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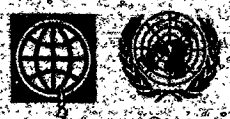
Report No. 6915-GA

Gabon: Issues and Options in the Energy Sector

July 1988



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Report No. 6915-GA

GABON

ISSUES AND OPTIONS IN THE ENERGY SECTOR

JULY 1988

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ABSTRACT

Gabon possesses significant petroleum, natural gas, hydroelectric and forestry resources. The commercial energy consumption per capita (600 kgoe in 1985) is high compared to other countries of Sub-Saharan Africa. The mission preliminary estimates of the total fuelwood consumption per capita was about 390 kgoe, making the total per capita energy consumption per capita in 1985 990 kgoe.

The mission reviewed energy sector development and investment plans following the drop in 1986 in international oil prices. As agreed with the government, the present report focuses mainly on petroleum and electricity subsectors which were the most affected by oil price decline. Utilization of natural gas has also become a priority issue since the discovery of large resources.

The report addresses other issues and evaluates options related to (a) optimization of oil production so as to sustain economic recovery; (b) a restricted power investment plan; and (c) development of coherent pricing policies to promote efficient energy supply and consumption. Finally, it recommends institutional reforms pertaining to energy sector planning, management and coordination.

ACRONYMS

BEICIP	Bureau d'Etudes Industrielles et de Coopération de l'institut français du pétrole
COGER	Compagnie Gabon Elf de Raffinage
DGE	Directorate General of Energy
DGH	Directorate General of Hydrocarbons
GPP	Groupement Professionnel des Pétroliers
IMF	International Monetary Fund
MEHR	Ministry of Energy and Hydraulic Resources
MFBP	Ministry of Finance, Budget and Participations
MMH	Ministry of Mines and Hydrocarbons
MPE	Ministry of Planning and Economy
OPEC	Organization of Petroleum Exporting Countries
Petrogab	Société Nationale Pétrolière Gabonaise
SEEG	Société d'Energie et d'Eau du Gabon
SGEPP	Société Gabonaise d'Entreposage des Produits Pétroliers
SNEA	Société Nationale Elf Aquitaine
SOBRAGA	Société des brasseries du Gabon
SOGARA	Société Gabonaise de Raffinage
SPAFE	Société des Pétroles de l'Afrique Equatoriale
UNDP	United Nations Development Programme

ABBREVIATIONS

bbl	barrel
b/d	barrel(s) per day
b/y	barrels(s) per year
BSCF	billion standard cubic feet
BTU	British Thermal Unit
CIF	cost, insurance, freight
DER	Directorate of Regional Exploitations
FCV	Franceville
GDP	gross domestic product
GWh	gigawatt-hour
ha	hectare
hl	hectoliter
HV	high voltage
kcal	kilocalorie
kg	kilogram
kgoe	kilograms of oil equivalent
km	kilometer
km^2	square kilometer
ktoe	thousands tons of oil equivalent
kVA	kilovolt-ampere
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
l	liter
LBV	Libreville
LPG	liquefied petroleum gas
LV	low voltage
m	meter
m^3	cubic meter
MCF	thousand cubic feet
MMBTU	million British Thermal Units
MVA	megavolt-ampere
MV	medium voltage
MW	megawatt
Nm^3	normal cubic meter
NWE	Northwest Europe
POG	Port-Gentil
toe	tons of oil equivalent
ton	metric ton
yr	year

CURRENCY AND FUEL EQUIVALENTS

Currency Unit - CFA Franc (CFAF)
Exchange Rate: 350 CFAF/US$ 1 a/

Fuel	Calorific Value (million kcal/ton)	toe
Crude Oil	10.2	1
LPG (Butane)	10.8	1.059
Gasoline	10.5	1.029
Jet Fuel	10.4	1.020
Kerosene	10.3	1.007
Gas Oil	10.2	1
Fuel Oil	9.7	0.951
Firewood	3.5	0.343
Charcoal	7.0	0.6863
Natural gas	233.0 b/	22.84 c/

Electricity

4000 kWh = 1 toe for hydroelectric supply on a thermal replacement basis (thermal efficiency 34.4%).

1 GWh = 86 toe (thermal replacement value).

a/ Exchange rate at time of mission. Rate used in the report, unless otherwise noted.
b/ Million kcal/MMCF
c/ toe/MMCF

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SUMMARY AND RECOMMENDATIONS

Scope of Inquiry

1. This Energy Assessment Report summarizes the findings of a mission fielded in October/November 1986. 1/ The mission coincided with a period of marked uncertainty for the Gabonese authorities. Its various economic development and investment plans were being revised following a severe drop in international oil prices. Although a comprehensive review of the entire energy sector had been planned, the anticipated macro-economic repercussions of the oil price decline (para. 1.6-1.7) modified Government priorities, as well as those of the mission. Consequently, the mission chose, with the agreement of the Government, to highlight issues whose key parameters had been altered by the oil price decline, thereby affecting short- and medium-term decisions.

2. As a result, this report focuses mainly on the petroleum and electricity subsectors. Utilization of natural gas as a long-term option of electricity generation (para. 4.27-4.31) has also become a priority issue since the discovery of large reserves which will allow for the supply of natural gas to the Société d'Energie et d'Eau du Gabon (SEEG) at competitive costs. A decision regarding natural gas is important in the short term. Terms of Reference for an in-depth gas feasibility study, to be undertaken immediately, are given in Annex 5.

3. The remaining issues addressed by the mission fall into the following general groupings:

(a) the best strategy to simultaneously maximize the present value of remaining petroleum reserves and optimize current crude oil production so as to sustain economic recovery, with emphasis on contractual arrangements to provide incentives for exploration and development;

(b) competitivity and efficiency of petroleum product supply to the domestic market, including arrangements for procuring crude oil

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and refined products, and product distribution and storage requirements;

(c) priorities for revising and scheduling electric power investment requirements in the short- to medium-term, as well as long-term considerations;

(d) development of coherent pricing structures and policies to promote efficient energy supply and consumption; and

(e) requirements for institutional reform to enhance sector coordination and planning, and to address various financial management problems.

4. Several other issues normally found in an energy assessment report were excluded from this exercise. These include: household energy; supply and demand of woodfuels; and utilization of agricultural residues and other non-conventional energy resources. Gabon has very little information on these areas at present. The Ministry of Energy and Hydraulic Resources (MEHR) has commissioned a study of household energy, and its results were expected in late 1987. Based on a review of the terms of reference, it seems that the study will give a rough estimate of global household demand. It will not, however, categorize the extent to which particular fuels are consumed, or the purposes for which they are used. Nor will there be a systematic examination of the supply networks for household fuels (most importantly woodfuels). The mission has annexed to this report (Annex 24) draft Terms of Reference for a household energy survey which would provide such information. In order to round out its energy data base, the Government should consider launching similar inquiries within the agriculture sector and among small industrial consumers to gather information on the use of non-conventional fuels in other sectors. Both surveys can be postponed for the medium term.

Overview of Energy and the Economy

5. The Gabonese Republic possesses significant petroleum, natural gas, hydroelectric, and forestry resources. Proven petroleum reserves, at present, are almost 961 million barrels (bbls) (para. 1.9). Associated natural gas production was estimated at 2.0 billion Nm^3 in 1985. It will substantially increase after the development of the discoveries, confirmed in 1987: Rabi and Coucal particularly. The Ogooué River and its tributaries provide the country with a hydroelectric potential of 50,000 GWh/yr, only 1% of which is developed. Dense tropical rain forests cover over 22 million hectares (ha), or 80% of Gabonese territory.

6. Per capita commercial energy consumption was estimated as 600 kilograms of oil equivalent (kgoe) in 1985. The addition of mission

estimates of fuelwood consumption among the rural populace (less than half the total population) increases this figure to almost 990 kgoe, which is high compared to the neighboring countries of West Africa. Petroleum products account for over 73% of net domestic consumption (excluding primary consumption of crude oil and natural gas by the petroleum industry), while woodfuels and electricity account for 16% and 10% respectively. Natural gas is used exclusively for the production of secondary energy (electricity) or in petroleum production, and so does not enter the national energy accounts under net domestic consumption (Table 1.2). The petroleum industry is the largest energy consuming sector in Gabon, although most of its consumption is in the form of primary energy (associated natural gas reinjected for crude production and crude oil consumed in refining operations). The structure of final demand is 33% households, 28% nonoil industry and 17% transport, 8% petroleum industry, and 11% public sector/civil works.

7. The energy sector has played a crucial role in the development of Gabon since the early 1970s, when petroleum output emerged as the major determinant of national economic activity. Following a rapid expansion resulting from accelerated oil production and increasing oil prices, heavy external borrowing in the late 1970s to support an ambitious public investment program led to an external debt and liquidity crisis. The crisis lasted for about two years (1977-78) before the second international oil price increase helped fuel economic recovery from 1980 to 1984. The petroleum sector represented 45% of GDP and petroleum revenues made up 66% of total government receipts.

8. The economy grew sluggish in early 1985, then was shaken considerably by the drop in oil prices at the end of the year. Although short-term projections to 1990 indicate continued economic difficulties, the picture is likely to improve substantially by the mid-1990s, fundamentally due to increased oil production and improved oil prices. In the short run, however, oil revenues could top 200 billion CFAF (constant 1985 prices), but this is still only about 55% of 1985 levels. The potential for significant increases in government revenues from other sectors during this period is limited. Thus the Government will be forced to curtail recurrent expenditures and all but essential investments.

Priority Petroleum Subsector Issues

Optimizing Production of Crude Oil

9. Most petroleum fields currently in production have been fully developed and now are undergoing a natural decline in output. Their combined annual output will not be enough to sustain current production levels (8 million tons) until 1990 (Table 2.2). The development of crucial new discoveries, such as the Rabi field (para. 2.10-2.11), as well as the Coucal field (para. 2.12), also would be necessary to sustain

production. The projections of annual oil production in Table 2.3 indicate that development of Rabi will be essential to maintaining production levels above the 8 million tons/yr threshold after 1990. These projections do not take into account the possibility that fields other than Rabi and Coucal could be developed and brought into production. However, they do emphasize the importance of Rabi's output for the short- to medium-term recovery of the economy: without this production, oil revenues have little chance of regaining pre-1985 levels.

10. The strategy adopted by the Government in order to simultaneously approach these two goals should consist principally of providing the proper fiscal and legal framework for encouraging development, especially during periods of oil price uncertainty such as occurred in late 1985/early 1986. The Government should take advantage of its expanded role under newly adopted production-sharing contracts (para. 2.18-2.21) to: (a) improve monitoring of upstream petroleum activities; and (b) develop relevant fiscal and investment policies (para. 2.21).

11. The Directorate General of Hydrocarbons (DGH) has been the beneficiary of long-term technical assistance by well-qualified international experts who should design and implement an intensive training program in this area (para. 2.23). A review and possible revision of the experts' terms of reference should ensure that they are instructed to: (a) advise the DGH on the best arrangements to systematically monitor petroleum operations; (b) provide on-the-job training for the senior professional DGH staff selected for this function; (c) advise the DGH, as the need arises, on specific monitoring issues requiring inputs from technical specialists; and (d) train DGH staff to audit the oil company accounts under both types of exploration contracts (para. 2.17-2.20).

12. In the short term, the Government should establish the petroleum production profile for Gabon based on reserve/production ratio and oil export revenues. It would serve as the principal element in long-term planning for the national economy, and should be updated regularly.

