Public Disclosure Authorized

Public Disclosure Authorized

Africa Gas Initiative

Congo

Volume IV

ESM240
Vol 4

Energy

Sector

Management

Assistance

Programme

ESMAP

Report 240/01

February 2001

JOINT UNDP / WORLD BANK

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions on three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG) composed of representatives of the UNDP and World Bank, other donors, and development experts from regions benefiting from ESMAP's assistance. The ESMAP CG is chaired by a World Bank Vice President, and advised by a Technical Advisory Group (TAG) of four independent energy experts that reviews the Programme's strategic agenda, its work plan, and its achievements. ESMAP relies on a cadre of engineers, energy planners, and economists from the World Bank to conduct its activities under the guidance of the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported over the years by the World Bank, the UNDP and other United Nations agencies, the European Union, the Organization of American States (OAS), the Latin American Energy Organization (OLADE), and public and private donors from countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States of America.

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information, a copy of the ESMAP Annual Report, or copies of project reports, contact:

ESMAP
c/o Energy and Water
The World Bank
1818 H Street, NW
Washington, DC 20433
U.S.A.

Africa Gas Initiative
Congo

Volume IV
February 2001

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

Copyright © 2001
The International Bank for Reconstruction
and Development/THE WORLD BANK
1818 H Street, N.W.
Washington, D.C. 20433, U.S.A.

All rights reserved
Manufactured in the United States of America
First printing February 2001

ESMAP Reports are published to communicate the results of the ESMAP's work to the development community with the least possible delay. The typescript of the paper therefore has not been prepared in accordance with the procedures appropriate to formal documents. Some sources cited in this paper may be informal documents that are not readily available.

The findings, interpretations, and conclusions expressed in this paper are entirely those of the author(s) and should not be attributed in any manner to the World Bank, or its affiliated organizations, or to members of its Board of Executive Directors or the countries they represent. The World Bank does not guarantee the accuracy of the data included in this publication and accepts no responsibility whatsoever for any consequence of their use. The Boundaries, colors, denominations, other information shown on any map in this volume do not imply on the part of the World Bank Group any judgement on the legal status of any territory or the endorsement or acceptance of such boundaries.

The material in this publication is copyrighted. Requests for permission to reproduce portions of it should be sent to the ESMAP Manager at the address shown in the copyright notice above. ESMAP encourages dissemination of its work and will normally give permission promptly and, when the reproduction is for noncommercial purposes, without asking a fee.

Contents

Tables

Figures

Foreword

The Africa Gas Initiative (AGI) Study is aimed at identifying countries where gas flaring could be reduced, for better utilization in the industrial and commercial sectors of their economies. This study was conducted by Mourad Belguedj, Senior Energy Specialist and Team Leader at the Oil and Gas Division of the World Bank and Henri Beaussant, Gas Economist and consultant.

The focus of the study, aimed initially at select countries on the West Coast of Africa, is of direct relevance to ESMAP's mandate and might be useful to Policy makers, Industry and practitioners in the target countries. The Study is published as part of the ESMAP series of reports and may usefully contribute to Project Identification and to addressing key Policy Issues in these countries, as well as enriching the debate on Energy Sector Reform. The authors wish to express their gratitude to all the colleagues who contributed directly or indirectly, to the review and completion of this work

Abbreviations and Acronyms

AGI	Africa Gas Initiative (World Bank)
AIC	Average Incremental Cost
API	American Petroleum Institute
CCGT	Combined-Cycle Gas Turbine
CFA	Communauté Financière Africaine
CFCO	Chemin de Fer Congo-Océan
CIF	Cost, Insurance, Freight
CORAF	Compagnie Congolaise de Raffinage
DRC	Democratic Republic of Congo
ESMAP	Joint World Bank/UNDP Energy Sector Assistance Management Program
FCFA	Franc - Communauté Financière Africaine
FOB	Free On Board
GDP	Gross Domestic Product
GNP	Gross National Product
GoC	Government of Congo
GT	Gas Turbine
HC	Hydro-Congo
HHV	Higher Heating Value
HV	High Voltage
IOC	International Oil Company
ISO	International Standards Organization
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases
PSA, PSC	Production Sharing Agreement / Contract
RTP	Reserves to Production ratio
SBM	Single Buoy Mooring
SDR	Special Drawing Rights (IMF)
SNH	Société Nationale des Pétroles du Congo
SNE	Société Nationale d'Electricité
SSA	Sub Saharan Africa
ST	Steam Turbine
UNDP	United Nations Development Program
USD	US Dollar

Units of Measure

bcf	billion cubic feet
bcm	billion cubic meters
bcmy	billion cubic meters per year
bl, bbl	barrel, barrels
bpd	barrel per day
cf	cubic foot (feet)
cfd	cubic feet per day
GJ	gigajoule
cm	cubic meter
GWh	gigawatt, gigawatthour
kcal	kilocalorie
km2	square kilometer
kW	kilowatt
kWh	kilowatthour
Mcal	megacalorie
mbpd	thousand barrels per day
mcf	thousand cubic feet
mcfd	thousand cubic feet per day
mcm	thousand cubic meters
mcmd	thousand cubic meters per day
mcmy	thousand cubic meters per year
mmb	million barrels
mmbtu	million BTU (British Thermal Units)
mmcfd	million cubic feet per day
mmcm	million cubic meters
mmcmy	million cubic meters per year
mmt	million tons
mt	thousand tons
mtoe	thousand tons oil equivalent
mty	thousand tons per year
MW	mega volt ampere
MWh	megawatt
t	megawatthour
tcf	ton
tcm	trillion cubic feet
toe	trillion cubic meters
tpy	
TWh	
TOE	ton oil equivalent
TPY	ton per year
TWH	terawatthour

Conversion Factors

Volume

1 barrel	=	159 liters
1 cm	=	6.29 barrels
1 cm	=	35.315 cf
1,000 cf	=	28.3 cm

Energy

1 mmbtu	=	252 Mcal = 293 kWh
1 mmbtu	~	1 mcf
1 GJ	=	0.95 mmbtu
1 kWh	=	0.86 Mcal = 3,412 btu

Oil products

crude oil	7.30 bbl/ton
diesel/gas oil	7.46 bbl/ton
fuel oil	6.66 bbl/ton
jet fuel	7.93 bbl/ton
kerosene	7.74 bbl/ton
naphtha	8.80 bbl/ton

Rules of Thumb

1 bpd	~	50 tpy
1 mmbtu	~	1 mcf ~ 1 GJ
1 mmcfd	~	10 mmcmy
1 USD/mmbtu	~	40 USD/mcm
1 tcf	~	30 bcm

1

OIL AND GAS RESOURCES

Overview of the Oil and Gas Sector

1.1 The Republic of Congo possesses significant hydroelectric, forestry and petroleum resources. The River Congo and its tributaries provide a large hydroelectric potential. Dense tropical forests covering about two-thirds of the country, particularly in the thinly populated northern regions, provide large quantities of woodfuels that still account for most of the domestic energy consumption. Significant petroleum resources have been established since the early seventies in the coastal basin's offshore inner shelf (up to 200 m water depth). Proven petroleum reserves are estimated to be about 150 million tons (mmt) of oil along with relatively large quantities of natural gas, which have yet to be fully evaluated. In addition, probable oil reserves in areas yet to be explored, such as the coastal basin's offshore outer shelf (more than 200 m water depth) and the entire inland basin north of the country, are estimated at 150-200 mmt. The petroleum sector, with an oil production that has been steadily increasing to reach about 13.2 million tons per year (265,000 bpd) in 1998, has become the country's principal export commodity and the major determinant of the entire national economy, although its contribution to the overall domestic energy demand remains very small. Since the mid-eighties and until recently, declining international petroleum prices have severely depressed the economic activity. At the same time, natural gas, a valuable resource, of which substantial quantities have been discovered and partly produced in association with crude oil, has not benefited the economy.

1.2 The general policy of the Government of Congo (GoC) is that oil exploration, development and production activities are carried out by IOCs under a combination of the old Congo concession terms based on the 1962 Mining Code that focuses essentially on crude oil, and the production sharing contract (PSC) terms based on the 1994 petroleum legislation. The following year, IOCs were given the option of converting existing E&P joint ventures to PSCs, which all major operators have done in their respective fields developments. In April 1998, GoC established a new national petroleum company, the Société Nationale des Pétroles du Congo (SNPC). SNPC is to market Congo's crude oil and to deal with all upstream functions of the former state-owned company, Hydro-Congo. The process of privatizing Hydro-Congo's downstream operations has been underway since 1997, but is not completed.

Oil and Gas Activities

Exploration

1.3 Congo has two sedimentary basins, the proven petroliferous coastal offshore Lower Congo Basin (28,000 km^2), which extends from Gabon to the Angola's province of Cabinda and into the Atlantic Ocean, and the much less explored onshore Congo Cuvette Basin (100,000 km^2), which extends north of Brazzaville as a continuation of the Central Basin. The country's first oil and gas discovery was made in 1957 and was put on production in 1960 at Pointe Indienne, some 20 km north of the coastal city of Pointe Noire, on the onshore edge (7,800 km^2) of the Lower Congo Basin. Petroleum exploration activity increased substantially following the discovery in 1966 of the Malongo giant complex of fields in offshore Cabinda, near Congo's territorial waters. Since then, significant activities have been carried out in the Lower Congo Basin, essentially offshore. So far, more than 170 structures have been identified, of which about 100, the most sizeable ones, have been explored. Oil and gas have been found in about 30 structures, of which 14 containing sufficient commercial oil accumulations have been developed and put into production (Emeraude 1972, Loango 1977, Likouala and Mengo 1980, Yanga and Kundji 1981, Bindji 1982, Sendji 1983, Tchibouela 1987, Zatchi 1988, Tchendo and Yombo 1991, and N'Kossa 1996 and Kitina 1997), and 4 containing significant quantities of natural gas, which remained undeveloped (Litchendjili, Move, Banga and Louvessi). With the discoveries of N'Kossa and Kitina bearing large oil and gas reserves, petroleum exploration is now shifting to deeper water offshore.

1.4 Congo's onshore petroleum exploration activity has been confined, so far, to the Lower Congo Basin's land portion, which extends some 50 km into the country along the coast. It has been on and off over the years and much less successful than offshore. After Pointe Indienne field, which was depleted several years ago except for insignificant quantities of oil and gas, three other small oil and gas fields, Mengo, Kundji and Bindji, were discovered at about 45 km southeast of Pointe Indienne. The three fields were completely depleted during the period of 1980-1991 and abandoned since then. Another small heavy oil field (Tiete-1x with 0.6 million tons of total reserves and an estimated flow rate of 233 tons per day equivalent to 1,700 bpd) was discovered in 1982 near the border with Gabon, but remained undeveloped. A 1993 exploration licensing located within 40 km east of Pointe Indienne, at Kouakouala, on La Loeme permit resulted in a yet another small discovery, which tested some 134 tons of oil per day (980 bpd). This discovery is reportedly too small to warrant further development. In general, the Lower Congo Basin's onshore oil and gas discoveries have been relatively small and typically of poor quality.

1.5 Congo's petroleum exploration activity, although on the decrease in the first half of the nineties, is still quite substantial. About one third of its yearly drilling program, which has leveled off at approximately 30 wells since 1993, is for evaluating new prospects. With the discoveries of N'Kossa and Kitina, exploration in more than 200 m water depth has gained momentum. Shell, the new comer to the area, has carried out a major seismic survey in a large block (Marine IX permit), where water depth varies between 500 and 1500 m. Most of the exploration so far carried in the Lower Congo Basin

has been driven by the search for structures while the basin's geology is highly favorable for oil traps. Recent developments in 3D seismic resolution techniques are expected to facilitate identification of such geological traps and improve previous poor data quality caused by the basin's thick salt formation. Deep water drilling technology is also expected to substantially accelerate Congo's offshore oil exploration and development activity.

Oil and Gas Production

1.6 As for many a country in the region, the oil history of Congo dates back to the 1970s, at the time of the first oil shock, when it began becoming profitable to put on stream fields with higher production costs. Emeraude, discovered in 1969 near the territorial waters limit between Congo and Angola (Cabinda) at about 25 km from the coast, was Congo's first major oil field. It was put on stream in 1972 and produced most of the country's oil output, about 2 mmty and 0.7 million cubic meters per day (mmcmd) of associated gas until 1977 when Loango, another major oil field discovered in 1972 in the northern part of Congo's offshore area at about 40 km from the coast, was put into production, thus adding about 1 mmty of oil and about 0.3 mmcmd of associated gas. Since then, production has been increasing steadily as new fields were put on stream. Most producing fields are within 50 km distance from the shore in less than 140 m water depth. In addition, a number of other small discoveries made at the periphery of producing fields are being gradually produced as subsea satellites tied into existing facilities or through low cost offshore loading facilities (single buoy mooring/SBM).

1.7 Since the early 1970s, the country's oil production is about doubling every decade. It has increased from about 3 mmty in 1978 to 7.2 mmty in 1988 and 13.2 in 1998. Generally, field reservoirs are at shallow depths (600-2500 m), often requiring a large number of well platforms and the use of slant drilling techniques. Except for the field of N'Kossa, Congo's oil is generally viscous and rather heavy (22-27 degree API) with up to 2% of hydrogen sulfide (H_2S) content, which is considered relatively sour by West African standards but sweet by international standards. Most of the fields, particularly the oldest ones, produce through artificial lift (downhole pumps). Offshore production is piped through 3 major gathering lines to the Djeno onshore terminal located about 15 km south of Pointe Noire.

1.8 Congo's oil production has recently increased by about 2 mmty and another 1 mmty when the two large fields, N'Kossa (Elf) and Kitina (Agip), were put on stream in June 1996 and December 1997, respectively. The production is expected to reach about 15 mmty (300,000 bpd) by the year 2000 when these two fields are fully developed. N'Kossa, Congo's largest oil field, is operated by Elf (51 percent) on the Haute Mer permit, with Chevron (30 percent), SNPC (15 percent) and Energy Africa (Engen, 4 percent) as partners. Production is 1998 was only 67,000 bpd instead of 100,000 – 110,000 bpd planned, due to technical problems that were resolved in 1999. All of N'Kossa associated gas production, estimated at more than 1 mmcmd, was planned for re-injection into its own reservoir for pressure maintenance to improve the field's productivity. Recoverable reserves are estimated at 500 million barrels (mmb), including 40 mmb of LPG. A recent discovery by Elf, also in Haute Mer, is the Moho field, with

estimated reserves of 400 mmb. Together with the smaller N'Kossa-Sud, it is expected to improve returns on the field when it begins feeding into N'Kossa's existing export facilities.

1.9 Although smaller than N'Kossa, the second largest producing field, Kitina, is operated by Agip (36 percent), with Chevron and SNPC as major shareholders. Estimated recoverable reserves amount to 145 mmb, and production is currently close to that of N'Kossa (60,000 bpd). Kitina field reported associated gas production is about 0.15 mmcmd, of which a small portion is used for field's own consumption and the remaining is flared. Other, smaller operators include the US independent CMS Nomeco, who took over Amoco interests in the Yombo field in 1994, and Shell, who is newer to the country.

1.10 Complexity of the reservoirs, which are heterogeneous and highly fractured, along with the viscous nature of the crude affects the proper drainage of oil in place. As a result, the overall oil recovery is relatively poor with less than 15 percent of the reserves in place in spite of the extensive use of pumping equipment. Any future development in oil field production technology, particularly in the area of artificial lift, would benefit Congo's oil output.

Refining and Downstream Oil

1.11 CORAF, one of the smallest refineries in SSA is located in Pointe-Noire, Congo's oil industry operation center. Nominal capacity is 21,000 bpd (1.05 mmty), but actual operation does not go beyond half of it. As part of the former Hydro-Congo's privatization program, it was agreed to transfer HC's majority ownership and management to Elf and Shell, who also agreed to purchase HC's network of 120 service stations and related infrastructure. Actual transfer is currently subject to improvement of security conditions across the country.

