrial developments where there may be conflicts between proposed terms and conditions. Conflicts should be investigated between applicable laws all the way down the investment chain and resolved prior to embarking on the gas strategy.

The pulling together of these elements is an essential next step to coordinate a viable and implementable plan. An integrated Gas and Power Master Industrial Development Plan integrated into, and based upon, the Dynamic Gas Model will be the key to success.

Financial and Project Management

5.23 Amongst concerns of IOCs about what they consider are important issues in this area are:

- deduction/recovery of interest expenses
- equity share financing without the need for government approval
- rights to hard currency and domestic currency bank accounts within host country
- rights to transfer hard currency outside of host country
- contractors (hire and pay of suppliers and contractors of IOC's choosing in whatever currency is appropriate)
- right to exchange domestic currency for hard currency at non-discriminatory exchange rates
- conversion of currency (i.e. no mandatory conversion)
- repatriation of capital item expenses, including import duties and imposts
- repatriation of profit
- convertibility of local currency
- remitability (i.e. right to import/export/exchange currency)
- The investment climate can only be improved if some or all of these are taken account of.

Investment Promotion

5.24 In order to reactivate and build economic growth and bring other benefits to the country and its people, Nigeria, along with other countries in the region, is competing for foreign investment. Many countries, including some in Africa, may present a more attractive proposition in terms of macroeconomic policy, infrastructure, manpower skills, security, etc. They may also be succeeding better in facilitating such investment. To meet such competition and to attract a greater portion of FDI, the country will need to examine ways of establishing an effective promotion program as one of the key steps to success. Such a program could include the following elements:

Investment Generating Activities

- proactively seeking potential investors both domestically and internationally
- targeting specific locations (e.g. perhaps focusing on a single location for an industrial park)

Investor Servicing Activities

- advertising
- investment seminars in country and abroad (general and industry specific)
- participation in targeted investment exhibitions
- providing media with information and press releases
- conducting investment missions abroad
- visits to target companies including the IOC's to discuss strategic preferences
- assisting potential investors visiting Nigeria
- targeted information packages
- provision of background information
- arrangement of itineraries and contacts
- assistance in the approvals process
- identification of potential local partners

5.25 Generally speaking, direct marketing, pro-active seeking out of investors, etc likely to be more effective that broad-based strategies. In the current situation, promotion of Nigeria to advertise its opportunities and capabilities to a wide audience is not likely to be the most constructive approach and would not be the best use of what are probably limited resources.

Industrial Development Vehicles

Industrial Parks

5.26 Some of the main principles behind the provision of industrial parks are:

- providing a means of planning industrial development (with due regard for such aspects as strategic locations, industrial zoning, HSE, security, etc)

- setting up of industrial complexes to function as a growth centre
- targeting specific areas of national economic interest.
- providing purpose-designed industrial zone equipped with a focus for provision of services and infrastructure at attractive rates
- achieving agglomeration efficiency (clustering economic activity, integrating processing, sharing resources such as gas, electricity, water, providing communications, etc)
- providing employment, training and education opportunities in and around the parks and EPZs
- providing a ring-fenced location for application specific terms (e.g. as export processing zones or EPZs)

Export Processing Zones (EPZs)

5.27 Traditionally Export Processing Zones (EPZs) are fenced-in industrial estates specialising in manufacturing for export. Their aim is to provide a free-trade and defined regulatory environment for the companies involved. Amongst their primary goals are the provision of foreign exchange earnings, provision of jobs and creation of income, attraction of FDI and the attendant technology transfer and knowledge acquisition.

5.28 Companies operating in EPZs typically benefit from:

- reduced bureaucracy (e.g., via large degree of autonomy from central government albeit within specific guidelines)
- flexible labour laws, generous fiscal terms and concessions
- better communication services/ infrastructure
- terms for duty-free imports of equipment and materials
- Incubators for future sustainable businesses.

5.29 A recent World Bank report acknowledged that "under certain conditions—including appropriate set-up and good management—EPZs can play a dynamic role in a country's development, but only as a transitional step in an integrated movement towards general liberalization of the economy (with revisions as national economic conditions change)."

5.30 Typical general EPZ goals are:

- Provision of foreign exchange earnings by promoting non-traditional exports
- Provision of jobs to alleviate employment or under-employment problems

- Attraction of FDI, engendering of technology transfer, knowledge acquisition and demonstration effects to act as catalysts for entrepreneurs

5.31 The same World Bank report indicates a number of general policy guidelines to enhance the probability of success for such undertakings:

- general economic environment

  Sound and stable monetary and fiscal policies (low inflation, budget management, independent monetary policy) clear private property and investment laws provide a general environment favorable towards EPZ success.

- taxation and tariff structure

  Moderate income and corporate tax rates are recommended without a need for overly friendly tax incentives. Provide for accelerated depreciation, rationalize and minimize indirect taxation and licensing practices. Improved collection rate can partially compensate for potential revenue loss due to reduced tax rates. Ensure that EPZs can import and export free of trade taxation and tariffs.

- infrastructure and utilities

  Private development and management of EPZs is favored including onsite infrastructure. Provision of infrastructure external to the zone proper can have positive spillovers for the local and national economy by facilitating transport and communications. In this case, if private development is not available for the infrastructure external to the zone, the public role is justified as an economic rationale. Subsidizing utilities encourages over consumption and discourages economically rational use of resource and factors of production, detracting from the benefits of the zones, however the inclusion of adequate roads, airports, helipads, internet and communications network hubs along with training and educational facilities all enhance the zone and neighboring district. Jebel Ali in Dubai, UAE and China's Special Zones are examples where this peripheral investment paid huge dividends.

- labor rights, wages and worker safety

  Labor market constraints increase labor costs and slow market adjustment. More business-friendly laws are beneficial but this should not be at the expense of any regard for HSE and labor rights. Strengthening regulatory and monitoring activities will help to reduce labor turnover, absenteeism and improve labour productivity.

- environmental issues

  In some cases developing countries have lax laws and implementation. Concern exists regarding the EPZs large production volumes (and potential pollution levels) compared to those of host economy production levels. It is therefore necessary to have better qualitative and quantitative understandings of waste management and the impact of industrial activity on air, water, soil and human health. Follow-up regulation, provision of incentives and monitoring (through EIAs, etc) should be tailored accordingly.

Human Resources

5.32 Gas development projects will undoubtedly need significant resources of managers, engineers, technicians, etc. For Nigeria, a reasonable pool of oil industry personnel are available. However, new skill sets will need to be learned to deal with specific issues of gas. Particular issues involve safety of an extremely flammable and high-pressure fluid to understanding of the utilization options and economics of the gas business as a whole. Whilst encouragement of the development of indigenous skills may be a long-term goal, there is an economic trade-off in terms of potential foregone output and a more general target of establishing a rigorous credibility in the international marketplace.

5.33 In the short-term enterprises hampered by an absence of suitable skills should utilize expatriate resources but tied to a scheduled and robust program for training and skills transfer.

5.34 A list of areas for further consideration include:

- immigration and employment rules to enable import of technical and skilled labor
- indigenous technical and commercial competence assessment (skills audit)
- expatriate usage and program for technical knowledge transfer
- unemployment and development of training program
- civil servant resources - adequacy of numbers of officials who have the relevant expertise within country and education for professional development (e.g., in gas practices)

6

Conclusions and Recommendations

Gas Reserves and Gas Usage Options

6.1 Nigeria's proven gas reserves at end 2000 were put at over 150 Tcf (according to IHS Energy's own database). Predictions of the so-called yet to find reserves (YTF) (carried out in-house as part of a wider IHS Energy project) indicate that for the Niger Dalta Basin the potential gas reserves figure (over and above the 3P numbers) is in the range 140 Tcf.

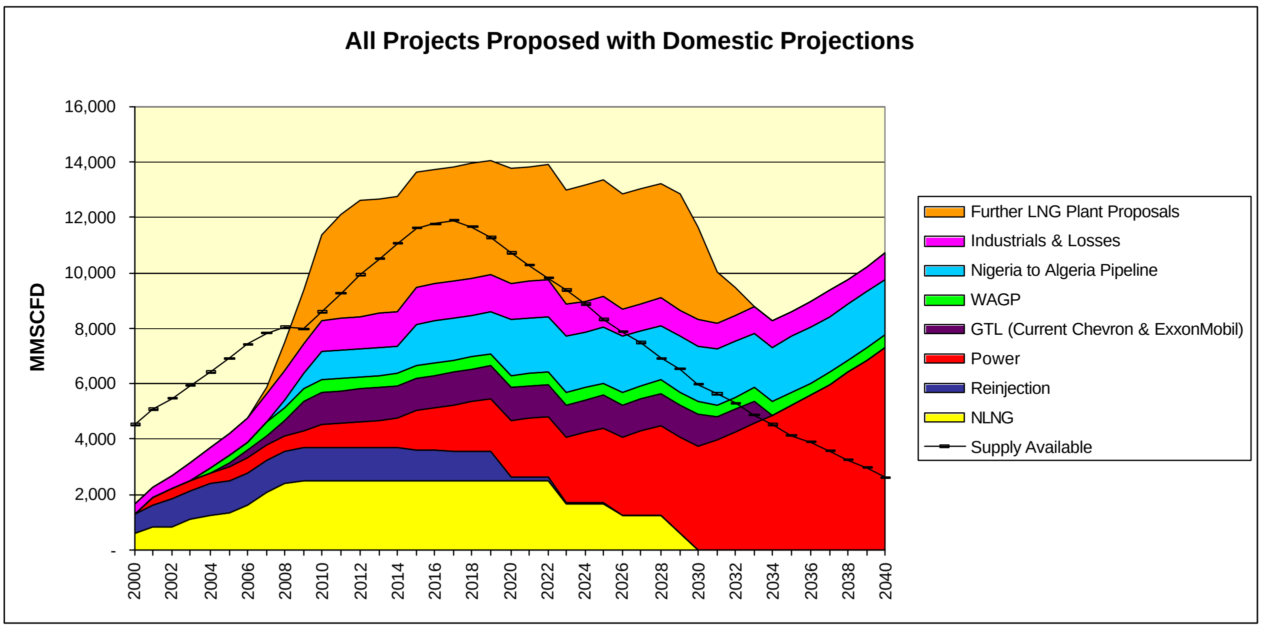
6.2 Nigeria is fortunate to have such a large and balanced reserves base (AG and NAG) giving a producing life of over 100 years for proven reserves and over 200 years for all estimated likely reserves should production rates remain at current levels. Should the FGN wish to harness this reserve base and increase production to a higher level, yet maintain a prudent production life of 30 to 50 years for proven reserves, then this is achievable, whilst still keeping to the flare out goals set for 2008 and positively change the lives and status of their population in the process. The issues facing the FGN are mostly time driven, and as such, a coordinated comprehensive plan can be made to implement a set of building blocks that achieve maximum overall long-term benefit to Nigeria. Key institutional and regulatory reform is needed to allow progress to be made, a program with strict timelines should be put in place as soon as is practical to ensure the sustainability of the proposed solutions herein. It should be noted, however, that a complete set of actions must be carried out across the whole supply chain for it to be successful as any link not done breaks that chain.

6.3 The NLNG project has been a great step forward in that direction and the completion of trains 3 to 5 will solidify that start in a timely manner. Future projects, however, should be judged more on overall Nigerian terms, firstly to broaden the benefit to more of the Nigerian population and then to spread the risk in response to market size and variability. But first, *domestic project development* should take priority in response to the current and future unfulfilled market that would be further triggered and justified by domestic investments and policies. *These industries are gas, power, cement, steel, and ammonia/urea.*

6.4 This study has taken the projects proposed by the major oil companies and under consideration by the FGN, and integrated a realistic level of domestic consumption on the basis a major overhaul of the power industry is implemented and the expansion of the Cement and Steel industries. To complete the picture the pipeline and gas shrinkage losses are estimated to arrive at an overall view of demand by use versus supply available. Figure 6.1 shows the unconstrained, and perhaps uncontrolled result.

6.5 Figure 6.1 clearly shows that when projects are put in approximately benefit order (bottom to top) and supply is diverted to those more beneficial projects, then the four additional LNG projects, at some level, exceed the overall supply available. One additional LNG project is likely to be feasible, but it should be at a later date and probably be larger than any of the proposed future projects to gain the necessary netbacks. This could only be decided upon later; once more discoveries are made that is part of the Yet-to-find (YTF) resources.

Figure 6.1: Unconstrained Gas Utilization Development Scenario



6.6 Moving forward and putting the first steps together to decide which projects most effectively benefit the Nigerian people and economy, we offer the following logical conclusions in order of merit:

1. The first and most obvious priority is to start the path to reset the foundation in the power sector. The refocusing of NEPA and privatisation of Generation and/or final distribution are, without a doubt, better managed privately or at least in public-private partnership. The use of private, diesel fired power generation by large numbers of the population is a clear indication of both the need for stabilisation of the power supply

and the ability of the population to pay for a service that is reliable at economically sustainable rates.

2. Three projects drive the way forward in achieving results in the time desired and in being able to create future benefit to the largest number of Nigerians all of which give reasonable returns at sustainable prices. These should be supplemented by realistic but immediate reinjection and/or storage programs to both preserve value and to minimise more damage to the environment.

The key projects are:

1. Initiate the rebirth of the gas fired Power Sector with domestic backbone infrastructure
2. The WAGP
3. An enhanced GTL Project
4. The Nigeria to Algeria Pipeline

The first, second and last projects complete the backbone for natural gas distribution across the vast majority of the country where hydroelectric power is not accessible. Pipeline projects, whilst complex in political terms to set up if all parties involved are not committed to their success, are easier to build up market share from lower production levels. If planned in this way, a pipeline is more flexible than a new LNG plants in attaining large contracted gas volumes prior to project initiation, and thus are easier to finance. The projects also support the objective of getting gas to all new power plants countrywide.

To enable more future options, it is recommended that a major link be made from the Eastern Sector to this system. To ultimately enhance the utilization of gas countrywide, the pipeline revenue could be arranged to allow for one price for delivery into the pipeline system and one price for extracting from the pipeline system, regardless of wherever you are in the system. Brazil has taken this approach and this allows the use of gas to be more evenly distributed across the country and thus a greater shared benefit. It also has the great advantage of setting a stable price for small Nigerian owned producers to monetize their gas, enabling more players to enter the business.

3. A GTL project is recommended, even though it is relatively unproven at the plant sizes suggested. This is because its timing is not dependent on any current market and can thus be built to a fixed schedule from approval to meet the primary flare down target dates. Furthermore,

the market for its products is huge, even if more specialized products are not deemed viable.

The plant location for the first GTL plant is probably better served by being located at Escravos in the Western Sector. However, the question that should be asked is 'why not build a larger plant?' at 70 – 90,000 bpd, rather than a 35,000 bpd plant suggested by Chevron. This larger plant is likely to improve the project economics and allow the participation of more players and fits in better with the estimated production profiles and need to meet flaredown by 2008.

ExxonMobil's plans were for a plant much later in the timescale, to coincide with the blow down of the OSO field, and this is still valid but is planned 5 to 6 years later than the first so does not help flare down in 2008.

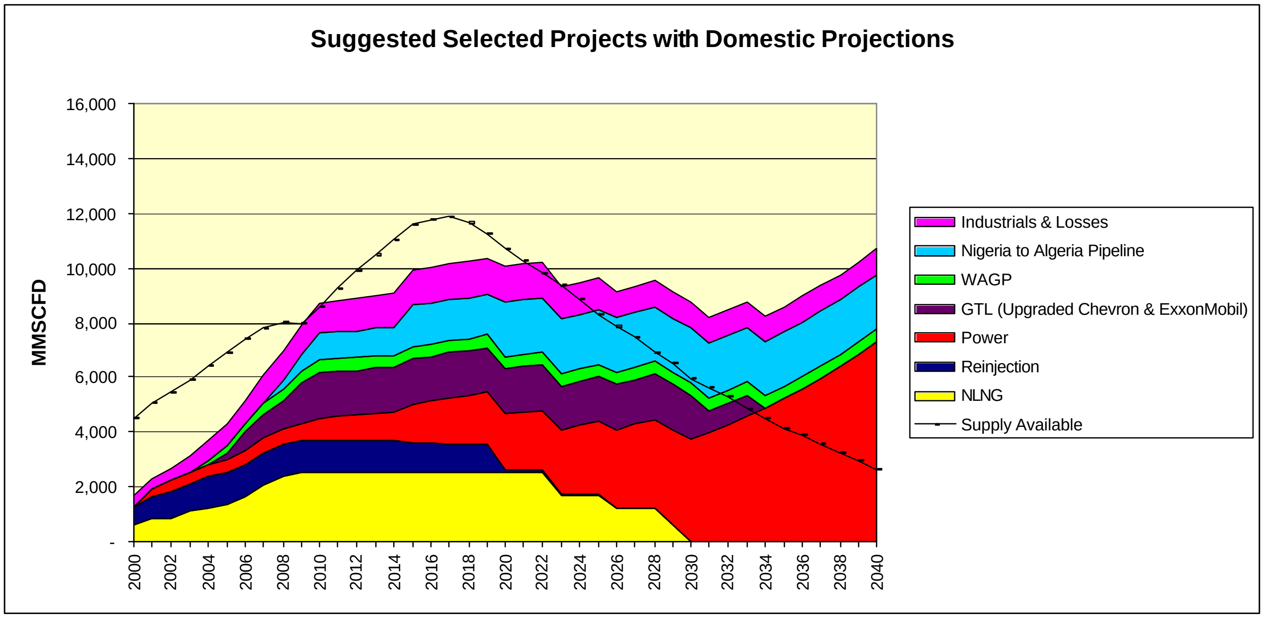
4. Given the implementation of the first set of projects, the options to proceed are much broader. Fertilizer and cement plants should be put in main demand locations to meet the likely country's expanded needs and avoid importation. Local plants minimize the transportation of their products and thus enable lower local commodity costs to be achieved.

5. From this point additional export projects could be considered. For instance, further LNG plants, Petrochemical derivatives or an additional GTL plant. The next LNG facility, if sufficient capacity is built into the East West Connector, could be placed anywhere from Calibar to West of Lagos to suit the draft requirements of current LNG carriers not the production location. This Network would then allow the direct connection of deepwater projects to the main infrastructure and play a part of the ongoing development of the country.

6.7 Figure 6.2 below outlines the effect of a properly phased build up of projects in the order and magnitude suggested above. It shows that the majority of projects are feasible in terms of adequate gas resources and because the initial projects are 'in country beneficial', the return on investment to the country for this selection are an order of magnitude higher than the minor contribution differences in return between export only projects.

6.8 Before any selection of further projects is concluded, it will be desirable to have a few more discoveries logged (conversion of Yet to Finds) to assure adequate supplies can be brought in a timely manner for the whole length of the project. From the analyses it seems around 2 Bcfd is likely to be available for development/use, and a consolidated LNG plant proposal would seem to fit this.

Figure 6.2: Planned Gas Utilization Development Scenario



6.9 Whatever projects are actually selected, the dynamic planning process should be maintained up to date and linked to other "in country" development growth plans to maximize the benefits. Future projects should take maximum advantage of the economies of scale rather than isolated small groups of operators or investors.

Technical and Implementation Action Plans

Planning

6.10 There are a number of areas for which provisional conclusions have been drawn but which have been based on relatively limited data or high level assumptions viz extent and timing of power generation and other potential industrial/commercial uses. The following areas constitute a series of steps that is required to implement a workable and self-sustaining plan.

Phase 1—Forming the Basis of the Plan

- least-cost plan for domestic power

The appraisal of the power generation sector has been made with reference to other studies carried out by the World Bank and others. However, these have principally looked at refurbishment of the power generation and have been generally qualified by concerns about the lack of a firm basis for improvement with reasonable degree of confidence. In this study, assumptions have been made about the existing demand from previous work on the basis that the economic conditions have not altered greatly in the last decade. The use of more independent power (IPP) producers including improving the transmission system, with the consequential implementation of a workable framework in which the companies can be assured of payment, is key to the expansion of the sector.

- detailed survey for potential domestic commercial/industrial gas uses

The assessment of gas demand for these sectors has been estimated in outline only because little country data was available. It is in any case difficult to quantify latent demand. Key city focus areas and local demand pictures require quantifying to assess the full extent of the industrial, commercial and residential use in conjunction and in coordination with the National Gas Strategy and ability to pay commercial rates. This will look at the distribution and pipeline requirements for LPG, Cement, Steel, Ammonia/Urea requirements and critical mass and economic sustainability calculations.

- detailed evaluation of regional and major export projects

The technical business plan to include an assessment and market identification for those projects that are potentially acceptable as part of this strategic plan. This includes the GTL project, Nigeria to Algeria Pipeline, The West African Power pool and distribution system etc.

- Gas Supply Side Plan

Confirming, aligning and updating of all upstream Operators and their plans following the roll-out of the Master Plan. Setting up a framework and methodology for continuous and timely updating of individual work plans and consequential key project and production chronology. Resulting exercise completes the level 2 supply side plan.

- Health, Safety and the Environment (HSE) Assessment

Development of applicable HSE criteria and standards and an assessment of their impact on proposed and future projects, including capacity building, tools and systems to monitor the same.

Phase 2—Integrating the Plan

- Integrated Master Hydrocarbons plan

Develop a complete level 2 dynamic plan covering both Supply and Demand. Level 2 detail includes field level for upstream and individual phases of projects for midstream and downstream.

- Industrial Development Plan

Based upon the Hydrocarbons plan, develop an Industrial Development Plan (IDP) incorporating the current manufacturing, fabrication and service domestic and regional capability, developing the sector-by-sector demands and plans for future sustainable businesses and JV's. The IDP would also formulate Policy initiatives and incentives to maximize FDI.

Phase 3—Sector Plan Developments, Roll Out and Training

- Development of Sector Plans

Systematic development of sector plans for key growth areas for incorporation into Nigeria's industry and investment promotion plans

- Hook up, Training and Hand over of Integrated Dynamic Models

Continuous on the job training throughout the development, creation of key expert users and trainers and inclusion of industry participation. Action plans and work methodologies to keep, maintain and update the model on an ongoing basis. Provision of all software and hardware platforms necessary.