Supply Arrangements for Crude Oil

13. Gabon's oil refinery, the Société Gabonaise de Raffinage (SOGARA), is the principal supplier of finished products to the domestic market. It is obligated by statute to refine the locally produced crude, and all companies producing in Gabon must sell a fraction of their (after tax) production to the refinery. The crude is purchased from Elf-Gabon at a set price (para. 19), but up until 1987, payments were made through Petrogab, the national oil company (para. 2.24). Petrogab was liquidated in late 1987 (para. 2.26). As a result, direct invoicing by Elf-Gabon could be re-established. The transaction could be monitored periodically by the DGH (para. 3.8).

Product Distribution Strategy

14. Gabon's infrastructure requirements and associated investments in the storage and transport of petroleum products were the subject of a study in early 1983 (para. 3.13-3.14). Taking into account lower activity scenarios following the oil price decline, the mission modified the study's recommendations in two areas. First, Gabon should minimize its storage investments by adopting a commercial inventory of less than 45 days, 25 days being the proposed reserve level. The Government may choose a slightly higher level, if 25 days is considered inadequate for strategic reasons (para. 3.14). Second, the recommended establishment of additional service stations in the interior does not appear to be the most economic interim strategy. Other solutions, such as using drum supply in conjunction with hand pumps, should be considered (para. 3.17).

15. The study by the French Petroleum Institute's Bureau d'Etudes Industrielles et de Coopération (BEICIP) recommended that two 2,000 m^3 butane spheres be installed at Owendo in order to improve the supply costs of butane. The mission agrees that one of these spheres should be installed immediately, on condition that the payback period is less than two years. In the short term, the Government should undertake a full analysis of butane demand and supply. This analysis could be included as part of the development of a household energy strategy, and should take into account the conclusions of the petroleum pricing study (para. 3.16).

Petroleum Subsector Institutions

16. Of the six petroleum product marketing companies operating in Gabon until 1987, all were private companies (Government share: 10%), with the exception of the national marketing company, PIZO. PIZO (Government share: 50%) was created to ensure that all regions of the country have access to petroleum products and, as recently as 1985, was the market leader for inland product sales (para. 3.9). As a result of its public service mandate and its high proportion of public sector customers, PIZO found itself saddled with numerous financial problems (para. 3.10-3.11). The Government decided that these problems would best be resolved by liquidating the company and selling its assets. The final liquidation plans, which will shortly go into effect, should include clear provisions for the payment and/or cancellation of PIZO's debts and accounts payable by clients before it is implemented.

17. There are two key institutions involved in the supervision of operations, investments, planning and pricing in the petroleum subsector: the Ministry of Finance, Budget and Participations (MFBP), and the Ministry of Planning and Economy (MPE) (para. 2.23-2.26; and 3.18-3.22). Although their responsibilities are defined in legal texts, there is considerable duplication in these documents. A "de facto" division of responsibilities permits the subsector to operate without major difficulties. However, lack of clear distinction of responsibilities restricts coordination between the ministries and leaves gaps in the exercise of supervisory functions.

18. A comprehensive institutional study has been recommended for the subsector to confirm the proper roles of the DGH, MEHR, MFBP and MPE and develop recommendations to strengthen them in these roles. The principal tasks to be undertaken in the study are: (a) fully assess the effectiveness of each institution in its current "de facto" roles; (b) make a thorough accounting of major operational and supervisory responsibilities which are not exercised or poorly executed under the current system; (c) evaluate the capabilities and resources of the various institutions relative to (a) and (b); (d) identify appropriate divisions of responsibilities and modify legal texts accordingly; and (e) determine new staffing, training, and resource requirements where needed and develop a plan to implement proposed changes (para. 3.22).

Product Pricing

19. Under the current system, ex-refinery prices are set by the MFBP. The price is based on the MFBP's assessed value of crude oil plus a margin calculated to both cover SOGARA's costs and provide a small profit (para. 3.24-3.25; 3.28). The price at which SOGARA actually purchases the crude, the official price of the Organization of Petroleum Exporting Countries (OPEC) at the time of pumping, can differ substantially from the MFBP assessed value (para. 3.26). That final ex-refinery prices are substantially higher than import parity indicates that local refining might not be the most economic source of petroleum product supply. In fact, the cost-plus system of determining ex-refinery prices offers little incentive to reduce costs (para. 3.29-3.30; Table 3.5). In order to encourage a more economic supply of products through local refining, the Government should return to import parity pricing (as was the case prior to 1981) as the basis for ex-refinery prices (para. 3.31).

20. The MFBP sets prices at the retail level, also. Prices are calculated according to a complex structure which includes the ex-refinery price, transport costs, distributors' renumeration, financial costs, retail margins, and various taxes and subsidies (para. 3.33-3.38). The structure should be simplified to five major cost components (para. 3.43). Adjustments made to retail prices in April 1986 reflect the lower cost of crude oil and changes to fiscal policy (para. 3.39-3.40). The mission recommends that, as a first phase, the retail price of gas oil be increased (possibly by applying a larger "taxe complémentaire") so that all retail prices more closely approximate their relative economic costs (para. 3.41-3.42). The advantage of that solution is also its fiscal implications.

21. In the second phase, all the mechanisms for pricing petroleum products from the refinery to the final customer are in need of review. Price adjustments are infrequent, and it does not appear that regular consultations are held with all relevant parties to ensure that prices reflect economic costs (para. 3.25-3.27; 3.34). The reforms to the pricing system should be precisely defined within the context of a refining and product pricing study, which would include three main

components: (a) the examination of the systems and the costs of supplying crude oil and petroleum products to the country; (b) a diagnostic evaluation of refinery operations and a management audit of SOGARA; and (c) a review of the product distribution strategy and of the pricing system (para. 3.31). Institutional arrangements for product pricing should be consistent with the recommendations of the subsector institutional study (para. 18).

Priority Electricity Subsector Issues

Electricity Demand Forecasts

22. In 1984, Société d'Energie et d'Eau du Gabon (SEEG) calculated a detailed long-term forecast of electricity consumption throughout the system (Annex 16), upon which it based its long-term development plan (para. 24). The forecasts were revised in early 1986 to reflect more moderate growth after the oil price decline (para. 4.17-4.18; Table 4.3). The mission felt that neither forecast was adequate for input to the long-term system development plan, however, as they were calculated using demand trend assessment methods (para. 4.19). Thus, it was recommended that SEEG revise its demand forecasts (particularly those for low voltage consumption) according to a more appropriate methodology, to include: (a) a disaggregated market survey of each major class of consumer (in addition to surveys of large industrial individual consumers) for each of the subsystems; and (b) a macroeconomic consistency check, based on the most recent macroeconomic projections to be provided by the MPE. A new scenario, which predicts a recession in the electricity subsector, was constructed in early 1987, using a synthetic analytic approach (para. 4.20). These forecasts should be used to define the least-cost long-term development plan (para. 4.27).

Medium-Term System Development to 1995

23. The revised 1987 forecasts for electricity demand confirm the conclusion that the existing generating capacity in the three large load centers (Libreville, Port-Gentil, and Franceville) will be sufficient to meet demand until the early 1990s (para. 4.21). A complementary 12 MW gas turbine could prove necessary in Franceville after 1992 to decrease the risks of shortages in dry years. The final decision should be made in 1988-1989 (para. 4.22). Previous plans for installation of gas turbines at Port-Gentil in 1992-1994 (para. 4.23) should be reviewed, once a scenario including the Libreville-Port-Gentil interconnection (para. 4.28-4.29) is re-evaluated. No new generating capacity will be needed for either of these subsystems before 1996, in any case.

24. In early 1986, SEEG reduced its original development program for the isolated centers (DER) from 24 to 15 target load centers (para. 4.23). After decreasing the scope of the planned program once more, the Government finalized the conditions for executing the

readjusted program in 1987, with financing provided by the Canadians. The Government is still negotiating with the French Government for equipment for centers not included in the Canadian program. SEEG should subject each project remaining in the development program to a full economic and financial analysis so that they can be prioritized and the program continued according to an extended schedule (para. 4.25).

Long-Term System Development

25. The interconnection of the Libreville-Port-Gentil subsystems was the principal element of the initial long-term development plan formulated by SEEG in 1984. The interconnection was to be put in service in 1990-1991, and would have been followed by the installation of two 21 MW gas turbines at Port-Gentil. The third element of the plan included development of a hydroelectric site near Libreville, to be commissioned in the mid-1990s (para. 4.28-4.30). The plan was revised in 1987 to take into account SEEG's new demand forecasts and uncertainties concerning the availability of natural gas and financial resources. The revised strategy consists of separate development of the LBV and the POG networks (para. 4.23; 4.27).

26. SEEG should begin immediately to examine again its long-term development plan. New scenarios will have to be evaluated under revised assumptions for key parameters, including: (a) demand forecasts and anticipated consumption growth rates (para. 22); (b) projected consumption of natural gas, natural gas availability and natural gas prices; (c) trends in fuel prices; and (d) discount rates. Complementary soil investigations for potential hydro sites should be completed immediately so that full information will be available for taking a decision regarding the first major investment by late 1989. This date is crucial, as the lead times are six years for the hydroelectric options and four years for the interconnection. If the interconnection is found to still be the optimal first stage in the development plan, construction should begin in 1992, but no later than 1994 (para. 4.31).

27. The timing for deciding on the appropriate sequence for system development is less crucial for the other subsystems. In Franceville, a decision concerning the timing of new hydroelectric capacity, possibly in 1996 or 1997, will be needed by 1992 (para. 4.32). The projected economic conditions up to mid-1995 should constrain any return to full-scale development of DER until 1996, as investments required in other subsystems will take priority over these. The Government should take advantage of the period of slowed development to: (a) clearly define its development strategy for the DER; (b) re-assess the energy needs in targeted load centers; (c) identify economic interim solutions; and (d) seek alternatives for financing these solutions (para. 4.33).

Other Issues

28. Tariffs. The SEEG undertook a detailed tariff study in 1984 to complement its investment plans. The proposed tariffs are based on the

long-run marginal costs of supply (under the old development plan), subject to the constraints of: (a) public service policies, such as geographic cross-subsidies; and (b) revenue generation requirements, to ensure a sufficient gross margin to support the financing of future investments. The study appears to be methodologically sound (para. 4.39). The tariffs will have to be updated to incorporate: (a) the re-optimized system development plans and (b) modifications to the load curve and consumption patterns envisaged following the economic slowdown and during the recovery period (para. 4.42). In the interim, the proposed tariff structure should be implemented, although tariff levels will need to be adjusted after the study has been updated.

29. Public Service Reform. The MEHR has considered a proposal to reform the public service arrangements for electricity and water. Under this reform, SEEG would be converted from a parastatal enterprise (Government share: 63%) to a completely public enterprise. Upon conversion, all buildings and equipment owned or used by SEEG would become state property, and SEEG's only retained responsibility would be managing system operations (para. 4.44-4.45). The mission identified several disadvantages to this proposal (para. 4.46), and recommends that private shareholders remain active in SEEG ownership in the short term (para. 4.47). Investment by other entities or individuals should also be encouraged. If some private participation in ownership is maintained, preferential tariffs for large consumers who are also shareholders should be reviewed; instead, shareholders should be the beneficiaries of any profit realized from SEEG operations (para. 4.47). In the interim, all proposals for reforming or restructuring the subsector should be reviewed, preferably within the context of an in-depth examination of SEEG's financial situation and a management audit of the electricity subsector.

30. Financial Status. Like many parastatal enterprises in developing countries with a public service mandate, SEEG has a severe cash balance problem caused by 4 months arrears and/or non-payments (about FCFA 15 billion in 1985). The structure of the arrears--85% of outstanding billings attributable to public sector bodies--is such that even vigorous collection programs are not sufficient to tackle the problem (para. 4.49-4.51). A full examination of SEEG's financial situation and of subsector management should be undertaken immediately, with the ultimate objective being the scope for financial and organizational restructuring of SEEG vis-à-vis the Government. The transfer of assets, or a debt-to-equity exchange, would clear up Government debt and give SEEG more financial autonomy (para. 4.52). A review of operating costs may also yield some potential for cost reductions (para. 4.53). The company is pursuing all efforts to bring its operating costs under control.