Gas Resource Base

1.12 ***Associated Gas.*** After Nigeria, Angola and Cameroon, Congo is considered the fourth largest gas resource base in SSA. Based on currently available data, Congo's total initial in place gas can reasonably be estimated at 150 bcm (about 5.2 tcf)[1], of which about 120 bcm would be proven, 6 bcm probable and 24 bcm possible. Of the 120 bcm initial in place proven gas, about 54 bcm would be associated gas and 66 bcm would be non-associated gas. Of the 66 bcm non-associated gas, 10 bcm would be gas-cap gas, 15 bcm in separate gas bearing reservoirs located in four producing oil fields (Loango 4.5, Tchibouela 2, Tchendo 0.5, and N'Kossa 8), and up to 41 bcm in undeveloped gas fields (Litchendjili 9 to 23, Banga 4, Move 9, Louvessi 4, and other small fields). Of the 54 bcm associated gas, about 50 bcm would be in N'Kossa and 4 bcm in seven other fields. The remaining 4 bcm associated gas is being produced at a rate of about 1.8 to 2.0 mmcmd.

[1] Other, more conservative estimates (US DoE's EIA) give 3.2 tcf.

1.13 ***Non-Associated Gas.*** Except for the 10 bcm of gas-cap gas (which will not be produced until underlying oil reserves are depleted) and the 15 bcm of non-associated gas (in separate gas bearing reservoirs in producing oil fields), all remaining non-associated gas is in undeveloped fields. Although non-associated gas has been found in more than 30 reservoirs, the least cost producible sizeable non-associated gas reserves, are, so far, in the Litchendjili field. Litchendjili gas has a high condensate content with about 500 cm per mmcm of gas. The field reservoir seems to be suitable for gas recycling, which would maximize condensate recovery. Assuming 23 bcm of reserves, a normal depletion without recycling, the minimum recoverable reserves would be 20 bcm over a 20 year-production period and about 1.2 to 1.5 mmt of condensate. A gas recycling of about 6 years would increase the condensate recovery to more than 6 mmt. A development and production program, which would maximize condensate and other liquids (possibly LPG) recovery would be best option.

1.14 ***Gas Flaring.*** Congo's associated gas production varies between 1.8 and 2 mmcmd, of which 1.5-1.8 mmcmd is flared. Because Congo's oil generally is heavy and viscous, gas production and subsequent flaring was low by West African standards, although it has substantially increased since production of Kitina field started. Flaring has been of great concern to GoC, which is keen to develop a gas utilization policy in general and eliminate or minimize flaring in particular.

2

PROSPECTS FOR NATURAL GAS

Industrial Sector

Sector Development Constraints

2.1 Like many oil-and-gas SSA producing countries, Congo has yet to introduce natural gas in the country's energy balance. Although substantial quantities of associated gas have been being flared for several years, remaining reserves are more than sufficient to meet the country's thin needs. Lack of interest in gas development observed so far at both State and operators level is assumed to be linked to several factors: (i) the existing industrial and commercial market, which could benefit from natural gas, is still of small size and geographically fragmented between the main two population centers of Brazzaville, the political capital, and the city-harbor of Pointe Noire, the oil capital – not to mention remote operations in the forest; (ii) exploration continues to focus on the search for crude oil, which is now the core of the country's economic development; (iii) contractual arrangements with operating IOCs have no specific provisions for development of natural gas; (iv) introducing natural gas as a source of energy into urban areas usually requires complex and costly operations (which local institutions are not familiar with or prepared for); (v) decision makers are not always kept aware of the long-term economic benefits, which can be derived from domestic use of natural gas; and, (vi) Congo lacks the long-term financial resources required for the development of natural gas.

A Limited Potential Market

2.2 The known natural gas reserves are well in excess of the local market's needs but seem too little to support an export scheme, such as a liquefied natural gas (LNG) project. Most of these gas reserves have not been delineated but estimated on the basis of existing limited seismic and drilling data. The US Government's agency Trade and Development Corporation (TDC) provided a grant financing to GoC in 1991 for a gas utilization study, which has been entrusted to M.W. Kellogg of the USA. The study, which is reportedly in a draft form since 1993, was disrupted by the civil disturbances. Kellogg, who has yet to officially present the study to GoC, is proposing production of ammonia and urea, which would require about 2 mmcmd of gas. Some of the currently produced and flared gas would not be used under the Kellogg proposed project due to high content (about 3 percent) of hydrogen sulfide (H_2S) and (about 25 percent) of carbon

dioxide (CO_2). A desulfurization and purification scheme would make the recovery program uneconomic. The possibility of another use of currently produced associated gas should be further assessed.

2.3 At the present time, natural gas is not marketed in Congo. Oil companies have long been using gas on drilling rigs to drive the combustion turbines that generate power for their offshore activities. Elf uses about 10 mmcm annually of associated gas from the small oilfield at Pointe Indienne that drives a 5.6-MVA turbine at its Djeno operating base. The gas is moved from Pointe Indienne (some 20 km north of Pointe Noire) to Djeno via a 40-km onshore pipeline that draws a half-ring around Pointe Noire. Although Pointe Indienne is equipped with a compressor station, it is not used. There has been no attempt to using the Pointe Indienne field, which is in the depletion phase, as a gas supply base for the potential market in Pointe Noire, but associated gas from nearby fields could be gathered for such purpose.

2.4 Oil products consumption in Congo, a country of 2.7 million people is very limited. Total domestic oil demand is around 300,000 tpy, most of it being used in the transportation sector.

Table 2.1 – Oil Products Demand (1997)

(mt)	*Domestic Demand*	*Imports*	*Exports*
LPG	3		
Gasoline	53		
Aviation Gasoline	57		
Jet Fuel	12		
Kerosene	48		
Gas oil, Diesel oil	81		10
Heavy Fuel oil	42	5	293
Marine Bunkers			10

Source: IEA, Energy Statistics and Balances of non-OECD Countries (1999 Edition)

2.5 With regard the industrial sector, potential consumption is concentrated in the three main urban areas: Brazzaville (14 mmcmy of gas equivalent), Dolisie (11 mmcmy), and Pointe Noire (10 mmcmy). Market weakness in Dolisie and Brazzaville, located 120 and 400 km respectively in straight line from Pointe Noire, means that it is not economically feasible to supply them from there by pipeline. The gap between the current market, not including Pointe Noire, and the economic minimum is such that the construction of a pipeline would not prove cost-effective for this market alone, even over the long term. While the potential market in Kinshasa, located close to Brazzaville across the 4 km-wide River Congo, might improve the economic return of such a project, it could help create the needed critical mass to make it competitive. A preliminary study of the Kinshasa market would be worthwhile to assess the feasibility of such a gas pipeline.

Gas distribution project in Pointe Noire

2.6 In Pointe Noire, the industrial market alone is too weak to warrant a gas project, while potential consumption in the residential and commercial sector -- for cooking and hot water, and possible air-conditioning of some buildings -- does not justify the installation of a street network within the city. However, a gas project supported by gas demand from a major consumer, such as power generation, could in turn lead to development of an industrial network; the Pointe Noire industrial zone, concentrated along the airport road, although limited to a few establishments, should be easily accessible at modest marginal cost.

2.7 The use of natural gas would be limited to the Pointe Noire suburban area, and depend on the need for gas for power generation. The project would consist of the following components :

- construction of a gas pipeline from the offshore pipeline landing point (or any convenient off-take between the landing point and the future thermal power plant) to the industrial zone entry point -- should the existing gas pipeline not be usable;
- construction of the industrial distribution network;
- conversion of the plants' thermal equipment (boilers, furnaces, etc.);
- set up of arrangements to handle financing of plant conversion, where appropriate;
- technical and commercial training for operations personnel.

2.8 A preliminary estimate of the cost of the project amounts to a modest USD 2.5 million. Given the ease and flexibility with which natural gas can be supplied to potential users (except for air-conditioning), technical considerations should not be a problem. The factors determining the feasibility of such a project will be primarily economic, associated with the cost of gas-sector components, e.g., cost of gas at pipeline entry point; costs of transmission, distribution, and plant conversions.

Gas for Power Generation

Current situation

2.9 Prior to the 1997 civil war, Congo's National utility, Société Nationale d'Electricité (SNE) was one of the several government entities considered for privatization. Subsequent damage inflicted upon SNE's infrastructure in the Brazzaville area during the civil war has decreased the likelihood of immediate privatization. The French firm, Electricité de France, had expressed interest in SNE, and has offered assistance in restoring services in Brazzaville.

2.10 The AGI has commissioned a pre-feasibility study of the use of gas for power generation, bearing in mind that a driving force – a sizable gas-consuming project --

is usually required to launch grass-root gas operation. Although Congo is one of the best-endowed SSA countries with regard to hydro potential, prospects for gas-based power generation look very attractive on economic terms, due to the comparatively higher capital cost, longer construction time, and negative social and environmental impact of hydro schemes. The pre-feasibility study was performed before a consortium of South African companies, including Rand Merchant Bank, recently started to undertake the first phase of the Sounda hydro scheme. Due to lack of finance and to the political situation prevailing in the country, the project had been delayed several times, and its final capacity is still unclear. With some similarities with Cameroon's Edea hydro scheme, Sounda is a stepped project, linked to the operation of mining activities in an area north of Pointe Noire, with no direct relationship with the needs of the power utility's other customers. However, should the project's full capacity be ever reached, part of the electricity generated could be directed towards the bulk of these minor customers.

2.11 The AGI's study clearly shows that gas-fired gas turbines are able to produce electricity at a much lower cost than Sounda would do, which makes a gas-based project still very attractive with regard to global economics. Depending on the size finally reached by the Sounda project and the allocation of its output, however, the need for gas-fired power plant in Pointe Noire might not prove as stringent as the AGI's proposal shows it. Due to a gas-based power project's better economics, and because the future of Sounda is unclear in terms of final capacity and associated mining industries, however, the AGI considers that the thermal option is still the best one, and recommends such option. While the detailed report of the pre-feasibility study is presented in Chapter 3, this section presents the summary of the current situation and the main conclusions of the AGI's study.

2.12 If completed, the Sounda Gorge hydroelectric project would not only make Congo self-sufficient for a long period of time, but might transform the country into a significant regional exporter of electricity. It would, however, have to compete with DRC's Inga. Implementation of the first phase has begun at the Limpopo River site, located 140 km north of Pointe Noire. This first phase is modest, as it involves the installation of two 10-MW turbines that will be used to generate cash flow for subsequent phases. The second phase involves construction of a 130-foot high dam, which would boost the plant's generating capacity to either 160 or 240 MW, using two or three 80-MW turbines. A third phase, which would represent a quantum leap, would increase the dam's height to over 300 feet and its generating capacity to 1 GW. South African companies, including Rand Merchant Bank, the Credit Guarantee Insurance Corporation, and Interpro-Sulzer have reportedly undertaken financing and construction for the first two phases. Financing for the third phase is yet to be determined. Serious doubts remain, however, on the likeliness of building a completely new hydro scheme on the reported economic basis of USD 925/kW of installed capacity, and on the economics of such project compared with gas-fed power generators costing around USD 400/kW.

2.13 The current situation of the power system is heavily marked by the country's difficult political situation, where the recent armed conflict has followed several years of inefficient centrally-planned economy. Even considering a slow demand increase rate, the present domestic generation capacity is definitely not sufficient to meet the total

demand of the interconnected network. In terms of energy, the average annual production of Moukoukoulou and Djoué, the major hydro plants, and the limited availability of thermal units at Pointe-Noire cannot exceed some 600 GWh per year. This corresponds to the supply (at production level) required for the year 2000. With regard to installed capacity, the total available is 97 MW during the wet season, thus meeting the peak power demand. But it is as low as 52 MW at the end of the dry season, where available capacity is barely half the capacity demand.

Potential options

2.14 Several options have been considered in the study to revamp existing facilities and increase power generation capacity. Among the two possible routes, hydro and thermal, gas-based thermal power plants lead to much lower present values when compared to domestic hydro schemes, such as the hydro project of Sounda. Cost difference comes mostly from (i) lower capital expenditures of gas turbines per kW of installed capacity, that have been significantly decreasing over time, while energy efficiency improves steadily; (ii) modularity of small-scale units that allow for implementing the units step by step, i.e. only when they are required; and (iii) shorter construction lead time.

2.15 Another (non-domestic) option would be to increase imports from the DRC, coming from the neighboring Inga hydro plant where additional nominal capacity could be available for export. A cross-border HV transmission line would be built between Inga and Pointe Noire through Cabinda to supplement the existing Kinshasa-Brazzaville line. The capacity of the new 220 kV, 210 km-long would be 200 MW, i.e., it would help Congo to meet the expected demand growth beyond 2015. The cost estimate of the line (around USD 38 million, based on updating previous estimates) would make this option an attractive one -- cheaper than conventional thermal options based on oil products -- provided that the current, rather favorable imports tariff grid is pursued. However, Congo has proved unable in the recent years to meet the payments; although electricity supply was never interrupted on such grounds, increasing significantly the amount of energy imported might prove unbearable to a country that is now even more fragile than it used to be. Moreover, relying on Inga only to meet all of the additional demand of Congo over the next twenty years or so raises concerns with regard to the technical conditions of the existing facility, where technical problems are periodically reported. The share of Inga, which accounted for up to 36 percent of the demand before Djoué was put back on stream after being flooded, would represent 55 percent of the electricity supplied to the inter-connected system in 2015. Such a dependency ratio would clearly become unbearable if a major breakdown would occur at the production site on in any place of the cross-border transmission system.

Gas-based power generation project

Alternative new production schemes

2.16 As many as twelve scenarios have been constructed and tested to determine the least cost generating option at horizon 2015 (at pre-feasibility level). Half of them do not consider natural gas and serve as reference scenarios, while the other six do consider gas available in the short term. Those scenarios that include hydroelectric schemes, such as the regulation of the Bouenza River basin, the construction of the Sounda dam on the Kouilou river and the Imboulou dam on the Lefini river, are by far the most expensive ones in terms of present value. Gas turbines running on gas oil prove to be expensive options too, due to high fuel costs. In spite of slightly higher capital cost, gas-operated gas turbines are the cheapest option.

2.17 All identified *hydro projects* (Sounda, Djoue 2, Imboulou and the Bouenza regulation dam) lead to very high investment costs, i.e. high total discounted costs over the period. These discounted costs range from 112 to 116 million USD depending on the hydro projects choice and ordering. Better results may be achieved with mixed hydro/thermal schemes, comprising one or two hydro projects along with gas oil-fired gas turbines. Discounted costs range, for these scenarios, from 97 to 99 million USD provided they are based on "light" hydro projects such as Djoué 2 or Bouenza.

2.18 Considering first *non-gas thermal options* (i.e. running on oil products), the least-cost option would consist in installing 3 x 50 MW gas oil-fired gas turbines, respectively in 2002, 2009 and 2014. The total discounted cost in that case is only 89 million USD. Options with larger-size units (1 x 50 + 1 x 100 MW) give similar economic results. As the operating cost of thermal units is higher than the cost of imported energy from Inga (2.60 US cents per kWh), the share of imports in the total supply – although limited to current level -- remains important and, conversely, the average working time of gas turbines is low, at 1,500 hours per year on average.

2.19 Assuming natural gas would be made available in Pointe-Noire at a relatively low economic cost (calculations have been made on the basis of 1.50 USD/GJ, i.e. about 1.60 USD/mmbtu), the solution with 3 x 50 MW *gas-fired gas turbines* becomes the least-cost alternative, with a total discounted cost of 66 million USD. In that case, the variable cost of the gas turbines is below the cost of imported energy, which means that almost all the incremental demand is met by these natural gas units. Gas consumption thus regularly increases from 50 mmcmy in 2002 to 250 mmcmy in 2015. Its average netback value over the period is 2.96 USD/GJ. A combined-cycle option (2 x 50 MW GT + 1 x 50 MW ST) is not optimal in the present context because slow annual demand increase does not allow for taking full advantage of such facility, which has to work on base load to fully benefit from higher efficiency. The combined-cycle facility, initiated in 2002 with the first gas turbine, would not be completed before 2012, when the third (steam) unit is put on stream. The benefit of higher efficiency would thus be effective only during the very last years of the study period, and would not offset higher investment cost. A smaller-size combined-cycle plant (in the range of 90 MW, i.e. 3 x 30 MW) could better fit the system and possibly become the least-cost option.

2.20 Among all generation sources, imports from DRC are cheapest if both investment and operating costs are taken into consideration (on a variable costs basis, natural gas units and, of course, hydro energy are cheaper than imports). As a result, alternative scenarios assuming that the power limitation on imports is raised to 100 MW (which is the technical limitation of the interconnection between Inga and Brazzaville) lead, of course, to lower economic costs, respectively 52 and 53 million USD for gas- and gas oil-based options. However, the level of external dependence of the Congolese system would then be very high, and the conjunction of risks, either political, economical and technical (the availability rate of Inga has been reported to be deteriorating) could become unacceptable.