Policy, Strategic Objectives, and Priorities

6.11 Government policies for high grading of projects can then be based upon a number of strategic objectives, particularly the following:

- normal population growth and need for power
- higher economic growth
- increase in oil exports up to OPEC quotas
- reduced flaring
- generation and saving of foreign exchange
- industrial diversification and increase in non-oil exports
- creation of employment
- creation of downstream added value (to domestic resources)
- acquisition of foreign technology
- reduction in import dependency
- Attracting FDI in all sectors

6.12 The setting of the gas sales price into the system (upstream price) and the gas price/tariff/return for gas out of the backbone transmission system (downstream price) is an essential element to initiate, sustain and equalise the opportunities in the future gas and power industries in Nigeria. This must be agreed upfront and prior to approval of any more utilization projects. The setting of these prices must be done in reverse, starting with the average desired prices for power in the majority of the country, calculating a reasonable rate of return to produce that power, adding the cost of the backbone system, then subtracting from the cost of supply. If the net-back costs are less than the cost of supply then the FGN needs to adjust the upstream tax take and take into account the tax that will be taken from the Power Producers and any VAT from the consumers to get their total tax take balance. The dynamic gas plan will enable these type of balances to be calculated and justified, enabling a careful balance of relaxation of fiscal terms now to stimulate growth and receiving adequate additional returns later from both the upstream and downstream industries. Calculations performed in this study show that there is room for all in this apportionment of returns, both to the private investors and producers, and to the FGN. The FGN should also consider its position in both the power and oil and gas industries.

6.13 While full participatory ownership is often desirable and difficult to give up, other governments have achieved significantly accelerated growth by denationalizing whilst maintaining a Golden Share, equity investment and regulatory control. In the implementation plan these issues should be raised, discussed and planned for if changed.

6.14 An Industrial Development plan, built on top of and integrated with the Master Gas Plan, should be made to predict and measure the wider benefits derived from the massive investments that will be made and to encourage and plan for the realistic maximization of Nigerian content.

6.15 To implement the process, government policy initiatives will be required to address the institutional framework needed for this gas development, including some, if not all, of the following elements:

- policy development via a policy and regulation framework
- project approvals procedure that is transparent and consistent, with a purpose-designed vehicle for good co-ordination (i.e. a one stop shop)
- development of various framework elements (legal, fiscal, financial, etc)

6.16 The policy initiatives should include the following aims:

- promotion of development projects, upstream and downstream for domestic benefit
- provision and application of a competitive investment climate
- promotion and attraction of private investors (including FDI)
- fostering collaboration between upstream and downstream investors for the provision of infrastructure and markets for gas
- facilitating the establishment of downstream industries
- determining the extent of government participation in investment in downstream ventures

- development of human resources and training programs
- define a time bound implementation plan

Appendix 1

List of Reports Provided by the Nigerian Government via the World Bank and other Data and Reports Evaluated

Reports/PowerPoints Supplied to Consultant:

1. Paper by CIS Nigeria 1-2 Nov. 99, Natural Gas and LPG.
2. Paper by Otu Ekong (Dr.), Imeh T. Okopido, 15/16 April 02, Global Gas Flaring Reduction Initiative - Nigeria Next Step.
3. Memorandum by SPDC, 7-14 May 01, Issues for Consideration, N. Gas Policy & Legislative Agenda.
4. Paper by DAO Balogon, SPDC, 26 Sept. 01, Creating Value from NG & Eliminating Routine Flaring in Nigeria.
5. Report to WND LNG Steering Committee, ChevronTexaco, 7 Feb. 02.
6. Presentation to World Bank on Flare Reduction & Gas Utilization, NNPC/CNC JV (Chevron), 8 Jan. 02.
7. NNPC/CNL Reserves Base Presentation.
8. NAOC Gas Projects 2007.
9. Shell Nigeria (SPDC) PowerPoint, Details of Reserves/Supply Demand & Projects and SPDC's Gas Utilization Study.
10. Business Execution Plan, Phillips Oil Co., Sept 01, Brass LNG Downstream, Project Conceptual Phase.
11. ExxonMobil Gas Projects in Nigeria, Nigeria Gas Utilization Study.
12. NAOC JV Strategy, 2001, Meeting Deadline on Gas Flaring.
13. Statoil, The Natural Gas Report.
14. TotalFinaElf (TFE), Oct 01, Gas Strategy Presentation
15. ExxonMobil's Nigerian Gas Utilization Study, September 2000.

16. World Bank/World LP Gas Association, West Africa LPG Market Development Study, March 2001

17. AGFA (Associated Gas Framework Agreement) letter to SPDC, March 1992

18. Vision 2010

Data

A.1.1 In addition to these reports, data and content has been taken from a number of sources with the principal ones described under the headings listed below:

IHS Energy Group Databases, Software and In-House Information

A.1.2 **Probe:** contains well, field, reservoir, and survey data providing decision support for hydrocarbon exploration, and is used in 'Yet To Find' reserves estimation

A.1.3 **GEPS (Global E&P Service):** provides world-wide coverage of E&P news via a scouting service provided to the industry. GEPS has been used to provide historical and current information on all aspects of E&P development in Nigeria and in other countries in the region which have an influence on this study.

A.1.4 **PEPS (Petroleum Economics and Policy Solutions):** provides E&P statistics and commercial information, including detailed legal, fiscal and environmental analysis. This information provides a vital input to the development of a strategic plan, allowing the comparison of legal and fiscal terms with those of other countries world-wide. The appropriateness of selected terms, and competition from other countries with differing terms, can be assessed.

A.1.5 QUE**$TOR:** this software package contains extensive regional cost databases and is used for field development planning and cost estimation.

A.1.6 **Previous IHS Energy Group Studies:** are used to provide and verify data where this is not confidential. The study benefits in particular from access to work such as the 'Remote Gas Strategies' project carried out on a multi-client basis by a partnership between IHS Energy Group and Zeus Corporation. The study reviewed the development costs of stranded gas reserves world-wide, and the economics of gas utilisation options for the development of these reserves. Such a major and comprehensive piece of work provides a benchmark for verification, and background data regarding the issues Nigeria faces in the development of its gas resources.

Industry Sector Reports, Publications, and Journals

A.1.7 The following recognized industry reports have been used as general data sources and background commentary throughout the study:

- *Natural Gas in the World 2000 Survey*, Cedigaz
- *World Energy Outlook 2000*, International Energy Agency
- *Annual Energy Outlook 2001*, Energy Information Administration

- *BPAmoco Statistical Review of World Energy 2000*.

A.1.8 In addition a large number of specialist reports, industry publications and journals have also been consulted, in particular to extract information on the commodities derived from gas usage. These are all listed in the references section at the back of this report.

Process Licensors

A.1.9 Data was sourced from a number of process licensors, notably:

- Kellogg Brown and Root (ammonia and methanol)
- Lurgi Oel Gas Chemie (methanol)
- Syntroleum Corporation (gas-to-liquids)
- Shell International Gas Ltd (gas-to-liquids).

Appendix 2

Gas Utilization Options and Economics

Gas Utilization Sectors

Gas Utilization Options

Chemical Feedstock Sector

Ammonia / Urea

General Background

A.2.1 Over 85 percent of ammonia production is used either directly or indirectly (via urea and other nitrogen products) as fertilizers and this sector drives the overall ammonia market. In the long term, fertilizer demand is driven by population growth (with consequent growth in food demand) and by rising living standards, which increases both the quantity and quality of food consumed. In the short and medium term, growth and profitability in the fertilizer industry is more influenced by world economic growth and factors creating temporary imbalances in supply and demand. These factors include weather patterns, the level of world grain stocks relative to consumption, new production capacity as well as temporary disruptions in fertilizer trade, such as changes in the buying patterns of major players such as India and China.

A.2.2 Besides fertilizers, some 20 million metric tons of ammonia are used annually in non-agricultural industries (fiber production, explosives, plastics and chemicals, metallurgical uses and as a refrigerant and a cleansing agent). The wide range of uses for non-agricultural nitrogen products means that overall market growth closely follows world GDP growth. While ammonia demand for agricultural use is forecast to grow at a little over 2 percent per year, demand for non-agricultural use is expected to grow at some 4 percent per year. However, many of these downstream products require a nitric acid step and due to this product's highly corrosive and oxidizing properties, most ammonia production is built near the ultimate user site. Nitric acid and downstream technical nitrogen capacity is therefore concentrated mostly in the industrialized countries.

A.2.3 In fertilizer production, overall nitrogen application is dominated by urea (some 46 percent of total nitrogen demand worldwide). Since ammonia is less easy to transport than a solid bulk product like urea, an ammonia/urea complex is often jointly established.

Market Structure

A.2.4 Since the early 1990's, there have been fundamental changes in the structure of the international ammonia market. Following the collapse of the FSU and the drop in internal demand, Russia and Ukraine together have become the world's largest exporters of nitrogen products. Plants in these countries are located close to port facilities and are focusing on exports. However, this increased availability of urea and other nitrogen products is likely to change as gas costs continue to rise and it is therefore uncertain how long it will remain economic for the FSU to maintain high volume exports. In particular, increasing gas costs in the Ukraine have raised the floor price for FSU ammonia and contributed to the increase in ammonia prices.

A.2.5 In the US, the economics of marginal suppliers with high costs are key to the determination of prices. When ammonia prices are low, the producers with high costs tend to exit the market for a period, thus tightening supplies. In general, Asian prices closely mirror benchmark US Gulf Coast prices.

A.2.6 Both China and India (the two most populous countries in the world) exert considerable influence in the marketplace for fertilizer products. India provides considerable subsidies to its domestic industry because it considers the security of fertilizer supplies paramount for its food supplies. China has taken the step of banning all imports of urea. As a condition of its application to join the WTO, China will have to adopt a much freer access to its markets, thus providing an opening for urea producers for those best placed to meet the demand.

A.2.7 Industry restructuring is likely in to the market based on over-supply and low margins.

World Supply/Demand

A.2.8 The current world ammonia nominal plant capacity is some 125 Mmtpy with about 89 million of this available as capacity for fertilizers (both figures N equivalent). The current world annual nitrogen consumption for fertilizers is some 83 Mmty. The breakdown of consumption for the world regions is shown in Figure A.2.1 with the current balance of supply/demand in A.2.2.

Figure A.2.1: World Consumption of Nitrogenous Fertilizer (by region)

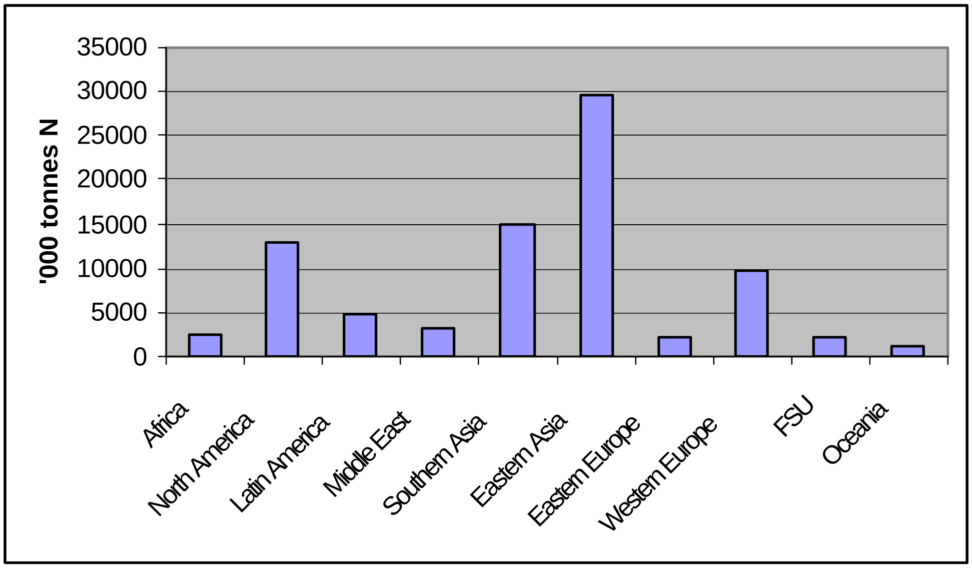
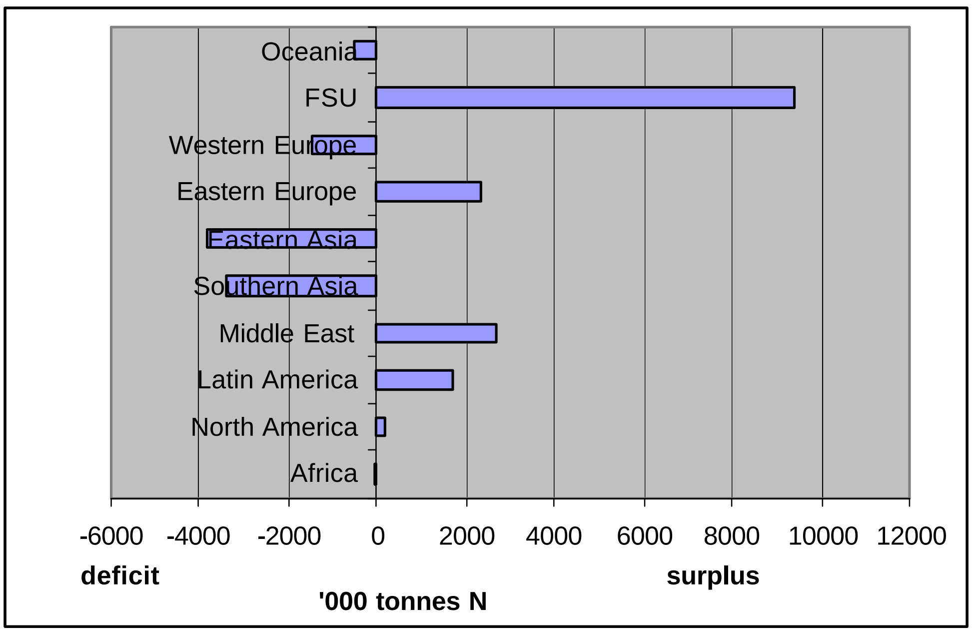


Figure A.2.2: World Supply / Demand Nitrogen Balance Forecast 2003-4

(by region)



A.2.9 There is a predominance of nitrogenous export surpluses in the FSU (Russia and the Ukraine), Central America (Trinidad) and the Middle East. The FSU has seen drastic reductions in consumption during the 1990's and early this century but this picture is changing. Nitrogen demand is expected to rise which will reduce its exports.

There is still a very substantial and increasing production of nitrogenous fertilizers in very populous countries such as China and India, which do not have adequate gas reserves. To date, these major agricultural-producing countries have wished to keep control over an input that is essential for their food supplies. Countries dependent on imports of gas and LNG, including India, are considering the use of alternative feed stocks (such as coal) to produce ammonia.

A.2.10 The significant growth regions for capacity are now expected to be those with easy access to cheap gas, such as Trinidad, the Middle East, SE Asia and to a lesser extent from new South American projects. In South America, Venezuela is likely to show the biggest capacity growth, increasing 135 percent, to 1.7 Mmtpy by 2003. Iran and Oman will show the biggest capacity increases in the Middle East, while in SE Asia, Indonesian capacity is expected to grow 22 percent to 5.6 Mmtpy. By 2003, it is forecast that capacity growth will stagnate in Canada, US, Japan and Eastern Europe.

Demand Market Growth

A.2.11 In the period to 2010, the International Fertilizer Association forecasts that world consumption of fertilizer will increase by 2.1 to 2.9 percent per year. Most of this future increase is expected to be generated by less developed countries, particularly in SE Asia and South America, where the agricultural industry does not yet use fertilizer in sufficient amounts to optimize production and where growth rates of population and GDP are expected to continue to increase. In developed countries, demand growth is expected to be stagnant and capacity is forecast to decline, due to increased imports from Asia, Eastern Europe and South America.

A.2.12 Over the next few years, world demand for ammonia is therefore expected to outpace capacity additions and plant utilization rates should continue to improve. For urea, the converse is true; there is too much capacity chasing too little demand.

Ammonia / Urea prices

A.2.13 Ammonia: World nitrogen prices were near record lows in mid-1999 but rose rapidly throughout the spring and summer months of 2000. The increase was due to a combination of strong world nitrogen demand and plant closures in the US and elsewhere around the world (figures for ammonia in late-2000 were US$150-200/t and in early 2001 US$200-225/t).

A.2.14 Urea: The US Gulf Coast price for urea averaged US$172/t in mid-2000, almost double the price in mid-1999.

A.2.15 Prior to withdrawing from international urea markets, China was by far the largest importer of urea, in excess of six million metric tons in 1995 and 1996. China's absence from international urea markets combined with the FSU supplying the market with urea at low prices has adversely impacted urea prices in the last three years. However, China has recently reached an agreement on terms for entry into the World Trade Organization. This may hasten China's return to the import market, for at least some limited tonnage of urea in the near future.

Ammonia / Urea Market Drivers and Economics

A.2.16 The main competition factors in the market are largely those of reliability of supply, price, delivery time and quality of service. For the producer, this translates to feedstock availability to the production facility and the cost and efficiency of production, transportation and storage facilities. Trade regulation can also be an important competitive factor.

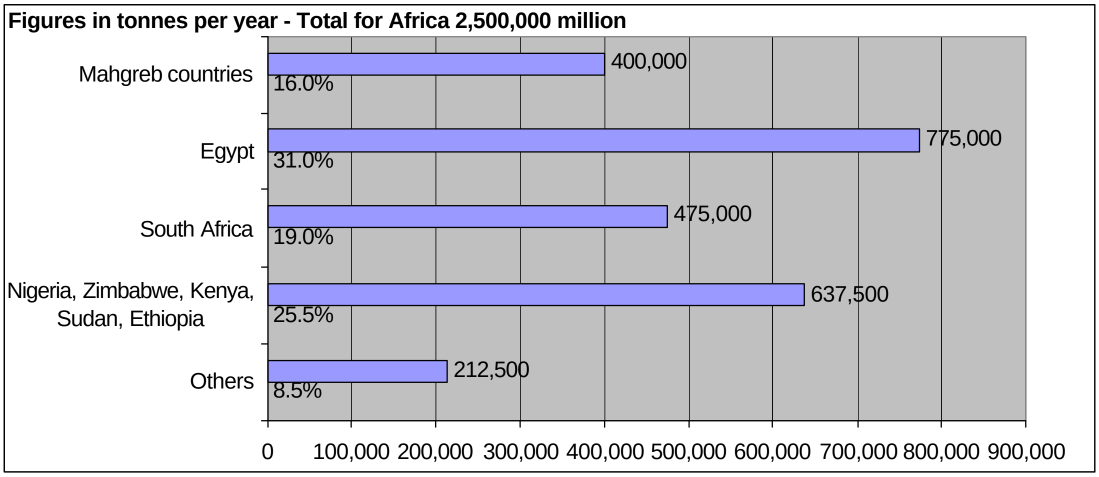
A.2.17 As an example of economic sensitivity, in the North American market at US$2.25/MmBTU natural gas, 75 percent of the production cost of ammonia is gas costs. At US$4.30, this rises to 85 percent (for example US$145 out of US$170). Hence, the situation can quickly develop where rising gas prices can result in production at a loss or curtailing production altogether (temporarily or permanently). Gas prices in North America have escalated considerably over the past year and since this region accounts for some 15 percent of world production, a significant number of closures here can quickly tighten the world market supply. Having access to low cost gas (less than US$2/MmBTU) is a competitive advantage for ammonia production.

A.2.18 Because of relatively low African fertilizer consumption, to heavily increase fertilizer production, Nigeria will have to target markets on a world basis outside of the African continent. In 1999-2000, consumption of nitrogen fertilizers in Africa totaled some 2.5 million metric tons (N) as shown in Figure A.2.3. In sub-Saharan Africa, five countries mainly account for 34 percent of this total, which equates to approximately 850,000 tpy. These countries are Nigeria, Zimbabwe, Kenya, Sudan and Ethiopia. The Mahgreb countries (Algeria, Libya, Morocco and Tunisia) account for 16 percent, Egypt 31 percent and South Africa 19 percent.

A.2.19 Transport costs figure prominently in ocean freight of fertilizer commodities. Ammonia (requiring refrigeration to ship in large quantities) commands freight costs of over US$50/t for voyages of 6000 nautical miles (typical distance to US). Urea, shipped in bulk carriers, has lower transport costs at typically US$25/t for the same journey.

Figure A.2.3: Africa Nitrogenous Fertilizer Consumption 1999

(nitrogen equivalent)

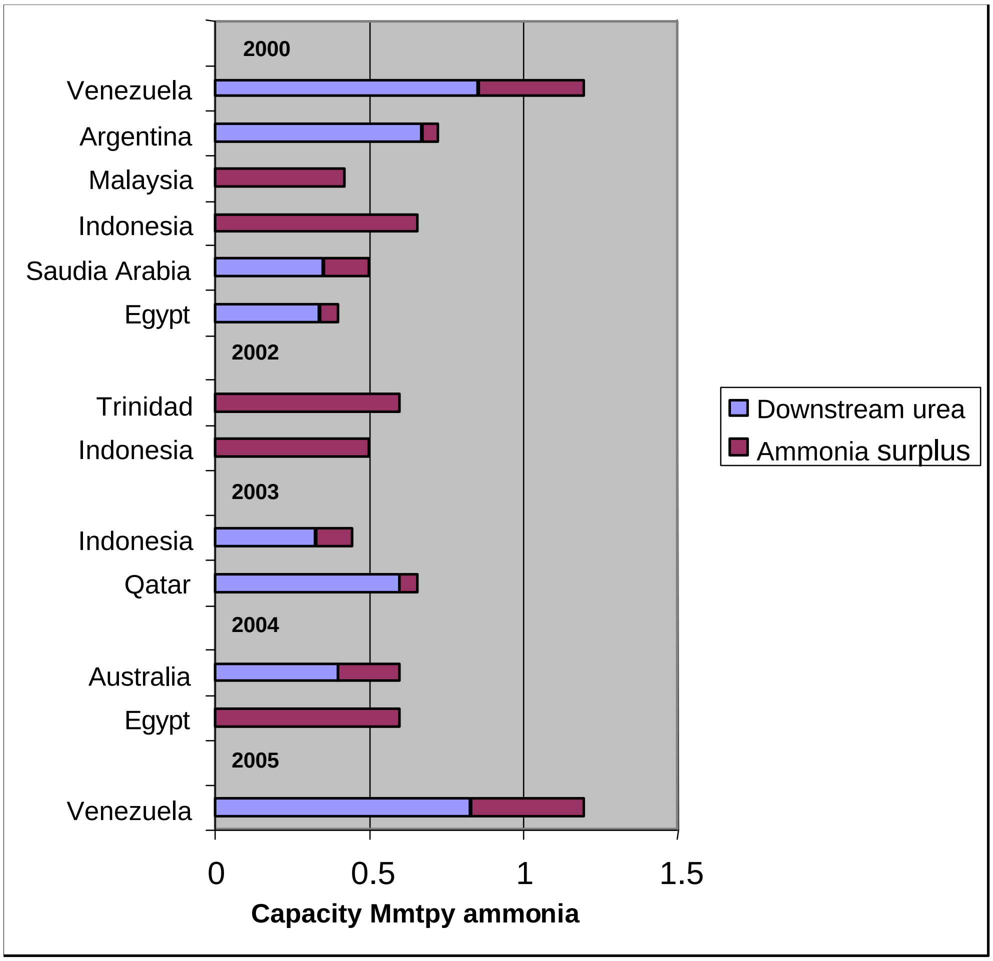


Source: International Fertilizer Industry Association

New Projects

A.2.20 There are a number of export-orientated starting up projects in the next few years, many of which will have an impact on the Atlantic Basin market (shown in Figure A.2.4 as capacity additions by year). Much of the ammonia capacity will go to urea (shown by the dark red bar).