Summary of Priority Recommendations

31. The key recommendations of the previous sections are presented below according to their priority for implementation.

Core Program for Public Investment

32. The following projects should receive absolute priority in future investment budgets:

(a) investments for butane and reduced storage investments for other petroleum products (Table 3.5): 1.86 million CFAF;

(b) improvements to electricity distribution in Libreville and Franceville (Table 4.5): 6 billion CFAF; and

(c) the first phase of a scaled-down program for developing the DER subsystem (Table 4.5): 4.5 billion CFAF;

33. Investments in transmission at Libreville, including the Bissegue substation transformation capacity (2 billion CFAF) and a new 225 kV overhead line connecting Kinguele to Libreville (5 billion CFAF) can be deferred to 1990. Further investments in the DER subsystem are anticipated at an annual rate of 1.5 billion CFAF until 1990.

Priority Investigations and Studies

34. The following studies are set for, or should be launched in, 1987/1988:

(a) natural gas feasibility study, to be launched immediately (Annex 5): cost to be determined;

(b) least-cost system development plan, including the results of the gas utilization study: 1 billion CFAF;

(c) scope for financial restructuring of SEEG, and SEEG's status vis-à-vis the Government (para. 4.52): US$150,000 - 40 staff weeks (1985 US$);

(d) revisions to the electricity tariff study (para. 4.42); and

(e) a diagnostic evaluation of refinery operations and management audit of SOGARA;

35. The following studies should be scheduled after 1988, to be completed no later than 1991;

(a) comprehensive institutional review of the petroleum subsector (para. 3.22): cost to be determined;

(b) second and third phases of petroleum product refining and pricing study (para. 3.31); and

(c) revised development policy and investment plans for DER (para. 4.33): cost to be determined;

36. Further surveys of household energy and non-conventional fuels could also be carried out during this period, as funding permits.

Institutional and Policy Reforms

37. The following reforms should be implemented immediately, or as soon as the studies upon which they are based are completed:

Petroleum Subsector

(a) the "taxe complémertaire" should be applied to gas oil prices so that all retail prices more closely approximate their relative economic costs (para. 3.42);

(b) the terms of reference of in-house experts should be reviewed/revised to ensure proper intensive training of national counterparts in monitoring upstream petroleum operations (para. 2.22);

(c) the retail price structure should be revised to include about five components, rather than the 30-plus components of the current structure (para. 3.43); and

(d) ex-refinery prices should be established on the basis of import parity (para. 3.31).

Electricity Subsector

(e) private shareholders should remain active in SEEG ownership, and preferential tariffs should be eliminated. All proposals for institutional restructuring should be reviewed, following a full examination of subsector finances and management; and

General

(f) revision of legal texts following petroleum subsector institutional review to eliminate duplication/ambiguities and fill in the gaps.

Manpower Planning and Training

38. In addition to training requirements identified in the recommended studies, the following activities should be launched as soon

as possible:

(a) an intensive training program in the DGH, supervised by foreign experts already in-house, to develop the DGH's capacity to monitor petroleum operations, and usefully utilize annual accounting audits submitted to the DGH by operating oil companies (para. 2.23-2.26);

(b) technical assistance and training to the DGE for (i) collection of energy data, (ii) analysis of energy/economy links, and (iii) constructing and maintaining national energy balances;

(c) after 1992, technical assistance and training to the DGE for the consolidation of energy demand projections, and the elaboration of detailed five-year plans for energy demand and supply.

I. THE ENERGY SECTOR IN GABON

Overview

1.1 The Gabonese Republic (Gabon) lies astride the equator along 800 km of the west African coast. The country extends over 267,000 km^2, three quarters of which is covered by tropical rain forests. The Ogooué River and its tributaries traditionally have provided the major transportation link to the interior.

1.2 Estimates place the total population of Gabon at about one million in 1985, including Europeans and non-Gabonese Africans. More than half of the population is estimated to live in urban areas. The urban population growth rate is twice that of the total population (2.3%/yr). By contrast, rural population growth is only 0.9%/yr, due to the relatively high pace of rural-to-urban migration (1.3%/yr).

The Economy

1.3 Since independence in 1960, economic growth in Gabon has been heavily dependent on the output of its extractive industries: petroleum, manganese, uranium, and forestry. Forestry and mining, exclusive of petroleum, were the mainstays of the Gabonese economy in the early 1970s (30% of GDP). By 1984, these two sectors accounted for only 4.3% of GDP. Petroleum, on the other hand, represented 45% of GDP and 66% of total government revenues.

1.4 Agriculture's share of GDP has remained relatively constant at around 4.5% for the past decade. Manufacturing and construction represented 13.3% of GDP in 1985, and public administration and taxes another 15%. The contribution of other sectors include 7.6% for non-government services, 6.6% for trade, and 3.8% for transport.

1.5 Petroleum output emerged in the early 1970s as the major determinant of Gabon's GDP. Economic development became highly dependent on the evolution of international petroleum markets. This linkage is evident in the three distinct periods of economic growth between 1970 and 1983. From 1970 to 1976, the economy expanded rapidly (14.1%/yr on average) in conjunction with the increase in both oil production and international oil prices. Then in 1976-1979, heavy external borrowing to support an ambitious public investment program, coupled with stagnating oil revenues contributed to an external debt and liquidity crisis. Consequently, the economy experienced a sharp contraction as real GDP fell by an annual rate of -12.6%. In 1979, an IMF stabilization program was adopted to diversify the economic structure, create conditions for non-inflationary growth and reduce external debt. Its efficacy was enhanced by the second international oil price increase. The otherwise

spectacular economic recovery which resulted during the period 1980-1984 was sharply undercut by high rates of inflation. Although the economy exhibited strong growth in current terms (16.13%/yr), annual real growth averaged only 1.54%.

Initial Impact of the Oil Price Decline

1.6 The economy grew sluggish in early 1985 and then was s[illegible]ken considerably by the sharp drop in international oil prices at the en[illegible] of that year. Oil production declined slightly (-1.2%) and the appreciation of the CFAF vis-à-vis the U.S. dollar failed to keep pace with the rapidly decreasing dollar price per barrel. As a result, oil revenues declined by more than 10%. There was no accompanying moderation of domestic investment and consumption, which in fact grew by 17.3% and 6.9%, respectively. As a consequence, GDP registered its first negative real growth in a number of years (-2.5%). The full impact on the Gabonese economy will be felt in early 1987, when GDP is expected to drop to almost half its 1985 level. 1/ Oil revenues are expected to drop from 63% to 23% of total government revenues, causing the budget to also be halved and bringing about the curtailment of government expenditures and all-but-essential investments.

1.7 Short-term projections of economic growth indicate a very slow recovery. The most conservative hypothesis assumes that oil prices will rise very slowly to only $16/bbl in 1990. This hypothesis has already been surpassed, oil prices having rebound to $20/bbl by mid-1987. Should prices continue at this level, government oil revenues could reach over 200 billion CFAF (constant 1985 prices) in 1990. This is still only about 55% of its 1985 level. Real GDP will grow only marginally, not to regain previous levels until well into the 1990s.

Energy Resources

1.8 Gabon has a number of indigenous energy resources, including petroleum, natural gas, hydroelectricity, wood, uranium and solar. Only part of potentially exploitable resources have been developed for energy use, both for domestic consumption and for export. To date, the Gabonese have been quite prudent in developing their energy resources. As a result, the country largely is self-sufficient in energy, with the exception of some petroleum product imports.

1/ This one year delay occurs because petroleum sector revenues in any given year are accrued by the Government in the following year.

1.9 In 1987, Gabon's proven petroleum reserves amounted to 133.4 million tons (961 million bbls). This quantity reflected the increase in reserves following new discoveries in 1986 and 1987 (para. 2.10-2.11).

1.10 Natural gas production in association with petroleum was estimated at 2.0 billion Nm^3 in 1985. Only a fraction of this production is consumed for electricity generation and petroleum production and the rest is flared. Official estimates place total proven reserves between 40 and 45 billion Nm^3. Most of these reserves are associated, although there have been minor non-associated discoveries. Economic recovery of natural gas on a large-scale basis poses a number of difficulties, as the gas is found in numerous offshore reservoirs scattered along 400 km of coastline. This situation has improved recently, thanks to Shell's discovery of additional gas reserves. Shell is proposing a conservation policy (reinjection) in the development plans submitted to the Government.

1.11 The total exploitable potential of Gabon's hydraulic resources has been estimated at 50,000 GWh/yr. Slightly more than 1% of this potential is developed; annual hydroelectric production in 1985 was 668 GWh. This quantity accounts for just under 80% of total electricity generation in the country. Total installed hydroelectric capacity now stands at 161 MW (para. 4.3; Table 4.1).

1.12 Over 22 million ha, 80% of the Gabonese territory, is covered by rain forests. Approximately 8 million ha of forest cover is exploited for an annual production of 1.5 million m^3 of industrial wood. An estimated 3 million m^3 (720 ktoe) of unutilized wood wastes is generated annually as a by-product of forestry operations and wood processing industries.

1.13 As there is a relative abundance of economic energy resources, low priority has been given to exploiting the potential for nuclear and solar energy. Gabon has the capacity to produce up to 1,500 tons/yr of yellow cake uranium. Production in 1985 was only 900 tons, and is expected to decrease to 700 tons in the next few years as a result of the international economic slowdown. Authorities at one time considered using this potential for producing electricity, but the utilization of nuclear energy remains limited to small technological applications. The country's high degree of insolation would make it an ideal candidate for solar applications, especially in remote rural areas. To date, there has been only minor research to adapt current solar technologies to local needs and conditions.

Energy Consumption

1.14 Total energy consumption in Gabon is difficult to estimate because of the total lack of information on consumption patterns of fuelwood, charcoal, and other non-commercial fuels. Rough estimates place the per capita consumption of commercial energy marketed in Gabon (petroleum products, natural gas, and electricity) at 600 ktoe in 1985. If use of natural gas and crude oil in petroleum production is included, this figure increases to over 870 ktoe. 2/ By contrast, the commercial energy consumption in Côte d'Ivoire is only 170 ktoe, and in the Congo, it is 150 ktoe. This is exceptionally high for sub-Saharan Africa and indicative of Gabon's relative prosperity. With the addition of fuelwood consumption among the rural populace, total energy consumption per capita is almost 990 kgoe, according to mission estimates.

1.15 The historic consumption of commercial energy is presented in Table 1.1. Consumption grew at an average annual rate of almost 6.0% between 1978 and 1985, before dropping sharply in the aftermath of the oil price drop. Per capita consumption also displayed steady growth of 5.8%/yr. Annual fluctuations in the growth rates during this period reflect the relative weight of petroleum products, which account for 86% of commercial energy consumption. The demand for petroleum products is, in turn, closely linked to the economic situation.

1.16 The 1985 energy balance for Gabon (Table 1.2) shows the current structure of energy demand. The consumption of traditional woodfuels by the rural population has been very conservatively estimated at just over 76 ktoe annually; other statistics show a moderate consumption of fuelwood by sawmills for industrial heat and electricity generation (24.7 ktoe/yr). When these figures are taken into account, as well as primary consumption of natural gas and crude oil by the petroleum industry, the three largest energy consuming sectors are the petroleum industry (34%), households (24%), and other industries including mining (20%). Transport and public sector/civil works follow, with 12% and 8% respectively. 3/ Petroleum products represent 53% of the net domestic consumption, natural gas 24%, fuelwood 12%, and electricity only 8%.