2.21 Conversely, one may be interested to consider the case where energy imports from the DRC would be stopped definitively in 2000. What would be the cost, for Congo, of choosing a strict self-sufficiency policy for its future power supply? In that case, gas oil-based solutions would become prohibitive and, as a matter of fact, more expensive than some hydro options. In fact, only natural gas still remains economically attractive in that case. The solution based on a combined-cycle unit would then become the best choice, with a total discounted cost of 87 million USD. Compared to the least-cost option, it means that the cost of replacing the imports by gas-based own generation is about 21 million USD in discounted value. However, comparing this scenario to the best scenario without gas still brings to light a small economic benefit (2.4 million USD). In other words, combining imports suspension and natural gas introduction into the system is still a slightly cheaper scheme than continuing with imports and gas oil units.

The Proposed Project

2.22 The proposed project identified under the AGI for Congo is based on gas-fired thermal capacity. It includes two components that need to be implemented in close relationship: (a) the construction of several gas-fired gas turbines in Pointe Noire in a phased, consecutive manner, so that the implementation schedule follows the evolution of the electricity demand; and (b) the rehabilitation of the interconnected electricity network between Brazzaville and Pointe Noire. In order to better fit the estimated evolution of the demand, smaller-size units (30 MW) are considered, to take full advantage of the system's modularity.

2.23 *First phase.* A first gas turbine needs to be put on stream in the short term. In the beginning, it is dedicated to mostly supply Pointe Noire with electricity, as the condition of the interconnection does not allow Brazzaville to receive electricity from Pointe Noire in a reliable manner. Gas demand would reach 6 mmcfd. In the same time, the rehabilitation of the interconnection needs to be undertaken. The first section to be revamped is the eastern part of the transmission line, between Moukoukoulou (located about halfway between Brazzaville and Pointe Noire) and Brazzaville, including the large transformer station of Mindouli. The main purpose is to allow Moukoukoulou and Djoué to supply Brazzaville at full capacity, thus limiting imports from Inga to a few months during the dry season (July-October). When the eastern section is back into service, the western section (Moukoukoulou to Pointe Noire) should be rehabilitated to enable in a first step Pointe Noire to be backed up by Moukoukoulou when required. Later on, when the

demand in Brazzaville exceeds the generation capacity of the hydro plants, gas turbines in Pointe Noire will be able to supply Brazzaville where required through the revamped inter-connection.

2.24 When Phase 1 is completed and during the next six years or so, electricity demand in Pointe-Noire is mostly met by local thermal capacity, including the new gas turbine. Additional quantities of energy can be received from Moukoukoulou when required, in limited amount. Base load for Brazzaville is provided chiefly by Moukoukoulou and Djoué. Peaking is provided by Djoué and Inga. During the first few years, the interconnection is almost idle between Moukoukoulou and Pointe Noire, thus allowing the western section of the line to be rehabilitated.

2.25 *Second phase.* From 2006 on, additional capacity is required. Two additional units are to be put on stream in 2006 and 2009 in the same location (Pointe Noire). Depending on the price of gas when the third unit is needed, this last unit can consist of a steam turbine, thus giving way to a combined cycle plant of 90 MW. At the end of the period a fourth unit is required. Electricity transfers from Pointe Noire to Brazzaville are significantly increasing during this period, as the two existing hydro plants are no longer sufficient to supply Brazzaville. At the end of the period, the structure of the production is fairly balanced : domestic hydro capacity provides 45 percent of the demand; 42 percent is supplied by thermal capacity connected to the inter-connected line; 11 percent are still imported from Inga, mainly for peaking, while the balance (around 2 percent) is met by local, isolated gas oil-fired small-scale generators.

2.26 The economic cost of the power generation component of the project is estimated at USD 52 million. This does not include the cost of fuels nor the cost of gas supply from the field to the plant's gate. Gas consumption increases over time from 20 to 134 mmcmy (2 to 13 mmcfd in average). Gas netback value at plant gate ranges from USD 2.80/mmbtu to USD 3.10 in the most favorable configuration.

Potential Gas Sources

Associated gas from Kitina

2.27 There is no gas immediately available in Congo. While gas from the Pointe Indienne onshore gas field has been used for a long time by Elf to produce electricity at their facilities in Djeno, the field is now nearing depletion. Gas projects have thus to be supplied from offshore fields. In a first step, GoC had requested that Agip, the operator of the Kitina oil field, evaluate the option of supplying associated gas from their field in order to reduce gas flaring. Two alternative scenarios were considered :

- Transport the wet gas from the offshore platform to the land with minimal processing, and build all gas processing, including condensate and LPG extraction facilities, onshore, and
- Process all the associated wet gas on the offshore platform and ship dry gas as well as condensate and LPG onshore.

2.28 As oil production infrastructure is required anyway, Agip's cost estimate covers only the additional capital and operating costs dedicated to the production of natural gas and its associated components. The oil that is produced from the offshore platform is initially passed through a separation unit which produces (a) oil - which is further treated to remove water, salts, etc. and then stabilized for transport; (b) water - which is treated to remove pollutants and discharged; and (c) associated gas, including condensate. In order to maximize the revenue from gas utilization, the extraction of LPG and condensate from the gas stream has been considered. Production profiles then made by Agip showed that as much as 1.57 million barrels of condensate and 370,000 tons of LPG could be recovered over the field's 22 years lifetime.

2.29 Capital cost as established by Agip ranges from USD 98 million where compression is located off-shore (case B) to USD 106 million where compression is located on-shore (case A). Larger pipeline's diameter in case A is mostly responsible for the cost gap. Rough estimates by the World Bank indicate much leaner costs, at USD 57 million and USD 62 million, respectively. Such large discrepancies require that additional in-depth calculations be conducted. Although marketing these products would not prove sufficient to make condensate and LPG extraction profitable, it enables to decrease the cost of producing gas as a by-product to a level compatible with its value on the Pointe-Noire market, thus making the combined operation profitable. Based on World Bank cost assumptions of the extraction facilities, rough economic calculations show that the project would generate an economic return of 16 percent where gas is valued at USD 1/mmbtu.

2.30 Production profile for Kitina is actually the major issue faced by the project. After peaking sharply on year 2 of operation, oil (and associated gas) production decreases at a fast rate. In the meantime, gas demand follows electricity requirements and increases slowly. Gas production and demand curves intersect after 7 years of gas use by the power plant. From this time on, Kitina does not produce enough gas to supply the market in Pointe Noire and requires a back-up supply source to meet existing and future demands.

Non-associated gas from Litchendjili

2.31 While there may be some uncertainties about the level of proven gas reserves necessary to support an LNG export scheme, there is no doubt that sufficient reserves exist to support development of projects for domestic use such as power generation, condensate and LPG production. One option would be to develop the Litchendjili gas field. Litchendjili is the largest non-associated gas field in Congo. It is located offshore at about 20 kilometers from Pointe Noire. Reserves are estimated to be around 20 bcm of gas and 8 mmt of condensate. Conservative assumptions on reserve recovery (i.e. 70 percent) suggest that Litchendjili could be produced at a plateau production rate of about 2 mmcmd for about 12 years, with a producing life of at least 18 years. Development of the Litchendjili field could be followed by development of two other fields, Banga (3.5 bcm) and Louvessi (1 bcm), located about 15 kilometers from Litchendjili. Development of Litchendjili would include (a) the recovery of natural gas liquids (NGL) and LPG; (b) the recovery of some of gas currently flared; and (c) the use of gas for power generation and in the industrial sector of Pointe Noire.

2.32 The development of Litchendjili field would be the best prime mover of Congo's natural gas utilization program. The proposed scheme is to maximize the condensate recovery by recycling gas into the field, for about 4-5 years (during which time gas would not be supplied). Given the high condensate content in the gas, two development options can be considered. One of these options would be to maximize the condensate recovery through gas recycling. Under this option, the field development program would consist of: (i) a 3-D seismic coverage; (ii) drilling of about 18 appraisal, injector and production wells; (iii) construction of a gas processing and compression platform; (iv) installation of an SBM with storage barge or construction of a condensate pipeline to transport it; and, (v) construction, towards the end of the field's recycling life, about 4-5 years later, of a gas pipeline for transportation of gas to onshore gas users. The recycling option would cost between USD 200 and 250 million.

2.33 The other option would be gas production and supply with condensate recovery limited to the gas dehydration process. Under this second option, which is also called normal depletion, the field development program would consist of: (i) a 3-D seismic coverage; (ii) drilling of about 12 appraisal and production wells; (iii) construction of a gas gathering platform; (iv) construction of a pipeline to transport both gas and liquids for processing onshore; (iv) construction of a gas processing facility onshore including a supply line to gas users. The depletion option would cost between USD 150 and USD 180 million. A development scheme combining both options would substantially improve the economics of the project. If the gas reserves of N'Kossa are added, it would improve substantially the long term gas supply curve for Congo.

Prospects for LPG

Supply and demand patterns

2.34 Development prospects associated with Kitina and Litchendjili, not to mention N'Kossa, along with the potential market for LPG, make formulation of an LPG project focused on butane (and possibly propane) very attractive. Marketed LPG has long been limited to the CORAF refinery's yield, 4,000 tpy in average, supplemented by spot, expensive imports when shortage was too critical. Numerous technical and institutional issues (insufficient railroad capacity between Pointe Noire – where the refinery and main storage facilities are located -- and Brazzaville; shortage of cylinders; imports monopoly; price grid leading to uneconomic operation) have kept availability of product and cylinders as well, well below demand.

2.35 LPG production and consumption are limited to so-called "butane", actually a mix of butane and propane. The volume of propane obtainable in the refining process (about 1,800 t at the present level of the refinery operation) is too low to warrant installation of a costly extraction plant dedicated to C_3. Part of the propane associated with the refining process is thus combined with butane in an 85:15 mix, while the remainder is incorporated into refinery gas for on-site consumption. Propane itself is not imported, and thus not used in Congo.

2.36 "Butane" is produced by the CORAF refinery at Pointe Noire, at an average rate of 4,000 t a year. The processed crude (Djeno blend), which is quite heavy, gives a low production coefficient of 0.8 percent. In other words, the maximum production figure is 8,000 t if the refinery is operating at its rated capacity (1 million t/year), but actually only half of it due to low level operation. Except for fuel oil, almost all of which is exported, refined products are sold to SNPC, which channels them exclusively to the domestic market. Sporadic imports of butane are necessary when CORAF's output is insufficient, which has occurred every other year on average since the refinery came on line in December 1982. For example, the deficit in 1994 was unusually large, with production of a mere 1,350 t. Although costly import of an equivalent volume of butane kept supplies at the normal level in Pointe Noire, the shortfall had a serious impact on supplies to Brazzaville, where over half of total demand could not be met.

2.37 Under the conditions that prevailed until recently[2], the volume of butane brought to the market depends directly on refinery output as planned each year by CORAF and SNPC. Imports are called only to make up for unforeseen drops in production. Hydro-Congo, which held the distribution monopoly until the recent restructuring, does not appear to have made particular efforts to promote sales of LPG. This explains why consumption has remained remarkably stable over the last 12 years, at roughly 4,200 tpy, with the following average distribution pattern: Brazzaville, 3,000 t; Pointe Noire, 1,100 t; Dolisie, 100 t; and remote Center and North regions, 40 t, transported by barge. If the comparison is made with other sub-Saharan countries where butane sales have rapidly developed (e.g. Senegal and, to a lesser extent, Cote d'Ivoire and Cameroon), present consumption appears to be well below the potential level, both geographically (Brazzaville and Pointe Noire account for 95 percent of sales) and from the standpoint of reliability of supply (many butane users often have to resort to substitute fuels).

2.38 Another potential source of supply for the country would be to tap the huge amount of LPG produced by the N'Kossa field. With 250,000 to 300,000 tons released every year, N'Kossa's overall production is by far considerably higher than Congo's requirements, even over the long term, and is currently entirely sold in the international market, with special emphasis on Brazil. Depending on the remaining available production capacity, if any, and contractual arrangements with purchasers, N'Kossa could represent the much required resource base for development that CORAF is unable to provide due to limited operation.

Technical issues

2.39 Development of consumption is hindered for two reasons: (i) CFCO, which operates the rail link between Pointe Noire and Brazzaville, has insufficient transportation capacity; and (ii) availability of gas cylinders is far from meeting needs. The following paragraph analyzes the issues faced by the supply of LPG (and other products) from Pointe Noire to Brazzaville prior to the interruption of rail traffic caused by the second outburst of the civil war at the end of the decade. All rail traffic is understood to be currently halted

2 This is expected to change as private sector actually takes over downstream oil activities.

due to the destruction of major components of the railway link. While overall issues may only have worsened as a consequence of the war, the transportation issue will be back as soon as traffic is able to resume.

2.40 *Transportation capacity.* Under the terms of an agreement between the former Hydro-Congo and CFCO, the latter is committed to 2.5 round trips a month between Pointe Noire and Brazzaville. If adhered to, this frequency means that the three available tanker wagons can move 240 t of butane a month, a figure already slightly less than average consumption in Brazzaville. The fact is that the shortage of traction equipment and the state of the track barely enable CFCO to manage two round trips a month, which translates into a maximum of 190 t of butane shipped monthly to Brazzaville. In combination with the Brazzaville LPG plant's poor storage capacity, this shortfall results in an estimated yearly supply deficit of 800 t, i.e. 25 percent of the capital's average demand. To rectify the situation, Hydro-Congo has ordered two additional tanker wagons from South Africa3. When in service, the strains created by inadequacies in transportation capacity would diminish. However, the problem of inadequate storage capacity in Brazzaville would remain, unless one or two wagons can be used there for emergency storage purposes (but this does nothing to eradicate the underlying problem). The combination of these obstacles means that the Pointe Noire LPG plant's storage capacity is saturated as not all the butane delivered to it from the refinery can be shipped out. In normal circumstances, its 650 t of storage capacity would be adequate; but it does happen that butane is blended into gasoline at the refinery because there is no storage capacity left at the Pointe Noire LPG plant.

2.41 *Shortage of gas cylinders*: The second obstacle is the recurrent shortage of cylinders. No one knows just how many 12.5 kg cylinders (the most widely used size) are actually in use. A very approximate estimate would be 50,000. One reason for the shortage is the smuggling of cylinders -- a consequence of the difference between the price of the deposit in Congo (FCFA 4,000 until recently) and in some neighboring countries (e.g., FCFA 12,000 in Kinshasa) -- although an adjustment of the deposit to CFA 8,000 is believed to have helped mitigate the issue. The other reason is a familiar one: the shortage is self-propagating, in the sense that households hoard more cylinders than needed for fear of being affected by a worse shortage. Despite periodic purchases of cylinders (about 16,000 since 1984) from manufacturers abroad, mainly from Cameroon and France, the shortage remains acute.

Financial and institutional distortions

2.42 Since an agreement between CORAF and Hydro-Congo on ex-refinery prices (transfer prices) came into effect in February 1995, the future of butane distribution is seriously threatened by the fact that the distributor's mark-up has become negative. What appears to have occurred during the negotiation of the agreement is that the sole concern was to keep CORAF profitable, while Hydro-Congo was left to bear the structural losses affecting the distribution chain. Based on former conditions (mid-1990s) which

---

[3] Whether they have been put in service in unknown.

may have changed since, transfer (bulk) price (FCFA 396 per kg) was 24 percent higher than the retail price (FCFA 320) that had remained unchanged since 1984 despite the devaluation of the CFA Franc in January 1994; transfer price was even 70 percent higher than the before-tax retail price (FCFA 232), generating for Hydro-Congo a negative margin of FCFA 164 per kg. Obviously, this was not a situation that will encourage any private - or public -- sector operator to enter a market where each kg of product sold generates a substantial loss.

LPG Development Project

2.43 The project's objective is to make butane accessible to 50 percent of the urban population, a range close to that observed in the sub-Saharan countries mentioned earlier. This would raise butane consumption to 16,000 t per year in the medium-term (after 5 years) by 150,000 households (a four-fold increase over an estimated 39,000 households using butane in 1995). In addition to production installations, the project would include, but not be limited to, the following components:

- rehabilitation and appropriate expansion of the Pointe Noire and Brazzaville LPG plants (storage, filling and testing facilities);
- construction of an LPG plant and a filling center in Dolisie, and possibly in other urban areas;
- importation and tagging of 150,000 12.5-kg cylinders to eliminate the present shortage and interruptions of the distribution cycle;
- importation and tagging of 120,000 6-kg cylinders and of 120,000 cylinder+burner packages so as to make butane more accessible to lower income households;
- development of retail outlets;
- establishment of credit arrangements for the purchase of cylinder+burner packages by households still without this equipment;
- campaigns to make households aware of the advantages of butane and necessary safety measures,
- technical assistance for drafting LPG regulation and institutional framework.