Figure A.2.4: New Export-Orientated Ammonia/Urea Projects



A.2.21 Details of the most immediate and significant projects located in the Atlantic Basin are

Table A.2.1: Significant New Fertilizer Projects—Atlantic Basin

Location	*Company*	*Capacity (Tpy)*	*Comments*
Point Lisas - Trinidad	Caribbean Nitrogen	645,000	On stream 2004, reported gas price $0.90/MmBTU
Argentina	Profertil	1,000,000 urea	500,000 tonnes for export
Venezuela	FertiNitro	1,200,000 ammonia 1,500,000 urea	2 plants of each product. All urea for export, overall production to rise from 1.9 to 4.6 Mmtpy

A.2.22 These projects are significant competitors to any potential expansion of the Nigerian fertilizer sector.

Methanol

(a) General Background

A.2.23 Methanol is one of the largest organic chemical intermediates with some 70 percent being used in further chemical synthesis (the three largest users being formaldehyde, MTBE/TAME and acetic acid). Figure A.2.5 shows the uses for these three major users. The breakdown of uses of methanol is given below in Figure A.2.5.

A.2.24 Two generally accepted product quality standards are produced (designated as chemical-grade and fuel-grade) according to the intended use.

A.2.25 Economies of scale are putting considerable pressure on ever increasing plant sizes. World scale plants are in the order of 2500 Tpd or larger, whereas many older plants have capacities of 1000 Tpd or less.

Figure A.2.5: Global Breakdown of Uses for Methanol

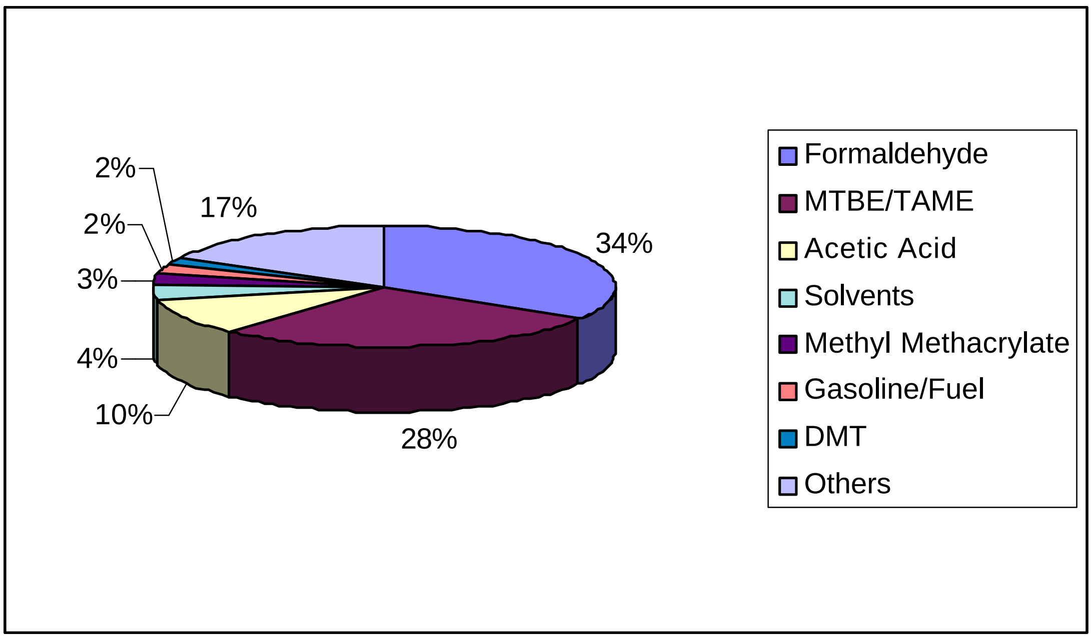


Table A.2.2: Products from Methanol and Their Uses

Product	*Chemical process from methanol*	*Uses*
Formaldehyde	Catalytic dehydrogenation of methanol	• Resins for wood products by reacting with urea, phenol and/or melamine. • Adhesives • Engineering plastic (polyacetal) by polymerization with ethylene glycol
MTBE/TAME	Reaction of methanol and isobutylene (latter from refinery FCC unit)	• Octane booster in gasoline
Acetic acid	Carbonylation of methanol	• Vinyl acetate monomer and poly vinyl acetate (PVA) • Terephthalic acid • Polyester resins • Acetic anhydride

(b) Market Structure

A.2.26 The global market in methanol has seen considerable structural changes since the early 1990s. The industry has evolved from a relatively large number of fragmented producers to a group of much larger, sophisticated international distributors and marketers. This structural change has seen the emergence of such market leaders as Methanex and SABIC and consolidation of production in major hub countries such as Chile, Trinidad, Saudi Arabia and New Zealand. These centers present considerable challenges to new players because a critical mass of capacity and expertise has been built up over a number of years. Statoil, in Norway, has joined these centers with its 2500 tpd plant, now in operation for over a year. In 2001, there will be another addition in the Atlantic Basin with AMPCO in Equatorial Guinea. This rationalization of capacity is reflected in North America, where since 1997, over 2 Mmtpy of capacity has been shutdown. As a general rule, industry experience suggests that when feedstock prices are below US$2.00/MmBTU, local production could compete with offshore facilities. However, when they rise above US$2.00-2.50, local plants lose competitiveness. Future rationalization is expected in the drive to reduce average operating costs.

A.2.27 In the FSU, increasing gas costs and transport costs have caused some sources of methanol to dry up from the region. As an example of the deteriorating economics, the two most efficient plants (750,000 tpy units at Tomsk in Siberia and Gubhaka in the Ural mountains) are respectively 4200 and 2200 Km from European markets and exposed to expensive rail charges. In Europe, only two producers - ICI and

Methanor - use natural gas (and the ICI plant is being shutdown following purchase by Methanex). The rest use refinery off-gases or are integrated into petrochemical complexes. The European market has some unique features such as a quarterly fixed-price contract structure and low levels of spot activity. This makes it more difficult for exporters to divert spot cargoes into the European market.

(c) World Production Capacity, Demand, and Plant Utilization

A.2.28 The current world production capacity of methanol is 38 Mmtpy with demand at 28.0 Mmtpy. The breakdown of the capacity figure into regions is given in Table A.2.3.

Table A.2.3: World Methanol Production Capacity (by region)

Region	Capacity ('000tpy)	% World Total
North America		
US	6100	
Canada	1890	
Mexico	250	
North America Sub-total	**8240**	**21.7%**
South America		
Chile	2700	
Trinidad and Tobago	2950	
Venezuela	1520	
Others	436	
South America Sub-total	**7606**	**20.0%**
Europe		
Germany	1800	
Norway	933	
Netherlands	800	
Others	490	
Europe Sub-total	**4023**	**10.6%**
FSU Sub-total	**3225**	**8.5%**
Middle East/Africa		
Bahrain	425	
Equitorial Guinea	850	
Iran	915	
Saudi Arabia	3940	
Qatar	825	
Libya	660	
Others	236	
Middle East/Africa Sub-total	**7851**	**20.7%**
Asia/Pacific		
New Zealand	2420	
China	2354	
Indonesia	990	
Malaysia	660	
India	390	
Others	231	
Asia/Pacific Sub-total	**7045**	**18.5%**
TOTAL	**37990**	**100.0%**

A.2.29 Current plant utilization factors of 75 percent are expected to persist over the next five years as additional capacity comes onstream, matching predicted growth in demand. The drive to decrease operating costs is reflected in part in the increasing size of plants.

A.2.30 New plants expected to onstream in the next few years are listed below in Table A.2.4. The net effect on world production capacity is a growth of about 3.7 percent per year for the next five years.

Table A.2.4: Future Planned Methanol Projects—Atlantic Basin

Location	*Company/Project*	*Capacity (Tpd)*	*Onstream Date*
Equatorial Guinea	AMPCO	2500	2001 2Q
Plaza Huincul, Argentina	Repsol	1259	2002
Point Lisas, Trinidad	BPAmoco/Saturn Methanol (Methanex-owned)/Beacon Group Atlas Project	4700	2003
Point Lisas, Trinidad	Methanol Holdings	4700	End 2003/early 2004
Sohar, Oman	Oman Oil Company	5000	Early 2005

A.2.31 The first two plants listed above are expected onstream before end of 2002 but are offset by two notable closures in the same period. The Borden Chemicals and Plastics 990,000 Tpy plant in the US closed in January 2001 and ICI's 500,000 Tpy plant in the UK was due for closure in April 2001.

A.2.32 Methanex, who operate significant methanol capacity in New Zealand, indicate that their contracted natural gas entitlements are sufficient to run their plants at capacity only until 2005. Further exploration for gas is continuing and they have been offered quantities to extend operations by two years. During this period, further supplies may be developed but they report that there is no assurance that they will be able to secure supplies at economically attractive terms.

(d) Regional Supply / Demand Balance and Potential Markets

A.2.33 The current picture of the regional supply and demand balance indicates that North America is roughly in balance; deficit regions are Europe and Asia/Pacific, while surpluses exist in South America, FSU and the Middle East.

(e) Price

A.2.34 The market price of methanol has undergone large swings in the recent past, with the spot price doubling from a low in January 2000 to highs of US$230-240/t in the latter part of the year (2001 figures show US$250-270/t). This was been largely in response to the hike in US gas prices (to US$5.00/MmBTU and above), unscheduled production problems and plant shutdowns. The current industry viewpoint is that these prices are unlikely to be sustained if there is a decline in MTBE demand. Indeed, there may well be another price trough by 2003-04. Because of the likely low penetration of methanol into the fuel market for the near future, it is expected to be some time before methanol tracks fuel prices.

(f) Market Growth

A.2.35 Growth in demand over the past 10 years has been driven by a market of providing oxygenates for use in reformulated gasoline (RFG) and as a lead replacement component. Growth in the future is expected to be around 2 percent/year over the next few years but may decline towards the end of this period because of the potential drop in the market for MTBE. The main import markets are Europe, Asia and the US.

A.2.36 The likelihood that MTBE will be phased out over the whole of the US is a major concern for methanol producers. Moreover, in Europe, the new gasoline regulations are likely to lead to an increase in demand for MTBE in that region (one industry prediction suggests that an additional 250,000 Tpy of methanol will be needed by 2005).

A.2.37 Apart from MTBE, the methanol market is expected to grow at traditional levels, with acetic acid growth being particularly strong over the next few years. This product is produced by the methanol route rather than via the older ethylene/acetaldehyde process.

A.2.38 As for alternative uses, fuel cells remain a promising new opportunity, but the mass market potential is still some years away. Motor manufacturers do not expect initial use to be more than 320,000 metric tons per year. For several years this demand can be accommodated by more fully utilizing the production capacity of existing plants.

A.2.39 Another possible alternative use of methanol is methanol-to-olefins. To achieve the necessary economics, methanol plant sizes would have to be increased still further, possibly as high as 10,000 tpd. Initial economics see this route as being more costly than an ethane cracker but competitive against naphtha.

(g) Transportation

A.2.40 Methanol shipping has also changed in recent years, resulting in an increasing percentage of dedicated methanol tankers (estimates of more than 30 today) and increasing vessel capacity to match the economies of scale growth in plant sizes. For example, Methanex now utilizes a 98,000-dwt tanker to ship product from the southern hemisphere to Europe. This is a significant increase from the previous standard of 45,000 dwt with a claimed per metric ton 40 percent reduction in ocean freight costs. On the downside, there are currently only a small number of terminals that can handle ships of this size.

(h) Methanol Economics

A.2.41 The general conclusion of the industry is that in order to penetrate new markets (particularly for use as fuel) methanol plant gate prices need to be US$90/t or less. There are three main ways to bring this about:

- Reduction in the cost of gas (to figures in the region of US$0.50/MmBTU or less)

- Improvements in economies of scale of plants (increasing plant sizes to 5,000 or even 10,000 Tpd)
- Improvements in synthesis gas technology to improve overall plant efficiencies.
- One crucial choice in synthesis gas technology is the use of an oxygen-blown secondary reformer. This leads to a number of advantages:
- Reduced natural gas consumption per metric ton methanol by 8-10 percent
- Reduced size of the steam reformer and equipment in synthesis gas front-end and methanol synthesis loop
- Reduced compression requirements for the methanol synthesis loop
- Reduced emissions of carbon dioxide and nitrogen oxides

A.2.42 This process scheme involves the use of an expensive air separation unit. At large plant capacities (well above 1500 Tpd) this will likely to improve overall economics. However, with higher plant capacity there is higher risk involved in keeping the plant operating at high utilization factors and high plant reliability. In sensitivity analysis, the requirement for a high onstream/utilization factor is considerably more significant than that of the processing cost.

A.2.43 With this in mind, the Atlantic Methanol plant in Equatorial Guinea, which came onstream in 2001, offers some interesting reported comments on its economics. The gas price to the methanol plant is said to be US$0.25/MmBTU and the plant should have a delivered cost of US$0.19 per gallon of methanol ($65/tonne). This compares with US$0.32 per gallon ($109/tonne) production cost for US Gulf Coast methanol producers at a gas price of approximately US$2.20/MmBTU. The US plants would need spot gas prices to fall to US$0.90/MmBTU to achieve operating costs equal to the AMPCO plant. Two tankers have been leased for 15 years to transport the methanol at a rate of US$ 0.07 per gallon (equivalent to US$24/tonne).

A.2.44 By comparison, the price of gas for the Statoil Tjelbergodden plant in Norway is said to be in the range US$0.75-1.00/MmBTU.

A.2.45 Bearing in mind the significance of transport costs in the price for delivered product, the probable target market for any new methanol would be southern Europe or U.S. Gulf Coast.

Ethylene

(a) General Background

A.2.46 Ethylene is one of the main building blocks of the modern petrochemical industry and is manufactured by steam cracking of ethane or liquid feedstock, principally naphtha. Ethane-based crackers produce fewer by-products than their naphtha feed counterparts, particularly resulting in less propylene. Ethane is widely used as a cracker feedstock in the US Gulf Coast region, Western Canada and the Middle East. In this latter region, the availability of large volumes of low-cost associated gas, with low alternative value as fuel, has encouraged ethane cracking. By way of example, this region has some 5.2 Mmtpy of ethane recovery that could increase in the next 20 years by an additional 20 Mmtpy.

(b) Economics

A.2.47 Two conditions must exist for ethane to be extracted from natural gas and be used as a cracker feedstock:

- The ethane must be available in sufficient quantity to provide enough feedstock for a world scale cracker (to take advantages of economies of scale)
- The extracted ethane must have a greater value as cracker feed than if left in the gas for sale as fuel.

A.2.48 Unless the gas source is very rich in ethane, the quantities of gas required to support a world scale cracker are extremely large.

A.2.49 Ethane extraction as part of the gas pre-treatment for a current and future NGL or LNG plants offers some interesting opportunities.

A.2.50 On top of this, any project for ethylene production would need to look at its downstream companion plant to produce HDPE/LDPE. There is an alternative route to ethylene via methanol, but to date no commercial plant has been built and this possibility is not included in this review.

Gas-to-Liquids (GTL)

(a) Background

A.2.51 Gas-to-Liquids (GTL) technology has been in development for many years, but there are only three commercial plants in operation, all in special economic circumstances. In the past few years, GTL has been 'pushed' by the need to reduce flaring and the opportunities to develop stranded gas reserves. Equally, it is now likely to be 'pulled' by the requirement for sulfur free diesel, but will be predominantly used as a blending stock in the production of fuels to meet future, stricter, environmental legislation. There are now an additional number of plants planned or in the design phase.

A.2.52 The current state of play of the GTL industry is best examined with reference to those companies who are active in the market. SASOL and Shell have experience in commercially operating plants. Exxon has demonstration plants and since the merger with Mobil, commercial experience. All of these plants operate in special economic circumstances. Governments eager to develop security of supply subsidized

SASOL and Mobil. Shell, in Malaysia, targeted a niche market in specialty waxes. All of these companies have further commercial plants planned and are likely to expand their production capacity. Shell and ExxonMobil will not license their technology but utilize it where they have operational interest. SASOL requires part of the equity of any gas field and therefore intends to use its technology as a means of entering the upstream business.

A.2.53 Syntroleum are also in the market as technology providers but do not currently have any commercial plants in production. Texaco, Marathon, Arco (BP), Kerr-McGee, Repsol-YPF, the Government of Western Australia and Ivanhoe Energy (independent) currently hold licenses for Syntroleum technology. The company claims that its technology is economic at smaller plant sizes than the oil majors' processes can achieve, because there is no requirement for a front-end air separation plant.

A.2.54 Other oil majors and licensors are currently developing technology. The Rentech/Texaco alliance believed to be nearing commercial production capability.

A.2.55 A summary of the existing commercial and demonstration / pilot plants is given in the Table A.2.5.

Table A.2.5: GTL Commercial and Demonstration Plants

Shell	*Sasol*	*ExxonMobil*	*Syntroleum*
Commercial Operation			
12,500 bpd high quality waxes Bintulu, Malaysia	3 x 7,500 Bpd South Africa (Mossgas with Sasol technology) – energy security	11.5 Bpd New Zealand – energy security	
Demonstration / Pilot			
Pilot scale since 1989	100 Bpd demo plant	200 Bpd demo plant since 1993	70 Bpd demo plant

Products

A.2.56 The following products can be produced from GTL plants:

- LPG
- Naphtha
- Gasoline
- Kerosene
- Diesel
- Wax
- Lubes

A.2.57 Current technology is focused on producing diesel and naphtha although specialty market products such as waxes have been produced (specifically in Shell's case at its Bintulu plant). Specialty markets will quickly become saturated once GTL production capacity builds and those who own the technology will operate small plants in these markets themselves. Exact yields depend on the specifics of each individual plant, but it can be assumed that a general basis for product yields is 80 percent diesel, 20 percent naphtha, as in general producers aim to maximize the production of diesel.

Markets—Diesel

A.2.58 By mid-2006 environmental regulations will cut the permissible sulfur levels in diesel for transportation as follows:

- U.S.: reduced from 500 parts per million (ppm) to 15 ppm (verified via EPA)
- Europe: from 350 ppm to 50 ppm (verified via EU).

A.2.59 These levels will require the addition of new hydrotreating facilities at most refineries. However, as an alternative to achieving the requisite levels, GTL diesel can be used as a blending component. GTL diesel is sulfur-free, and can therefore be sold at a premium over refinery blending stock. The value of GTL diesel as a blending stock is the value of existing refinery diesel, plus a premium reflecting the requirement for new hydrotreating facilities if GTL diesel is not used, plus a premium because GTL diesel is sulfur-free.

A.2.60 European countries vary in their current ability to produce fuels to meet these regulations in 2005. For example, the UK already produces diesel to this specification. In the longer term, environmental regulations are likely to tighten further, to 5-10 ppm, requiring an additional refinery investment (again, some countries in Europe can already produce to this tighter specification).

A.2.61 The US refining industry is further from meeting the stricter limits to be imposed upon them in 2006. Estimates of the cost to the refining industry vary widely between EPA and API studies, but the levels of investment are substantial.

A.2.62 In the long term, if sulfur-free diesel may be sold directly as a niche market environmentally friendly fuel, some advantages with current Nigerian Refining Capacity may be possible. The likely characteristics of this market, once it reaches a substantial size, are too uncertain to predict economic parameters with sufficient confidence.

Future Projects

A.2.63 GTL plants planned in the near future are listed in Table A.2.6, broken down by principal technology providers.