2/ Since these quantities do not enter the domestic retail market, they are not usually counted among the Government's domestic consumption figures.

3/ Well over 50% of the energy demand in the public sector/civil works sector is attributable to construction of the Transgabonese railroad.

1.17 It should be noted that exclusion of natural gas and crude oil consumption totally changes the ranking of sectors according to energy demand. Households (33%), other industry (28%), and transport (17%) become the top consumers in this case, with the petroleum industry relegated to fifth place (8%), just behind public sector/civil works (11%).

Table 1.1: GABON - INDICATORS OF COMMERCIAL ENERGY CONSUMPTION
1978 - 1986

Indicator	1978	1979	1980	1981	1982	1983	1984	1985	1986 a/
Total Commercial Energy Consumption ('000 toe)	350.79	352.93	400.17	437.74	443.77	459.83	489.27	523.29	474.56
Electricity	42.24	45.99	48.72	52.61	57.38	62.69	68.38	74.07	75.08
Petroleum Products	308.55	306.94	351.45	385.12	386.39	397.13	420.89	449.22	399.48
Commercial Energy Growth Rate (%/yr)		0.61	13.39	9.39	1.38	3.62	6.40	6.96	-9.31
Per Capita Consumption (kgoe)	473.03	465.21	515.62	551.34	546.38	553.42	575.61	601.80	533.48
Electricity	56.96	60.62	62.77	66.27	70.65	75.45	80.45	85.18	84.40
Petroleum Products	416.06	404.58	452.85	485.07	475.73	477.96	495.16	516.61	449.08
Growth of Per Capita Consumption (%/yr)		-1.65	10.84	6.93	-0.90	1.29	4.01	4.55	-11.35
Energy Intensity (kgoe per CFAF) b/	0.29	0.28	0.25	0.28	0.27	0.28	0.29	0.32	0.38
Energy Coefficient c/		0.12	0.55	49.69	0.44	-2.38	1.44	-2.80	0.38

a/ Preliminary estimates.
b/ GDP in 1985 CFAF.
c/ Ratio of GDP growth to growth of commercial energy.

Source: Mission estimates, MFBP, MEP.

Table 1.2: GABON ENERGY BALANCE, 1985

('000 TOE)

	Primary Energy					Petroleum Products									
	Fuelwood	Natural Gas	Hydro	Crude Oil	Electri-city	Gaso-line	Kero-sene	Jet Fuel	Gas Oil	Fuel Oil	Avgas	LPG	Other	Tot. Pet. Products	TOTAL
Gross Supply															
Production	821.20	1,382.40	166.90	8,626.00											10,996.50
Imports							13.85		10.73			1.80		26.38	26.38
Primary Exports				(7,984.79)											(7,984.79)
Primary Cons. b/		(207.36)		(28.00)											(235.36)
Unutilized c/	(720.00)	(1,114.21)													(1,834.21)
Stock Changes d/				1.26											1.26
Tot. Avail. Supply	101.20	60.83	166.90	614.47			13.85		10.73			1.80		26.38	969.77
Conversion															
Refining				(614.47)		63.53	88.07		228.19	183.92	2.61	7.73	21.46	595.52	(18.96) e/
Thermal Gen.		(60.83)			16.45				(11.34)					(11.34)	(55.71) e/
Hydro Gen.			(166.90)		57.41										(109.49) e/
Autoproduction f/					0.20				(0.99)					(0.99)	(0.79) e/
Trans. and Dist. Losses g/					(8.97)										(8.97) e/
Stock Changes h/						2.94	(2.80)		14.49	25.98	0.00	(0.10)		40.51	40.51
Net Supply	101.20				65.09	66.47	99.12		241.09	209.90	2.61	9.43	21.46	650.09	816.37
Secondary Exports						(1.17)			(1.06)	(124.35)	(0.75)		(15.97)	(143.30)	(143.30)
Bunker Sales									(5.33)	(48.63)				(53.96)	(53.96)
Net Domestic Cons.	101.20				65.09	65.30	15.99	83.13	234.70	36.92	1.86	9.43	5.49	452.82	619.11
Household/Comm	76.50				24.99	59.42	10.87		30.51					100.81	202.30
Transport						0.12		83.13	17.84		1.86			103.55	103.55
Petroleum Ind.						0.26			51.63					51.90	51.90
Other Industry	24.70				34.89	2.55	0.80		56.80	36.92		9.43	5.49	111.98	171.57
Agriculture						0.39			18.07					18.46	18.46
Public/Civil Works					5.21	1.96	4.32		59.85					66.12	71.33

a/ Hydroelectric supply converted on a thermal replacement basis, assuming 34.4% efficiency.
b/ Consumption of natural gas reinjected for petroleum production, and crude oil used in refining. Although consumed on national territory, these quantities to not reach the domestic market.
c/ For fuelwood, quantities of wood wastes generated annually which go unutilised, but could be tapped as a potential energy resource. For natural gas, quantities of gas associated with annual petroleum production which currently are flared, but potentially could be tapped in part for consumption.
d/ Additions to (negative) or withdrawals from (positive) SOGARA stocks.
e/ Conversion losses associated with transformation from primary to secondary energy.
f/ Purchases from Shell-Gamba for the national grid.
g/ Difference between SEEG net production and SEEG sales.
h/ Additions to (negative) or withdrawals from (positive) distribution stocks.
i/ Assumes rural population consumes on average 200 kgoe/capita/yr. Estimate should be very low, given the high moisture content of wood.

Source: Mission estimates, SEEG, DGH, Sogara, MEHR.

II. HYDROCARBON EXPLORATION AND DEVELOPMENT

Background

2.1 The medium-term evolution of Gabon's economy will depend primarily upon the evolution of oil prices, the prospects for continued investment in the oil sector, and the exploitation pattern of recently discovered oil deposits. This heavy reliance of the economy on oil activities underscores the key issues facing the sector:

(a) the optimum petroleum production profile which will ensure the maximization of the present value of remaining reserves;

(b) the level at which investments should be maintained in both exploration and development activities to offset declining oil production and expand the hydrocarbon reserve base; and

(c) the modifications needed to the fiscal and legal framework governing the activities of the petroleum companies in Gabon to encourage new investment.

Geology of the Region

2.2 Gabon's sedimentary basins cover a total area of 200,000 km^2, which is divided between a small eastern basin (45,000 km^2) and a coastal/offshore basin (155,000 km^2). The coastal/offshore basin is further subdivided into a continental shelf (3,500 km^2) with a water depth of less than 200 m and a deep water (200-300 m) offshore area (120,000 km^2). The continental shelf contains all known commercial hydrocarbon accumulations.

2.3 The sedimentary basins consist of sequential layers ranging from mesozone to recent (predominantly shale/sand) formations, with some carbonate intervals and a thick evaporate section. Reservoirs have been found at depths of 1,000-3,000 m and are mainly constituted by sands and sandstones of various ages and origins. The majority of hydrocarbon bearing traps in Gabon are salt-induced structures, although pre-salt reservoirs are generally tied to basement controlled structures.

Exploration and Production History

Past Activities

2.4 Intermittent oil exploration began in 1928, but the first discovery was not made until 1956 by the Société des Pétroles de l'Afrique Equatoriale (SPAFE), an affiliate of the French Elf Group. Output from the three newly discovered fields (Ozouri, Pointe Clairette, and Port-Gentil) averaged 3,500 barrels per day (b/d) in 1957, equivalent to an annual rate of 177,000 tons. In 1959, Mobil and Shell joined SPAFE, now known as Elf-Gabon, in a series of joint ventures in a 25,000 km^2 area extending south to the Congo. As a result of these efforts, 16 new fields had been discovered and brought on stream by 1964, pushing production to 20,000 b/d (1 million tons/yr).

2.5 From 1965 to 1969, exploration slowed perceptibly as the oil companies concentrated their investments in development. Annual production increased five-fold during this period. Renewed exploration from 1970 to 1977 led to 15 new discoveries. Annual production soared to over 11 million tons in 1974, where it remained for over three years before declining. Output dropped below 8 million tons/yr in the early 1980s, but since has been maintained above that threshold as new fields have been put into production. Table 2.1 shows the evolution of production since 1976.

2.6 The high prospectivity of Gabon's sedimentary basin, coupled with progressive Government policies in the oil sector, encouraged substantial exploration activity during the past decade. Investment expenditures for research and exploration were particularly large between 1979 and 1982 (Annex 2), primarily due to the attractive terms offered in production contracts for that period. By the end of 1983, more than 205,000 km of seismic lines were recorded and about 411 wildcat wells had been drilled, totalling more than 925,000 m (Annex 3). The addition of two new discoveries brought into production at that time raised the estimate of remaining proven reserves to 467 million bbl (65 million tons).

Table 2.1: ANNUAL PETROLEUM PRODUCTION BY OPERATOR, 1976-1986
('000 tons)

Year	ELF	SHELL		AMOCO	TOTAL
	Mandji a/	Gamba a/	Lucina a/	Oguendjo a/	
1976	8,930	1,894	510		11,334
1977	9,254	1,599	414		11,267
1978	8,872	1,392	356		10,620
1979	8,318	1,198	282		9,798
1980	7,509	989	389		8,887
1981	6,300	886	421		7,607
1982	6,299	923	570		7,792
1983	6,270	797	538	237	7,842
1984	6,277	814	663	977	8,731
1985	6,199	734	656	1,037	8,626
1986	6,248	637	614	794	8,293

a/ Gabonese crude oil is classified in four categories according to its density, which ranges from 31° to 39° API. The four types and their barrels per ton equivalent are: Mandji - 7.221
Oguendjo - 7.436
Gamba - 7.259
Lucina - 7.596

Source: DGH.

Current Activities

2.7 There are now 27 international oil companies exploring in Gabon with permits covering 68,000 km^2, including 32,000 km^2 onshore. Seven companies (Elf-Gabon, Shell, Mobil, Amoco, Conoco, Tenneco, and Exxon) act as operators on behalf of the others. Elf-Gabon and Shell control over 80% of the permit area and account for 75% and 15% respectively of total production. Approximately 30,000 km^2 remain free areas, excluding offshore areas with depths over 1,500 m. Of the 45 fields discovered and put into production since 1956, 30 are currently being operated. All but three are operated by Elf-Gabon, primarily under concession agreements (para. 2.17). Amoco's only field in production, Oguendjo, produces under a production sharing contract (para. 2.19), as does the Konzi field operated by Elf-Gabon.

2.8 Commitments for exploration investment in 1986 remained relatively high at 31 billion CFAF (US$91.2 million). Expenditures by Elf and Shell amounted to 90% of the total. Following the sharp decline of oil prices at the end of 1985, Elf and Shell are expected to postpone

some exploration expenditures and concentrate on developing their new discoveries (para. 2.10-2.12). Exploration investments in 1987 and 1988 are expected to be around US$120 million and US$150 million respectively, approximately half of which will be by smaller operators who have only recently begun prospecting in Gabon (Conoco, Agip, Tenneco and Sunoco). Companies, especially those who have recently signed production sharing contracts, have presented a very encouraging work program to the Government.

Future Petroleum Production Prospects

Development of Proven Reserves

2.9 Most fields currently in production have been fully developed and now are undergoing a natural decline in output. As a result, total annual production is expected to drop below 8 million tons in 1987. The anticipated addition to output from fields to be brought into production by Tenneco and Amoco during 1987 and 1988 will be sufficient to sustain total production at this level (Table 2.2).