2.44 The cost of the project is estimated at USD 20 million, of which about 60 percent consist of cylinders and packages purchase.

2.45 As part of the work of formulating the components of a possible project in detail, the following studies should be undertaken:

- study of the cost structure of butane and necessary adjustments to it; this would include (among other things) study of the distributor's mark-up and the cost and conditions of transporting LPG from Pointe Noire to Dolisie, Brazzaville, and possibly further north;

- study of the potential market for butane and propane in the country's main urban areas.
- review of the [present] price structure (including its taxation component), which should capture the economic cost of bringing the product to market. This review should also incorporate a detailed study of butane production and distribution costs.

3

GAS FOR THE POWER SECTOR

Methodology and Assumptions

3.1 In many cases, the power sector appears as the only one capable of absorbing sufficient quantities of gas to make an initial gas infrastructure profitable. This may then serve as a backbone for further gas transmission and distribution projects aimed at supplying other types of consumers such as industrial zones or densely populated residential areas. Accordingly, the objective of the power pre-feasibility study presented in this chapter is to analyze the technical and economic conditions for introducing natural gas within the power system, either in existing or in future generating units.

3.2 The question of natural gas availability (reserves estimates, production profiles and costs) is not dealt with in this part of the study. The potential market of natural gas is calculated without consideration to supply limitations, i.e. under the assumption that enough cheap gas can be made available to power plants in the area considered. For simulation purposes (generating units ranking by merit order), the economic cost of gas at the plant gate is taken as 1.5 USD/GJ[4] in all cases. However, the actual value of gas is calculated in all cases independently of that assumption. Gas value and foreseen gas consumption profile will constitute the basis for the final appraisal of the economics of gas use in the power sector.

3.3 A set of possible development scenarios have been established regarding the power generation system. They have been optimized using a computerized linear programming model developed by the Consultant. The model has been designed for optimizing the development of a generation and transmission system, taking account of investment and operating costs. It is generally applied to problems where geographical aspects are to be considered (plant site comparison, generation or transmission investment balancing, etc) and then features a geographical description of the network topology. In the present case, these network aspects have not been included in the modeling exercise, though they are important and should be covered in a later stage. The model has been used to optimize the choice of generating units and their commissioning years, and the whole

[4] 1 GJ = 0.95 mmbtu. 1.5 USD/GJ = 1.58 USD/mmbtu

system operation (unit commitment) on a yearly and seasonal basis. Finally, the model results are synthesized in economic calculation sheets that will be used to compare the total discounted economic costs and the value of gas for all considered scenarios.

3.4 All calculations are made on an economic basis, i.e. aiming at optimizing decisions from the point of view of the national economy. No national taxes, duties or subsidies are therefore included the cost of any commodity. All costs (both investment and operation) incurred to supply electricity over the study period (20 years) are discounted at a uniform rate of 10 %.

3.5 Congo owns significant hydroelectric resources, which constitute the basis of its power generation system. Thermal units are generally limited to peak load generation, emergency backup and supply to remote areas. Present thermal units are either diesel engines or gas turbines. The future development of thermal generation in these countries will probably face the same limitations, and it is very unlikely that heavy base-load thermal units such as steam generators would be appropriate in this kind of small-scale systems. Therefore, only two types of thermal units have been considered among the options for developing the generation systems: single-cycle gas turbines (GT) and combined-cycle gas turbines (CCGT). The main standard characteristics for these units have been determined on the basis of a market review, as explained below.

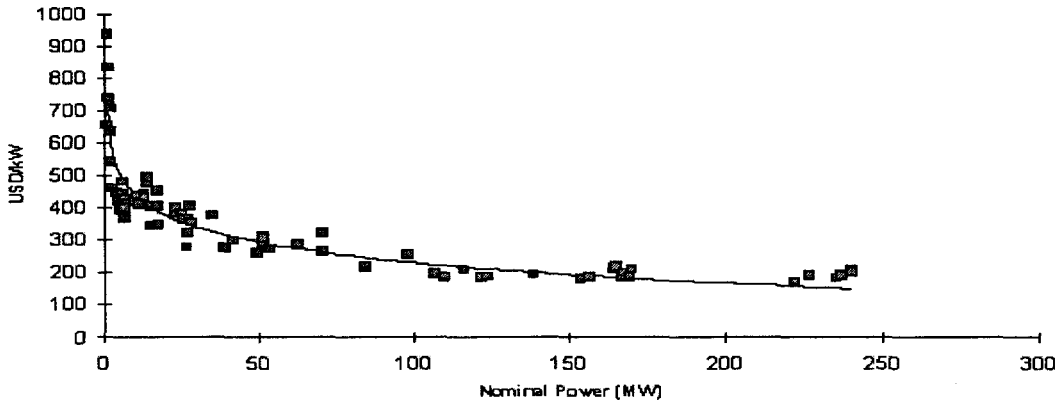
3.6 Fig. 3.1 shows the observed relationship between nominal power and unit price (USD/kW), for 76 best-selling gas turbines[5]. The figure also shows a regression curve calculated to best fit the observations. Based on this curve, one may estimate an average equipment cost for different typical sizes of gas turbines. Two typical sizes have been considered here:

- 50 MW: In order to have a real available ("derated") power of 50 MW in running conditions in African countries, one will have to install a unit of 55 MW nominal power. Using the regression curve, the typical cost will be 282 USD/kW, or 310 USD per derated kW. This covers only the equipment itself, FOB factory; it does not include items such as step-up transformers, switchgear, fuel treatment and compression equipments, foundations, freight and insurance, real estate, contingencies, etc. In order to estimate the total turnkey installed plant price, one typically may add between 50 and 100 percent to the equipment cost. Assuming 75 % in the present case, this leads to a total installed cost, excluding taxes and duties as well as financial and debt service charges, of 543 USD/derated kW.
- 100 MW: Similarly, a real 100 MW available power will correspond to some 110 MW installed capacity. The regression curve gives a typical cost of 219 USD/kW, or 241 USD/derated kW. Assuming 75 % non-equipment costs, it gives a total 421 USD/derated kW.

5 Source: average price data published in the *Gas Turbine World Handbook*.

- The investment cost is assumed to be 5 % higher for dual-fired turbines, designed to operate either on a natural gas or on a gas oil basis.

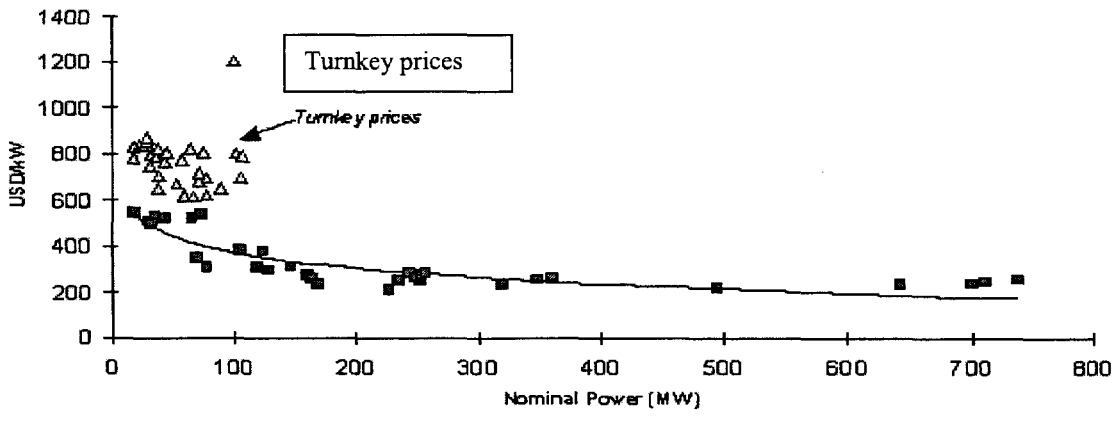
Figure 3.1: Turbogenerator Price Levels



Note: Prices are for equipment only, FOB factory.
Add between 75 and 100% for turnkey prices

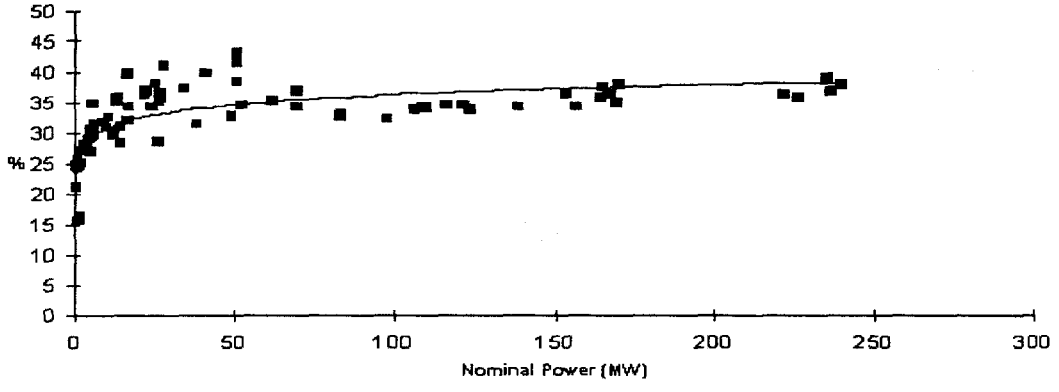
3.7 Fig. 3.2 shows the observed relationship between nominal power and unit price (USD/kW), for 31 commonly marketed combined-cycle packages (same data source as for gas turbines). The regression curve, calculated to best fit the observations, allows to estimate the equipment cost for typical sizes of combined-cycle plants. Taking account of the relatively small size of the power system, units of no more than 150 MW have been taken as standard options for the present study. As for open-cycle gas turbines, nominal power has been taken as 10 % higher than derated power. The equipment cost, estimated for a 165 MW (nominal) unit, is 323 USD/kW, i.e. 356 USD per derated kW. Considering the higher degree of uncertainty on the investment cost of combined-cycle plants (due to the greater impact of site requirements, of competitive market conditions), the non-equipment share of the total cost has been taken as 100 % of the equipment cost. Thus, the turnkey investment cost that has been used for calculation purposes is 711 USD per derated kW.

Figure 3.2: Combined Cycle Price Levels



3.8 Fig.3.3 shows the ISO thermal efficiencies (LHV basis) for the same set of 76 single-cycle gas turbines as considered above. Though data dispersion is greater, a similar regression calculation has been performed. For a 50 MW (55 MW nominal) unit, it gives a 34.8 % net efficiency under ISO conditions (15°C, sea level and 60 % relative humidity). Assuming a 10 % degradation under real African climatic and operating conditions, that leads to a 31.3 % net efficiency. For a 100 MW gas turbine, the same calculation results in a 36.3 % ISO efficiency and 32.7 % under actual conditions.

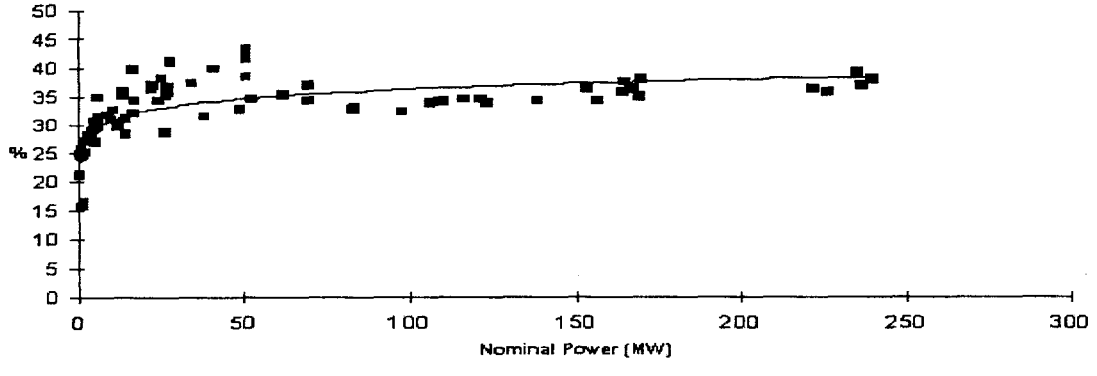
Figure 3.3: Typical Turbogenerator efficiency



Note: Net efficiencies under ISO conditions (15°Celsius, sea level and 60% relative humidity

3.9 On the basis of a similar regression analysis (Fig.3.4.), the ISO thermal efficiency for a 150 MW combined-cycle package (165 MW nominal) is estimated at 51.7 %; under operating conditions, the actual efficiency is assumed to be 10 % lower, i.e. 46.5%.

Figure 3.4: Typical Combined Cycle Efficiency



3.10 Assumptions have been made on the cost of competing fuels. As a matter of fact, gas oil is the best alternative to gas for feeding future thermal units (either gas turbines or combined-cycle units) and is used as the reference energy carrier. The price ratio of gas oil over crude oil is based on actual observations of the spot price of gas oil in

the NWE market (Rotterdam) vs. the OPEC basket. Over the observation period the index shows at 128. That ratio has thus been adopted for the present study. The future evolution of crude oil price is assumed to be flat, at 21 USD per barrel, FOB loading port. The corresponding gas oil price is 26.88 USD/bl, or 194 USD/ton, FOB Rotterdam.

3.11 For calculation purposes, natural gas is assumed to have a lower calorific value of 37 MJ/cm after treatment (LPG extraction). It is assumed to be supplied at a minimum pressure of 25 bar, which is sufficient for most gas turbines and combined-cycle units.

Infrastructure

3.12 The state-owned utility SNE (Société Nationale d'Electricité), established in 1967, is responsible for electricity production, transmission and distribution in Congo. However, in the past years, most of planning and financing issues have been dealt with at Ministry level. As a consequence of the increasing difficulties encountered in looking for financing sources, the sector has recently entered into a liberalization process that should lead to privatizing at least some parts of SNE's activities. Efforts are now being made to encourage independent power production; though power production has never been a state monopoly, the legal and regulatory frameworks need to be somewhat adapted in that perspective.

3.13 The interconnected network covers the southern part of the country, from Brazzaville to Pointe-Noire. The area covered by that network corresponds to some 70 percent of the country population. The main towns of the central and northern parts of the country are supplied from diesel- or hydro-based local networks.

Production

3.14 The hydroelectric potential of Congo is important, since currently identified projects sum up to some 1,300 MW installed capacity and 7.5 TWh energy in an average year[6]. Electricity consumption is low as most households in rural areas rely on wood as their primary source of fuel. Moreover, electricity transmission links are non-existent in many parts of the country, in particular to the north of Brazzaville, and in recent years, civil war has periodically disrupted power supplies. Only two hydro sites, Moukoukoulou and Djoué, have been equipped so far, for a total installed power of 89 MW. Congo also imports up to one-fourth of its needs as cheap energy from the Inga dam in neighboring Democratic Republic of Congo (DRC), through a 220 kV cross-river interconnection between Kinshasa and Brazzaville. The major activity centers of Brazzaville and Pointe Noire are connected to the main production centers (hydro) while thermal generation has almost disappeared.

3.15 Moukoukoulou is the largest hydro plant in Congo. A reservoir dam located on the Bouenza river, halfway between Brazzaville and Pointe-Noire, it has an

6 Other sources estimate potential at 3,000 MW.

installed capacity of 74 MW. The available energy in an average year is 430 GWh, which is high when one considers that firm power is only 29 MW due to the very low water level of the Bouenza river during the dry season (July to October). The second hydro plant is the smaller facility of Djoué, located in the outskirts of Brazzaville, another reservoir plant with an installed power of 15 MW. Firm capacity, when waters are highest (in december) is 12 MW. After the plant was flooded in 1991, Djoué remained out of order until 1997 when it was put back on stream with assistance from Rotek, a branch of the South African power company Eskom.

3.16 Since the old Brazzaville diesel plant was definitively shut down, thermal generation capacity (outside isolated power plants, mainly in the north) is limited to the 7 diesel units located in Pointe-Noire, totaling 24 MVA. Only two of these units, totaling 10 MVA (about 8 MW) are presently operational. They consume diesel oil and are not suitable for conversion to natural gas. In addition to the customers of the SNE, a few large or medium-sized consumers rely on their own generation means:

- Elf-Congo (Pointe-Noire): available capacity 5.6 MW onshore (Dieno) and 41 MW offshore;
- Coraf (refinery - Pointe-Noire): 16 MVA installed capacity, actually requires 3 MW;
- Saris (cane sugar factory): 6 MW (based on bagasse);
- Comilog (CFCO workshops - Makabana): 2.6 kVA;
- Some sawmills and other forestry estates.
- Most of them, however, operate in remote areas (sugar mills, timber) and could not be easily connected to the network in the foreseeable future.