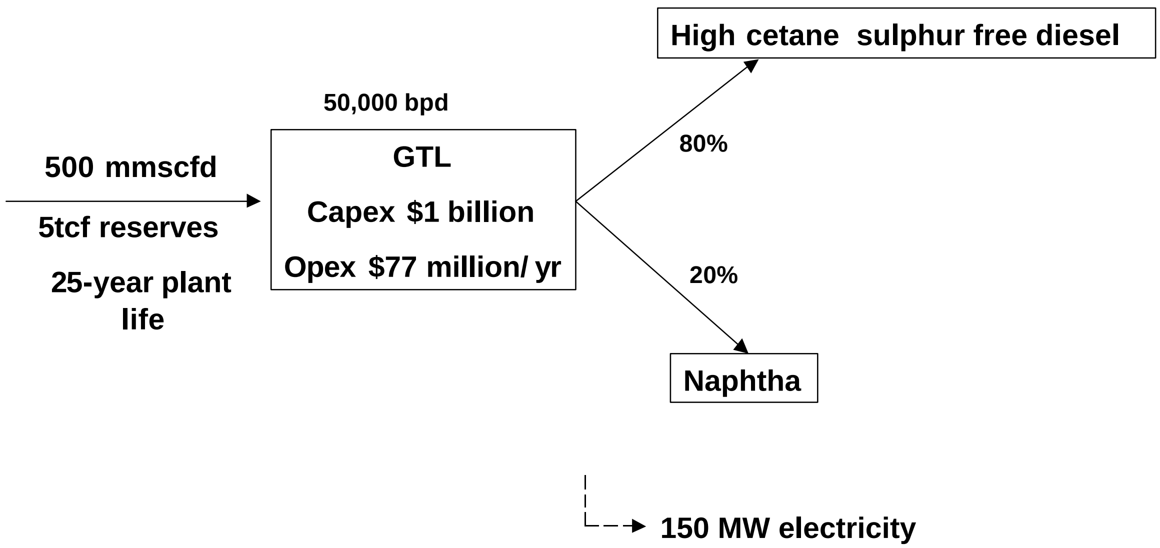
Table A.2.6: Planned Commercial GTL Plants

Location	*Capacity (bpd)*	*Product(s)*	*Start-up/Notes*
Shell			
Egypt	75,000	Diesel and naphtha shipped to Europe for use as blending stock	Late 2005
Indonesia	70,000	Clean fuels shipped to Singapore for use as blending stock	2Q 2002, discussion stage
Trinidad	75,000		2004/2005
Iran (South Pars)	70,000		2005, MOU
Sasol			
Qatar	20,000		With QGPC and Phillips, feasibility stage completed
Nigeria	30,000	Diesel shipped to Europe for use as a blending stock, naphtha possibly to Asia for use as petrochemical cracker feed	2005 with Chevron
ExxonMobil			
Qatar	50-100,000		Discussion stage
Alaska	100,000		Discussion stage
Syntroleum			
Western Australia	10,000	domestic refining blend stock, or shipment to Singapore refineries for use as a blending stock	End 2002

Economics

A.2.64 A summary of the main economic features of the GTL technology of Sasol, Shell or ExxonMobil is given in this section. Typical plant parameters are shown below:

Figure A.2.6: GTL Typical Plant Economic Parameters

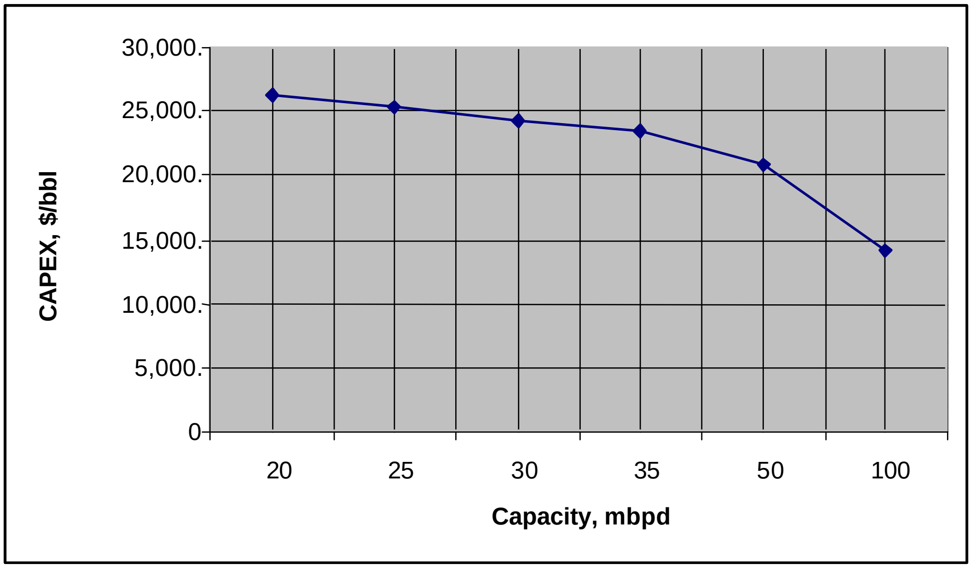


A.2.65 It should be noted that exact product split, conversion rates, cost of electricity generation etc, depend on the location, technology, plant configuration, feed gas composition and many other factors relevant to each individual plant. In general, 1 bpd product requires 10 mcfd of feed gas.

A.2.66 There are substantial economies of scale with Sasol, Shell and ExxonMobil technology and the lowest economic plant size in locations where there is little or no existing infrastructure is generally considered to be 50,000 Bpd.

A.2.67 Developments in experience with the technology in the past two to three years have led to claims of significant cost reductions by the major players in the market. The figures below are from a paper published by SASOL in June 2000, showing indicative unit capital costs for typical GTL plants. The costs from this figure for a 50,000 Bpd plant ($20,800/Bbl) match quite well with Shell's recent claims that unit CAPEX costs for their plants are now down to approximately US$20,000/Bbl.

Figure A.2.7: GTL Plant Capital Investment



A.2.68 Operating costs for Sasol, Shell and ExxonMobil processes are similar – estimated at around US$150 million/year for a 100,000 Bpd plant. As a large proportion of the cost is based on syngas conversion and catalyst consumption rates, this figure is likely to change with improvements in catalyst technology.

Syntroleum GTL

A.2.69 Syntroleum claims that because its process does not require an air-separation plant, their technology is economic down to much smaller plant sizes than the competition. Thus, use of this technology may be more appropriate where smaller gas reserves or lower feed rates are available or to reduce risk by having lower levels of investment. A number of economic examples have been developed in conjunction with Syntroleum Corporation (as there are no commercial plants operating, and therefore there is no data in the public domain).

Others

(b) DME (dimethyl ether)

A.2.70 Dimethyl ether is predominantly used as a propellant for aerosol formations but more recently there is considerable interest in developing it for use as an alternative to or as a blend with diesel fuel. Its use in this sector is being tested in North America, Europe and Asia. With a vapor pressure of about 5 bar it has similar properties to, and can be handled like, LPG. Its heating value is lower than diesel and LPG but higher than methanol. It makes a good diesel substitute because it has no sulfur but a higher cetane number than diesel at 55-60. The research program into its possibilities as a diesel substitute still has some time before resolution.

A.2.71 The DME process is similar to methanol synthesis with a two-step process of natural gas to methanol and then methanol to DME. There are merits in combining the methanol and DME synthesis and such a one-step process is being developed by Haldor Topsoe, Denmark and Air Products, USA, but is not yet competitive with the conventional route. Since no large-scale plants have been built of the size needed for economies of scale, this product has not been examined in more detail. However, recent press reports indicate that a world scale project is being considered by a group of Japanese companies in Western Australia.

(c) Carbon Black

A.2.72 The main use for carbon black is in the production of tires (70 percent of world output) and in rubber products such as hoses and belting (20 percent). Kvaerner has developed a novel process for its manufacture by use of a plasma torch to convert from natural gas. One plant is understood to be operating successfully in Canada. The process uses about 61,000 Scf per ton of carbon black and a typical industrial scale plant would be about 100-150 Tpd (thus consuming relatively small amounts of gas at 6-9 Mmcfd). Capital costs are around US$80 million for a 120-Tpd plant. Hydrogen is produced as a by-product and any plant needs to be located alongside a plant with a hydrogen demand, such as a refinery, to gain the greatest benefit.

Industrial Fuel Sector

Aluminum

Background

A.2.73 Aluminum use exceeds that of any other metal except iron and it is important in virtually all segments of the world economy. Examples of the many uses for aluminum are in transportation (cars, aircraft, trucks, railcars, marine vessels, etc), packaging (cans, foil, etc), construction (windows, doors, etc), consumer durables (appliances, cooking utensils, etc), electrical transmission lines and machinery. Aluminum metal is produced by the Hall-Heroult electrolytic process for the smelting of alumina, which in turn is produced from bauxite. Most bauxite comes from sub-tropical countries and three countries (Australia, Guinea and Jamaica) account for about 60 percent of world output.

A.2.74 Many of the big aluminum companies (Kaiser, Alcoa, Alcan, Norsk Hydro) are significantly vertically integrated between the various steps of mineral production to the finished aluminum products.

A.2.75 The smelting process is highly energy intensive, using typically 14-15 MWh per ton of metal produced and the smelter economics are strongly linked to the availability of sources of cheap electricity. Over 60 percent of world capacity is produced using hydroelectric power. This fact has resulted in some significant events in the past year. For example, in the US Pacific Northwest, well over 90 per cent of the region's 1.6 Mmtpy capacity has been shutdown on a 'temporary' basis as companies prefer to sell their electricity capacity rather than make aluminum with power at hugely increased prices. There is some concern that not all the aluminum companies will reopen their idle capacity.

Market

A.2.76 The market for aluminum is primarily linked to assumed economic and industrial production growth rates. World consumption in 1998 was 21.7 million metric tons and in the medium-term consumption is projected to grow at 3.25 percent per year average. There are some 120 primary smelters in the world with a production capacity of some 26 Mmtpy. New additions to the world market in 2000 were Mozal, a 250,000-Tpy plant in Mozambique and Alcan's new 375,000-Tpy smelter in Québec, Canada.

A.2.77 In addition to primary production, more than 7 Mmtpy of metal is produced from recycled scrap. Aluminum can be recycled over and over again and the proportion of aluminum produced from scrap (so-called secondary aluminum) is rising rapidly (since it requires only 5 percent of the energy needed to make primary metal). In addition, the fabrication of recycled aluminum ingot eliminates more than 90 percent of CO2 emissions that occur in the primary metal production process.

A.2.78 The breakdown in production and consumption is shown in the following tables:

Table A.2.7: Aluminum Production by Country

Region	*% world production*
USA	16
Russia	13
China	11
Canada	10
Australia	7
Brazil	5
Norway	4
Other	34
Total	**100**

Table A.2.8: Aluminum Consumption by Region

Region	*Metric Tons*	*% World Consumption*
Europe	5774	26.6
Africa	283	1.3
Asia	4469	20.6
Americas	7338	33.9
Oceanía	370	1.7
Eastern Europe/FSU/China	3434	15.8
Total	21668	**100.0**

Prices

A.2.79 Aluminum is a globally traded commodity with current prices listed on the London Metal Exchange. During 2000, the aluminum selling price ranged between US$1750/t and US$1570/t and high variations were evident in 2001 with the market reaching US$1600 in May from lows of less than US$1500. Forecasts for primary aluminum are US$1720/t in 2002.

Economics

A.2.80 Production of aluminum requires a cheap source of electricity and for such users of large quantities of electricity, predictable costs over a long period are the most important input in determining the location of any new smelter.

A.2.81 Operational reliability is a key factor and aluminum smelting is a continuous 24/365 process requiring continuity of a reliable and secure supply of electricity. Interruptions of three to four hours require a total restart of capacity (taking many weeks to re-establish). Even shorter interruptions of one to two hours have substantial impact and cost in the order of several million dollars.

A.2.82 Access to highly competitive sources of alumna is essential. Although smelter technology has remained largely unchanged for more than a century, gains are continually being made in design of electrolytic cells (pots), their size, anode technology and in more mechanization.

A.2.83 Information in this report is based on a 250,000-Tpy smelter (the same size as Mozambique's recently commissioned plant) with a 460 MW gas-fired power plant located alongside. Any plant needs to handle alumina feedstock either from a local source or imported and finished ingot product will have to be substantially exported. Thus, any plant requires close proximity to port facilities.

Steel (Direct Reduction)

(a) Background

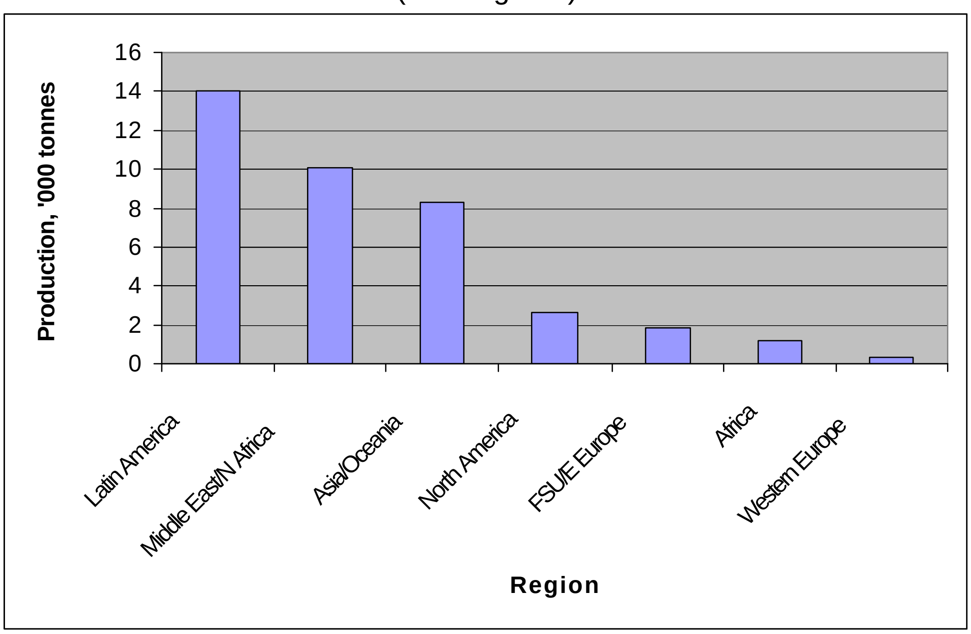
A.2.84 The majority of world steel production is by the traditional blast furnace technology, involving high levels of investment. Steel is also produced from scrap by the electric arc furnace (EAF) and by direct reduction of iron. Direct reduction is a process for converting iron oxide to metallic iron that utilizes natural gas as the energy source and the reformed gas as the reducing agent. The product, Direct Reduced Iron (DRI), is used in the EAF process. Plants using DRI technology do not have to seek such high economies of scale to be economic and therefore overall investment costs are lower (typical plant sizes range from 400,000 to well over one Mmtpy in a single train).

World Capacity

A.2.85 In recent times, while the production of steel via the blast furnace route has only been increasing slightly, production via the EAF and DRI routes has increased dramatically (for DRI from some 800,000 tpy in 1970 to over 37 Mmtpy by 1998). Of the several DRI processes now available, the MIDREX process, developed by Midrex Direct Reduction Co., a wholly-owned subsidiary of Kobe Steel, accounts for nearly 70 percent of worldwide production. Figure A.2.8 gives the world production of DRI by region in 1999.

Figure A.2.8: World Production of DRI by Region

(1999 figures)



A.2.86 Venezuela and Mexico are the two largest steel producers in the world. Midrex forecasts that world DRI production will rise to 65 Mmtpy in 2005 and 75 Mmtpy in 2010 driven by:

- The growth in EAF steel production
- The movement of EAF producers into higher quality products
- An insufficient supply of prime quality scrap
- Environmental concerns of traditional blast furnace plants.

Market

A.2.87 DRI product is used with scrap in the steel-making process and DRI prices have historically been tied to certain scrap prices. Owing to its cost, DRI is not a complete substitute for scrap but effectively a diluent to lower the level of "tramp" elements. DRI competes with higher grades of scrap and where this is in limited supply, such as in developing countries, it is competitive. Where there is a large premium for quality scrap over lower grades, DRI enables lower-grade scrap to be used. It therefore acts as a cost-stabilizing element for steel producers to counter the more volatile scrap market and a quality-stabilizing element because of having a defined specification.

Process

A.2.88 The process consists of two main parts: the reformer, which generates the reforming gas (about 90-92 percent H2 and CO) and the shaft furnace into which the reformed gas is introduced and where the iron is reduced. Iron oxide is fed to the top of the shaft where it flows downward by gravity and is discharged from the bottom. The process can use both lump and pellet form iron ore but generally needs ores with a 67 percent minimum iron content. The process produces two basic grades: DRI and hot-briquetted iron (HBI), which barely oxidizes and can be easily transported. Plants are frequently located alongside an EAF for producing semi-finished steel products (slab and billet). The process has a gas consumption figure of some 23 Mmcfd for a 800,000 Tpy plant, 8000 hours per year onstream time.

Economics

A.2.89 World price for DRI steel is around US$160/tonne, representing a small premium over scrap steel. Information included here is based on producing HBI as a transportable product. The production of semi-finished steel is not as a single commodity specification but tied to specific customer requirements and hence is more difficult to predict than a more universally tradable commodity such as DRI/HBI. Any plant location must be close to port facilities because of the logistics of raw material imports and product exports.

A.2.90 Steel has been classified as a "structurally troubled industry" (Economist Intelligence Unit comments) and the African sector is no exception. The South Africa industry is concerned about the potential impact on its industry of the Maputo Iron and Steel project as one of the world's lowest cost steel makers.

Cement

(a) Background

A.2.91 Cement is the binding agent that enables the formation of concrete, the most important construction and building material. There are several different types of cement, the most common of which is ordinary Portland cement, a gray powder obtained from grinding cement clinker. It is a bulky material with a low value-to-weight ratio, making it expensive to transport over long distances. Inputs to cement production are similarly bulky and have even lower value-to-weight ratios. To minimize transport costs most cement plants are located close to the source of raw materials and the majority of production is sold locally to the nearest regional market. World per capita production obviously has strong links to levels of construction activity.

A.2.92 There are three basic steps in the cement manufacturing process:

1. Raw milling of the cement kiln feed
2. Calcining and burning or clinkering in the kiln
3. Finish milling – the grinding of clinker to produce cement

A.2.93 It is in the second energy-intensive stage where use of natural gas can be made as fuel source for the kiln in the stages of evaporation and preheating, calcining and clinkering. There has been significant evolution of the technologies for clinker production with corresponding reduction in the energy consumption from the older wet process through to the dry process with an increasing number of preheater stages.

Economics

A.2.94 In the world's best practice, energy consumption is typically 680 Kcal/Kg clinker for fuel and 90 KWh/t cement for electricity. The clinker/cement product ratio is about 0.88 so the fuel figure equates to 2.4 MmBTU/t cement. For the Nigeria model we have assumed figures of 3.15 MmBTU/t cement for fuel and 110-120 KWh/t cement for electricity (typical mid-range numbers).

Other Uses as Industrial Fuel

A.2.95 Natural gas has fuel applications in industries for the manufacture of basic commodities where there is local supply of the other raw materials needed.

A.2.96 For example, details of existing domestic brick manufacture are unknown but it is assumed that such an industry would be an essential part of the supply of basic construction materials. Modern gas-fired brick kilns typically require around 4.3 MmBTU/t product of thermal energy and 95 Kwh/t product of power. Taking the thermal demand alone and making some broad assumptions of domestic demand on the basis of increased industrial activity in country, production of some 500,000 Tpy of bricks generates a gas demand of some 5 Mmcfd.

A.2.97 Other industries where gas as fuel could be considered include ceramics and tiles, glass making, fish and other food processing, etc.

LNG Sector

Natural Gas Overview

A.2.98 The production, consumption and international trade of natural gas continue to increase. Gas currently provides 22 percent of primary energy with power generation now accounting for approximately 30 percent of gas consumption and rising.

A.2.99 Gas consumption increased by 2.4 percent from 1998 to 1999 to almost 2,400 Bcm, with FSU and the US continuing to be the largest producers. The following table shows a breakdown by region of the production, consumption and trade in natural gas.

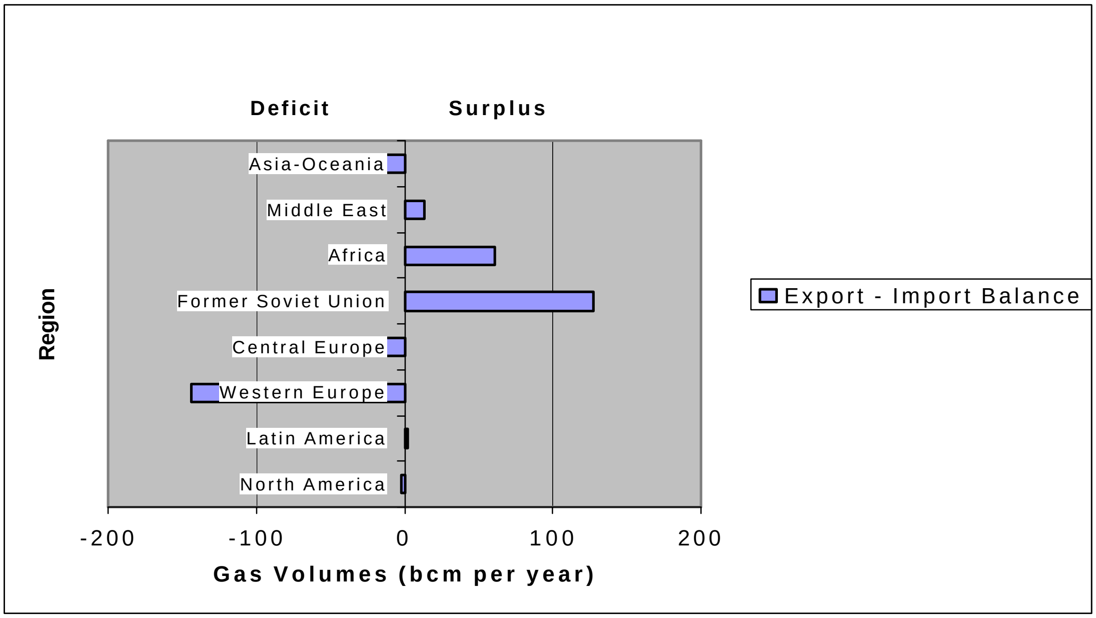
Table A.2.9: World Natural Gas Production, Trade and Consumption 1999

(in Bcm)

Region	*Marketed Production*	*Exports*	*Imports*	*Consumption*
North America	704.15	99.41	102.03	706.77
Latin America	128.86	7.30	5.33	126.89
W Europe	274.45	95.25	238.65	417.85
C Europe	23.76	0.00	42.79	66.55
FSU	702.86	217.21	89.52	575.17
Africa	116.09	61.50	1.10	55.69
Middle East	192.79	21.02	7.85	179.62
Asia-Oceania	254.42	79.37	93.79	268.84
World Total	**2397.38**	**581.06**	**581.06**	**2397.38**

A.2.100 A summary of these figures expressed as an export-import balance is shown in Figure A.2.10.

Figure A.2.9: World Natural Gas Export—Import Balance



A.2.101 International gas trade in 1999 of 581.1 Bcm was up by 10 percent on the previous year. This trade comprises 79 percent transported by pipeline and 21 percent as LNG in tankers. The share of LNG in gas trade has risen steadily from 6 percent in 1970. It should be noted, however, that the figures quoted above include gas transportation within the extensive distribution networks of North America and the FSU. When considering only long distance, inter-regional trade, LNG accounts for approximately 50 percent. Such trade is forecast to triple by 2030 from the 1999 figure of 124 bcm.

A.2.102 The largest LNG exporter was Indonesia with some 40 Bcm, followed by Algeria (30 Bcm) and Malaysia (21 Bcm).

A.2.103 The Atlantic Basin differs from that of the Pacific in that the former has a considerable degree of regional integration by long-distance pipeline networks.

World LNG Trade Movements

A.2.104 The total trade in LNG in 1999 of some 124 Bcm is broken down in Table A.2.10 to show the individual import and export countries.

Table A.2.10: World LNG Imports and Exports (1999)

EXPORTS	*IMPORTS* *USA*	*Belgium*	*France*	*Italy*	*Spain*	*Turkey*	*Japan*	*South Korea*	*Taiwan*	*Total Exports (Bcm)*
USA							1.65			**1.65**
Trinidad & Tobago	1.30				0.75					**2.05**
Qatar	0.60		0.08	0.04	0.84		5.90	0.67		**8.13**
UAE	0.08			0.20	0.31		6.40	0.08		**7.07**
Algeria	2.20	4.04	10.10	2.10	4.22	3.10				**25.76**
Libya					0.96					**0.96**
Nigeria			0.08	0.50	0.08	0.08				**0.74**
Australia	0.31						9.76			**10.07**
Brunei							7.40	1.01		**8.41**
Indonesia							24.80	11.36	2.65	**38.81**
Malaysia	0.08						13.37	4.40	2.70	**20.55**
Total Imports (bcm)	**4.57**	**4.04**	**10.26**	**2.84**	**7.16**	**3.18**	**69.28**	**17.52**	**5.35**	**124.20**
Total Imports (Mmt)	**3.34**	**2.95**	**7.49**	**2.07**	**5.23**	**2.32**	**50.57**	**12.79**	**3.91**	**90.67**

Source: International LNG Importers Group (GIIGNL)

A.2.105 Nearly 75 percent of the LNG traded was supplied to the Pacific Basin with Japan importing over half the world total. In the Atlantic Basin, Algeria is still the dominant supplier with Europe the main import destination. In 1999, the first new LNG projects for 20 years were commissioned, both in the Atlantic Basin (Trinidad supplying the US and Spain, Nigeria supplying several counties in Europe). Although most trade is in the Pacific Basin, the Atlantic Basin's percentage of the world total is rising. Some exporters in the Pacific Basin supply importers in the Atlantic Basin but not the converse.