Table 2.2: PROJECTED ANNUAL OUTPUT OF FIELDS CURRENTLY IN PRODUCTION ('000 tons)

Operators	1986 (actual)	1987	1988	1989	1990	1991	1992
Elf-Gabon	6,248	5,838	5,450	5,183	4,709	4,527	3,907
Shell	1,251	1,157	958	795	659	548	455
Amoco	794	682	922	719	562	440	344
Tenneco a/	____	169	707	749	555	378	224
Total	8,293	7,846	8,037	7,446	6,485	5,893	4,930

a/ Development expenditures already committed to bring three small fields into production in the second half of 1987. Peak production anticipated in 1989.

Source: DGH, mission estimates.

2.10 The Rabi field, discovered by Shell in August 1985, constitutes a crucial element to sustaining short- to medium-term production levels. With recoverable reserves estimated at about 374 million barrels, 299 million proven, Rabi is the largest discovery ever made in Gabon. It is located onshore in the northern section of the Sette Cama block of the Ogooué exploration permit, which is operated by Shell (42.5%) in association with Elf-Gabon (25.5%), the Société Nationale Elf-Aquitaine

(SNEA) (17%) and the State (15%). The southern section of the Rabi field is well defined and conceivably could be put into production two years after a decision is made to invest in production facilities and infrastructure. Negotiations with the Government have advanced sufficiently for production to begin by early 1989. The northern extension to the field has been confirmed and will require further development expenditures. Total costs for developing Rabi, 4/ including drilling, infrastructure, pipelines and modifications to Shell's Gamba terminal for evacuating the crude, were estimated at US$495 million in June 1987. These investments would be phased over a six year period.

2.11 Shell's proposal for phased development of Rabi would start in the southern section, with approximately 25 wells producing in successive phases 20,000 b/d, 60,000 b/d, and 80,000 b/d. The production level would build rapidly to a plateau of 100,000 b/d (4 million tons/yr) by the first quarter of 1990 through the development of other wells, for a total of 58. The plateau could be maintained for approximately four years.

2.12 Two other fields which could be developed are the Rousette field and the Coucal field, operated by Elf-Gabon. Development of these fields could be deferred if Elf-Gabon chooses not to support development investments for this field simultaneously with its participation in the Rabi development.

Oil Production Scenarios

2.13 The mission's estimates for future oil production are presented in Table 2.3. The scenario assumes that Rabi and Coucal will be developed and brought into production. It should be stressed that the projections in Table 2.3 are merely indicative. They do not include the possibility that new fields other than Rabi and Coucal could be developed and brought into production. Seventy-five to 114 exploration wells are expected to be drilled between 1987 and 1991, and some of these are likely to yield successful results.

2.14 The mission has taken a conservative position in its projections to emphasize the importance of Rabi's output for the short- to medium-term. It cannot be automatically assumed that maintaining production above the 8 million tons/yr threshold will prove to be the best strategy for maximizing the present value of all production from the new discoveries, current and future. Still, it is essential to the recovery of the Gabonese economy that high levels of production be maintained. In order to meet both of these objectives, the Government's medium-term strategy should consist principally of providing the proper environment for encouraging exploration and development, especially

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4/ The project financing would include a government participation in addition to investments by Shell, Elf-Gabon and SNEA.

during periods of oil price uncertainty. The implications of this role are discussed in the following section.

2.15 In the short term, the mission recommends that a profile of optimum petroleum production for Gabon be developed, based on oil price projections and estimates of remaining reserves, in order to maximize the present value of the country's petroleum reserves. This profile will serve as the principal element in long-term planning of the national economy (by providing projections of petroleum revenues), and should be updated regularly.

Table 2.3: PROJECTED OIL PRODUCTION, 1987-1992
('000 tons)

	ELF		SHELL				
Year	Present Fields	Coucal	Present Fields	Rabi	AMOCO	TENNECO	Total
1987	5,838		1,157		682	169	7,846
1988	5,450		958		922	707	8,037
1989	5,183		795	1,080	719	749	8,526
1990	4,709		659	3,712	562	555	10,197
1991	4,527	1,247	548	3,712	440	378	10,852
1992	3,907	1,995	455	3,953	344	224	10,878

Source: DGH, Oil companies, mission estimates.

Legal and Fiscal Framework

2.16 Two types of petroleum exploration and production contracts currently are used in Gabon. Under the first type, the concession contract, oil companies are granted the exploration and exploitation rights to a particular concession for a certain period. The maximum period is five years for exploration, three-times renewable in blocks of up to five years. Exploitation rights are granted for 75 year periods, renewable in blocks of 25 years. Four companies operate under this type of contract, including Elf-Gabon and Shell. Approximately 29,500 km^2 (22,000 km^2 onshore) of the area currently under exploration is governed by concessionary agreements, most of which are due to expire in mid-1991.

2.17 The Government and the oil companies sign a "convention d'établissement" (establishment agreement) governing the administrative, legal, fiscal and technical scope of company activities. As an OPEC country, Gabon normally employs the fiscal provisions recommended by the organization. The Government receives an after-tax profit equivalent to

its share in the capital of every producing company that operates under a concessionary agreement. This share can reach 25% and can be taken in kind.

2.18 In line with a new policy, the Government signed its first production-sharing contract in March 1977; pre-existing concessionary agreements remained in force. Under these new agreements, the company has a "work and financial obligation" for exploration, valid for a maximum period of five years. Exploration risk is assumed entirely by the oil company; exploration costs are reimbursed only if there is a commercial discovery. Companies recover their costs by taking up to 40% or 50% of production ("cost oil"), while the remaining 50% to 60% ("profit oil") is split between the Government and the company on a sliding scale basis linked to field output. The company pays no taxes and is free to export its production share with minimal restriction. 5/ The company's financial situation is audited each year by independent accountants hired by the Government.

2.19 The Government initially awarded eight areas under production-sharing contracts to Elf-Gabon and several newly-created associations. Of the three discoveries made to date in these areas, two are currently in production (Konzi for Elf and Oguendjo operated by Amoco on behalf of a consortium). A third, Obando marin (operated by Tenneco on behalf of a consortium) came on-stream September 3, 1987. Production-sharing contracts account for about 26% of the total areas covered by exploration permits and licenses, and about 15% of annual oil production.

2.20 Although existing permits granted to the oil companies remain valid, the Government is expected to assume a greater role under the new production-sharing agreements. It currently is negotiating with a number of companies to ensure maximum uniformity and cohesiveness in the fiscal conditions applied under its various contracts. Another round of bids took place between spring and November 1987.

2.21 The Government should continue to exercise sound judgement in negotiating under the provisions of the new contractual arrangements, and that it act with the same prudence in its negotiations to ensure that the climate of confidence, which traditionally has characterized exploration activity in Gabon, is maintained. Specifically, the Government should take advantage of the expanded role permitted under production sharing contracts, which it has implemented, to:

(a) improve the monitoring of upstream petroleum activities; and

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5/ Companies are required to sell a small fraction of their output to the local refinery (para. 3.6).

(b) develop relevant fiscal policies which simultaneously (i) serve as incentives for continued exploration efforts by international concerns and (ii) optimize the conditions for government take.

2.22 The team currently assigned to monitor exploration activities within the Directorate General of Hydrocarbons (DGH) is working in this direction. The mission recommends that their terms of reference be reviewed and amended to give them official responsibility and accountability for (a) formulating appropriate policy and (b) identifying possible mechanisms for its implementation. The specific provisions to be included should be determined in the context of the petroleum subsector institutional review recommended in Chapter III (para. 3.22). The institutional review should also define the requirements for additional training in this area.

Sector Organization

2.23 The Ministry of Mines & Hydrocarbons (MMH), through the DGH, monitors petroleum exploration and production activity in Gabon, as well as domestic refining activities. The DGH also negotiates with the oil companies and represents the government interest in the companies' executive boards. The DGH's responsibilities are subdivided among three main functions: technical, financial, and documentation. At the time of the mission, the DGH was being restructured with the help of long-term technical assistance from international experts. The mission recommends that the DGH take advantage of the presence of these international experts to design and implement an intensive training program in order to:

(a) increase its ability to monitor exploration and development activities; and

(b) more importantly, take full responsibility for developing and managing petroleum sector fiscal and investment policies.

2.24 The Government created the national oil company Petrogab in 1979 in order to coordinate more effectively its interest in the petroleum sector. Petrogab's statutes were very broad, covering all aspects of hydrocarbon exploration and development, as well as product and crude transport and storage. Until 1983, Petrogab's primary duty was to market 25% of the government share of Elf-Gabon's production. (The rest was marketed directly by the DGH.) Petrogab also served as an unremunerated intermediary between Elf-Gabon and the SOGARA refinery, for the invoicing of purchases of crude oil (para. 3.7). This activity seemed to be redundant, as the refinery can be supplied directly by the companies.

2.25 Following an agreement between MMH and the oil companies in 1983, Petrogab undertook a limited active role in exploration by acquiring a minor share in the Oguendjo and Olende fields. It has also secured an exploration permit through Gaborep (40% Petrogab, 60% Perrodo Group), with work obligation of US$7 million in three years. This permit includes an area relinquished by Shell (two wells tested, but the discovery was not considered economical by Shell) and subsequently allocated to Gaborep.

2.26 Petrogab's role in the petroleum sub-sector has long been poorly defined. It was questionnable even if Petrogab need exercise some of the responsibilities it had been granted in official statutes, given that many were already performed quite satisfactorily by the DGH and other petroleum sector institutions (para. 3.18-3.21). Consequently, the Government decided in 1987 to liquidate Petrogab, a step which the mission approves. The mission recommends that Petrogab's former activities and responsibilities be thoroughly examined and revised within the context of an institutional review of the entire petroleum subsector, as defined in para. 3.22, and that the scope of these activities be precisely attributed to other sub-sector institutions in amendments to official statutes.

Potential for Natural Gas Development

2.27 The Government has been investigating gas utilization since 1968, when it formed its Gas Committee ("comité gaz") (para. 2.19). There have been a number of limited studies since then to ascertain the magnitude of reserves and the feasibility of production for certain projects. One such project was the production of ammonia, studied by Pierre-Fite-Auby in 1973 and again by Voest Alpine in 1978; the project was scrapped in mid-construction after the latter study did not confirm its economic feasibility. Two important studies were conducted in the early 1980s, one by Elf-Gabon (1981) and the other by Degolyer and MacNaughton/Bechtel (1984) to determine the feasibility of recovering gas from the Torpille (30% of remaining gas reserves) and Anguille fields, extracting the liquids and then storing the gas in the old Lopez Nord oil field to be used at a later date. Elf-Gabon concluded that the project was not economic and that any attempt to exploit gas reserves for commercial use could not be justified economically. Degolyer and MacNaughton/Bechtel, on the other hand, found the project marginally economic at a price of US$1.56/MMBTU, if the gas is used mainly for power generation.

2.28 There are three distinct points of view expressed by the principals involved in the development and utilization of natural gas. From the consumer side, the electric company, SEEG, appears for the moment to be the only major potential user if gas is developed. SEEG would be interested in gas only if it could be delivered at a price competitive with planned hydroelectric developments (para. 4.27-4.30),

and if the supply could be assured over the long term. From the producer side, the oil companies want to be assured that the gas price will cover their costs of development and exploitation. Many are convinced at this point that there is no way to economically develop the quantities of gas needed by SEEG at prices required for thermal generation to be competitive with hydroelectric power. The third view is held by the promoters, who counsel that by use of their exploitation techniques, extracting the gas from certain fields and storing it in empty reservoirs for later use would be marginally economic.