Transmission

3.17 The interconnected network covers the southern part of the country, from Brazzaville to Pointe-Noire. The area covered by that network corresponds to some 70 percent of the country's population, which is already concentrated for half of it in the main two urban centers of Brazzaville and Pointe Noire. The smaller centers of the central and northern parts of the country are supplied from diesel- or hydro-based local networks. The interconnected network is mainly constituted of a 450 km East-West 220 kV line linking Brazzaville and Pointe-Noire through Moukoukoulou. Pointe-Noire was first connected to the Moukoukoulou hydro plant in 1983, and from there to Brazzaville in 1987. A few 110 kV lines connect the Moukoukoulou hydro plant and some smaller cities (Loubomo, Nkayi) to the backbone line. Recurrent plans exist for extending the HV network northwards from Brazzaville, but the extremely low actual and potential demand in these regions makes it impossible to justify economically such a project. It seems that disseminated local supply sources (either diesel or micro-hydro units) would be the only realistic way to supply power to the small towns of the northern region.

3.18 Since 1983, the Congolese transmission system has been connected to the DRC's HV network by a 220 kV line crossing the Congo river. Though the technical power limitation of the Mbuono transformer substation, located near Brazzaville, is about 100 MW, the contractual (but often exceeded) limitation is 60 MVA, corresponding to some 50 MW. This interconnection allows Congo to import electricity from the huge Inga hydro plant, and also greatly contributes to improving the stability of the Congolese network.

System Operation

3.19 The total energy supplied by the interconnected system in 1997 amounted to 431 GWh, plus 114 GWh supplied by Inga. Brazzaville typically accounts for about 55-60 percent of the total, and Pointe-Noire for percent, the balance corresponding to the smaller towns located alongside the interconnection. The peak power demand is about 90 MW, while local peaks in Brazzaville and Pointe-Noire for the same year reach 45-50 MW and 25-30 MW, respectively.

3.20 For the last ten years, the interconnected system has been supplied almost exclusively from hydro sources. Thermal units, which used to supply Pointe-Noire before the city was connected to Loudima and Moukoukoulou in 1982, are operated only as backup units, and generate no more than 2 to 3 GWh per year. Domestic hydro generation has increased regularly from 1978 (commissioning of Moukoukoulou) to 1990. Since then, the unavailability of Djoué until 1997, and restrictions to the transit capacity of the interconnection due to transformer problems have caused domestic hydro generation to significantly decrease and, consequently, has led to a strong increase of imports from the DRC.

3.21 Energy supply from the DRC to Congo is ruled by a contract signed in 1981, when the decision was taken to build the 220 kV interconnection power line. The minimum (take-or-pay) purchase is 45 GWh per year, and energy is guaranteed up to 130 GWh per year. Additional quantities of energy may be supplied, by mutual agreement, which was the case in several occasions since 1991. The purchase price is decreasing as imported quantity increases, and it is indexed on the SDR. There is no fixed charge. In the mid-nineties, the maximum price (for the first block of 45 GWh) was about 17 FCFA/kWh, and the minimum price (for quantities above 130 GWh) was 12.5 FCFA/kWh, leading an average price of FCFA 14.6/kWh (about USD 0.026/kWh).

3.22 In spite of the recent unavailabilty of the Djoué plant, the regularity of supply to Brazzaville, at the HV level, has been fairly good in the past few years, due to the absence of problems on the interconnection line with the DRC. The situation is worse in Pointe Noire, due to its full dependence on the single transmission line crossing the country from Brazzaville to Loudima and Pointe-Noire. This 220 kV line, which is long and loaded only at both ends, also crosses the dense Mayombe forest (causing an important capacitance effect). As a consequence, and in spite of the existing reactive power compensation reactances in Pointe Noire and Mindouli, the system remains rather unstable, both in voltage and in frequency. In addition, the regularity of supply has also been jeopardized since 1990 by important technical damages that have occurred on the two main

substations of Loudima and Mindouli. These damages have affected the power transit from Moukoukoulou to the consuming areas and especially to Pointe-Noire.

Supply / Demand Gap

3.23 Two 5-step approximations of the load duration curves have been elaborated for the present study, respectively for the dry season (from July to October, Fig. 3.5) and for the wet season (from November to June, Fig. 3.6). Their shapes are quite similar, but the peak level is 10 percent lower for the dry season. The presented curves correspond to a constant annual load factor of 64.3 percent or 5,630 hours of average utilization. These curves have been built on the basis of graphical load curves, since no detailed load figures have been made available to the mission. Therefore, they are nothing more than very rough approximations, probably acceptable for this first analysis but which would require a more thorough calculation for later study stages.

Figure 3.5: Dry season load curve (Jul-Oct)

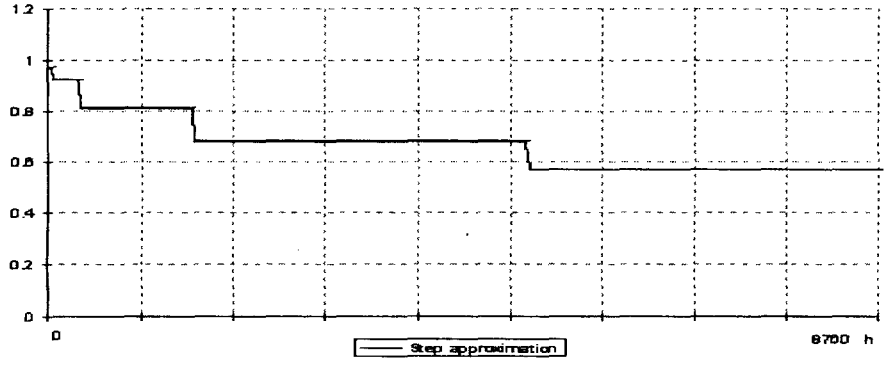
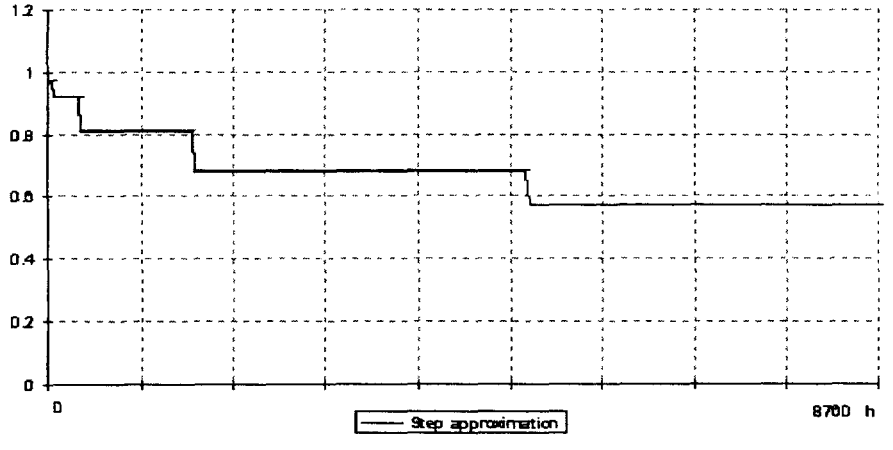


Figure 3.6: Wet season load curve (Nov-Jun)



3.24 SNE load forecast is detailed in a document called "Etude Prévisionnelle de la Charge et de la Demande du Réseau de Transport Interconnecté". Separate forecasts are presented for the main cities supplied (Brazzaville, Pointe-Noire, Bouenza-Niari and

Moukoukoulou). No information is given, however, on how these projections have been established. The forecasted energy demand for the year 2000 is 585 GWh, corresponding to an average demand growth of 3.3 percent per year. Many factors plead for such moderate growth forecasts, among which:

- the low general economic conjuncture and prospects, especially in the industrial sector;
- the drastic decrease of the average purchasing power, resulting e.g. from the CFA devaluation and from the very irregular payment of salaries to the public sector employees;
- the reduction in the ambition and means devoted to expansion of the interconnected network; this clearly appeared in the "Priority Government Program" which gives the priority to local micro-hydraulic developments for rural electrification.

3.25 Therefore, in the present context, the SNE forecasts seem realistic and may serve as a basis for the present calculations, at least for the period up to the year 2000. After that, the impact of the above mentioned adverse factors is assumed to be somewhat reduced, and a uniform growth rate of 5 percent per year will then be adopted. The resulting forecast up to 2015 is detailed in Table 3.1 and Fig. 3.7 and 3.8 (historical figures are also presented for comparison purposes). Assuming a uniform growth for the different zones and cities, the total peak of 146 MW in the year 2005 would correspond to a peak power requirement of some 44 MW for Pointe Noire at that time. Actual demand could be a even larger if independent self-producers, who have shifted to self-generation over time due to the lack of reliability of SNE, would join the interconnected network once the network is back to normal operation. Although no reliable data exist on self generating capacity, it is estimated that it could represent about 30 percent of the network capacity, in particular in the Pointe Noire area. Capacity requirements in Pointe Noire would then be close to 60 MW in 2005.

Table 3.1: Power and Energy Demand Forecasts

	Total Energy Demand (GWh)	*Energy to be Produced (GWh)*	*Annual Utilization (h)*	*Peak (MW)*	*Annual Energy Growth Rate (%)*
1980	157	161			
1981	177	177			12.3%
1982	215	221			21.3%
1983	287	288			33.9%
1984	329	333			14.5%
1985	350	377			6.3%
1986	367	398			5.0%
1987	407	429			10.9%
1988	432	441			6.1%
1989	419	461			-3.1%
1990	425	507			1.7%
1991	460	537			8.2%
1992	483	533	5878	91	4.9%
1993	482	521	5902	88	-0.1%
1994	479	501	5516	91	-0.7%
1995	498	548	5632	97	4.0%
1996	514	566	5632	100	3.3%
1997	531	584	5632	104	3.3%
1998	549	604	5632	107	3.3%
1999	567	623	5632	111	3.3%
2000	585	644	5632	114	3.3%
2001	615	676	5632	120	5.0%
2002	645	710	5632	126	5.0%
2003	678	745	5632	132	5.0%
2004	711	783	5632	139	5.0%
2005	747	822	5632	146	5.0%
2006	784	863	5632	153	5.0%
2007	824	906	5632	161	5.0%
2008	865	951	5632	169	5.0%
2009	908	999	5632	177	5.0%
2010	953	1049	5632	186	5.0%
2011	1001	1101	5632	196	5.0%
2012	1051	1156	5632	205	5.0%
2013	1104	1214	5632	216	5.0%
2014	1159	1275	5632	226	5.0%
2015	1217	1338	5632	238	5.0%

Figure 3.7: Historical and forecasted energy demand (interconnected system)

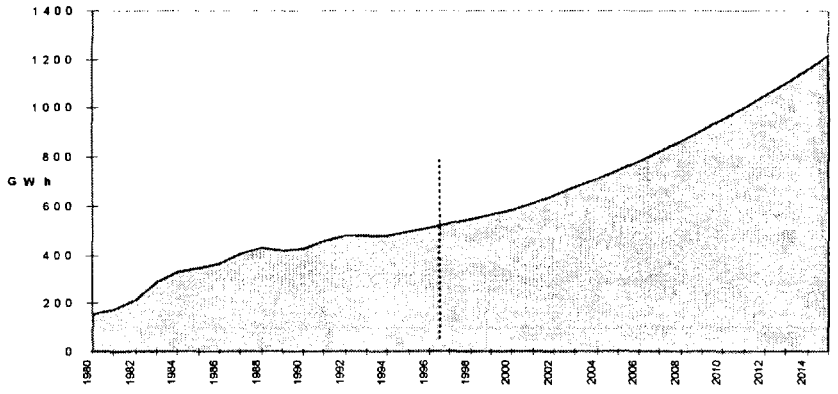
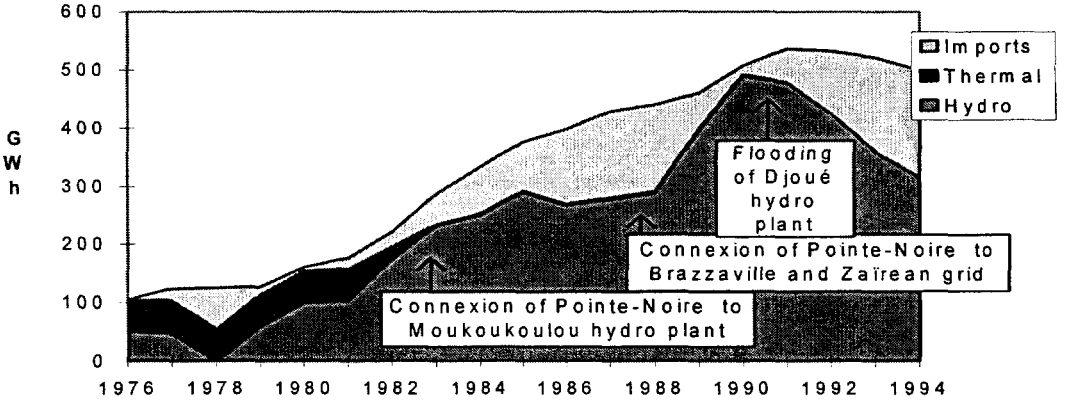


Figure 3.8: Electricity Supply in Congo: Historical Breakdown



Network Rehabilitation

3.26 Rehabilitation works are required for both generation and transmission facilities. After being flooded in 1991, the Djoué hydro plant was the object of major repairs, the cost of which is estimated at 418 million FCFA, and was back to operation in 1997. In Pointe Noire, 5 out of the 7 diesel units are out of order. The four oldest ones (AGO type, 6 MW on the whole) could technically be repaired, but considering they are almost 30 years old, they are considered as obsolete for the present study. The fifth one (12PC type, 4 MW) is assumed to be repaired for a remaining lifetime of 10 years. The two operational units are integrated in the present study with a remaining lifetime of 10 years for the other 12PC type and 15 years for the Sulzer unit. Concerning the transmission network, the defective transformers at the Mindouli and Loudima substations are considered to be back in operation, and 20 MVAR of additional reactances installed to improve the network stability.

3.27 The existing 15 MW Djoué hydro plant is in fact only the first phase of the initial project that was designed for a total 30 MW installed capacity. The project still exists of completing the plant (Djoué 2nd phase). The average annual energy, however, would not be doubled but only increased by 73 percent, from 120 GWh to 208 GWh. The estimated investment cost is 58 million USD, i.e. almost 4,000 USD per kW, which appears quite expensive at first glance. Data on this and other considered hydroelectric projects may be found in Table 3.2 hereunder.

Table 3.2: Considered Hydroelectric Projects

	Sounda	*Djoué 2*	*Imboulou*
Type	Reservoir	Reservoir	Reservoir
River	Kouilou	Djoué	Léfini
Installed Power (MW)	160	15	100
Firm Power in dry season (MW)	128	12	80
Min. Power in extra-dry season (MW)	107	12	75
Availability (%)	82	82	82
Average Energy (GWh)	700	88	645
Estimated Investment Cost (MUSD)	230	58	200
Cost per kW (USD)	1438	3867	2000

Note: Investment costs are given without interests during construction.

Options for Power Generation

Hydro

3.28 The hydroelectric project of Sounda, about 140 km northeast of Pointe-Noire, on the Kouilou river, had been identified and studied decades ago, before independence, and was initially designed to supply a huge aluminum factory. It has been included for several years in the Priority Government Program. The ultimate potential is about 1,000 MW, to be developed in several stages. After a modest first stage, the second stage reportedly under construction consists in installing 3 units, for a total power of 240 MW. The site of Sounda presents many interesting characteristics, such as its physical configuration resulting in moderate civil works costs, the low seasonal variations of the Kouilou river, and the geographical location - not very far from Pointe-Noire - allowing a better distribution of supply sources along the network. In the present study, Sounda is considered completed in the year 2002, under its 160 MW (2 turbines) configuration. In that case, the annual energy output would be 700 GWh. The investment cost is estimated at 230 million USD, i.e. 1,440 USD/kW.