Atlantic Basin LNG Trade

(a) Long-term contracts

A.2.106 Long-term supply contracts in force in 2000 for Atlantic Basin importers are shown in Table A.2.11. The figures include those where LNG is not yet being delivered but where firm sales and purchase agreements and first LNG deliveries are due to start before the end of 2002. The relevant aspects for this study are those contracts with end dates at the earlier end of the duration spectrum when buyers will be looking to renegotiate contracts or seek new suppliers. For the Pacific Basin, the Middle East suppliers are of interest since they are also potential competitors for European and US markets even though their long-term contracts are with Pacific Basin importers.

Table A.2.11 : Long-Term LNG Supply Contracts Atlantic Basin) at year 2000

Trade	*Seller*	*Buyer*	*Million tpy*	*Duration*
Algeria-France	Sonatrach	Gaz de France	1.20	to 2013
Algeria-France	Sonatrach	Gaz de France	2.70	to 2013
Algeria-France	Sonatrach	Gaz de France	4.00	to 2013
Algeria-Spain	Sonatrach	Enagas	2.70	to 2004
Algeria-Belgium	Sonatrach	Distrigas	3.60	to 2006
Algeria-Turkey	Sonatrach	Botas	2.12	1994-2014
Algeria-Italy	Sonatrach	Snam	1.44	1997-2014
Algeria-USA	Sonatrading	Distrigas	0.96	1978-2003
Algeria-USA	Sonatrading	Distrigas	total 48 cargoes (2.9Mmt)	
Algeria-USA	Sonatrading	Duke Energy	up to 3.20	1989-2009
Libya-Spain	Brega Pet. Marktg	Enagas	0.70	to 2008
Trinidad-Spain	Atlantic LNG	Enagas	1.20	1999-2018
Trinidad-USA	Atlantic LNG	Cabot LNG	1.80	1999-2018
Trinidad-USA (Puerto Rico)	Atlantic LNG	Cabot LNG	0.50	2000-20
Nigeria-Italy	Nigeria LNG	Enel	2.60	1999-2022
Nigeria-France	Nigeria LNG	Gaz de France	0.37	1999-2022
Nigeria-Spain	Nigeria LNG	Enagas	1.23	1999-2022
Nigeria-Turkey	Nigeria LNG	Botas	0.90	1999-2022
Nigeria-Portugal	Nigeria LNG	Transgas	0.25	2000-2022
Total			**34.37**	

Source: International LNG Importers Group (GIIGNL)

(b) Short-term contracts

A.2.107 Until the 1990s, relatively little LNG was traded on a short-term basis, but at this point countries with rising LNG demands imported LNG on a short-term basis to supplement long-term supplies. If this type of trade is discounted, short-term trade has averaged about 2.2 million Tpy or about 2.5 percent of world total trade. The short-term LNG trade in 1999 rose from these levels of the previous five years to nearly 4 percent.

The figures for 1999 are given in Table A.2.12 (Note: short-term is defined as contracts of up to 5 years duration).

Table A.2.12 : Short-Term World LNG Trade

(1999, million metric tons)

	IMPORTS									
EXPORTS	*USA*	*Belgium*	*France*	*Italy*	*Spain*	*Turkey*	*Japan*	*South Korea*	*Taiwan*	*Total Exports*
Qatar	0.43		0.05	0.03	0.64					1.15
UAE	0.06			0.15	0.22			0.06		0.49
Algeria	0.11			0.23	0.36	0.22				0.92
Australia	0.26									0.26
Indonesia							0.11	3.01	0.73	3.85
Malaysia	0.05							1.28		1.33
Total Imports	0.91	0.00	0.05	0.41	1.22	0.22	0.11	4.35	0.73	8.00

A.2.108 For the Atlantic Basin, appraisal of the long-term annual contract quantities and the deliveries made in 1999 under both long- and short-term contracts shows the following:

Table A.2.13: LNG Contract Quantities and Trade (1999)—Atlantic Basin

(million metric tons)

Long-term Contract Quantities	*Trade under long-term contracts*	*Trade under short-term contracts*	*Total Trade*
28.27	20.59	2.81	23.4

LNG Worldwide Liquefaction Plants

A.2.109 The world's LNG liquefaction plants are listed in Table A.2.14. All capacity figures are actual (figures in parentheses are nominal capacities).

Table A.2.14: World LNG Liquefaction Plants

Country	*Location*	*Owner*	*Start-up*	*No of Trains*	*Capacity (Mmtpy)*	*Storage (m^3)*
Saharan Africa						
Algeria	Arzew GL4Z	Sonatrach	1964	3	1.1 (1.7)	71,000
Algeria	Arzew GL1Z	Sonatrach	1978	6	7.6	300,000
Algeria	Arzew GL2Z	Sonatrach	1981	6	8.5	300,000
Algeria	Skikda GL1K	Sonatrach	1972	3	3	112,000
Algeria	Skikda GL2K	Sonatrach	1981	3	3.5	196,000
Libya	Marsa el Brega	Sirte Oil	1970	3	1.3 (2.6)	96,000
Middle East						
UAE	Das Island	Adgas	1977	2	3.2	240,000
UAE	Das Island	Adgas	1994	1	2.5	
Qatar	Ras Laffan	Qatargas	1996	3	7.7	340,000
Qatar	Ras Laffan	Rasgas	1999	2	6.6	280,000
Oman	Qalhat	Oman LNG	2000	2	6.8	240,000
Sub-Saharan Africa						
Nigeria	Bonny Island	Nigeria LNG	1999	2	5.9	168,000
Nigeria	Bonny Island	Nigeria LNG	2002	1	2.95	84,600
South America						
Trinidad	Point Fortin	Atlantic LNG	1999	1	3.2	204,000
Trinidad	*Point Fortin*	*Atlantic LNG*	*2002*	*2*	*6.6*	*102,000*
USA	Kenai (Alaska)	Phillips/Marathon	1969	2	1.4	108,000
Asia Pacific						

Indonesia	Blang Lancang	PT Arun NGL	1978	3	Total Arun 8.8 (13.2)	508,000
Indonesia	Blang Lancang	PT Arun NGL	1984	2		
Indonesia	Blang Lancang	PT Arun NGL	1986	1		
Indonesia	Bontang	PT Badak NGL	1977	2 (A,B)	Total Bontang 22.0	380,000
Indonesia	Bontang	PT Badak NGL	1983	2 (C,D)		127,000
Indonesia	Bontang	PT Badak NGL	1989	1 (E)		
Indonesia	Bontang	PT Badak NGL	1993	1 (F)	1	
Indonesia	Bontang	PT Badak NGL	1997	1 (G)		
Indonesia	Bontang	PT Badak NGL	1999	1 (H)		127,000
Australia	Withnell Bay	North West Shelf Joint Venture	1989	2	Total 7.5	260,000
Australia	Withnell Bay	North West Shelf Joint Venture	1992	1		
Malaysia	Bintulu	Malaysia LNG	1983	3	8	260,000
Malaysia	Bintulu	Malaysia LNG Dua	1995	3	8	65,000
Malaysia	*Bintulu*	*Malaysia LNG Tiga*	*2002*	*2*	*7.6*	*120,000*

Source: International LNG Importers Group (GIIGNL)
Note: Two trains of PT Arun in Indonesia were shut down during 2000.

LNG Reception Terminals—Atlantic Basin

A.2.110 The LNG reception terminals in the Atlantic Basin are listed in Table A.2.15.

Table A.2.15: Atlantic Basin LNG Reception Terminals

Country	*Location*	*Owner*	*Start -up*	*Total Vaporisation Capacity (Mmcmd)*	*No of Tanks*	*Storage Capacity (m3)*
North America						
USA	Everett	Distrigas (Cabot LNG)	1971	12.6	2	155,000
USA	Lake Charles	CMS Energy	1982	20	3	285,000
USA (Puerto Rico)	Penuelas	Ecoelectrica	2000	2.3	1	160,000
USA	*Elba Island*	*El Paso*	*2002*	*14*	*3*	*189,000*
USA	*Cove Point*	*Williams*	*2002*	*21*	*4*	*280,000*
Europe						
Belgium	Zeebrugge	Distrigas	1987	18	3	261,000
France	Fos-sur-Mer	Gaz de France	1972	22	3	150000
France	Montoir	Gaz de France	1980	31	3	360,000
Greece	Revithoussa	DEPA	2000	12	2	130,000
Italy	Panigaglia	Snam	1969	11	2	100,000
Portugal	*Sines*	*Transgas*	*2003*	*7*	*2*	*210,000*
Spain	Barcelona	Enagas	1969	24	4	240,000
Spain	Huelva	Enagas	1988	11	2	165,000
Spain	Cartagena	Enagas	1989	3.6	1	55,000
Spain	*Bilbao*	*Baha de Bizkaia*	*2003*	*8*	*2*	*300,000*
Turkey	Marmara Ereglisi	Botas	1994	16	3	255,000
Turkey	*Izmir*	*Egegaz*	*2002*	*12*	*2*	*280,000*
Latin America						
Dominican Republic	*Andres*	*AES*	*2002*	*3*	*1*	*165,000*

Source: International Gas Union WOC-3

Notes:

1. The plants listed in italics were projects under construction at 01/01/2001
2. The Cove Point and Elba Island terminals in the US were built in the 1980's but are now being refurbished to allow resumption of LNG shipments.
3. Typical tariff (Cove Point and Elba Island) is in range $0.25-0.30/MmBTU
4. Cabot LNG is now a wholly owned subsidiary of Tractebel.
5. BP and Shell have taken capacity at Cove Point (as has El Paso in addition to its ownership position at Elba Island).

LNG Trade Participants

(a) LNG Producers

Table A.2.16: Stakeholders in LNG Liquefaction Terminals

Organization	*Capacity million (Mmtpy)*	*% World Capacity*
National or Local Government Organization		
Sonatrach (Algeria)	23.7	19.3
Pertamina (Indonesia)	16.9	13.8
Petronas (Malaysia)	9.7	7.9
Qatar General Petroleum Corp.	8.9	7.3
Abu Dhabi National Oil Corp.	4.0	3.3
Oman Government	3.4	2.8
Brunei Government	3.3	2.7
Nigeria National Petroleum Corp.	2.9	2.4
Sirte Oil (Libya)	1.3	1.1
Sarawak State Government (Malaysia)	1.2	1.0
National Gas Company of Trinidad & Tobago	0.3	0.2
Subtotal	75.6	61.8
Other Organizations		
Shell	9.0	7.3
ExxonMobil	5.0	4.1
Mitsubishi	5.0	4.1
JILCO	4.6	3.8
TotalFinaElf	4.5	3.7
BP	2.9	2.4
Mitsui	2.2	1.8
VICO	2.2	1.8
Unocal	2.2	1.8
Woodside	1.3	1.0

BHP	1.3	1.0
Chevron	1.3	1.0
Phillips	1.0	0.8
BG	0.8	0.7
Korea LNG	0.6	0.5
Repsol	0.6	0.5
Agip	0.6	0.5
Marubeni	0.5	0.4
Marathon	0.4	0.3
Itochu	0.4	0.3
Tractebel/Cabot	0.3	0.2
Nissho /Iwai	0.2	0.2
Partex	0.1	0.1
Total	122.7	100.1

Source: LNG Trade, Global Energy Reports, SMI Publishing, 2001

A.2.111 State-owned oil and gas companies and government organizations as a type hold the larger stake (at almost 62 percent) in liquefaction capacity. Many of the IOC's active in upstream operations are operating companies in LNG and of these Shell, ExxonMobil, TotaFinaElf and BPAmoco are among the most influential.

(b) LNG Importers

Table A.2.17: Atlantic Basin LNG Buyers

Company	*Country*	*% World LNG Imports 1999*
Gaz de France	France	8.1
Enagas (Spain)	Spain	5.9
Distrigas (Belgium)	Belgium	3.2
Cabot (USA)	USA	2.5
Botas (Turkey)	Turkey	2.4
Snam (Italy)	Italy	2.1
CMS Energy	USA	1.2
Edison Gas (Italy)	Italy	0.25
Enron (USA)	USA	0.06
Coral (USA) (Shell affiliate)	USA	0.05
Total		**25.76**

LNG Future Supply and Demand

A.2.112 The next decade is expected to see strong growth in world LNG demand and figures for the current situation together with forecasts for supply/demand in 2010 for the two basins are as follows:

Table A.2.18: Current and Forecast LNG Supply/Demand

Year	*Atlantic Basin*		*Pacific Basin*		*Total*	
	Supply	*Demand*	*Supply*	*Demand*	*Supply*	*Demand*
2000	35	27	80	70	115	97
2010	75	60	165	110	240	170

Source: Petroleum Economist (attrib. BPAmoco Gas and Power)

A.2.113 By comparison, LNG Trade, Global Energy Reports, SMI Publishing, 2010 prediction suggests a worldwide total of 195 million metric tons, with a range 160-210 million metric tons.

A.2.114 For the purposes of evaluating the potential for marketing LNG from Nigeria, it is expected that the Pacific and Atlantic Basins can be treated as separate market entities. Although there have been a small number of Pacific Basin cargoes sold in the Atlantic Basin they are likely to form a very small part of overall trade. The only exceptions to this are the Middle East producers, who have provided spot cargoes in the past to Europe and the U.S. However, most of this capacity is dedicated to long-term contracts with Asian buyers.

A.2.115 The likely maximum potential LNG supply availability in the Atlantic Basin by 2010 could well be as listed in the table below.

Table A.2.19: Maximum Potential LNG Supply Capability Atlantic Basin (2010)

Location	*Capacity, million metric tons per year*		
	Probable	*Potential Expansion*	*Total Future*
Existing sites			
Algeria	24.3		24.3
Libya	1.8		1.8
Trinidad	9.8	3.3	13.1
Nigeria	16.7		16.7
Subtotal	**52.6**	**3.3**	**55.9**
Greenfield sites			
Egypt	3.0	9.0	12.0
Angola	4.0	4.0	8.0
Norway	4.0	4.0	8.0
Venezuela	4.0	4.0	8.0
Subtotal	15.0	21.0	36.0
Total			**91.9**

A.2.116 These figures are based on the following assumptions:

- All plants currently running will be in operation in 2010 (Note: by then over 16 million tpy of capacity will be > 30 years old)
- Middle East capacity is largely dedicated to Asian markets
- In Trinidad, Atlantic LNG builds a total of 4 trains (one in operation, trains 2 and 3 already planned)
- Nigeria goes ahead with trains 4 and 5 for Bonny Island and one other project
- Egypt builds all four of the projects currently in planning stages
- Norway and Venezuela build 2 trains each (unlikely).

A.2.117 It is considered that not all the above projects will materialize in the timeframe to 2010. A realistic lower bound would still give a supply capacity of around 70 million tpy.

A.2.118 There are two observations worth noting here about how existing liquefaction capacity can often be understated, due to:

- Typical excess of capacity in design by 10-20 percent above nameplate capacity

- Debottlenecking (often an additional 5-10 percent is achievable after only 3-5 years)

A.2.119 Potential additions to Atlantic Basin reception terminals are listed in the table below.

Table A.2.20: Potential New LNG Reception Terminals (Atlantic Basin)

Location	*Company*	*Capacity Mmcmd*	*Notes*
Americas			
Grand Bahama Island, Bahamas	Enron	Unknown	Potential LNG source - Trinidad Interconnecting pipeline to Florida
The Carolinas, USA	El Paso		
Recife, Brazil	GNL do Nordeste	6.0	Feed to power plants
Ceara State, Brazil	Repsol/BPAmoco		Feed to 500 MW power plant
Europe			
Verdon, France	TotalFinaElf	9.0	Atlantic coast site
Reganosa, Spain	Endesa + others	6.0	LNG source—Algeria

A.2.120 A number of LNG reception terminals are being evaluated on the west coast of North America. However they are not considered relevant here, as the majority of LNG carriers are too large to navigate the Panama Canal. Notes on market developments in the relevant European countries in the Atlantic Basin, USA and Brazil to 2010 are given in the table below.

Table A.2.21: Country Outlook for LNG Demand to 2010/2015—Atlantic Basin

Country	*Outlook*
France	Deregulation will reduce the need to diversify supplies, reducing the percentage of gas imported via LNG, and increasing pipeline trade. LNG is expected to remain an important part of the gas supply mix in the south, the most remote part of the country from pipeline supplies. An increased requirement of 2-3 million Tpy LNG is forecast by 2010, if LNG gains 30% of the expected growth.
Belgium	The contract with Algeria is expected to be renewed in 2006, but at a lower level than 3.6 million Tpy. Demand is forecast to be about 3 million Tpy by 2010, with the shortfall from the reduced contract with Algeria made up by short-term contract deliveries. Hence potential for increased LNG supplies is small.
Spain	Gas consumption in Spain is forecast to grow quickly with plans for new power plants. LNG terminals at Bahia de Bizkaia and Reganosa are expected to be supplied from North Africa, Nigeria and Trinidad but new supplies may be needed depending on demand, possibly from the Middle East. Potential penetration of LNG market by new suppliers depends in part on the renewal of existing contracts with Algeria and Libya in 2004 and 2008 respectively. Long-term contracts will then amount to about 13 Mmtpy. By 2010, LNG demand could be 14 Mmtpy.
Portugal	The country has been importing LNG using the Huelva terminal in Spain but will have its own reception terminal at Sines by end 2003. First-phase capacity will be 1.8 Mmtpy and supplies are expected to increase over the next ten years by 2 mmtpy, sourced largely from Nigeria.
Italy	LNG demand is expected to grow to about 7 Mmtpy by 2015. Additional reception terminals are being investigated, e.g. Brindisi, offshore Porto Levante
Turkey	The country forecasts a rapid rise in gas demand and two LNG terminals are currently planned. However there is uncertainty over future forecasts of gas demand and the competitive position with pipeline supplies from Russia and Iran. The requirement for LNG could be between 6 and 10 million Tpy by 2010.
Greece	LNG demand is forecast to increase from the current 0.5 Mmtpy level but only to around 1.0 Mmtpy as the balance is derived from pipeline supplies from Russia
USA	Mothballed regas plants being re-activated. LNG accounts for only about 1% of total US demand but is important in certain areas. US helping to develop something like a spot market (of some 40 spot trades in 2000, many went to the US). Extent of LNG imports dependent primarily on the path for gas prices. Independent Forecasts of 8 and 11 MMmtpy by 2010 and 2015 respectively.
Brazil	Likely to be up to 3 and 4 mtpy by 2010 and 2015 respectively, mainly in the North of the country.

LNG Industry Trends

A.2.121 From an overall perspective there is a considerable weight of opinion that the industry is undergoing a number of fundamental changes in business approach, including:

- Strategic positioning across the supply chain

Because potential demand exceeds supply there is strong competition to secure LNG markets in both the Asia-Pacific and Atlantic Basins. Some major players are positioning themselves across the chain of supply (and across both Pacific and Atlantic Basins). For example, BP already has a strong presence straddling the two sides of the Atlantic Basin via its shareholding in Atlantic LNG in Trinidad, its proposed supply of LNG to AES's Dominican Republic gas-fired power plant, its strategic alliance with Repsol for the sale of LNG to Spain, two potential LNG liquefaction projects in Egypt and orders for two LNG carriers. It also has interests in LNG projects in Asia and Australia. To balance this, BP is developing its In Salah fields in Algeria for routing through the pipeline system to Europe, and the Algerian Government is entertaining the notion of a cross African pipeline from Nigeria

- Gas trading participants

Companies wishing to expand into gas trading are investing in regasification terminals, e.g. El Paso, CMS Energy.

- LNG cargo movement optimization

There is likely to be significant movement to minimize the distances that LNG cargoes are shipped. Sellers and buyers are entering into swaps arrangements with LNG cargoes to reduce shipping costs (so-called "optimization:"). This may develop into a market whereby regional supply centers become much more closely aligned with a corresponding regional customer center(s). This exercise also creates a virtual market allowing long-term contracts to be transferred to new LNG plants (thus getting them financed) and a spot market to develop for the potentially expanding US market.

- Contract philosophy

Projects are emerging whereby only part of the capacity is committed to long-term contracts. Also, changes in existing markets such as deregulation and liberalization are creating uncertainty so that buyers are reluctant to commit themselves to new long-term contracts. There is also a growing short-term market and while it is unlikely to predominate it is likely to achieve levels that could fundamentally influence aspects of the market.

- Renegotiated contracts

During the next ten years, a significant number of contracts fall due for renewal and buyers will want to pursue improved terms. Some sellers will be in a better position to respond where their capital-intensive investments have been already written off.

- Demand and pricing

In the Atlantic Basin, the current dominating market is Europe but that of the US is growing as a percentage of the total. The extent of this growth is dependent on gas price but is likely to persist if gas prices stay at or near current levels (approximately US$4/MmBTU). At present, there are three distinct markets/indices for pricing (a) US – NYMEX Henry Hub (b) Europe - related to prices of competing fuels and (c) Asia - indexed to a range of crudes imported into Japan, or in the case of Indonesia, by a formula related to Indonesian crude. These methods may develop a degree of convergence if LNG trade achieves a greater degree of globalization.

- Liberalization of gas markets

Spreading liberalization of gas and electricity markets is driving down contract prices and allowing the emergence of a larger spot market.

- Project economics

There has been a strong drive in recent years to make LNG more competitive, e.g. involving reductions in CAPEX and OPEX from technology improvements. If surpluses persist from time to time, plants will have to demonstrate the ability to remain profitable even at lower levels of plant utilization. Prices of LNG carriers have been much more keenly determined in recent years although the number of orders in 2000 and 2001 has resulted in some increase in prices. However, even this expenditure is being avoided in a number of cases by projects being initiated on the basis of using existing older carriers (e.g. Atlantic LNG train 1 output via Cabot and Enagas)

- LNG shipping

Purchases of LNG ships are emerging that are not committed to any particular project and more orders are being placed by private ship owners or LNG buyers rather than LNG sellers. Since some of these owners have significant LNG positions this makes these purchases far from speculative.