2.29 The Government has formed a Gas Committee to initiate and review the studies and proposals for gas development and utilization, and to decide upon gas development priorities. Committee members include representatives from the MMH (both directorates), the Ministry of Energy and Hydraulic Resources (MEHR), the Ministry of Planning and Economy (MPE), the Ministry of Finance, Budget and Participations (MFBP) and the Présidence. The major conclusions drawn by the Committee in earlier discussions were that:

(a) The oil companies are not interested in gas development, since the price of gas will not cover their exploitation costs. To meet SEEG's criteria, it is most likely that the "prix de cession" would have to be fixed on a political basis, and not by the market.

(b) The results of recent studies are biased by the apparent conflicts of interest of the groups conducting them, and thus the reliability of their findings is questionable.

(c) Although it would be impossible to develop all available reserves due to the nature of the reservoirs (para. 1.10), there are some fields which could be developed economically under certain conditions.

(d) The only viable consumer for the gas is SEEG, which is very skeptical about plans committing it to develop large, gas-based thermal generating capacity. The Government would be willing to "encourage" development of marginally economic fields if SEEG could guarantee that it would consume the quantities produced.

2.30 In the aftermath of the 1985 oil price drop, natural gas development was accorded a low priority in national energy planning. The only major market identified to date, SEEG, totally revised its investment plans to take into account new demand forecasts and limited availability of natural gas (para. 4.17-4.19). The discovery of new hydrocarbon reserves call once again for the re-evaluation of gas utilization scenarios. Major reserves of natural gas--an estimated 385 billion standard cubic feet (BSCF) of associated and 490 BSCF free gas-in-place--are associated with Shell's Rabi field (para. 2.10-2.12). Shell has already presented the Government with plans to conserve this

gas for future development through a reinjection program (5,150 million CFAF). In addition, Tenneco has made proposals for development of natural gas associated with its Obando Marin field. Approximately 75 BSCF could be made available to SEEG at an estimated cost of 12 CFAF/m^3 (about US$1.5/MBTU), based on demand projections supplied by SEEG. SEEG currently pays about 24 CFAF/m^3 for its purchases of natural gas.

2.31 The availability of competitively priced natural gas in sufficient quantities substantially changes the options for medium- and long-term electricity system development in the late 1990s and after. For this reason, the mission recommends that the options for exploiting and developing natural gas be fully determined with minimal delay. A feasibility study should be undertaken which will include:

(a) an evaluation of reserves using presently available data;

(b) a preliminary assessment of potential conventional markets (power, industrial, residential and commercial) and unconventional markets (transport, agriculture);

(c) an estimate of the investment costs to produce and transmit the gas to the main local markets;

(d) a preliminary analysis of pricing issues with respect to gas; and

(e) recommendations for future action.

The feasibility study would determine whether it is justifiable to undertake an intensive utilization study aimed at optimization of the use of projected supplies, further analysis and comparison of investment and conversion and consideration of contract provisions (pricing and taxation) which direct the interest of the Government's commercial partners in the development of reserves. Detailed Terms of Reference for the feasibility study are presented in Annex 5.

III. PETROLEUM SUPPLY AND DISTRIBUTION

Petroleum Product Demand

3.1 The total domestic market for petroleum products in Gabon (1985) amounted to about 464,000 tons (Table 3.1). Gas oil comprises more than half of total sales; however, only 11% of total gas oil sales are made through retail outlets while the largest 11 customers account for half the sales. Jet fuel is the second most important product in terms of sales volume (18%); an estimated 57% is consumed by the national airline and the air force, with foreign airlines accounting for the remainder. Gasoline, which accounted for about 14% of total sales is predominantly sold through the 99 petroleum product retail outlets across the country. Fuel oil accounts for only about 8% of sales, and is entirely accounted for by two consumers - Ciments du Gabon (92%) and the SOBRAGA Brewery (8%). Kerosene and butane, which account for only 2% and 3% respectively of sales, are primarily household fuels. Kerosene is sold through the petroleum companies' retail outlets and by peddlers in outlying areas, while butane is predominantly an urban middle class cooking fuel.

Table 3.1: DOMESTIC PETROLEUM PRODUCT SALES, 1980-1985 a/
('000 tons)

Product	1980	1981	1982	1983	1984	1985	Average Annual Growth Rate 1980-1985 (In %)
Butane	6.1	6.7	7.3	8.3	8.9	8.9	7.8
Aviation Gasoline	2.9	2.6	2.2	1.7	1.6	1.8	-9.1
Gasoline	51.2	53.5	56.8	61.7	62.2	65.3	5.0
Kerosene	9.7	10.0	10.7	12.0	14.7	15.8	10.2
Jet Fuel	68.6	75.6	74.8	70.5	78.3	81.5	3.5
Gas Oil	176.9	204.3	207.2	215.3	221.6	234.7	5.8
Fuel Oil	33.7	29.5	24.3	24.5	30.4	38.1	2.5
Asphalt	6.8	5.4	8.4	9.9	9.9	8.3	4.1
Total	355.9	387.6	391.7	403.9	427.6	454.4	5.0

a/ Excluding lubricants.

Source: DGH, GPP, MEHR.

3.2 The consumption of petroleum products is regionally skewed. Three of the country's nine provinces--Estuaire (the Libreville region), Haut Ogooué (the upland mining region), and Ogooué Maritime (the oil producing region)--accounted for 88% of gasoline consumption, 73% of the gas oil consumption, and 68% of the kerosene consumption. All the fuel oil and butane consumption also occurred in these regions.

3.3 Overall petroleum product sales averaged 5% volume growth between 1980 and 1985, with growth in 1984-85 amounting to 6.3%. The fastest growing fuels have been household energy fuels--kerosene and butane--which averaged 10% and 8% growth respectively over the 1980-85 period, but these products still only account for 5% of total sales. The consumption of gasoline and gas oil averaged relatively steady growth of 5% and 6% per annum respectively. Sales of jet fuel grew at a somewhat lower rate of 4% per annum over the period, but year-to-year sales have fluctuated considerably, reflecting the tendency of international airlines to base their purchases on relative prices vis-à-vis neighboring countries' airports.

Petroleum Refining

3.4 Gabon's oil refinery, the Société Gabonaise de Raffinage (SOGARA), is the principal supplier of finished products to the domestic market. SOGARA is structured as a private company with national priority status. The nine shareholders include the Government and various marketing companies operating in the country (para. 3.9). 6/ Its activities are heavily regulated by the DGH, within the MMH.

3.5 SOGARA's installations were integrated with those of the former COGER refinery in 1985, 7/ leaving it with a nominal distillation capacity of 1.2 million tons annually. Cracking and reforming capacities limit its efficient production capacity to 700-750,000 tons/yr, however. In 1986, the refinery was operated at about 650,000 tons throughput, which sufficed to meet domestic demand for gasoline, kerosene, gas oil, and fuel oil. However, some imbalance remains between domestic demand and refinery output. About 100,000 tons of excess fuel oil are sold on the international market, as well as occasional batches

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6/ Government: 25.00%, Elf: 18.75%, Total: 18.75%, Mobil: 11.6%, Shell: 11.39%, Texaco: 5.6%, Fina: 3.3%, BP: 3.10% and Agip: 2.50%. The Government has the option of increasing its share to 51.00%.

7/ The Compagnie Gabon Elf de Raffinage (COGER) was owned by the Government (30%) and Elf Gabon (70%) and was operated as an export-oriented refinery from late 1976 until 1985. Part of COGER's 1 million ton/yr capacity was leased to SOGARA before the installations were merged.

of naphtha. It is also necessary to import butane on a regular basis, as refinery output meets only about two-thirds of total demand. Butane imports currently amount to about 3,000 tons annually; because of limited butane storage capacity, these additional requirements must be imported in small lots, at very high unit costs (para. 3.16).

Table 3.2: SOGARA REFINERY CHARACTERISTICS

Facilities	Capacity
Processing Units (Tons/day)	
Atmospheric distillation	2,800
Hydrotreatment	680
Catalytic reformer	180
Thermal cracking and visbreaker	1,300
Storage Capacity (m^3)	
Butane	300
Gasoline	12,000
Jet Fuel/Kerosene	5,500
Gas Oil	28,000
Fuel Oil	29,400
Crude	19,940

Source: SOGARA.

Supply Arrangements for Crude Oil

3.6 SOGARA is obligated by government statute to refine the Gabonese crude, Mandji (29° API). All companies producing in Gabonese territory are required to supply a portion of their (after tax) production to meet SOGARA's needs. Elf-Gabon consolidates the production and delivers it to SOGARA in batches of 65,000 bbls via a 17 km pipeline from its terminal at Cap Lopez.

3.7 The crude is purchased from Elf-Gabon at a price set by the Ministry of Finance, Budget and Participations (MFBP) on a quarterly basis; this is generally the official OPEC price (para. 3.26). Payments were made through Petrogab, the national oil company (para. 2.32), on a 90 day basis. The purchase was billed in dollars, but the currency of payment was CFA francs (CFAF) at the exchange rate in effect at the end of pumping. Petrogab received no remuneration for this intermediary role, although one full-time engineer and three part-time administrative workers are allocated to this transaction, at cost to the company of an estimated 100 million CFAF/yr (US$333,000).

3.8 In view of the fact that Petrogab has been liquidated (para. 2.26) direct invoicing by Elf-Gabon could be re-established. Such direct arrangements have operated efficiently in the past. The transaction could be subject to periodic, unannounced audits by the DGH as part of its monitoring activities throughout the petroleum subsector.

Product Marketing and Distribution

Marketing Arrangements

3.9 Products destined for the domestic market are delivered to storage depots outside Port-Gentil by the marketing companies and the Société Gabonaise d'Entreposage des Produits Pétroliers (SGEPP). SGEPP is owned jointly by the marketing companies operating in Gabon in 1986: BP, Agip, Mobil, Total, Texaco and PIZO. The first five are affiliates of major international petroleum companies, with the Government holding 10% of their stock. PIZO, which because of financial difficulties was liquidated by the end of 1987, (para. 3.12) was the national marketing company. It was owned by the Government (50%), Shell (20%), Elf (20%) and Agip (10%) and was created to ensure that all regions of the country have access to petroleum products. PIZO was the market leader in 1985, with 36% of the total inland product sales (Table 3.3).

Financial Difficulties for PIZO

3.10 Almost all of the marketing companies service the interior of the country to some extent. The burden of supplying these (generally) low-volume demand centers has fallen disproportionately to PIZO because of its official mandate to supply the entire territory. Until 1986, PIZO operated almost half of the retail outlets outside of Libreville and Port-Gentil. The figures in Table 3.4 give some indication of PIZO's retail market share relative to the number of its retail outlets, as compared with other marketing companies.

Table 3.3: DOMESTIC MARKET SHARES OF THE DISTRIBUTION COMPANIES BY PRODUCT, 1985 a/
(%)

Products	COMPANIES						Retail Market c/
	TOTAL	MOBIL	TEXACO	BP	PIZO	ELF b/	
Gasoline d/	24.0	18.9	6.9	13.9	36.3	--	91.0
Kerosene	24.5	20.1	14.1	19.7	21.6	--	68.0
Gas Oil	29.1	12.7	9.0	13.3	35.9	--	13.0
Jet Fuel	9.8	30.9	--	--	38.7	10.2	--
Fuel Oil	20.3	19.5	4.0	14.9	41.3	--	--
Lubricants	20.3	36.1	3.9	11.7	28.0	--	15.0

a/ Excluding sales to international bunkers and airlines by Elf-Gabon and Shell.
b/ Elf does not market refined products within Gabon, except jet fuel sold to the national airline.
c/ The percentage of products sold on the retail market, as opposed to wholesale or bulk sales of products to large customers, e.g. SEEG, Elf-Gabon, Transgabonais, the State.
d/ Combined regular and super.