3.29 In order to improve the seasonal regularity of power and energy availability at Moukoukoulou, a new upstream reservoir dam could be built to assure the regulation of the Bouenza river basin. No new generation capacity would be installed but, according to the studies that have been made, the Moukoukoulou plant's firm power would increase

from 29 to 66 MW and its average energy output from 430 to 520 GWh/year. The cost of the dam is estimated to 80 million USD, i.e. about 2,200 USD per additional kW made available during the dry season.

3.30 The Imboulou hydro site is located on the Léfini river, about 150 km northeast of Brazzaville. The proposed power plant would comprise 4 units, for a total installed power of 100 MW. The firm power in a dry year would be 75 MW, and the average energy output would amount 645 GWh per year. The estimated investment cost is 200 million USD, i.e. 2,000 USD/kW. In addition, the cost of a 220 kV transmission line from Imboulou to Brazzaville has to be added up to that amount. Some other hydroelectric projects have been identified but do not seem to be given a high degree of priority by the Congolese authorities: these projects, such as Foulakary or Louessé, have not been explicitely taken into consideration for the calculations described below.

Thermal

3.31 Among the possible future generation options, several typical thermal units have been considered (Table 3.3): 50 or 100 MW conventional gas turbines, either gas oil- or natural gas-fired, and 150 MW combined-cycle units. Gas-fired units are assumed to be located in the Pointe-Noire region. As mentioned previously, the a priori economic cost of natural gas has been taken as 1.50 USD/GJ. Assuming the Pointe Noire refinery will remain in the foreseeable future in a position of net gas oil exporter, the economic opportunity cost of gas oil has been estimated considering that the alternative use is a local exportation to neighboring Central African countries. The calculation detailed on Table 3.4 shows that gas oil should be exported at 209 USD/t (FOB Pointe-Noire) to compete on the African market with imports from Europe. Adding internal transport and distribution costs (or margins), it gives an economic cost of 302 USD/t CIF in Pointe-Noire, or 7.10 USD/GJ.

3.32 The last supply option is the one that has been adopted, willy-nilly, during the last few years: increasing imports from neighboring DRC. From a strict economical point of view, it is clearly a low-cost solution under the present contract terms, and the arrangement appears as beneficial for both parties. However, the level of dependence on imported energy must be kept within reasonable limits if Congo wants to avoid losing all strategic control upon this key sector. In addition, some doubts now arise regarding the technical ability of the DRC's utility to fully guarantee the security of supply, taking into account the reported silting problems at Inga and lack of maintenance. The present study has adopted as basic assumption that imports from DRC will continue on the same basis as observed in the past few years, i.e. with a power limitation of 50 MW, but without limitation on energy other than technical availability. But the possibility - and economic consequences - of increasing or, on the contrary, stopping all imports and relying only on national supply sources will also be discussed.

Table 3.3: Technical data and assumptions on existing and (considered) future thermal plants

Unit	*Fuel type*	*Commis-sioning Year*	*Assumed Decommiss. Year (or expected lifetime)*	*Installed Power (MW)*	*Net Efficiency (%)*	*Specific Consump-tion (kg/kWh)*	*Lubricant Consumptio n (kg/kWh)*	*Equiv. Energy Consumption (MJ/kWh)*	*Variable Maintenance Cost (USD/MWh)*	*Total Variable Cost (USD/M Wh)*	*Availability (%)*
1. Existing:											
Pointe-Noire AGO	Diesel Oil	1979	2010	6.4	28.2%	0.3	0.01	15.15	10.00	117.47	70
Pointe-Noire 12PC	Diesel Oil	n.a.	2000	8.5	28.2%	0.3	0.01	15.15	10.00	117.47	75
Pointe-Noire Sulzer	Diesel Oil	n.a.	2010	4.2	30.3%	0.28	0.005	13.10	10.00	102.94	75
2. Future single-cycle gas turbines:											
TGGO50	Diesel Oil		20	50	31.3%	0.27	0.002	11.98	8.00	93.01	82
TGGN50	Natural Gas		20	50	31.3%		0.002	11.98	8.00	25.97	82
TGGO100	Diesel Oil		20	100	32.7%	0.26	0.002	11.49	8.00	89.52	82
TGGN100	Natural Gas		20	100	32.7%		0.002	11.49	8.00	25.23	82
3. Future combined-cycle units:											
CCGN	Natural Gas		20	150	46.5%		0.002	8.22	8.00	20.33	82

Table 3.4: Fuel Cost Assumptions (Taxes and Duties excluded)

		USD/bbl	*USD/ton*	*FCFA/l*	*USD/GJ*
Exchange Rate FCFA/USD	500				
Gasoil Density	0.86				
Gasoil L.H.V. (MJ/kg)	42.5				
Crude OPEC Basket FOB		**21**			
Gasoil FOB Rotterdam		26.88	194		
Europe-Africa Freight Cost			30		
Selling Price on the African Market			224		
Regional Freight Cost			15		
Gasoil FOB Export Pointe-Noire			209	89.7	
Int. Margins Gasoil				40.0	
Gasoil CIF Pointe-Noire			302	**129.7**	**7.10**
Natural Gas (a priori assumption)					**1.50**
Lubricants			1700		

3.33 On the basis of those investment options; many development scenarios may be imagined and a large number of them have been tested. Eight of them, assuming an unchanged import capacity of 50 MW, are presented here, chosen for being the most representative and/or economically attractive ones. They may be ranked in four categories; pure hydro, mixed hydro/thermal (gas oil-fired), pure thermal (gas oil-fired) and pure thermal (natural gas-fired). They are presented hereunder.

Scenarios without Gas Supply

3.34 A first pure hydro development program, defined as **Scenario 1**, is based on the Sounda plant which, under the adopted load growth assumption, becomes necessary to the system in the year 2002 and is expected to be completed by that time. Even considering its smaller configuration (160 MW), it is still sufficient to meet the demand over the entire study horizon, without any other production investment. As shown in Table 3.5 and on the associated chart, most generation is then hydro-based and the annual operating cost, calculated by the model, is limited to the cost of importing energy before 2002 and at the very end of the period. However, the investment cost is rather high, and the resulting total discounted cost, calculated with a 10 % discount rate, amounts to 116 million USD for this scenario.

3.35 **Scenario 2** combines the Bouenza regulation dam, in 2002, and the hydroelectric dam at Imboulou in 2006. The total investment cost is significantly higher than in the first scenario, but the largest part of it (Imboulou plant and transmission line) is

delayed by 4 years. As a consequence, the total discounted cost is slightly lower (113 million USD) in spite of increased imports between 2002 and 2006 (see Table 3.6).

3.36 The third hydro program, **Scenario 3**, is designed in such a way that the smallest investment (Djoué 2) comes first, in 2002, followed by the Bouenza regulation dam in 2006 and, finally, Imboulou in 2008. As a result (see Table 3.7), energy imports play an important role up to the year 2007, but the total discounted cost of this -Scenario is the lowest among pure hydro programmes (112 million USD); these differences, however, do not appear as very significant.

3.37 Considering the negative economic impact of large-size hydro facilities such as Sounda or Imboulou, it may be of interest to combine smaller-scale facilities, such as Djoué 2 or the Bouenza regulation dam, with thermal units (gas oil-fired gas turbines). Two scenarios have been built on that basis; **Scenario 4** combines the Bouenza regulation in 2002 and two 50 MW gas turbines, respectively in 2006 and 2012. Table 3.8 shows the drastic change in the cost structure, with important savings in investment costs, partly offset by the strong increase in operating costs. The total discounted cost, however, remains significantly lower than for pure hydro scenarios: 99 million USD. At the end of the study period, imports and thermal generation together cover more than half of the total supply. The second combined hydro-thermal investment program, **Scenario 5**, includes one more hydro scheme, the second stage of Djoué, in 2002, thus allowing to delay the Bouenza regulation dam and the two gas turbines. As shown in Table 3.9, the total economic cost is slightly reduced, to 98 million USD.

3.38 If only thermal options are considered, and still assuming the non-availability of natural gas, the least-cost option is defined as **Scenario 6**, and described in Table 3.10. It comprises three 50-MW gas oil-fired gas turbines to be put on stream in 2002, 2009 and 2014. In spite of the high cost of gas oil and, consequently, the high operating costs of the system, this scenario offers the best economic result, with a total discounted cost of 89 million USD. A variant of this scenario, with one 50 MW turbine in 2002 and one 100 MW turbine in 2009, gives almost the same result (90 million USD). That means that the lower investment cost and the improved efficiency of the 100 MW units are completely offset by the effect of investment anticipation.

Scenarios With Natural Gas

3.39 If natural gas is made available in the region of Pointe-Noire at a moderate economic cost, three additional investment options are taken into consideration: 50 or 100 MW open cycle gas turbines, and 3 x 50 MW combined-cycle units. **Scenario 7** (see Table 3.11) presents an investment program made of three 50-MW gas turbines, commissioned in 2002, 2009 and 2014. The investment cost is slightly higher than in scenario 6, due to the assumed 5 % additional cost for dual-fuel capability, but the operating costs are dramatically lowered. The total discounted cost is as low as 66 million USD, thus 23 million USD below the similar but gas oil-based scenario 6. Here again, the option with only one 50 MW unit followed by one 100 MW unit leads to a similar, but slightly worse, economic result: 67 million USD.

3.40 The variable cost of gas-fired gas turbines is, under the present cost assumptions, just below the cost of imported energy. As a result, these turbines operate in medium- or full-base load, as shown by their average operating times which are generally above 5,000 hours per year. Imports only covers peak load periods, especially during the dry season. The natural gas consumption buildup is therefore rather fast, reaching 100 mmcm in 2007 (5 years after commissioning of the first gas unit), and almost 250 mmcm at the end of the study period. It is to be noted that this result is very sensitive to the economic cost of natural gas. It has been obtained assuming that cost to be 1.5 USD/GJ, but if it is raised to 2 USD or above, imports become the cheapest energy source on a variable basis, after hydro of course. In that case, the operating time of gas turbines dramatically decreases to the same level as that of scenario 6, i.e. below 1,500 hours per year on the average. On the other hand, the sensitivity of the total discounted cost to the cost of gas is very moderate.

3.41 The netback value of gas, or average incremental benefit is defined as the total discounted benefit resulting from the use of gas -assuming a nil cost for gas - divided by the discounted quantity of gas consumed over the period. In the present case, since an a priori cost of 1.5 USD/GJ had been assumed for natural gas in all scenarios, this 1.5 USD has to be summed up with the result of the above calculation. The resulting netback value of gas in the present scenario is 2.96 USD/GJ.

3.42 **Scenario 8** studies the case of the progressive setting up of a 150 MW combined cycle unit. Two 50 MW gas turbines are installed in 2002 and 2009, and a 50 MW heat recovery steam boiler in 2012. This solution is characterized by its excellent thermal efficiency; however, this advantage becomes effective only when the cycle is completed, in 2012. Therefore, the gain in operating cost is not sufficient to compensate the higher investment cost, and the resulting discounted cost is 67 million USD, or 0.8 million USD above the cost of scenario 7, which definitely appears as the least-cost solution. However, the combined-cycle option should be further studied, as it seems probable that smaller-scale units, say 100 MW for the whole combined-cycle plant, could be built within a shorter time and give better economic results in the Congolese context.

3.43 As a consequence of its better efficiency, the combined-cycle option results in lower gas consumption levels after 2012 (see Table 3.12), and also in a higher netback value of gas (3.06 USD/GJ) since almost the same economic benefit is obtained with a lower gas consumption., electricity imports in 2015 would account for more than 52 % of the total supply. Howev

3.44 As already mentioned, the cheapest solution for future electricity supply is importing energy from DRC at unchanged prices. This is illustrated by **Scenarios 9 and 10**, combining an increased import capacity (up to 100 MW, no energy limitation) and, respectively, gas oil or natural gas-fired gas turbines. The resulting discounted costs are of course very low (53 and 52 million USD, see tables 3.21 and 3.22). The economic benefit of the introduction of natural gas is also much lower in this case, because gas-based electricity mainly substitutes imports (whose variable cost is only slightly higher) instead

of gas oil-based electricity. Consequently, the netback value of gas is also on the low side, at 1.72 USD/GJ.

3.45 These latter alternatives may not seem very advisable, for the reasons already explained, and considering that, in scenario 9 for instance er, these calculations are interesting as they may help estimate the cost, for Congo, of maintaining a sufficient level of self-sufficiency in its power supply. If no gas is available, limiting imports to 50 MW will cost some 36 million USD to the national economy (scenario 9 vs. scenario 6). If gas is available under economic conditions, that cost increase will be limited to about 13 million USD.

3.46 Conversely, what would it cost to Congo to decide stopping the imports as soon as possible? If no natural gas is available, the cost of a gas oil-based development plan would become extremely high, above that of full-hydro scenarios; but a similar plan based on 4 x 50 MW natural gas units (**Scenario 11**) would result in a total discounted cost of 87 million USD (see Table 3.15) which is still below the least-cost option without gas. Moreover, the combined-cycle option (**Scenario 12**) then becomes the least expensive (see Table 3.16), with a total cost of 87 million USD. In other words, a natural gas-based development plan would make it possible to do without energy imports, at no cost, and even with a small benefit. The netback value of gas, compared to the situation with imports, would then be 1.60 USD/GJ (open-cycle gas turbines) or 1.65 USD/GJ (combined-cycle units).

Table 3.5: Economic Calculation Sheet - Scenario 1

Country: Congo

Scenario: Sounda in 2002

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
GT Inv.cost: USD/kW
CC Inv.cost: USD/kW

	Generation Investments Sounda	*Transmission Investments*	*Operating Cost*	*Total*	*Natural Gas Consumption (Mm3/y)*	*Natural Gas Consumption (Million GJ/y)*	*TG50 GWH*	*TG100 GWH*	*CC GWH*	*Tot. gaz*	*Hydro*	*Diesel*	*Import*
Inv. Cost	*230*												
1995				**0.0**									
1996			1.5	**1.5**	0						502		59
1997			1.8	**1.8**	0						517		67
1998			2.0	**2.0**	0						526		75
1999	34.5		2.2	**36.7**	0						538		85
2000	57.5		2.7	**60.2**	0						538		102
2001	115.0		3.7	**118.7**	0						538	2	135
2002	**23.0**		0.0	**23.0**	0						707		
2003			0.0	**0.0**	0						742		
2004			0.0	**0.0**	0						780		
2005			0.0	**0.0**	0						820		
2006			0.0	**0.0**	0						859		
2007			0.0	**0.0**	0						904		
2008			0.0	**0.0**	0						949		
2009			0.0	**0.0**	0						994		
2010			0.0	**0.0**	0						1044		
2011			0.0	**0.0**	0						1095		
2012			0.0	**0.0**	0						1151		1
2013			0.1	**0.1**	0						1211		2
2014			0.8	**0.8**	0						1238		31
2015			2.6	**2.6**	0						1238		98
Res.Value	*-138*			***-138***									

Total Discounted Cost: **115.9** MUSD
Average Netback Value Of Gas: *#Div/0!* USD/GJ

Table 3.6: Economic Calculation Sheet - Scenario 2

Country: Congo

Scenario: Bouenza Regulation in 2002
Imboulou in 2006

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
GT Inv.cost: USD/kW
CC Inv.cost: USD/kW

	Generation Investments		*Transmission Investments*		*Operating Cost*	*Total*	*Natural Gas Consumption (Mm3/y)*	*Natural Gas Consumption (Million GJ/y)*	*TG50 GWH*	*TG100 GWH*	*CC GWH*	*Tot. gaz*	*Hydro*	*Diesel*	*Import*
	Bouenza Regulation Dam	*Imboulou*	*150 km HV line Imboulou-Brazzaville*												
Inv. Cost	*80*	*200*	*22.5*												
1995						**0.0**									
1996					1.5	**1.5**	0						502		59
1997					1.8	**1.8**	0						517		67
1998					2.0	**2.0**	0						526		75
1999	12.0				2.2	**14.2**	0						538		85
2000	20.0				2.7	**22.7**	0						538		102
2001	40.0				3.7	**43.7**	0						538	2	135
2002	**8.0**				2.1	**10.1**	0						628		80
2003		30.0			2.9	**32.9**	0						628		113
2004		50.0			4.0	**54.0**	0						628		153
2005		100.0			5.0	**105.0**	0						628		191
2006		**20.0**	**22.5**		0.0	**42.5**	0						859		
2007					0.0	**0.0**	0						904		
2008					0.0	**0.0**	0						949		
2009					0.0	**0.0**	0						994		
2010					0.0	**0.0**	0						1044		
2011					0.0	**0.0**	0						1094		1
2012					0.1	**0.1**	0						1147		4
2013					0.2	**0.2**	0						1205		8
2014					0.4	**0.4**	0						1255		16
2015					1.7	**1.7**	0						1273		63
Res.Value	*-48*	*-143*	*-14*			***-204***									