- Supply/demand balance

Excess capacity (in part due to conservative plant design or debottlenecking) has created a small pool of uncommitted LNG

More buyers and sellers could lead to more liquidity in the market and some commentators are suggesting that developing something of a surplus will help the LNG industry change radically.

Brazil

A.2.122 Brazil is South America's major energy consumer with total primary energy consumption in 1999 of some 140 million metric tons oil equivalent. In recent years its energy sector has undergone fundamental regulatory and structural changes. This has involved a) opening up of the electricity generation and distribution markets, b) ending of the monopoly of oil and gas E&P concessions and c) development of projects for international pipelines and transmission lines. Brazil is aiming for energy self-sufficiency, with Petrobras' objectives of reaching targets of 1.85 Mmbpd oil and 2120 Mmcfd gas by 2005.

A.2.123 Oil and hydro dominate the energy sector with hydro providing the bulk of the total power generation capacity of 307 GWh in 1997. Expected consumption of electricity is expected to rise faster than the GDP growth rate with nearly 60 percent of the increase coming from residential and commercial sectors. Out of a population of over 160 million, Brazil has only 43 million electricity consumers, with some villages having less than 50 percent electrification.

A.2.124 To meet electricity demand, Brazil will need to double generation capacity by adding some 64 GW by 2020. Hydroelectric generation, which currently accounts for some 90 percent of Brazil's electricity supply, is adequate in wet years but insufficient to meet demand in dry years. The expected mix of generation capacity is expected to change gradually with gas gaining an 11 percent share of the market and hydro declining to some 80 percent by 2020. The government plans to build 47 thermal power plans to satisfy domestic demand in the next few years with 44 of these using natural gas. Annual gas demand is expected to grow from its current level of 8.3 Bcm to 47.6 Bcm in 2010. Brazil's domestic production just met demand in 1997 so although domestic production is expected to rise there will be an increasing role for gas imports, principally by pipeline from Argentina and Bolivia.

A.2.125 For the sources of this gas, Petrobras plans to import 30 Mmcmd from Bolivia via the US$3 billion, 2350 Km Bolivia-Brazil pipeline (currently transporting 7.5 Mmcmd), with 15 Mmcmd from Argentina and the remaining 30 Mmcmd from domestic gas, principally from the Campos Basin (total supply form all three sources equivalent to some 27 Bcmy). Cedigaz forecasts indicate that by 2007, countrywide demand will match this figure.

A.2.126 The fastest growth is expected in the more isolated states in the north of the country. While much of this growth will be provided by hydro there is expected to be a role for gas. Since this region is much more remote from the Bolivian and Argentinean pipeline systems, there is the possibility of supply by LNG imports (possibly up to 5 Mmtpy by 2010). Shell and Petrobras have been discussing possible LNG schemes for some time, including a regasification terminal near Recife in northeast Brazil (equivalent capacity about 1.5 million Tpy LNG imported from Nigeria). This could be the first regasification terminal in South America and so has potentially important implications for LNG trade in the Atlantic Basin.

United States

A.2.127 The U.S. is the second largest producer of oil after Saudi Arabia although it imports just over half of its oil demand. In 2000, consumption averaged approximately 19.5 Mmbpd with domestic production at just less than 11 Mmbpd. The principal crude oil suppliers to the US are Canada, Saudi Arabia, Venezuela, Mexico, Nigeria and the North Sea. Crude oil reserves are put at around 21 billion Bbl, a decline of some 20 percent since 1990.

A.2.128 In natural gas, the US has the sixth largest reserves in the world with some 160 Tcf at the beginning of 2000. In 2001, consumption was 20.7 Tcf with domestic production at 17.8 Tcf, imports at 3.4 Tcf and 0.3 Tcf flared (mostly in new field start-ups in the Gulf of Mexico). While the bulk of gas imports were by pipeline (largely from Canada) the contribution from LNG doubled from the previous year to some 162 Bcf. Overall gas consumption is expected to rise significantly over the next 20 years reaching over 31 Tcf by 2020 with some forecasters indicating even stronger growth rates. Currently the main consumers are industrial (40 percent), residential (22 percent), electricity power generation (15 percent) and commercial (14 percent). In the electricity sector more than 275 new gas-fired power plants are forecast to come onstream by end 2010 although some slow down occurred due to the most recent recession and may extend further as the US struggles to get out of a low or no growth scenario.

A.2.129 From base levels of some US$2.50/MmBTU during 1999, gas prices in 2000 rose dramatically reaching highs of US$10.00/MmBTU in the 4Q at Henry Hub and other centers in the south of the country. Prices have since reduced to levels of US$2.0/MmBTU in late 2000 before recovering to around US$3.4/MmBTU mid 2002. Low wellhead prices in 1998, 1999 and in late 2001 led to reduced drilling levels and lower gas production levels. Gas inventories, although higher than previous years, are not filling as fast as expected. These factors plus deregulation in the electricity sector, environmental pressures and an expanding transmission system lead to a situation where gas was in tight supply. The future base level price of gas in the US will remain cyclical but is unlikely to revert to previous levels of the late 1990’s and is likely to only be stabilized by substantial volumes of LNG in the long term.

A.2.130 Increased gas prices and the knock-on effect on power costs is impacting sectors in US industry that are relevant to a number of commodities in this study, e.g. ammonia, methanol, and aluminum smelting. These issues offer countries with low gas prices opportunities if managed correctly.

A.2.131 Increased gas prices have led to the resumption of significant LNG imports and this market is expected to remain strong as demand grows. The US has five LNG terminals and regasification plants listed below (with state location and owner):

- Lake Charles (La) (CMS Energy)

- Elba Island (Ga) (BP, Shell)
- Cove Point (Md) (BP, Shell, El Paso)
- Everett (Ma) (Tractebel)
- Puerto Rico - US Commonwealth Territory - (Edison / Enron)

A.2.132 Most of these plants were mothballed, but all will be operational by mid-2002 with a total capacity of 2.8 Bcfd and capable of expansion to 4.8 Bcfd relatively easily. By comparison, Europe's LNG imports in 1999 were around 3.5 Bcfd and hence the US market is in a position to compete with Europe for gas supply, although due to the nature of gas trading in the US, IHSE believes it will grow itself into a largely spot or short-term contract market.

A.2.133 There is considerable activity in acquiring remaining existing capacity at the four US mainland terminals (e.g. BG has indicated its intention to take all available capacity at the Lake Charles terminal from the beginning of 2002). The end result is that most of the available capacity is likely to be contracted for the foreseeable future. Recently, ChevronTexaco announced a feasibility study for an offshore LNG receiving and regasification terminal in the Gulf of Mexico to handle some 7.5 million Tpy, however approval for this may be some way off.

A.2.134 Since Shell, BP and Tractebel are active in the southern European market there are now three main players with effective trading positions that link the two largest gas markets in the world (Europe and the US) together with LNG capacity in the Atlantic Basin.

Europe

A.2.135 Total primary energy supply in Europe (the geographical definition used here is the 15 countries of the EU plus Norway, Switzerland and Turkey) is predicted to grow by 1 percent annually in the period to 2020. The current pattern of energy supply is oil 38.5 percent, gas 21.5 percent, coal 20.5 percent, nuclear 12.5 percent, renewables 4.5 percent and hydro 2.5 percent. This pattern will change considerably over the next 20 years with gas making considerable gains to some 30 percent of the total, replacing the expected drop in contributions by coal and nuclear. Total primary gas supply is expected to increase at a faster rate than any other energy source (averaging almost 3 percent per year), making gains in market share in all sectors, although two-thirds of the increase is forecast to be gained by electricity generation.

A.2.136 Gas consumption in the defined area in 1999 was 423.2 Bcm (14.9 Tcf).

A.2.137 Sixty-five percent of the region’s consumption is derived from indigenous sources and around 7 percent is imported as LNG. Of the internal sources, Norway has the most promise for increased production via the country’s far-north waters that could be exploited through possible LNG exports or to continental Europe via pipeline.

A.2.138 Imports of LNG from more distant sources are increasing as new facilities start-up (Nigeria and Trinidad in 1999, Qatar and Abu Dhabi earlier). Other countries such as Oman, Egypt and Libya could seek European markets for LNG in coming years and a number of existing exporters will have additional volumes to sell. Libya is planning to join Europe's pipeline sources late in 2003. Total demand in Europe grew steadily until 1990 with France, Spain and Belgium the main consumers. Demand leveled off in the 1990's until 1996. It then started increasing again, when Turkey started imports and Italy resumed regular imports.

A.2.139 The drivers for the expected gas demand growth in Europe over this decade are:

- Liberalization

The EU Gas Directive requires that member states open their markets progressively from 2000 to (typically) 33 percent after 10 years. The 1999 EU Electricity Directive requires that member states open at least one-third of their power markets to competition by 2003. While competitive wholesale markets have developed in several countries in the north of the continent, southern Europe has been slower to embrace the changes. The next round of market opening in Spain and Italy is expected to speed up this process.

- Increased power generation efficiency

Some countries, for example Spain and Italy, have ageing plants that are likely to be increasingly exposed with the advent of liberalization. Italy also has traditionally built dual or even triple fuelled plants to utilize the cheapest fuel but these are much less efficient than modern CCGT units and contribute higher greenhouse gas emissions.

- Increased industrial demand

Some of the countries of southern Europe, notably Spain, expect above average industrial growth.

A.2.140 Although such factors promise an optimistic forecast for gas demand growth, the extent to which LNG from new sources is able to penetrate this market is less certain. The region has an established long-term trading pattern with sources in North Africa and although a number of these contracts become due for renewal in the next few years the economic competition will be fierce, not least because many of their liquefaction plants have recovered the initial investment. There is also additional LNG competition from short-term trading with some producers of the Middle East and likely new sources, e.g. Egypt. Pipeline sources will also continue to compete, largely via existing supplies from Russia and Algeria, with Libya announcing its intention to join this group. In the longer term (perhaps more than 10 years), there is the potential for new sources from Central Asia into Turkey.

A.2.141 In pricing terms, European gas prices have historically displayed a strong linkage to oil price. The introduction of liberalization means that new mechanisms of gas-to-gas competition will also progressively affect prices and erode the current take-or-pay terms that have been a traditional method of financing new gas projects in Europe

A.2.142 The overall picture for the region points to a market in transition where it may become progressively more difficult to sell LNG in traditional ways where there are large volumes requiring high levels of infrastructure.

Central America

A.2.143 Dominican Republic has seen a 100 Mmcfd sales agreement signed between BP and AES for power projects in Santo Domingo. AES expects to have its LNG terminal operational by end-2002 with the gas source likely to be from Trinidad.

Sector Returns and Economics

General Approach

A.2.144 This section describes the basic economic factors that determine what utilization sectors may be considered viable in Nigeria. Due to the short time period, the economic results presented here are generic rather than specific to particular projects proposed by the various interested parties.

A.2.145 For the purposes of developing a Strategic Gas Master Plan, it is useful to first look at the options without prejudice. This gives an unbiased balance of options before developing the combination of projects that give Nigeria the best overall benefit, flexibility and diversity of risk.

Commodities Investigated

A.2.146 Analysis was carried out for the commodities identified below:

- Chemical feedstock sector - ammonia and ammonia/urea, methanol, ethylene, GTL
- Industrial fuel sector - aluminum, steel (DRI)
- LNG sector
- Power sector

A.2.147 Each of these was examined as an export commodity with the exception of electrical power. This assessment indicates that in the circumstances of high future domestic power demand and/or concerns about security of supply in the main cities or their environs, gas-fired power generation is the long-term future and economics of such a plant is included.

Analysis and Reporting

A.2.148 For each of the commodities above, a cash flow model has been set up for a typical project period of 25 years to determine gas netbacks. For the export commodities, world market prices were assessed from desk research and shipping costs included for a range of potential world market destinations. In general, the potential markets considered were all in the Atlantic Basin on the basis of initial judgment.

A.2.149 Plant sizes were generally selected on the basis of world scale capacities to ensure the relevant economies of scale for competitive production in Nigeria. In other cases, notably for aluminum and steel (DRI), selection was based on known similar projects on the African continent. GTL was approached individually in that both large and smaller scale plants were considered through the relevant technologies to determine the significance of plant size on the economics. Successful commercial development of GTL technology is still in early stages of evolution and the large gas quantities required for the large-scale plants imply considerable commercial risk. The investigation of smaller scale plants is therefore essential in covering the economics of gas use for GTL.

A.2.150 The main parameters considered in the analysis were:

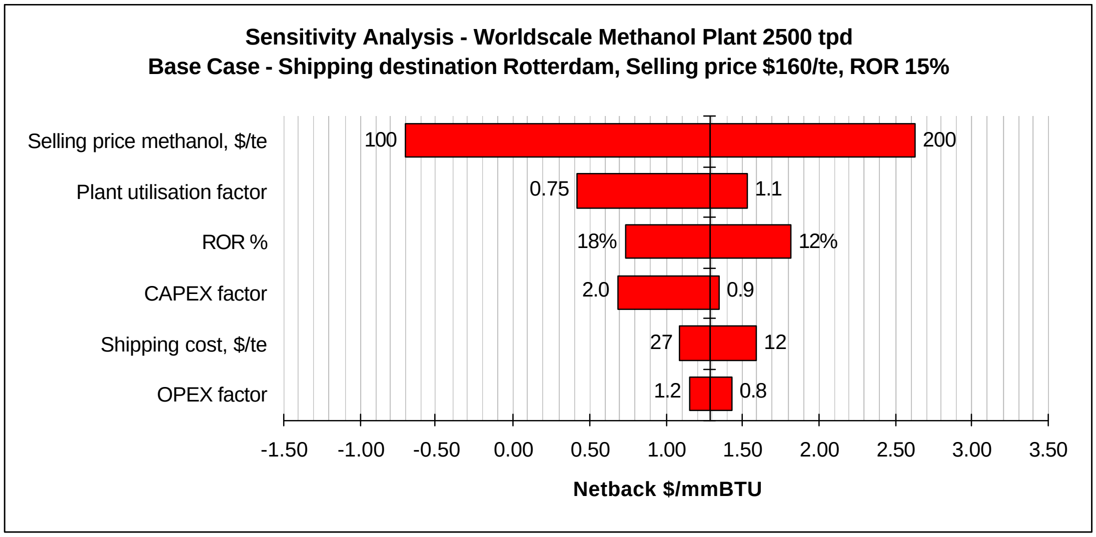
- Plant capital cost (CAPEX)
- Plant operating cost (OPEX)
- Selling price of the commodity
- Shipping cost
- Plant utilization factor
- Rate of return on investment (discount factor)

A.2.151 Capital and operating costs data are derived from industry sources, process licensors or relevant in-house reports. Wherever possible, comparisons are made with known recent historic cost data for similar plants. Existing and projected world market commodity prices and shipping costs were established from relevant industry journals.

A.2.152 Analysis has been carried out conventionally, with a base case situation developed using expected values for each input and a set of high and low values covering the anticipated range. Plant CAPEX and OPEX were varied as a percentage above and below the base case value. Plant utilization factor is varied as a percentage of total plant throughputs and can be regarded as a useful measure of the impact on economics of operating at a reduced load factor or suffering downtime because of unreliability or other enforced circumstances (e.g. loss of gas supply, utilities, etc). The impact of being able to operate above nameplate capacity, because of design margins, is also considered.

A.2.153 Sensitivity is reported in the form of a tornado plot with the sensitivity impact illustrated by the order of swing of each of the parameters around the base case values (Figure A.2.9).

Figure A.2.10: Sensitivity Analysis Diagram



Basis of Assessments

A.2.154 The derivation of gas netbacks and project profitability figures has been based on assumed data for each of the commodities concerned, summarized in Table A.2.22.

Table A.2.22: Key Data for Demand Side Commodity Assessments

Plant Capacity Tpy (unless otherwise stated)	*Commodity Selling Price (High/Base/Low) $/t (unless otherwise stated)*	*Shipping Costs (High/Base/Low) $/t (unless otherwise stated)*	*Notes*
Ammonia			
525,000	225/200/175	45/35/20	1500 Tpd plant
Urea			
920,000	225/200/150	26/20/11	1500 Tpd ammonia plant 2625 Tpd urea plant All ammonia converted to urea
Methanol			
875,000	200/160/100	27/21/12	2500 Tpd plant (chemical grade). Same scale plant as AMPCO, Equatorial Guinea
GTL (large plant)			
50,000 Bpd	$45/38/35 per Bbl	$5/4/3 per Bbl	Commodity price is for diesel @ as 80% of products
GTL (small plant)			
10,000 Bpd	$45/38/35 per Bbl	$5/4/3 per Bbl	Commodity price is for diesel @ as 80% of products
Aluminum			
250,000	2000/1800/1600	40/25/20	Same scale plant as Phase I of smelter in Mozambique (MOZAL)
Steel (DRI)			
800,000	250/225/175	20/15/12	Semi-finished steel products Same scale plant as Saldanha Bay, South Africa
Grassroots LNG			
4,000,000	$6.00/4.00/3.00 per MmBTU	Accounted for in supply chain	Based on proposed Texaco plant

A.2.155 The shipping costs represent three hypothetical export market destinations for the commodities:

- Base—Western Europe (Rotterdam)
- Low—South America (NE) (Brazil- Recife)
- High—US Gulf Coast (Houston-Galveston)

A.2.156 In addition, the same exercise was carried out for a gas-fired power plant but based on a domestic market case of 460 MW capacity, with base case electricity selling prices of US$0.025/KWh.

A.2.157 The LNG appraisal is based on US Gulf Coast market and assumes purchase of sufficient new vessels to supply 100 percent of plant output to the US (in this case five). Economics would change if some shipments were directed to nearer destinations and / or transportation was provided by using existing vessels on a day-rate charter.

Summary Results

Gas Netback Values

A.2.158 The netback gas values for each of the commodities evaluated are listed in the following tables, together with the sensitivities for the key parameters.

Table A.2.23: Ammonia Sensitivity Analysis – Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
CAPEX factor	0.9	1.00	1.5	1.21	0.84	-1.04	2.26
Selling price ammonia, $/t	175	200	225	-0.03	0.84	1.70	1.72
Plant utilisation factor	0.75	1.00	1.1	-0.42	0.84	1.18	1.59
ROR %	12%	15%	18%	1.58	0.84	0.03	1.55
Shipping cost, $/t	20	35	45	1.35	0.84	0.49	0.86
OPEX factor	0.8	1.00	1.2	1.05	0.84	0.62	0.44

Figure A.2.11: Ammonia Sensitivity Analysis—Tornado Diagram

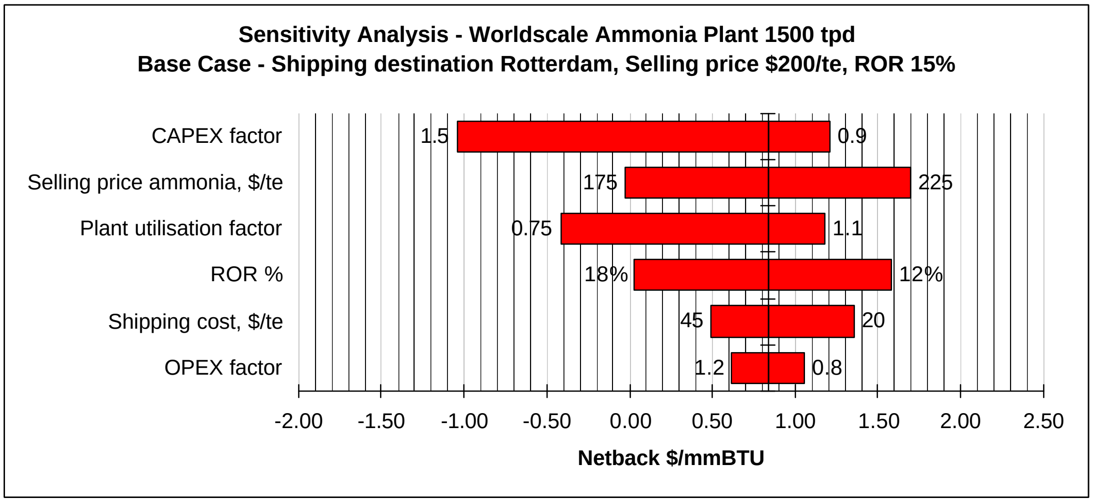


Table A.2.24: Urea Sensitivity Analysis – Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
Selling price urea, $/t	150	200	225	-1.23	1.34	2.62	3.85
CAPEX factor	0.9	1.00	1.5	1.91	1.34	-1.56	3.47
Plant utilization factor	0.75	1.00	1.1	-0.59	1.34	1.86	2.45
ROR factor %	12%	15%	18%	2.48	1.34	0.10	2.39
OPEX factor	0.8	1.00	1.2	1.76	1.34	0.91	0.85
Shipping cost, $/t	11	20	26	1.80	1.34	1.03	0.77

Figure A.2.12: Urea Sensitivity Analysis—Tornado Diagram

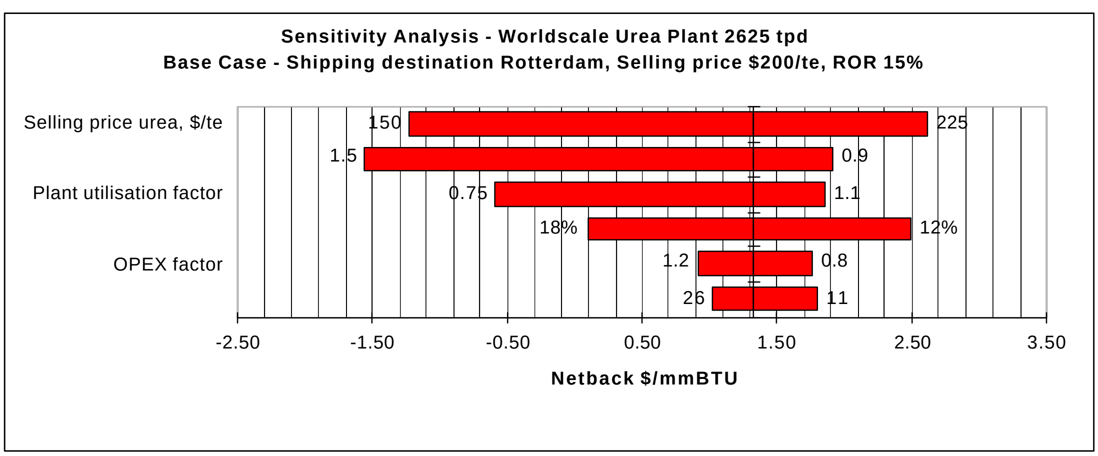


Table A.2.25: Methanol Sensitivity Analysis—Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
Selling price methanol, $/te	100	160	200	-0.71	1.29	2.63	3.33
Plant utilization factor	0.75	1.00	1.1	0.42	1.29	1.53	1.12
ROR %	12%	15%	18%	1.82	1.29	0.73	1.09
CAPEX factor	0.9	1.00	2.0	1.35	1.29	0.68	0.67
Shipping cost, $/te	12	21	27	1.59	1.29	1.09	0.50
OPEX factor	0.8	1.00	1.2	1.44	1.29	1.15	0.28