Source: GPP, MEHR, mission estimates.

Table 3.4: RETAIL MARKET INDICATORS FOR PETROLEUM PRODUCTS, 1985

	TOTAL	MOBIL	TEXACO	BP	PIZO	
Number of retail outlets						Total
Libreville and Port-Gentil	12	8	5	10	20	55
Interior	5	9	7	5	18	44
Total	17	17	12	15	38	99
Percent of retail sales						
Gasoline a/	21.3	20.9	7.4	14.5	35.8	
Gas oil	29.3	19.6	9.9	13.9	27.1 b/	
Lubricants	26.8	41.8	11.5	9.3	10.7	
Total Share of Retail Market	25.8	27.4	9.6	12.6	24.5 c/	

a/ Includes regular and super gasolines.
b/ Many of these sales are through the use of vouchers issued for use by government employees or employees of parastatal and public enterprises.
c/ Note that many of PIZO's sales were to bulk and/or preferential customers who do not purchase products on the retail market.

Source: GPP, MEHR.

3.11 PIZO also handled most of the public sector market for products. Nearly 35% of PIZO's market in 1985 was comprised of the public administration and public sector enterprise. The Government did not pay PIZO until at least 180 days after billing, and PIZO found it difficult to recover the full amount billed even at that stage. Public sector arrears to PIZO were commonly between nine and twelve months, amounting to a total 4 billion CFAF (US$13.3 million) by the end of 1985. As a result, PIZO's average arrears were 120 days, as compared to 35-40 days for Total, 38-40 days for Mobil, and 37 days for BP.

3.12 The severity of PIZO's financial difficulties led the Government to convene a technical working group in 1986 to address the problem. The group, which is composed of representatives from the MMH, MEHR, MFBP, MEP and PIZO, completed its evaluation in early 1987. Its main conclusion, based on a preliminary recommendation by the mission, was that PIZO should be liquidated and its assets sold to a private company. Shell has formed a new marketing company, with the Government as a minority shareholder, which has purchased PIZO's assets. A committee was appointed to oversee the implementation of the liquidation. The mission recommends that (a) the final liquidation plan include very clear provisions for the payment and/or cancellation of all or part of PIZO's debts and accounts payable before implementation is begun; and (b) the Government explore and identify economic interim solutions to ensure that remote areas are supplied following the liquidation of PIZO (para. 3.17).

Product Distribution Strategy

3.13 In early 1983, the consulting firm BEICIP (France) assessed the national requirements for infrastructure investments in storage and transport of petroleum products at the request of the Government. BEICIP's final recommendations were based on a medium growth hypothesis for future demand, one of several alternative demand growth scenarios prepared in the report (Annex 7). The minimum investment strategy proposed by BEICIP is split almost evenly between additions to existing storage capacity (7.5 billion CFAF) and transport investments (8.3 billion CFAF). The volume of the recommended additions to storage was calculated on the basis of 45 days of consumption.

3.14 In light of the recent economic slowdown, the mission has adopted a lower growth scenario (BEICIP's "low scenario") for product demand, and modified BEICIP's proposal accordingly (Annex 8). The mission recommends that Gabon minimize its storage investments by adopting a commercial inventory reserve of less than 45 days. An adequate reserve level could be 25 days, although the Government may choose to increase this level, if it is considered inadequate for strategic reasons.

3.15 The mission believes that a 25 day reserve would be adequate since Gabon is an oil producer, has a refinery which is located near the oil fields, and has good storage capacity at the refinery. There is also very good product supply availability on the West African coast, which would present alternative sources of supply. 8/ Adopting a 25 day reserve inventory, along with the low growth scenario for product demand, would imply total additional investment in product storage through 1992 of 22,500 m^3 at a cost of 1.5 billion CFAF. This would represent a substantial potential savings over a 30 day inventory (32,000 m^3 at 2.1 billion CFAF) or a 45 day inventory (55,200 m^3 at 3.0 billion CFAF).

3.16 Regardless of the overall inventory level decided upon, there is a need for major investment in butane storage facilities at Owendo. BEICIP has recommended that two 2,000 m^3 spheres be installed. These would establish the required reserve inventory and be sufficient to handle anticipated growth in butane demand, while also permitting a savings of up to $150/ton due to the ability to purchase butane in more economical volumes. For a demand of 3,000 tons per year, the annual savings would amount to about $450,000. This would have a significant beneficial impact on the current deficit in the equalization fund used to subsidize butane imports (para 3.22). The mission therefore recommends that one butane sphere be installed immediately but only if the investment can be justified by showing a payback period of less than two years. With such justification, the project would prove to be the best short-term strategy for meeting the current butane demand. In the meantime, an analysis of butane demand growth and the options for meeting this growth should be undertaken. This analysis could be included as a component of the household energy study proposed by the mission; in addition, it should incorporate the conclusions of the petroleum pricing study (para. 3.43-3.44). The need to install a second sphere should be examined around 1992, depending upon the growth in butane demand. A timetable for these and the other storage investments is given in Table 3.4 below.

3.17 The BEICIP study also recommended the establishment of additional service stations. While the mission supports the need to ensure that fuels are supplied to remote areas, it also feels that more economic interim solutions--e.g., using drum supply in conjunction with hand pumps--should be considered.

8/ BEICIP's analysis indicates that additional imports represent a less costly alternative to augmenting domestic supplies during supply interruptions (due to planned refinery shutdowns, for instance) than does additional storage.

Table 3.5: SUGGESTED INVESTMENT PROGRAM 1987-1991
(million CFAF)

	1987	1988	1989	1990	1991
TANKAGE					
Owendo					
Gasoline	--	200	200	--	--
Kerosene/Jet	--	232	--	--	--
Gasoil	--	--	200	232	--
Lambarene					
Gasoline & Kerosene	--	--	67	--	--
Gasoil	--	--	--	--	133
Moanda					
Gasoil	--	--	--	200	--
Jet	--	--	--	34	--
BUTANE					
Sphere	1,500	--	--	--	1,600
Bottles	--	150	150	100	100
RETAIL OUTLETS	20	20	20	20	20
Total	1,520	602	637	586	1,853

Source: Mission estimates.

Institutional Issues

3.18 The Ministry of Energy and Hydraulic Resources (MEHR), through its Directorate General of Energy (DGE), is nominally the ministry which oversees petroleum product marketing and distribution and ensures the domestic supply of refined products. However, several government ministries intervene to monitor product imports and total supplies, fix prices, and participate in various downstream activities. Although the responsibilities of the various ministries within the Government are defined by statute, there is a tendency for them to overlap.

3.19 Legal texts give authority to supervise refinery operations to both the DGH and the DGE. The DGE is also given authority to supervise "investment, marketing, policy [and] prices", activities which are equally under the mandate of the MFBP and the MPE.

3.20 In practice, the DGH supervises and monitors crude supply to the refinery and refinery operations, while the DGE supervises all petroleum sector operations not related to production. Both ministries act only in an advisory capacity, however, to the MFBP and the MPE on matters concerning annual investment and operating budgets (for SOGARA, PIZO, SGEPP), the price at which crude oil is purchased by the refinery, ex-refinery prices and market prices for refined products.

3.21 While this "de facto" division of responsibilities permits the system to operate without major difficulties, it is not clear that it is conducive to the most efficient operation of the marketing and distribution system. Under these arrangements, the MEHR's real authority is effectively limited to the approval of new depots or retail outlets. Although there is some communication of data and statistics from the marketing companies through the Groupement Professionnel des Pétroliers (GPP), it does not appear that the MEHR is kept regularly informed of product imports. Their documentation of refined product supply is incomplete, at best. Nor does the MEHR participate directly in the process to establish retail prices (para. 3.32). In effect, the lack of clear distinction of responsibilities not only restricts the coordination of policy between the ministries, but also leaves gaps in the exercise of supervisory functions.

3.22 The mission recommends that the Government review the existing legislation to amend all duplication of responsibility among the institutions of the sub-sector. This review should take place following a more extensive institutional review for the subsector to determine the proper roles for the DGH, MEHR, MFBP and MPE in product marketing and distribution. The extensive review should include, but not be limited to, the following tasks:

(a) fully assess the "de facto" roles of the various institutions and their effectiveness in fulfilling said roles;

(b) make a thorough accounting of the major areas of operational and supervisory responsibilities (some of which may already be accounted for in the legal texts) which are not exercised or are ineffectively carried out under the current system;

(c) evaluate the capabilities and resources of the various institutions relative to (i) the tasks which they currently exercise, and (ii) those tasks for which they are legally responsible;

(d) identify the appropriate division of responsibilities among the various institutions based on the evaluations in (a), (b), and (c); and

(e) determine new staffing, training, and resource requirements where needed and develop a plan to implement proposed changes.

Petroleum Product Pricing

3.23 The Government of Gabon intervenes heavily in the pricing of petroleum products at both the ex-refinery and retail levels. Its principal objective is to ensure relatively stable prices for petroleum products in the domestic market. Provision is also made through flexible fiscal policies to cover costs while allowing a reasonable profit margin for the refinery and the marketing and distribution companies. Changes in prices consequently take place only when there have been major international price shifts.

Ex-Refinery Prices

3.24 Until 1981, ex-refinery prices were established according to import parity (Caribbean) prices. Under the current system, the MFBP estimates the price at which crude oil will be purchased by SOGARA, then calculates a margin which will both cover costs and provide a small profit to SOGARA. The margin is determined on the basis of a budget presented by SOGARA.

3.25 The MFBP's assessed value of crude oil is a reference price based on estimates of the average official OPEC price. Although it normally is adjusted quarterly, adjustments were made monthly during the first two quarters of 1986 because of the rapid evolution in OPEC quotes following the 1985 price drop. 9/ The MFBP's assessed value for the third quarter 1986 crude price was fixed at $10.50/bbl.

3.26 The price at which SOGARA actually purchases the crude, the official OPEC price for Mandji, can differ substantially from the MFBP assessed value. 10/ For example, the MFBP assessed value of crude used in the price structure for the second quarter of 1986 (April 10, 1986) was $15/bbl at an exchange rate of 370 CFAF/US$. The actual OPEC quote for April was $13/bbl. During the first half of 1986, such differentials resulted in a windfall profit for the refinery. For the month of April, the windfall would have been equivalent to US$130,000 for delivery of one 65,000 bbl batch (para. 3.6), or about US$1.3 million annually for a $2 differential maintained throughout the year, not including the benefits arising from fluctuations in the exchange rate.

9/ The OPEC price moved as follows during this period: January - $21/bbl; February - $15/bbl; March - $14/bbl; April - $13/bbl; May - $13/bbl; and June - $12/bbl.

10/ As noted in para. 3.7, SOGARA's purchase price is billed in US dollars, payable in CFA francs using the exchange rate in effect at the time of pumping.

3.27 The windfall profit to the refinery only occurs when the MFBP underestimates the OPEC price. More commonly before the oil price drop, the quarterly price used by the MFBP in the pricing structure underestimated crude costs. This, combined with margins inadequate to cover SOGARA's actual operating costs, has led to losses which must be absorbed by the refinery, seriously reducing its working capital for improving operations.

3.28 The added margin covers operating costs, fixed and financial charges and profit. Forecasts of annual product sales and exports are prepared by SOGARA and submitted for review with an associate operational budget to the MFBP. The per unit costs projected for 1986 (at an exchange rate of 340 CFAF/US$) were comprised of US$20.3/ton in variable costs (including fuel), US$7.35/ton for transport, US$34/ton in overhead costs--a total of US$61.50/ton for operating costs--plus US$5.20/ton and US$8.60/ton for financial costs and depreciation, respectively. 11/ Both operating and financial costs appear unusually high compared to industry standards in West Africa.