Total Discounted Cost: **113.1** MUSD
Average Netback Value Of Gas: *#DIV/0!* USD/GJ

Table 3.7: Economic Calculation Sheet - Scenario 3

Country: Congo

Scenario: Djoue 2 in 2002
Bouenza Regulation in 2008
Imboulou in 2009

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
GT Inv.cost: USD/kW
CC Inv.cost: USD/kW

	Generation Investments			*Transmission Investments*	*Operating Cost*	*Total*	*Natural Gas Consumption (Mm3/y)*	*Natural Gas Consumption (Million GJ/y)*	*TG50 GWH*	*TG100 GWH*	*CC GWH*	*Tot. gaz*	*Hydro*	*Diesel*	*Impor*
	Djoue Second Stage	*Bouenza Regulation Dam*	*Imboulou*	*150 km HV line Imboulou-Brazzaville*											
Inv. Cost	*58*	*80*	*200*	*22.5*											
1995						**0.0**									
1996					1.5	**1.5**	0						502		59
1997					1.8	**1.8**	0						517		67
1998					2.0	**2.0**	0						526		75
1999					2.2	**2.2**	0						538		85
2000	23.2				2.7	**25.9**	0						538		102
2001	29.0				3.7	**32.7**	0						538	2	135
2002	**5.8**				2.2	**8.0**	0						626		81
2003		12.0			3.1	**15.1**	0						626		114
2004		20.0			4.4	**24.4**	0						626	2	153
2005		40.0	30.0		6.2	**76.2**	0						628	3	190
2006		**8.0**	50.0		3.7	**61.7**	0						716		143
2007			100.0		5.1	**105.1**	0						716		188
2008			**20.0**	**22.5**	0.0	**42.5**	0						949		
2009					0.0	**0.0**	0						995		
2010					0.0	**0.0**	0						1044		
2011					0.0	**0.0**	0						1095		
2012					0.0	**0.0**	0						1150		
2013					0.1	**0.1**	0						1205		3
2014					0.2	**0.2**	0						1264		6
2015					0.3	**0.3**	0						1325		11
Res.Value	*-35*	*-57*	*-154*	*-15*		*-262*									

Total Discounted Cost: **112.2** MUSD
Average Netback Value Of Gas: *#DIV/0!* USD/GJ

Table 3.8: Economic Calculation Sheet - Scenario 4

Country: Congo

Scenario: Bouenza Regulation in 2002
2 x 50 MW GO.GT

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
GT Inv.cost: 543 USD/kW
CC Inv.cost: USD/kW

	Generation Investments			*Transmission Investments*	*Operating Cost*	*Total*	*Natural Gas Consumption (Mm3/y)*	*G.T. Aver. Oper. Time (h)*	*Natural Gas Consumption (Million GJ/y)*	*TG50 GWH*	*TG100 GWH*	*CC GWH*	*Tot. gaz*	*Hydro*	*Diesel*	*Impo*
	Bouenza Regulation Dam	*50 MW GT*	*50 MW GT*													
Inv. Cost	*80*	*27.2*	*27.2*													
1995						**0.0**										
1996					1.5	**1.5**	0							502		59
1997					1.8	**1.8**	0							517		67
1998					2.0	**2.0**	0							526		75
1999	12.0				2.2	**14.2**	0							538		85
2000	20.0				2.7	**22.7**	0							538		10
2001	40.0				3.7	**43.7**	0							538	2	13
2002	**8.0**				2.1	**10.1**	0							628		80
2003					2.9	**2.9**	0							628		11
2004		4.1			4.0	**8.0**	0							628		15
2005		13.6			5.0	**18.6**	0							628		19
2006		**9.5**			6.2	**15.7**	0	40		2				628		22
2007					7.5	**7.5**	0	80		4				628		27
2008					8.9	**8.9**	0	180		9				628		31
2009					10.6	**10.6**	0	340		17				628		34
2010			4.1		15.3	**19.3**	0	1320		66				628		35
2011			13.6		20.6	**34.1**	0	2320		116				628		35
2012			**9.5**		25.2	**34.7**	0	1730		173				628		35
2013					30.9	**30.9**	0	2350		235				628		35
2014					36.2	**36.2**	0	2910		291				628		35
2015					42.6	**42.6**	0	3580		358				628		35
Res. Value	*-48*	*-14*	*-22*			***-83***										

Total Discounted Cost: **98.8** MUSD
Average Netback Value Of Gas: *#DIV/0!* USD/GJ

Table 3.9: Economic Calculation Sheet - Scenario 5

Country: Congo

Scenario: Djoue 2 in 2002
Bouenza Regulation in 2008
2 x 50 MW GO.GT

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
GT Inv.cost: 543 USD/kW
CC Inv.cost: USD/kW

	Generation Investments				*Operating Cost*	*Total*	*Natural Gas Consumption (Mm3/y)*	*G.T. Aver. Oper. Time (h)*	*Natural Gas Consumption (Million GJ/y)*	*TG50 GWH*	*TG100 GWH*	*CC GWH*	*Tot.gaz*	*Hydro*	*Diesel*	*Im*
	Djoue Second Stage	*Bouenza Regulation Dam*	*50 MW GT*	*50 MW GT*												
Inv. Cost	*58*	*80*	*27.2*	*27.2*												
1995						**0.0**										
1996					1.5	**1.5**	0							502		
1997					1.8	**1.8**	0							517		
1998					2.0	**2.0**	0							526		
1999					2.2	**2.2**	0							538		
2000	23.2				2.7	**25.9**	0							538		
2001	29.0				3.7	**32.7**	0							538	2	
2002	**5.8**				2.2	**8.0**	0							626		
2003		12.0			3.1	**15.1**	0							626		
2004		20.0			4.4	**24.4**	0							626	2	
2005		40.0			6.2	**46.2**	0							628	3	
2006		**8.0**			3.7	**11.7**	0							716		
2007			4.1		5.1	**9.1**	0							716		
2008			13.6		7.4	**21.0**	0							716	1	
2009			**9.5**		7.5	**17.1**	0	100		5				716		
2010				4.1	9.2	**13.2**	0	180		9				716		
2011				13.6	11.8	**25.4**	0	580		29				716		
2012				**9.5**	17.0	**26.5**	0	850		85				716		
2013					22.7	**22.7**	0	1470		147				716		
2014					28.0	**28.0**	0	2030		203				716		
2015					34.2	**34.2**	0	2700		270				716		
Res.Value	*-35*	*-57*	*-18*	*-22*		***-131***										

Total Discounted Cost: **97.5** MUSD
Average Netback Value Of Gas: *#DIV/0!* USD/GJ

Table 3.10: Economic Calculation Sheet - Scenario 6

Country: Congo

Scenario: 50 MW GO.GT in 2002
100 MW GO.GT in 2009

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
50 MW GT Inv.cost: 543 USD/kW
100 MW GT Inv.cost: 421 USD/kW

	Generation Investments			*Operating Cost*	*Total*	*Natural Gas Consumption (Mm3/y)*	*Natural Gas Consumption (Million GJ/y)*	*TG50 GWH*	*TG100 GWH*	*CC GWH*	*Tot.gaz*	*Hydro*	*Diesel*	*In*
	50 MW GT	*100 MW GT*												
Inv. Cost	*27.2*	*42.1*												
1995					**0.0**									
1996				1.5	**1.5**	0						502		
1997				1.8	**1.8**	0						517		
1998				2.0	**2.0**	0						526		
1999				2.2	**2.2**	0						538		
2000	4.1			2.7	**6.8**	0						538		
2001	13.6			3.7	**17.3**	0						538	2	
2002	**9.5**			4.6	**14.1**	0		2				538		
2003				5.6	**5.6**	0		5				538		
2004				6.8	**6.8**	0		8				538		
2005				8.1	**8.1**	0		11				538		
2006				9.7	**9.7**	0		21				538		
2007		6.3		11.6	**17.9**	0		31				538		
2008		21.1		15.0	**36.0**	0		60				538		
2009		**14.7**		18.6	**33.3**	0		106				538		
2010				23.1	**23.1**	0		156				538		
2011				27.6	**27.6**	0		207				538		
2012				32.6	**32.6**	0		263				538		
2013				38.2	**38.2**	0		324				538		
2014				43.2	**43.2**	0		381				538		
2015				49.2	**49.2**	0		448				538		
Res. Value	*-8*	*-27*			*-36*									

Total Discounted Cost: **89.5** MUSD
Average Netback Value Of Gas: *#DIV/0!* USD/GJ

Table 3.11: Economic Calculation Sheet - Scenario 7

Country: Congo

Scenario: 50 MW NG.GT in 2002
100 MW NG.GT in 2009

Monetary Unit: MUSD
Discount Rate: 10%

Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ

50 MW GT Inv.cost: 570 USD/kW
100 MW GT Inv.cost: 442 USD/kW

	Generation Investments		Operating	Total	Natural Gas	Natural Gas	TG50	TG100	CC	Tot.gaz	Hydro	Diesel
	50 MW GT	*100 MW GT*	*Cost*		*Consumption (Mm3/y)*	*Consumption (Million GJ/y)*	*GWH*	*GWH*	*GWH*			
Inv. Cost	*28.5*	*44.2*										
1995				**0.0**		0.0						
1996			1.5	**1.5**	0	0.0				0	502	
1997			1.8	**1.8**	0	0.0				0	517	
1998			2.0	**2.0**	0	0.0				0	526	
1999			2.2	**2.2**	0	0.0				0	538	
2000	4.3		2.7	**7.0**	0	0.0				0	538	
2001	14.3		3.7	**18.0**	0	0.0				0	538	2
2002	**10.0**		4.4	**14.4**	51	1.9	165			165	538	
2003			5.3	**5.3**	61	2.3	196			196	538	
2004			6.3	**6.3**	72	2.7	231			231	538	
2005			7.3	**7.3**	81	3.0	261			261	538	
2006			8.3	**8.3**	90	3.3	291			291	538	
2007		6.6	9.5	**16.2**	101	3.7	324			324	538	
2008		22.1	10.9	**33.0**	109	4.0	352			352	538	
2009		**15.5**	11.5	**27.0**	136	5.0	2	454		456	538	
2010			12.8	**12.8**	151	5.6	5	501		506	538	
2011			14.1	**14.1**	166	6.1	11	547		558	538	
2012			15.5	**15.5**	183	6.8	17	596		613	538	
2013			17.1	**17.1**	201	7.4	28	647		675	538	
2014			18.5	**18.5**	218	8.1	47	683		730	538	
2015			20.2	**20.2**	237	8.8	76	718		794	538	
Res. Value	*-9*	*-29*		*-37*								

Total Discounted Cost: **67.0** MUSD

Reference Discounted Cost: *89.3* *MUSD*

Average Netback Value Of Gas: **2.93** USD/GJ

Table 3.12: Economic Calculation Sheet - Scenario 8

Country: Congo

Scenario: 50 MW NG.GT in 2002
50 MW NG.GT in 2009
50 MW NG.ST (CC) in 2012

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
50 MW GT Inv.cost: 570 USD/kW
CC Inv.cost: 711 USD/kW

	Generation Investments			*Operating*	*Total*	*Natural Gas*	*G.T.*	*Natural Gas*	*TG50*	*TG100*	*CC*	*Tot.gaz*	*Hydro*	*Diesel*	*I*
	50 MW GT	*50 MW GT*	*50 MW ST*	*Cost*		*Consumption (Mm3/y)*	*Aver. Oper. Time (h)*	*Consumption (Million GJ/y)*	*GWH*	*GWH*	*GWH*				
Inv. Cost	*28.5*	*28.5*	*49.7*												
1995					**0.0**			0.0							
1996				1.5	**1.5**	0		0.0				0	502		
1997				1.8	**1.8**	0		0.0				0	517		
1998				2.0	**2.0**	0		0.0				0	526		
1999				2.2	**2.2**	0		0.0				0	538		
2000	4.3			2.7	**7.0**	0		0.0				0	538		
2001	14.3			3.7	**18.0**	0		0.0				0	538	2	
2002	**10.0**			4.4	**14.4**	51	3300	1.9	165			165	538		
2003				5.3	**5.3**	61	3920	2.3	196			196	538		
2004				6.3	**6.3**	72	4620	2.7	231			231	538		
2005				7.3	**7.3**	81	5220	3.0	261			261	538		
2006				8.3	**8.3**	90	5820	3.3	291			291	538		
2007		4.3		9.5	**13.8**	101	6480	3.7	324			324	538		
2008		14.3		10.9	**25.2**	109	7040	4.0	352			352	538		
2009		**10.0**		11.8	**21.8**	141	4540	5.2	454			454	538		
2010			7.4	13.2	**20.6**	156	5010	5.8	501			501	538		
2011			24.8	14.5	**39.3**	170	5470	6.3	547			547	538		
2012			**17.4**	12.5	**29.8**	128	6130	4.7			613	613	538		
2013				13.7	**13.7**	141	6740	5.2			674	674	538		
2014				14.9	**14.9**	153	4867	5.7			730	730	538		
2015				16.3	**16.3**	166	5300	6.2			795	795	538		
Res. Value	*-9*	*-19*	*-40*		*-67*										

Total Discounted Cost: **67.0** MUSD

Reference Discounted Cost: 89.3 MUSD

Average Netback Value Of Gas: **3.06** USD/GJ

Table 3.13: Economic Calculation Sheet - Scenario 9

Country: Congo

Scenario: Inga imports up to 100 MW
50 MW GO.GT in 2009
50 MW GO.GT in 2015

Monetary Unit:	MUSD
Discount Rate:	10%
Gasoil Cost:	7.10 USD/GJ
Natural Gas Cost:	1.50 USD/GJ
50 MW GT Inv.cost:	543 USD/kW

	Generation Investments		*Operating*	*Total*	*Natural Gas*	*G.T.*	*Natural Gas*	*TG50*	*TG100*	*CC*	*Tot.gaz*	*Hydro*	*Diesel*	*Impo*
	50 MW GT	*50 MW GT*	*Cost*		*Consumption (Mm3/y)*	*Aver. Oper. Time (h)*	*Consumption (Million GJ/y)*	*GWH*	*GWH*	*GWH*				
Inv. Cost	*27.2*	*27.2*												
1995				**0.0**										
1996			1.5	**1.5**	0							502		59
1997			1.8	**1.8**	0							517		67
1998			1.9	**1.9**	0							526		75
1999			2.2	**2.2**	0							538		85
2000			2.7	**2.7**	0							538		10
2001			3.5	**3.5**	0							538		13
2002			4.4	**4.4**	0							538		17
2003			5.3	**5.3**	0							538		20
2004			6.3	**6.3**	0							538		24
2005			7.3	**7.3**	0							538		28
2006			8.4	**8.4**	0							538		32
2007	4.1		9.5	**13.6**	0							538		36
2008	13.6		10.7	**24.3**	0							538		41
2009	**9.5**		11.9	**21.4**	0	20		1				538		45
2010			13.3	**13.3**	0	40		2				538		50
2011			14.7	**14.7**	0	80		4				538		55
2012			16.6	**16.6**	0	180		9				538		60
2013		4.1	18.6	**22.7**	0	320		16				538		65
2014		13.6	21.4	**34.9**	0	600		30				538		70
2015		**9.5**	27.3	**36.8**	0	980		98				538		70
Res. Value	*-18*	*-26*		*-43*										

Total Discounted Cost: **53.4** MUSD

Average Netback Value Of Gas: ***#Div/0!*** USD/GJ

Table 3.14: Economic Calculation Sheet - Scenario 10

Country: Congo

Scenario: Inga imports up to 100 MW
50 MW NG.GT in 2009
50 MW NG.GT in 2015

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
50 MW GT Inv.cost: 570 USD/kW