Figure A.2.13: Methanol Sensitivity Analysis—Tornado Diagram

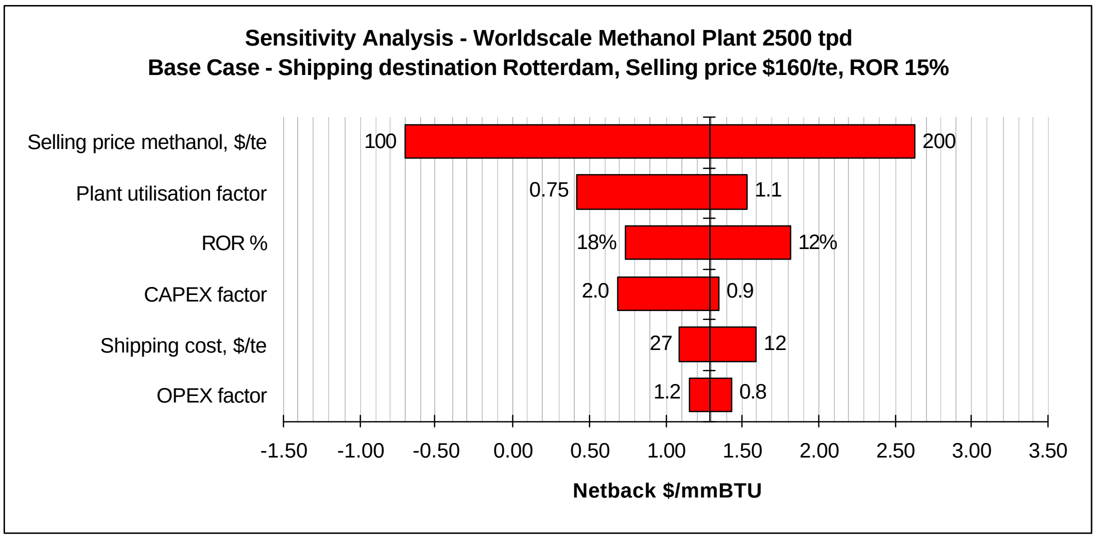


Table A.2.26: Aluminum Sensitivity Analysis—Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
CAPEX factor	0.9	1.00	1.5	1.76	0.60	-5.18	6.94
Plant utilisation factor	0.75	1.00	1.1	-3.39	0.60	1.69	5.08
ROR %	12%	15%	18%	2.90	0.60	-1.88	4.78
Selling price aluminium, $/t	160 0	1900	2000	-2.70	0.60	1.70	4.40
OPEX factor	0.8	1.00	1.2	2.29	0.60	-1.09	3.37
Shipping cost, US$/t	20	25	40	0.65	0.60	0.43	0.22

Figure A.2.14: Aluminum Sensitivity Analysis—Tornado Diagram

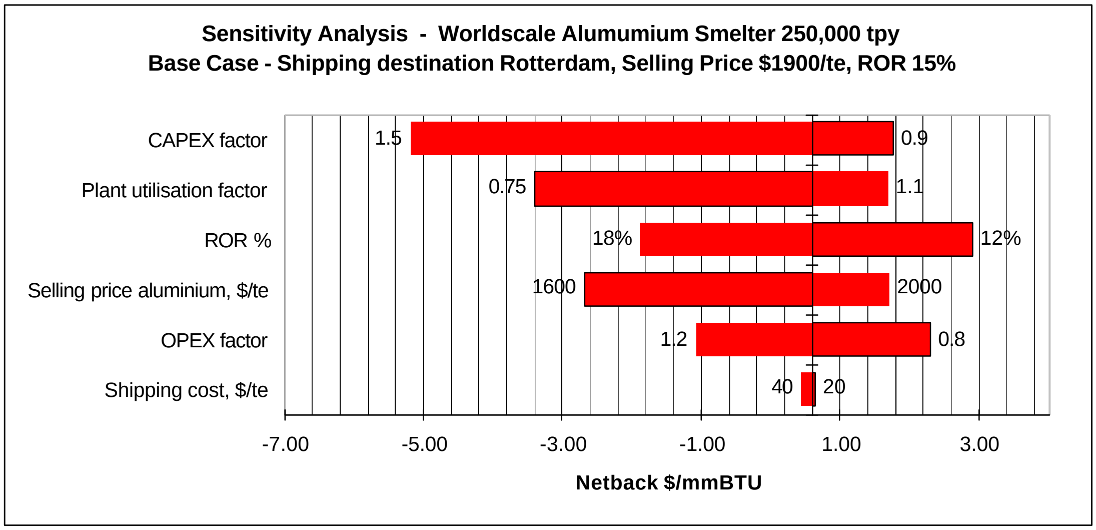


Table A.2.27: Steel (DRI) Sensitivity Analysis—Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
OPEX factor	0.8	1.00	1.2	3.25	1.45	-0.35	3.59
Selling price HBI/DRI, $/t	155	170	190	-0.08	1.45	3.49	3.57
CAPEX factor	0.9	1.00	1.5	1.99	1.45	-1.23	3.22
Iron oxide pellet price	45	55	65	2.90	1.45	0.00	2.90
ROR %	12%	15%	18%	2.52	1.45	0.30	2.22
Plant utilisation factor	0.75	1.00	1.1	-0.45	1.45	1.76	2.22
Shipping cost, US$/t	12	15	20	1.76	1.45	0.94	0.82

Figure A.2.15: Steel (DRI) Sensitivity Analysis—Tornado Diagram

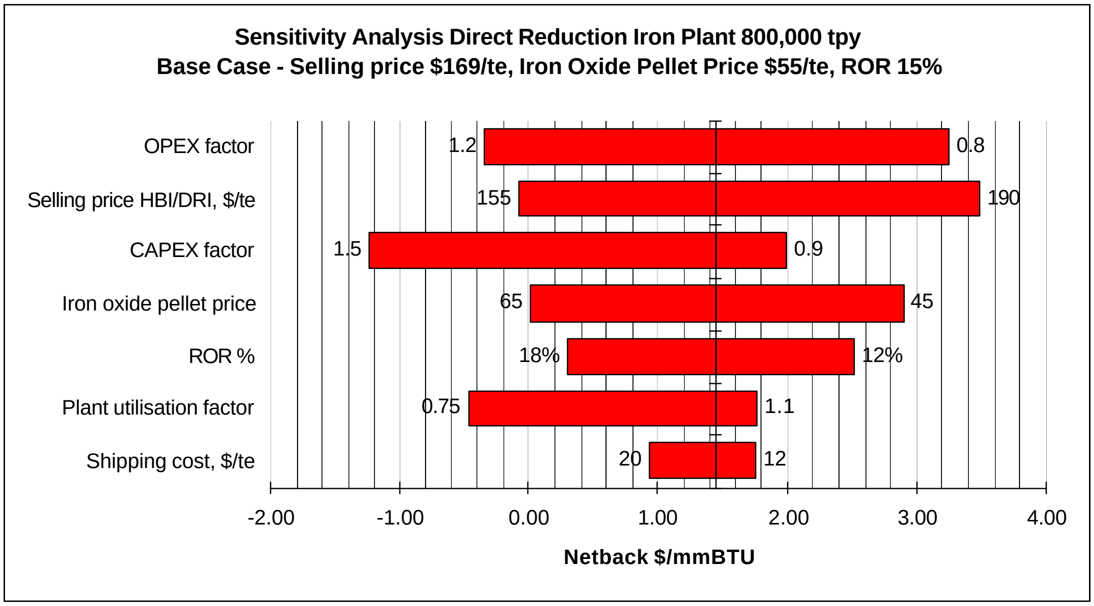


Table A.2.28: GTL (10,000 bpd) Sensitivity Analysis
Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
CAPEX factor	0.9	1.00	1.5	1.05	0.93	0.32	0.72
Diesel price, $/Bbl	35	38	45	0.74	0.93	1.36	0.62
Plant utilization factor	0.75	1.00	1.1	0.53	0.93	1.03	0.50
ROR %	12%	15%	18%	1.16	0.93	0.67	0.49
OPEX factor	0.8	1.00	1.2	1.01	0.93	0.84	0.17
Shipping cost, $/Bbl	3.00	4.00	5.00	1.00	0.93	0.85	0.15
Naphtha price, $/Bbl	30	33	40	0.88	0.93	1.03	0.15
Electricity price, cents/KWh	1.50	2.00	3.00	0.92	0.93	0.93	0.01

Figure A.2.16: GTL (10,000 Bpd) Sensitivity Analysis—Tornado Diagram

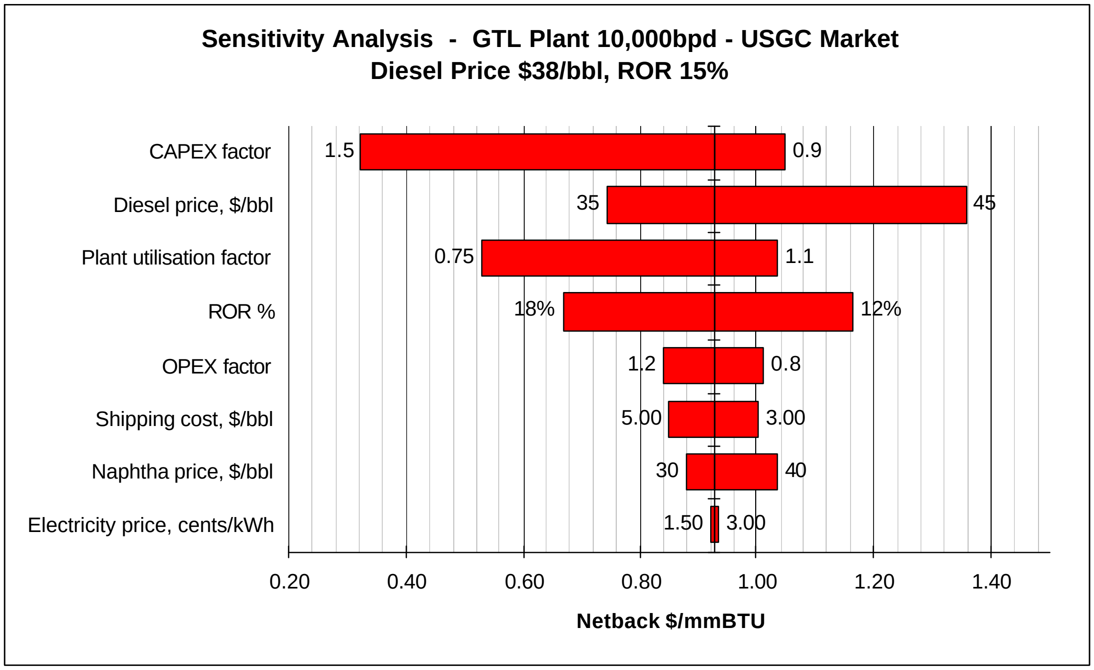


Table A.2.29: GTL (50,000 Bpd) Sensitivity Analysis Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
CAPEX factor	0.9	1.00	1.5	1.70	1.56	0.87	0.83
Diesel price, $/Bbl	35	38	45	1.32	1.56	2.12	0.80
Plant utilisation factor	0.75	1.00	1.1	1.10	1.56	1.69	0.59
ROR %	12	15	18	1.84	1.56	1.27	0.57
Shipping cost, $/Bbl	3.00	4.00	5.00	1.66	1.56	1.46	0.20
OPEX factor	0.8	1.00	1.2	1.66	1.56	1.46	0.20
Naphtha price, $/Bbl	30	33	40	1.50	1.56	1.70	0.20
Electricity price, cents/KWh	1.50	2.00	3.00	1.53	1.56	1.64	0.11

Figure A.2.17: GTL (50,000 Bpd) Sensitivity Analysis—Tornado Diagram

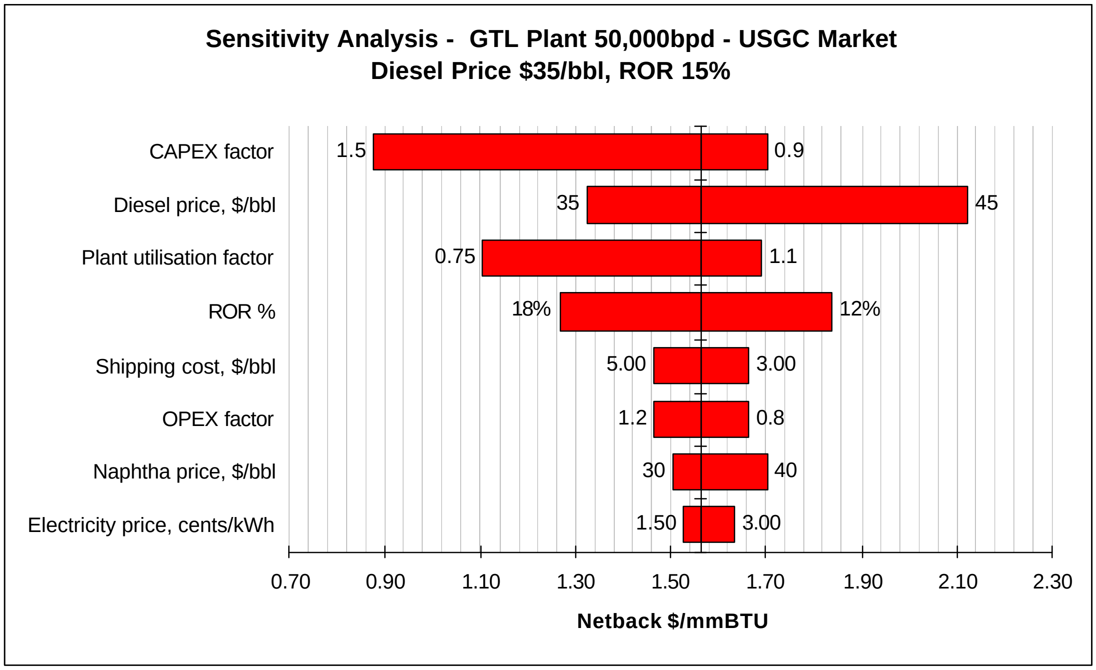


Table A.2.30: Grassroots LNG Sensitivity Analysis—Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
Sales gas price, US$/MmBTU	3.00	4.00	5.00	0.07	0.87	1.66	1.59
ROR %	12	15	18	1.29	0.87	0.39	0.90
Plant utilisation factor, %	0.8	1.0	1.1	0.38	0.87	1.04	0.66
Liquefaction plant CAPEX, US$ millions	110 0	1200	1560	0.95	0.87	0.57	0.37
Tanker CAPEX, US$ millions	750	900	990	0.99	0.87	0.79	0.19
LPG recovery factor	0.50	0.75	0.90	0.76	0.87	0.93	0.17
Tanker OPEX, US$ millions	55	80	96	0.97	0.87	0.80	0.17
Regasification plant CAPEX, US$ millions	270	300	390	0.89	0.87	0.79	0.10
Liquefaction plant OPEX, US$ millions	60	72	80	0.91	0.87	0.83	0.08
LPG price, US$/t	280	300	320	0.85	0.87	0.89	0.04
Regasification plant OPEX, US$ millions	14	17	20	0.88	0.87	0.85	0.02

Figure A.2.18: LNG Sensitivity Analysis—Tornado Diagram

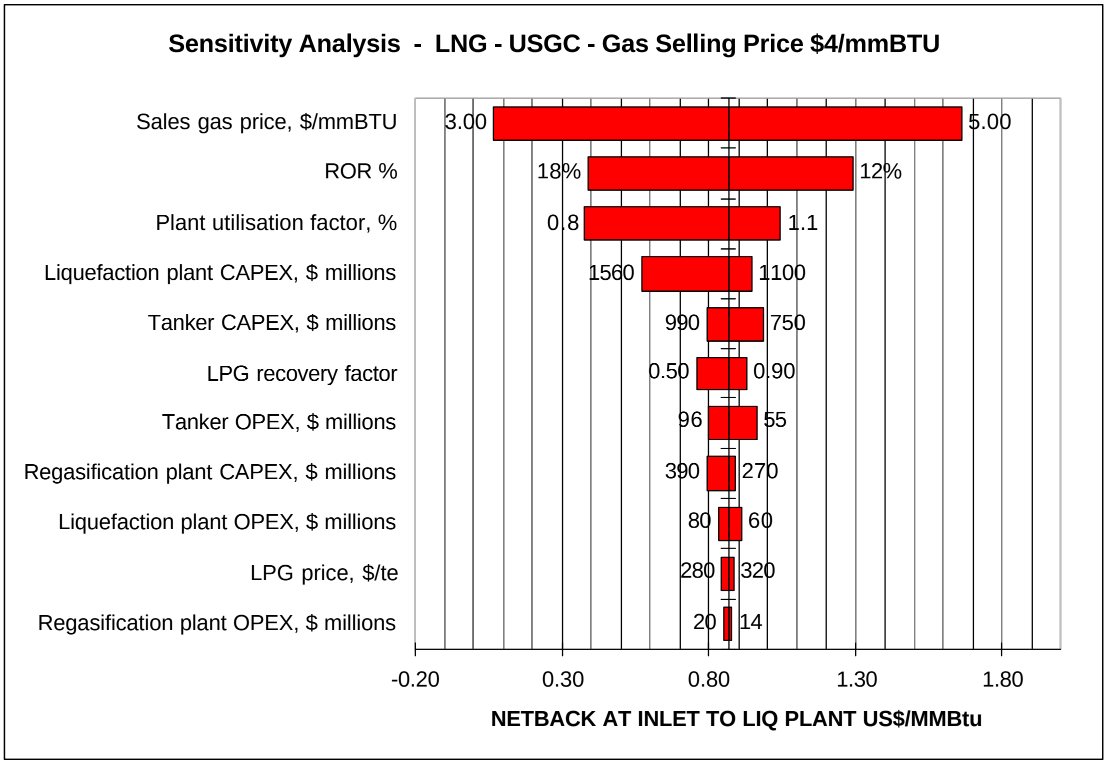
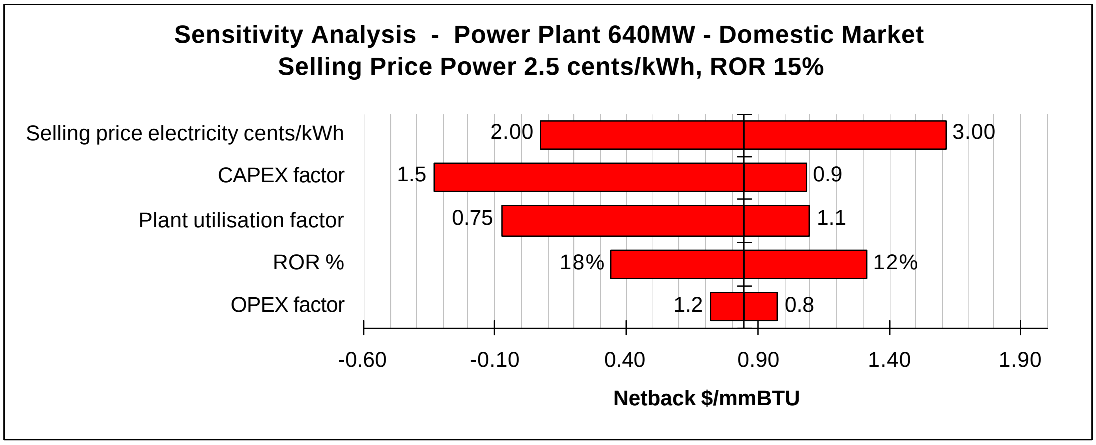


Table A.2.31: Power Plant (domestic market) Sensitivity Analysis

Input Values and Netbacks

Input Variable	*Input Values*			*Netback $/MmBTU*			*Swing*
	Low	*Base*	*High*	*Low*	*Base*	*High*	
Selling price electricity cents/KWh	2.00	2.50	3.00	0.08	0.85	1.61	1.54
CAPEX factor	0.9	1.00	1.5	1.08	0.85	-0.33	1.41
Plant utilisation factor	0.75	1.00	1.1	-0.08	0.85	1.10	1.18
ROR %	12	15	18	1.31	0.85	0.34	0.97
OPEX factor	0.8	1.00	1.2	0.97	0.85	0.72	0.26

Figure A.2.19: Power Plant (domestic market) Sensitivity Analysis Tornado Diagram



Appendix 3

Nigeria Reserves and Production Summary

Table A.3.1: Nigeria Reserves

	Onshore – Offshore Situation	*East or West*	*Oil MMbbl*	*Condensate MMbbl*	*Gas BCF*	*Nonassociated Gas BCF*
Abandoned Fields						
Cavendish Petrol. Nigeria Ltd	Offshore	West	14.40	-	3.00	-
Nigerian Petroleum Develop. Co	Onshore	East	16.00	-	0.90	-
Shell Pet. Dev. Co of Nigeria	Onshore	East	-	-	7.30	-
Shell Pet. Dev. Co of Nigeria	Onshore	West	11.74	0.30	39.46	-
Unknown	Onshore	East	17.16	3.00	99.96	-
TOTAL Abandoned Fields			59.30	3.30	150.62	-
Awaiting Development						
Texaco Overseas (Nigeria) Petroleum Co	Offshore	East	16.90	-	-	-
Texaco Overseas (Nigeria) Petroleum Co	Offshore	West	22.10	-	10.00	-
TOTAL Awaiting Development			39.00	-	10.00	-
Developing						
Addax Petroleum Exploration (Nigeria) Ltd	Offshore	West	16.00	-	5.00	-
Chevron Petroleum Nigeria Ltd	Offshore	East	55.00	-	1,200.00	-
Chevron Petroleum Nigeria Ltd	Offshore	West	20.00	-	6.00	-
Elf Petroleum Nigeria Ltd	Offshore	East	599.00	5.00	1,522.00	100.00
Mobil Producing Nigeria	Offshore	East	299.40	-	330.00	800.00