	Generation Investments		*Operating*	*Total*	*Natural Gas*	*G.T.*	*Natural Gas*	*TG50*	*TG100*	*CC*	*Tot.gaz*	*Hydro*	*Diesel*	*Import*
	50 MW GT	*50 MW GT*	*Cost*		*Consumption (Mm3/y)*	*Aver. Oper. Time (h)*	*Consumption (Million GJ/y)*	*GWH*	*GWH*	*GWH*				
Inv. Cost	*28.5*	*28.5*												
1995				**0.0**			0.0							
1996			1.5	**1.5**	0		0.0					502		59
1997			1.8	**1.8**	0		0.0					517		67
1998			1.9	**1.9**	0		0.0					526		75
1999			2.2	**2.2**	0		0.0					538		85
2000			2.7	**2.7**	0		0.0					538		102
2001			3.5	**3.5**	0		0.0					538		136
2002			4.4	**4.4**	0		0.0					538		170
2003			5.3	**5.3**	0		0.0					538		203
2004			6.3	**6.3**	0		0.0					538		243
2005			7.3	**7.3**	0		0.0					538		282
2006			8.4	**8.4**	0		0.0					538		321
2007	4.3		9.5	**13.8**	0		0.0					538		366
2008	14.3		10.7	**25.0**	0		0.0					538		411
2009	**10.0**		11.8	**21.8**	112	7180	4.1	359				538		97
2010			13.2	**13.2**	112	7180	4.1	359				538		147
2011			14.5	**14.5**	112	7180	4.1	359				538		198
2012			15.9	**15.9**	112	7180	4.1	359				538		254
2013		4.3	17.6	**21.8**	112	7180	4.1	359				538		316
2014		14.3	19.3	**33.6**	112	7180	4.1	359				538		372
2015		**10.0**	20.7	**30.7**	223	7180	8.3	718				538		80
Res.Value	*-19*	*-27*		*-46*										

Total Discounted Cost: **52.1** MUSD

Reference Discounted Cost: *53.4* *MUSD*

Average Netback Value Of Gas:1.72 USD/GJ

Table 3.15: Economic Calculation Sheet - Scenario 11

Country: Congo

Scenario: No imports after 1997
4 x 50 MW NG.GT in 1998,
2002, 2009 and 2014

Monetary Unit: MUSD
Discount Rate: 10%

Gasoil Cost: 7.10 USD/GJ
Natural Gas Cost: 1.50 USD/GJ

50 MW GT Inv.cost: 570 USD/kW

	Generation Investments				*Operating*	*Total*	*Natural Gas*	*G.T.*	*Natural Gas*	*TG50*	*TG100*	*CC*	*Tot.gaz*	*Hydro*	*Diesel*	*Im*
	50 MW GT	*50 MW GT*	*50 MW GT*	*50 MW GT*	*Cost*		*Consumption (Mm3/y)*	*Aver. Oper. Time (h)*	*Consumption (Million GJ/y)*	*GWH*	*GWH*	*GWH*				
Inv. Cost	*28.5*	*28.5*	*28.5*	*28.5*												
1995					0.0	**0.0**			0.0							
1996	4.3				1.5	**5.8**	0		0.0				0	502		
1997	14.3				1.8	**16.0**	0		0.0				0	517		
1998	**10.0**				2.0	**12.0**	23	1480	0.9	74			74	526		
1999					2.3	**2.3**	26	1700	1.0	85			85	538		
2000		4.3			2.8	**7.0**	31	2020	1.2	101			101	538	2	
2001		14.3			4.1	**18.4**	41	2660	1.5	133			133	538	2	
2002		**10.0**			4.4	**14.4**	53	1700	2.0	170			170	538		
2003					5.3	**5.3**	63	2030	2.3	203			203	538		
2004					6.3	**6.3**	76	2430	2.8	243			243	538		
2005					7.3	**7.3**	88	2820	3.2	282			282	538		
2006					8.4	**8.4**	100	3210	3.7	321			321	538		
2007			4.3		9.7	**13.9**	114	3660	4.2	366			366	538		
2008			14.3		11.5	**25.7**	127	4100	4.7	410			410	538		
2009			**10.0**		11.8	**21.8**	142	3040	5.2	456			456	538		
2010					13.2	**13.2**	158	3380	5.8	507			507	538		
2011					14.5	**14.5**	173	3713	6.4	557			557	538		
2012				4.3	16.0	**20.2**	191	4087	7.1	613			613	538		
2013				14.3	18.0	**32.3**	209	4487	7.7	673			673	538		
2014				**10.0**	19.0	**29.0**	227	3655	8.4	731			731	538		
2015					20.7	**20.7**	248	3990	9.2	798			798	538		
Res.Value	*-3*	*-9*	*-19*	*-26*		***-56***										

Total Discounted Cost: **87.4** MUSD

Reference Discounted Cost: *89.3* *MUSD*

Average Netback Value Of Gas:1.60 USD/GJ

Table 3.16: Economic Calculation Sheet - Scenario 12

Country: Congo

Scenario: No imports after 1997
3 x 50 MW NG.CC in 1998, 2002 and 2008
50 MW NG.GT in 2014

Monetary Unit:	MUSD
Discount Rate:	10%
Gasoil Cost:	7.10 USD/GJ
Natural Gas Cost:	1.50 USD/GJ
GT Inv.cost:	570 USD/kW
CC Inv.cost:	711 USD/kW

	Generation Investments				*Operating*	*Total*	*Natural Gas*	*G.T.*	*Natural Gas*	*TG50*	*TG100*	*CC*	*Tot.gaz*	*Hydro*	*Diesel*	*Imp*
	50 MW GT	*50 MW GT*	*50 MW ST*	*50 MW GT*	*Cost*		*Consumption (Mm3/y)*	*Aver. Oper. Time (h)*	*Consumption (Million GJ/y)*	*GWH*	*GWH*	*GWH*				
Inv. Cost	*28.5*	*28.5*	*49.7*	*28.5*												
1995						**0.0**			0.0							
1996	4.3				1.5	**5.8**	0		0.0				0	502		5
1997	14.3				1.8	**16.0**	0		0.0				0	517		6
1998	**10.0**				2.0	**12.0**	23	1480	0.9	74			74	526		
1999					2.3	**2.3**	26	1700	1.0	85			85	538		
2000		4.3			2.8	**7.0**	31	2020	1.2	101			101	538	2	
2001		14.3			4.1	**18.4**	41	2660	1.5	133			133	538	2	
2002		**10.0**			4.4	**14.4**	53	1700	2.0	170			170	538		
2003					5.3	**5.3**	63	2030	2.3	203			203	538		
2004					6.3	**6.3**	76	2430	2.8	243			243	538		
2005					7.3	**7.3**	88	2820	3.2	282			282	538		
2006					8.4	**8.4**	100	3210	3.7	321			321	538		
2007			7.4		9.7	**17.1**	114	3660	4.2	366			366	538		
2008			24.8		11.5	**36.3**	127	4100	4.7	410			410	538		
2009			**17.4**		9.3	**26.6**	95	3040	3.5			456	0	538		
2010					10.3	**10.3**	106	3380	3.9			507	0	538		
2011					11.3	**11.3**	117	3713	4.3			557	0	538		
2012				4.3	12.5	**16.8**	128	4087	4.7			613	0	538		
2013				14.3	14.2	**28.5**	141	4493	5.2			674	0	538		
2014				**10.0**	14.9	**24.8**	153	3660	5.7	2		730	2	538		
2015					16.3	**16.3**	168	3995	6.2	4		795	4	538		
Res. Value	*-3*	*-9*	*-32*	*-26*		***-69***										

Total Discounted Cost:	**86.9**	MUSD
Reference Discounted Cost:	*89.3*	*MUSD*
Average Netback Value Of Gas:	**1.65**	USD/GJ

Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
	Commercilizing Natural Gas: Lessons from the Seminar in Nairobi for Sub-Saharan Africa and Beyond	01/00	225/00
	Africa Gas Initiative – Main Report: Volume I	02/01	240/01
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
	Africa Gas Initiative – Angola: Volume II	02/01	240/01
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cameroon	Africa Gas Initiative – Cameroon: Volume III	02/01	240/01
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
	In Search of Better Ways to Develop Solar Markets: The Case of Comoros	05/00	230/00
Congo	Energy Assessment (English)	01/88	6420-COB

Region/Country	*Activity/Report Title*	*Date*	*Number*
Congo	Power Development Plan (English and French)	03/90	106/90
	Africa Gas Initiative – Congo: Volume IV	02/01	240/01
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95
	Africa Gas Initiative – Côte d'Ivoire: Volume V	02/01	240/01
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
	Africa Gas Initiative – Gabon: Volume VI	02/01	240/01
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
	Implementation Manual: Financing Mechanisms for Solar Electric Equipment	07/00	231/00
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83

Region/Country	*Activity/Report Title*	*Date*	*Number*
Malawi	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87
	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
Republic of South Africa	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84

Region/Country	*Activity/Report Title*	*Date*	*Number*
Sudan	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90
	Power Loss Reduction Volume 1: Transmission and Distribution SystemTechnical Loss Reduction and Network Development (English)	06/98	204A/98
	Power Loss Reduction Volume 2: Reduction of Non-Technical Losses (English)	06/98	204B/98
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
	Rural Electrification Strategy Study	09/99	221/99
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--
	Rural Electrification Study	03/00	228/00

Region/Country	*Activity/Report Title*	*Date*	*Number*
	EAST ASIA AND PACIFIC (EAP)		
Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
	Improving the Technical Efficiency of Decentralized Power Companies	09/99	222/999
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
	Institutional Development for Off-Grid Electrification	06/99	215/99
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94

Region/Country	*Activity/Report Title*	*Date*	*Number*
Vietnam	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
	Petroleum Fiscal Issues and Policies for Fluctuating Oil Prices In Vietnam	02/01	236/01
Western Samoa	Energy Assessment (English)	06/85	5497-WSO
	SOUTH ASIA (SAS)		
Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
	Environmental Issues in the Power Sector (English)	06/98	205/98
	Environmental Issues in the Power Sector: Manual for Environmental Decision Making (English)	06/99	213/99
	Household Energy Strategies for Urban India: The Case of Hyderabad	06/99	214/99
	Greenhouse Gas Mitigation In the Power Sector: Case Studies From India	02/01	237/01
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86
	EUROPE AND CENTRAL ASIA (ECA)		
Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97

Region/Country	*Activity/Report Title*	*Date*	*Number*
Central and Eastern Europe	Increasing the Efficiency of Heating Systems in Central and Eastern Europe and the Former Soviet Union	08/00	234/00
	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazakhstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
	Natural Gas Upstream Policy (English and Polish)	08/98	206/98
	Energy Sector Restructuring Program: Establishing the Energy Regulation Authority	10/98	208/98
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Slovenia	Workshop on Private Participation in the Power Sector (English)	02/99	211/99
Turkey	Energy Assessment (English)	03/83	3877-TU
	Energy and the Environment: Issues and Options Paper	04/00	229/00

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
Morocco	Energy Sector Institutional Development Study (English and French)	07/95	173/95
	Natural Gas Pricing Study (French)	10/98	209/98
	Gas Development Plan Phase II (French)	02/99	210/99
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean - Status Report (English and Spanish)	12/97	200/97

Region/Country	*Activity/Report Title*	*Date*	*Number*
LAC Regional	Harmonization of Fuels Specifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
	Introducing Competition into the Electricity Supply Industry in Developing Countries: Lessons from Bolivia	08/00	233/00
	Final Report on Operational Activities Rural Energy and Energy Efficiency	08/00	235/00
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
	Rural Electrification with Renewable Energy Systems in the Northeast: A Preinvestment Study	07/00	232/00
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88

Region/Country	*Activity/Report Title*	*Date*	*Number*
Jamaica	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
	Reform and Privatization in the Hydrocarbon Sector (English and Spanish)	07/99	216/99
	Rural Electrification	02/01	238/01
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Sub Andean	Environmental and Social Regulation of Oil and Gas Operations in Sensitive Areas of the Sub-Andean Basin (English and Spanish)	07/99	217/99
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR
	GLOBAL		
	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
	Rural Energy and Development Roundtable (English)	05/98	202/98
	A Synopsis of the Second Roundtable on Energy Efficiency: Institutional and Financial Delivery Mechanisms (English)	09/98	207/98
	The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank: A Carbon		

Region/Country	*Activity/Report Title*	*Date*	*Number*
Global	Backcasting Exercise (English)	02/99	212/99
	Increasing the Efficiency of Gas Distribution Phase 1: Case Studies and Thematic Data Sheets	07/99	218/99
	Global Energy Sector Reform in Developing Countries: A Scorecard	07/99	219/99
	Global Lighting Services for the Poor Phase II: Text Marketing of Small "Solar" Batteries for Rural Electrification Purposes	08/99	220/99
	A Review of the Renewable Energy Activities of the UNDP/ World Bank Energy Sector Management Assistance Programme 1993 to 1998	11/99	223/99
	Energy, Transportation and Environment: Policy Options for Environmental Improvement	12/99	224/99
	Privatization, Competition and Regulation in the British Electricity Industry, With Implications for Developing Countries	02/00	226/00
	Reducing the Cost of Grid Extension for Rural Electrification	02/00	227/00
	Undeveloped Oil and Gas Fields in the Industrializing World	02/01	239/01

2/13/01

ESMAP

The World Bank

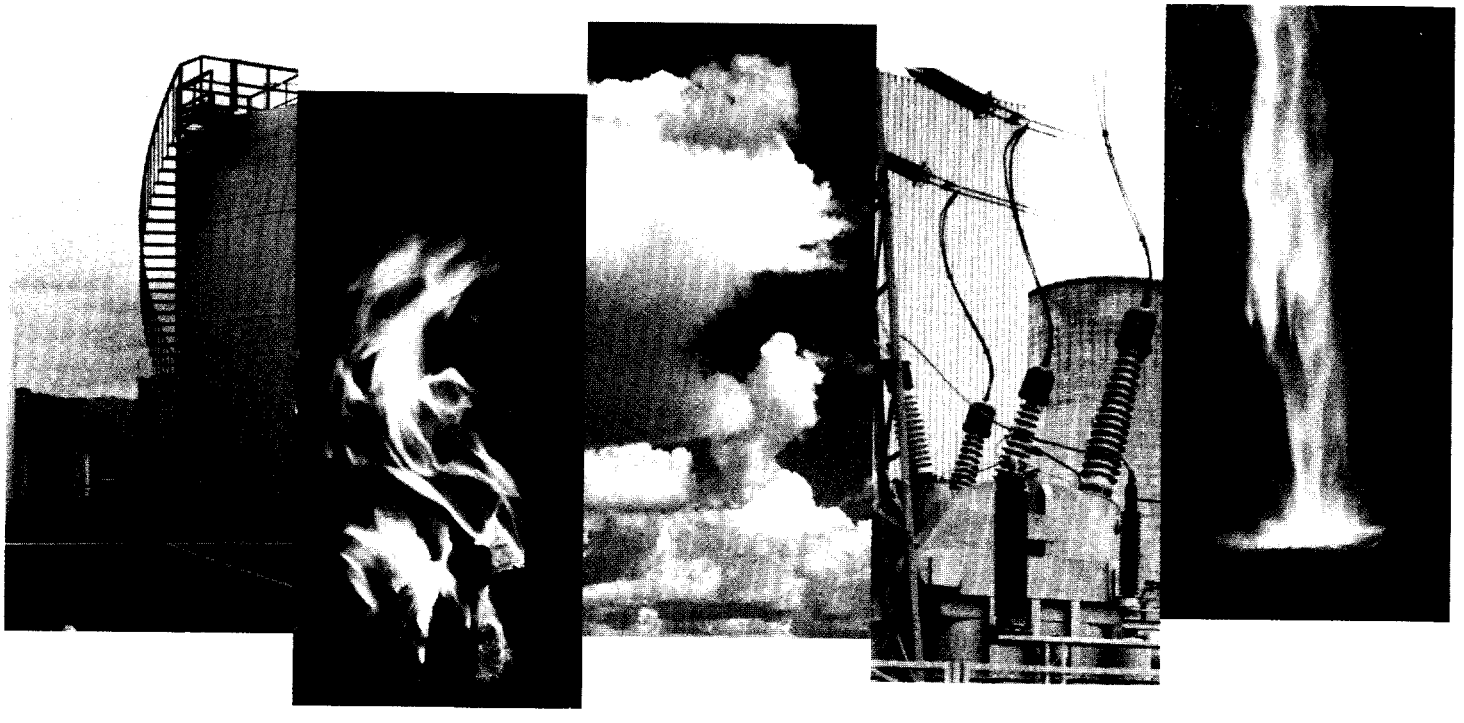
1818 H Street, NW

Washington, DC 20433 USA

Tel.: 1.202.458.2321 Fax.: 1.202.522.3018

Internet: www.esmap.org

Email: esmap@worldbank.org



A joint UNDP/World Bank Programme