Nigerian Agip Exploration Ltd (NAE)	Offshore Deep	West	175.00	-	50.00	-
Nigerian Agip Oil Co Ltd(NAOC)	Onshore	East	23.00	-	475.00	-
Nigerian Petroleum Develop. Co	Offshore	East	59.00	-	19.00	-
Nigerian Petroleum Develop. Co	Onshore	West	11.00	-	40.00	-
Peak Petroleum Ind. Nigeria Ltd	Offshore	West	17.41	5.15	687.72	-
Shell Nigeria E&P Co Ltd(SNEPCO)	Offshore Deep	West	1,100.00	-	450.00	-
Shell Pet. Dev. Co of Nigeria	Onshore	East	10.30	11.00	-	900.00
Shell Pet. Dev. Co of Nigeria	Offshore	West	350.00	0.15	625.00	-
Shell Pet. Dev. Co of Nigeria	Onshore	West	34.10	-	160.00	-
TOTAL Developing			**2,769.21**	**21.30**	**5,569.72**	**1,800.00**
Discovery						
Addax Petroleum Development (Nigeria) Ltd	Offshore	East	41.90	0.50	484.30	5.00
Addax Petroleum Development (Nigeria) Ltd	Onshore	East	-	-	-	50.00
Allied Energy Resources Ltd	Offshore Deep	West	75.00	-	-	-
Agip Energy & Natural Resource	Offshore	East	9.00	0.10	5.00	-
Amni Int'l Petroleum Dev Co	Offshore	East	5.70	-	5.00	200.00
Cavendish Petrol. Nigeria Ltd	Offshore	West	35.00	-	20.00	-
Chevron Petroleum Nigeria Ltd	Onshore	East	236.74	6.00	1,055.69	-
Chevron Petroleum Nigeria Ltd	Offshore	West	90.58	65.84	1,299.62	105.00
Chevron Petroleum Nigeria Ltd	Onshore	West	49.70	16.00	121.00	300.00
Conoco E&P Nigeria Ltd	Offshore Deep	West	154.00	15.00	45.00	300.00
Consolidated Oil Ltd	Offshore	West	22.00		80.00	15.00
Continental Oil & Gas Ltd	Offshore	East	10.00	-	1.00	-
Dubri Oil Ltd	Onshore	West	8.00	0.50	20.00	-
Elf Petroleum Nigeria Ltd	Offshore	East	263.85	-	335.00	200.00
Elf Petroleum Nigeria Ltd	Onshore	East	5.50	6.46	2.00	173.00
Elf Petroleum Nigeria Ltd	Onshore	West	77.19	2.60	73.60	650.00
Elf Petroleum Nigeria Ltd	Offshore Deep	West	200.00	-	-	-

Esso E & P Nigeria Ltd (EEPN)	Offshore Deep	West	600.00	-	400.00	3,000.00
Famfa Petroleum	Offshore Deep	West	1,020.00	-	2,400.00	-
Mareena Petroleum Ltd	Onshore	West	5.00	-	5.00	-
Mobil Producing Nigeria	Offshore	East	1,174.75	13.00	6,362.30	214.00
Moni Pulo Ltd	Offshore	West	0.20	-	10.00	20.00
Nigerian Agip Exploration Ltd (NAE)	Offshore Deep	West	55.00	-	30.00	-
Nigerian Agip Oil Co Ltd (NAOC)	Onshore	East	3.42	1.50	18.00	165.00
Nigerian Agip Oil Co Ltd (NAOC)	Offshore	West	10.00	-	50.00	-
Nigerian Agip Oil Co Ltd (NAOC)	Onshore	West	17.35	15.00	1,757.20	650.00
Nigerian Petroleum Develop. Co	Onshore	East	15.00	-	28.00	-
Nigerian Petroleum Develop. Co	Onshore	West	71.00	-	17.60	-
Oriental Energy Resources Ltd	Offshore	West	-	-	-	25.00
Pan Ocean Oil Co (Nigeria) Ltd	Onshore	West	11.00	-	10.00	-
Peak Petroleum Ind. Nigeria Ltd	Offshore	West	-	0.35	-	50.00
Shell Nigeria E&P Co Ltd(SNEPCO)	Offshore Deep	West	1,336.00	-	2,625.00	3,000.00
Shell Pet. Dev. Co of Nigeria	Offshore	East	165.10	32.70	4,704.00	725.00
Shell Pet. Dev. Co of Nigeria	Onshore	East	1,354.70	211.75	5,901.80	5,356.00
Shell Pet. Dev. Co of Nigeria	Offshore	West	31.20	3.00	393.00	85.00
Shell Pet. Dev. Co of Nigeria	Onshore	West	780.15	46.65	4,426.60	3,849.50
Solgas Petroleum Ltd	Offshore	East	6.00	-	6.00	10.00
South Atlantic Petroleum Ltd	Offshore Deep	West	500.00	-	750.00	-
Statoil (Nigeria) Ltd	Offshore Deep	West	100.00	-	1,575.00	-
Summit Oil International Ltd	Onshore	West	-	50.00	-	150.00
Sunlink Petroleum Ltd	Offshore	East	-	-	-	10.00
Texaco Nigeria Outer Shelf Ltd	Offshore Deep	West	30.00	-	-	-
Texaco Overseas (Nigeria) Petroleum Co	Offshore	West	33.98	10.10	220.75	455.00
Other	Onshore	East	-	-	-	715.00

Other	Offshore	West	16.30	-	1,005.00	5.00
Other	Onshore	West	1.50	0.05	5.00	15.00
TOTAL Discovery			**8,621.81**	**497.20**	**36,247.46**	**20,497.50**
Producing						
Addax Petroleum Development (Nigeria) Ltd	Offshore	East	95.16	-	614.83	-
Addax Petroleum Development (Nigeria) Ltd	Onshore	East	24.74	-	23.37	-
Agip Energy & Natural Resource	Offshore	East	143.09	47.05	285.00	-
Amni Int'l Petroleum Dev Co	Offshore	East	68.87	86.20	-	1,403.00
Atlas Petroleum Int'l Ltd	Offshore	West	34.78	-	20.00	-
Chevron Petroleum Nigeria Ltd	Offshore	East	16.53	-	95.70	-
Chevron Petroleum Nigeria Ltd	Onshore	East	88.67	0.75	195.45	-
Chevron Petroleum Nigeria Ltd	Offshore	West	1,247.33	73.00	3,901.06	17.67
Chevron Petroleum Nigeria Ltd	Onshore	West	655.01	55.21	3,359.24	-
Consolidated Oil Ltd	Offshore	West	45.86	-	11.48	-
Continental Oil & Gas Ltd	Offshore	West	15.50	-	35.00	-
Dubri Oil Ltd	Onshore	West	2.42	3.70	9.60	9.00
Elf Petroleum Nigeria Ltd	Offshore	East	61.06	57.48	90.58	-
Elf Petroleum Nigeria Ltd	Onshore	East	370.09	1.00	460.40	1,120.60
Elf Petroleum Nigeria Ltd	Onshore	West	84.40	-	65.60	18.70
Express Petroleum & Gas Co Ltd	Offshore	West	22.50	-	50.00	-
Mobil Producing Nigeria	Offshore	East	4,046.00	593.40	8,205.60	2,573.80
Moni Pulo Ltd	Offshore	West	27.67	-	77.00	-
Nigerian Agip Oil Co Ltd (NAOC)	Onshore	East	426.41	177.23	2,131.99	2,385.26
Nigerian Agip Oil Co Ltd (NAOC)	Offshore	West	21.00	-	227.00	-
Nigerian Agip Oil Co Ltd (NAOC)	Onshore	West	82.07	46.68	342.16	627.26

Table A.3.2: Nigeria Oil Production

Operator	East-West Onshore-Offshore	Remaining Reserves Oil (Mmb)	Remaining Reserves Cond (Mmb)	Oil R/P	Liquids Production BOPD 2000	Liquids Production BOPD 2001	Liquids Production BOPD 2002 (estimated)
Chevron Petroleum Nigeria Ltd	West Onshore	655.0	55.2	20.6	94,521	94,521	94,521
Dubri Oil Ltd	West Onshore	2.4	3.7			493	1,014
Elf Petroleum Nigeria Ltd	West Onshore	84.4	-	51.2	4,521	7,507	11,260
Nigerian Agip Oil Co Ltd(NAOC)	West Onshore	82.1	46.7	12.4	28,553	28,548	28,548
Nigerian Petroleum Develop. Co	West Onshore	12.5	15.0	17.2	4,384	4,384	4,384
Pan Ocean Oil Co (Nigeria) Ltd	West Onshore	41.8	16.0	28.9	5,479	7,342	10,986
Shell Pet. Dev. Co of Nigeria	West Onshore	3,429.5	213.8	25.0	398,795	416,438	438,356
Atlas Petroleum Int'l Ltd	West Offshore	34.8	-			2,658	5,342
Chevron Petroleum Nigeria Ltd	West Offshore	1,247.3	73.0	12.2	296,904	296,904	296,904
Consolidated Oil Ltd	West Offshore	45.9	-	32.3	3,886	7,808	7,808
Continental Oil & Gas Ltd	West Offshore	15.5	-		-	2,000	4,000
Express Petroleum & Gas Co Ltd	West Offshore	22.5	-			3,014	6,000
Nigerian Agip Oil Co Ltd(NAOC)	West Offshore	21.0	-	5.7	10,085	9,315	7,890
Shell Pet. Dev. Co of Nigeria	West Offshore	60.3	5.0	93.2	1,918	9,014	13,507
Texaco Overseas (Nigeria) Petroleum Co	West Offshore	242.3	8.5	14.6	47,066	47,068	47,068

Addax Petroleum Development (Nigeria) Ltd	East Onshore	24.7	-	16.5	4,103	4,110	4,110
Chevron Petroleum Nigeria Ltd	East Onshore	88.7	0.8	12.5	19,562	19,562	19,562
Elf Petroleum Nigeria Ltd	East Onshore	370.1	1.0	46.6	21,819	40,000	60,000
Nigerian Agip Oil Co Ltd(NAOC)	East Onshore	426.4	177.2	18.8	88,023	88,027	88,027
Shell Pet. Dev. Co of Nigeria	East Onshore	5,476.9	787.2	42.0	408,816	452,055	493,151
Addax Petroleum Development (Nigeria) Ltd	East Offshore	95.2	-	20.7	12,586	16,630	16,630
Agip Energy & Natural Resource	East Offshore	143.1	47.1	45.6	11,425	20,000	30,000
Amni Int'l Petroleum Dev Co	East Offshore	68.9	86.2			7,507	14,986
Chevron Petroleum Nigeria Ltd	East Offshore	16.5	-	2.7	16,630	12,822	7,452
Elf Petroleum Nigeria Ltd	East Offshore	61.1	57.5	3.6	90,866	75,753	52,055
Mobil Producing Nigeria	East Offshore	4,046.0	593.4	26.1	487,397	487,397	487,397
Moni Pulo Ltd	East Offshore	27.7	-	5.2	14,603	13,233	10,877
Nigerian Petroleum Develop. Co	East Offshore	46.0	-		-	4,986	10,000
Shell Pet. Dev. Co of Nigeria	East Offshore	39.7	9.0	12.6	10,573	10,349	10,588

Table A.3.3: Nigeria Gas Production

Operator	*East-West Onshore-Offshore*	*Remaining Reserves BCF* *Associated Gas*	*Non-Associated Gas*	*Gas R/P*	*Gas Production MCFD* *2000*	*2001*	*2002 (estimated)*
Chevron Petroleum Nigeria Ltd	West Onshore	3,359.2	-	26.5	347,306	347,306	347,306
Dubri Oil Ltd	West Onshore	9.6			-	774	1,590
Dubri Oil Ltd	West Onshore		9.0		-	725	1,491
Elf Petroleum Nigeria Ltd	West Onshore	65.6		323	556	5,835	8,752
Elf Petroleum Nigeria Ltd	West Onshore		18.7		-	5,014	10,000
Nigerian Agip Oil Co Ltd (NAOC)	West Onshore	342.2		15.0	62,461	62,461	62,461
Nigerian Agip Oil Co Ltd (NAOC)	West Onshore		627.3	40.1	42,856	100,000	150,000
Nigerian Petroleum Develop. Co	West Onshore	0.4	361.6	98.4	10,082	30,000	44,986
Pan Ocean Oil Co (Nigeria) Ltd	West Onshore	55.0			0	6,990	10,460
Pan Ocean Oil Co (Nigeria) Ltd	West Onshore		300.0	105	7,808	20,000	30,000
Shell Pet. Dev. Co of Nigeria	West Onshore	14,525.1		64.3	619,143	646,536	680,564
Shell Pet. Dev. Co of Nigeria	West Onshore		2,583.4	208	34,110	100,000	150,000
Atlas Petroleum Int'l Ltd	West Offshore	20.0	-			1,528	3,072
Chevron Petroleum Nigeria Ltd	West Offshore	3,901.1	17.7	41.0	261,863	261,863	261,863
Consolidated Oil Ltd	West Offshore	11.5	-	3.5	8,938	17,959	17,959

Continental Oil & Gas Ltd	West Offshore	35.0	-		-	4,516	9,032
Express Petroleum & Gas Co Ltd	West Offshore	50.0	-			6,697	13,333
Nigerian Agip Oil Co Ltd (NAOC)	West Offshore	227.0	-	23.5	26,503	24,480	20,736
Shell Pet. Dev. Co of Nigeria	West Offshore	301.4	-	308	2,685	12,619	18,910
Texaco Overseas (Nigeria) Petroleum Co	West Offshore	856.9	-	34.8	67,374	67,378	67,378
Addax Petroleum Development (Nigeria) Ltd	East Onshore	23.4	-	4.4	14,483	14,506	14,506
Chevron Petroleum Nigeria Ltd	East Onshore	195.5	-	20.0	26,760	26,760	26,760
Elf Petroleum Nigeria Ltd	East Onshore	460.40	-	85.2	14,800	27,133	40,699
Elf Petroleum Nigeria Ltd	East Onshore		1,120.60		158,553	198,000	215,000
Nigerian Agip Oil Co Ltd (NAOC)	East Onshore	2,132.0		14.9	393,203	393,222	393,222
Nigerian Agip Oil Co Ltd (NAOC)	East Onshore		2,385.3	17.2	379,356	379,356	379,356
Shell Pet. Dev. Co of Nigeria	East Onshore	41,365.7		156	725,312	802,024	874,935
Shell Pet. Dev. Co of Nigeria	East Onshore		4,363.8	979	12,212	70,000	150,000
Addax Petroleum Development (Nigeria) Ltd	East Offshore	614.8	-	101	16,713	22,084	22,084
Agip Energy & Natural Resource	East Offshore	285.0	-	38.0	20,564	36,000	54,000
Amni Int'l Petroleum Dev Co	East Offshore	-	1,403.0			11,320	22,598
Chevron Petroleum Nigeria Ltd	East Offshore	95.7	-	23.9	10,959	8,450	4,911
Elf Petroleum Nigeria	East	90.58	-	1.9	131,736	109,826	75,468

Ltd	Offshore						
Mobil Producing Nigeria	East Offshore	8,205.6		30.3	740,751	740,751	740,751
Mobil Producing Nigeria	East Offshore		2,573.8	14.9	473,973	473,973	473,973
Moni Pulo Ltd	East Offshore	77.0	-	7.2	29,205	26,466	21,753
Nigerian Petroleum Develop. Co	East Offshore	45.0	-		-	4,878	9,783
Shell Pet. Dev. Co of Nigeria	East Offshore	463.5	-	52.0	24,395	23,878	24,428

Appendix 4

Upstream Supply Costing Basis

QUE$TOR Cost Estimating Case Basis

Onshore Cases

(AG) Oil With Compression and without Compression

Reserves Sizes:	80 MMbbl, 135 MMbbl, 266 MMbbl, 400MMbbl
GOR (Scf/bbl):	2000
Plateau Rate:	30Mbbl/d, 50Mbbl/d, 100Mbbl/d, 150Mbbl/d
Associated Flow:	60MMcf/d, 100MMcf/d, 200MMcf/d, 300MMcf/d
Export Pipeline:	3km
Production Wells	5, 9, 17, 26

Gas costs are calculated as the difference in cost between the base oil case (with gas flared) and an integrated oil and gas export development.

(NAG) Gas

Reserves Sizes:	83 BScf, 138 BScf, 275 BScf, 414 BScf, 551BScf, 827BScf
LGR (bbl/MMcf):	20
Plateau Rate:	30MMcf/d, 50MMcf/d, 100MMcf/d, 150MMcf/d, 200 MMcf/d, 4000MMcf/d
Associated Flow:	0.3 bbl/d, 1bbl/d, 2bbl/d, 3bbl/d 4bbl/d 8bbl/d
Export Pipeline:	3km
Production Wells	2, 2, 4, 6, 7, 14

All onshore cases have a general development plan with Wellsites, production facilities and export pipeline.

Offshore Cases—Shallow Cases

(AG) Oil With Compression and without Compression

Reserves Sizes:	80 MMbbl, 135 MMbbl, 266 MMbbl, 400MMbbl
GOR (Scf/bbl):	2000 MMbbl
Plateau Rate:	30Mbbl/d, 50Mbbl/d, 100Mbbl/d, 150Mbbl/d
Associated Flow:	60MMcf/d, 100MMcf/d, 200MMcf/d, 300MMcf/d
Export Pipeline:	50 km

Production Wells 5, 9, 17, 26

Gas costs are calculated as the difference in cost between the base oil case (with gas flared) and an integrated oil and gas export development.

(NAG) Gas

Reserves Sizes: 83 Bcf, 138 Bcf, 275 Bcf, 414 Bcf, 551Bcf, 827Bcf
LGR (bbl/MMcf): 20
Plateau Rate: 30MMcf/d, 50MMcf/d, 100MMcf/d, 150MMcf/d,
200, MMcf/d 4000MMcf/d
Associated Flow: 0.3 bbl/d, 1bbl/d, 2bbl/d, 3bbl/d 4bbl/d 8bbl/d
Export Pipeline: 50km
Production Wells 2, 2, 4, 6, 7, 14

All shallow water developments assume wellhead platforms tied back to Production Platform with pipeline export (Note that low reserves sizes do not assume wellhead platforms, only one production platform.

Offshore Cases—Deep Water Cases

(AG) Oil With Compression and without Compression

Reserves Sizes: 266 MMbbl, 533 MMbbl,
GOR (Scf/bbl): 2000
Plateau Rate: 100Mbbl/d, 200Mbbl/d
Associated Flow: 200MMcf/d, 400MMcf/d
Export Pipeline: 100 km
Production Wells 17, 34

Gas costs are calculated as the difference in cost between the base oil case (with gas flared) and an integrated oil and gas export development.

(NAG) Gas

Reserves Sizes: 275 Bcf, 551Bcf, 1103Bcf
LGR (bbl/MMcf): 20
Plateau Rate: 100MMcf/d, 200MMcf/d, 400MMcf/d,
Associated Flow: 2000 bbl/d, 4000 bbl/d, 8000 bbl/d
Export Pipeline: 100km
Production Wells 4, 7, 14

All deepwater cases assume TLP with subsea sea tie back.

Costs on graphs are based on extrapolated cost date from the above cases, all cases in this study assume standalone developments. Costs per Mcf could be reduced if joint field developments are estimated.

Appendix 5

Oil and Gas Industry Perspective
Business Environment and Risk

Table A.5.1: Oil and Gas Industry Perspective Business Environment and Risk

Rank	Country	Overall Rating	Political					Socio-economic					Commercial			
			Overall	War	Unrest	Violence	Stability	**Overall**	Economic	Energy	Environment	Ethnic	**Overall**	Investment	Repatriation	Terms
Weightings:			***60%***	*10%*	*25%*	*35%*	*30%*	***20%***	*25%*	*20%*	*30%*	*25%*	***20%***	*35%*	*25%*	*40%*
13	Oman	**0.91**	**1.04**	0.81	1.00	1.00	1.20	**1.24**	2.20	0.80	1.00	0.90	**0.20**	0.50	0.50	0.50
18	Argentina	**0.99**	**1.01**	0.50	2.40	0.50	0.60	**1.48**	2.40	1.50	1.50	0.50	**0.48**	0.30	0.70	0.50
23	Qatar	**1.04**	**1.05**	1.80	0.10	1.20	1.40	**1.32**	2.60	0.10	0.50	2.00	**0.76**	1.50	0.60	0.20
37	Saudi Arabia	**1.45**	**1.59**	2.20	0.50	1.50	2.40	**0.78**	2.20	0.50	0.00	0.50	**1.70**	4.50	0.50	0.00
44	Eq. Guinea	**1.62**	**1.73**	2.50	1.50	1.00	2.50	**1.60**	2.30	1.00	1.50	1.50	**1.33**	0.50	3.00	1.00
53	Trinidad	**1.85**	**2.15**	0.00	2.20	2.00	3.00	**1.52**	2.20	0.60	0.50	2.80	**1.30**	1.50	1.50	1.00
55	Iran	**1.87**	**2.24**	2.20	2.40	2.00	2.40	**1.12**	2.80	0.10	0.50	1.00	**1.49**	1.00	2.00	1.60
57	Algeria	**1.92**	**2.17**	0.50	2.50	1.37	3.40	**1.63**	2.60	0.50	0.50	2.90	**1.45**	1.00	1.50	1.80
60	Libya	**1.92**	**2.48**	1.50	2.20	2.50	3.00	**1.12**	2.90	0.10	0.00	1.50	**1.08**	0.50	2.00	1.00
67	Venezuela	**2.17**	**2.48**	1.00	3.00	2.50	2.50	**1.96**	3.50	0.50	2.20	1.30	**1.46**	0.80	1.50	2.00
69	Mozambique	**2.18**	**2.53**	1.00	2.50	3.00	2.50	**2.15**	2.40	4.50	0.50	2.00	**1.20**	0.50	2.00	1.30
75	Egypt	**2.24**	**2.77**	2.00	2.20	3.20	3.00	**1.72**	2.40	1.60	1.00	2.00	**1.15**	0.50	1.50	1.50
88	Angola	**2.41**	**2.84**	3.00	2.50	2.90	3.00	**1.68**	3.70	0.50	0.50	2.00	**1.85**	1.00	2.00	2.50
102	Indonesia	**2.74**	**3.18**	1.80	2.70	3.20	4.00	**2.85**	3.50	2.60	1.50	4.00	**1.35**	0.50	1.50	2.00
113	Nigeria	**3.75**	**3.97**	2.00	3.80	4.70	3.90	**3.37**	3.70	0.50	3.80	4.80	**3.48**	3.00	3.30	4.00

Notes:

1. PEPS risk module designed for international oil and gas industry
2. For each variable a score is assigned between 0 and 5 (0 = lowest risk, 5 = highest risk)
3. Ratings based on a) surveys conducted with operators familiar with host country and
   b) commentary and analyses by trained political scientists, economists, and industry experts

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