3.29 The resulting ex-refinery prices are considerably higher than the economic costs of refined products, which are represented by import parity prices in Table 3.5. Clearly, the differential between the actual cost of crude and the MFBP's assessed value contributes substantially to the distortion of ex-refinery prices relative to import parity. Yet even when adjusted for this differential, ex-refinery prices are 26%-52% greater than import parity. Given that the ex-refinery prices presumably reflect the actual costs of refining, SOGARA may not be the most economic source of supply for the country. However, the mission was not able to determine during its brief assessment the scope for bringing the costs of local refining more in line with the economic costs of supply, and a full economic analysis of the refinery was outside of its mandate.

3.30 The cost-plus system of determining ex-refinery prices, based on an assessed value of crude, offers little incentive for least cost supply of refined products. The problems inherent to the system would not be alleviated simply by modifying the frequency of adjustments to MFBP's assessed value, as this appears to be only one of many factors contributing to high ex-refinery prices.

11/ SOGARA's financial costs for 1986 total almost 20 billion CFAF. This can be broken down into debt burden (14.4 billion CFAF) plus the net difference between receivables (16.8 billion CFAF) and accounts payable (11.4 billion CFAF). The high figure for receivables is primarily due to PIZO's outstanding debts (9 billion CFAF) to SOGARA.

Table 3.6: COMPARISON OF EX-REFINERY PRICES AND IMPORT PARITY, 1986
(US$/ton)

Products	Ex-Refinery a/	1st Quarter 1986 Import Parity d/	Ratio	4th Quarter 1986 c/ Import Parity e/	Ratio	Adjusted Ratio f/
Premium Gasoline	255	213	1.2	173.5	1.47	1.3
Regular Gasoline	265	198	1.34	158.5	1.67	1.52
Kerosene	239	244	0.98	170.0	1.41	1.26
Gas Oil	225	212	1.06	142.0	1.58	1.41

a/ Ex-refinery prices in price structure effective April 10, 1986 (Annex 9). Exchange rate: 340 CFAF/$1.00.
b/ As of April 1, 1986, before new price structure. Average spot value of Mandji - $15.50/bbl.
c/ As of October 23, 1986.
d/ NWE April 1986 plus insurance and freight.
e/ NWE October 1986 plus insurance and freight.
f/ Adjusted for "windfall component" in the ex-refinery price due to the difference between the assessed value for Mandji in the April 10 price structure (still in effect in October) - $15/bbl - and spot market value of Mandji in late October 1986 ($11.5/bbl).

Source: MFBP, mission estimates.

3.31 A restructuring committee has been formed to review the structure of ex-refinery prices. Nonetheless, the mission recommends that the Government return to import parity pricing as the basis for determining ex-refinery prices in order to encourage more economic supply of products. The exact nature of the pricing system should be defined in the context of an in-depth refining and product pricing diagnostic study. The three main objectives of this study will be to (a) undertake a diagnostic evaluation of refinery operations and a management audit of SOGARA; (b) examine the arrangements and costs for supplying crude oil and refined products to the country; and (c) review the petroleum product distribution strategy and pricing system. The study, which will follow-up a financial audit of SOGARA planned for the beginning of 1988 under the MPE's supervision, should examine, but not be limited to, the following:

(a) the efficiency and full costs of refining at SOGARA's facilities, including (i) a thorough evaluation and breakdown of all operational and financial costs and (ii) review of management practices which may affect refining costs;

(b) the scope for reducing refinery operating costs through financial restructuring (e.g, debt to government equity) and improving the technical, financial, marketing and managerial factors as identified in (a), so as to ensure sustained economic and financial viability;

(c) the optimal combination of cost reduction measures which would bring SOGARA's costs closer to import parity costs;

(d) the costs of importing products from alternative sources (including other West African refineries) versus local refining under a scenario of cost reduction; the economic cost to the Gabonese economy of choosing to supply itself from SOGARA rather than from alternative sources;

(e) the levels for ex-refinery prices, using import parity as the base, which will serve as an incentive for both (i) the implementation of cost reduction measures by SOGARA, and (ii) economically efficient operation of refining facilities in the future. The import supply alternative which is least costly to the economy (determinated in (d)) should be used as reference. An appropriate formula for calculating the ex-refinery prices should include components representing the costs of supplying the country from the next best supply source; 12/

(f) the appropriate institutional arrangements for monitoring and adjusting ex-refinery prices and the frequency with which they should be adjusted; and

(g) the reforms necessary to simplify the retail price structure, and to institute a formal mechanism for regular consultation and revision of retail prices, as specified below (para. 3.42-3.44).

3.32 SOGARA would be required to deliver products at the ex-refinery prices calculated under the import parity formula; its profit would be determined by the degree to which it can reduce its costs below this level.

12/ Principal elements of the formula thus defined would be: (a) freight and insurance; (b) terminalling, maintenance cost and operator profit; (c) port costs; and (d) capital recovery for investments required to allow efficient handling of products.

Retail Price Structure

3.33 The prices for all petroleum products in Gabon (except lubricants) are set officially. The MFBP calculates the prices according to a complex structure which includes the ex-refinery price, transport costs, distributors' remuneration, financial costs, retail margins, various taxes and the requirements for various policy-based funds. The main features of the resulting price structure are:

(a) cross-subsidization among products to benefit those considered "socially sensitive", either through ex-refinery price levels (butane) or through various taxes and levies (kerosene);

(b) stabilization of consumer prices over time with the objective to avoid frequent adjustments; and

(c) geographic cross-subsidization to minimize the differences in the price of a given product throughout the nation.

3.34 The retail price structure has been adjusted infrequently and only twice in the past three years. When the marketing companies consider a price adjustment is required, they make a request through the GPP. The request is made to the MFBP, which reviews the merits of the proposal. For the most part, requests are kept under advisement until there is need to modify one of the major components of the structure.

3.35 Table 3.7 below shows the major structural elements of the prices in Libreville and Port-Gentil for the four main products: premium gasoline, regular gasoline, gas oil and kerosene. The price structures for products sold in other localities (Annex 9) include additional elements for transport, storage, and (further) geographic equalization (para. 3.32). The transport component is fixed by decree, with "reimbursement" to the distribution companies according to the type and quantity of products delivered and the distance travelled (Annex 10). The price of locally refined butane also is constructed according to a rather complicated structure (Annex 11). The prices of other products, including fuel oil, jet fuel and asphalt, are set by decree.

Table 3.7: MAJOR COMPONENTS OF THE PETROLEUM PRODUCT PRICE STRUCTURE a/
(CFAF per 100 liters)

Component	Gasoline		Kerosene	Gas Oil
	Premium	Regular		
Ex-refinery	6,436.4	6,433.6	6,448.7	6,451.3
Stabilization Fund Tax	1,029.0	824.7	-2,860.4	377.7
"Stabilized" Cost	7,465.4	7,258.3	3,588.3	6,829.0
Taxe Complémentaire	14,700.0	14,700.0	700.0	3,500.0
Equalization Fund Tax	1,700.0	1,700.0	1,700.0	1,700.0
Other Taxes, Charges, Margins	4,134.6	3,841.7	2,811.7	2,871.0
Retail Price	28,000.0	27,500.0	8,800.0	14,900.0
Retail Price per liter	280.0	275.0	88.0	149.0

a/ Libreville and Port-Gentil, as of April 10, 1986.

Source: Directeur Général des Caisses de Stabilisation et de Péréquation.

3.36 Two of the most important components of the price structure are the Stabilization and Equalization Funds, both administered by the MFBP. The Stabilization Fund was established in 1972 to ensure the stability of petroleum prices, at the distribution stage, over time. Originally, only gasoline was taxed to support the prices of kerosene and gas oil. In 1986, the gas oil subsidy was ended and now gas oil sales also contribute to the fund. The Stabilization Fund covers the differential between the price of imported butane and the price of locally refined butane. Until 1986, contributions to this fund amounted to 32% of the retail price of super gasoline and 33% for regular gasoline. The stabilization component is considerably less in the price structure put into effect in April 1986: 4% for super, 3% for regular and 3% for gas oil. This dramatic shift is the result of policy changes which favor the "taxe complémentaire" (para. 3.39).

3.37 The Equalization Fund was created in 1968 (the current structure was put into effect in 1971) to minimize the difference in the selling prices of products throughout the nation. The objective of the fund is to keep prices of products sold in the outlying regions low enough to (a) not represent a constraint on consumption and

(b) discourage black market trade with the Congo and Cameroon. A levy of 17 CFAF per liter is collected on all clean products. This amount has more than doubled since 1983, when it varied from 5 CFAF per liter of kerosene to 8.75 CFAF per liter of gas oil. It is now uniform for all products.

3.38 In 1985, both the Stabilization Fund and the Equalization Fund carried deficits of about 1.5 billion CFAF each. In the case of the Stabilization Fund, this was attributed in part to the large subsidies on gas oil until 1986. These subsidies encouraged rapid and widespread substitution for the more costly gasoline, the sales of which were needed to support the subsidy. For the Equalization Fund, the old levies simply were not sufficient to meet subsidization needs. In both cases, the MFBP estimated that under revised forecasts of petroleum product demand, the levies carried in the new structure will permit the funds to recover their deficits and break even within the next two years. Since then, the situation has improved: the Stabilization Fund now has a surplus of almost 17 million CFAF, as a result of the increase in the taxe complémentaire. The Equalization Fund still carries a deficit, but it has decreased to 500 million CFAF.

3.39 The current price structure was put into effect in April 1986. 13/ It implements certain adjustments to reflect falling crude oil prices--including a minimal adjustment to retail prices (from 2-5 CFAF per liter depending on the product) in order to pass some savings on to the consumer--and reflects some policy changes in the utilization of taxes and subsidies. The principal adjustments were made in three areas:

(a) ex-refinery prices were reduced by nearly 50% to adjust for lower crude prices;

(b) the "taxe complémentaire" was increased radically to recoup for the national treasury the rent which previously had been absorbed by the refinery; and

(c) the major subsidies, the Stabilization Fund and the Equalization Fund (paras. 3.36-3.37) were modified to correct for deficits and to drop the subsidy on gas oil.

13/ The price adjustments made in April 1986 affected only the three main products. Price levels and pricing structures for butane, fuel oil and jet fuel remain the same as in March 1985.

Table 3.8: EVOLUTION OF TAXES AND SUBSIDIES ON PETROLEUM PRODUCT PRICES a/
(CFAF per 100 liters)

	PREMIUM			REGULAR			KEROSENE			GAS OIL		
	1983	1985	1986	1983	1985	1986	1983	1985	1986	1983	1985	1986
Retail Price b/	24,500	28,500	28,000	24,000	28,000	27,500	7,500	9,000	8,000	13,700	15,200	14,900
Taxe complémentaire	100	100	14,700	100	100	14,700	100	100	700	100	100	3,500
Stabilization Fund c/	7,783	9,179	1,029	7,773	9,232	825	(8,562)	(9,885)	(2,860)	(1,688)	(2,557)	378
Equalization Fund c/	775	1,390	1,700	775	1,390	1,700	500	1,390	1,700	875	1,390	1,700
Other Direct Taxes d/	397	401	430	407	411	430	226	230	400	166	170	407
Taxes and subsidy contributions as percent of retail price	37%	39%	64%	38%	40%	64%	---	---	---	---	---	40%
Taxes as percent of retail price e/	2.0%	1.8%	54%	2.1%	1.8%	55%	4.3%	3.7%	12.5%	1.9%	1.8%	26.2%

a/ Based on price structures for Libreville dated Sept. 1, 1983, March 18, 1985 and April 10, 1986. For 1986, price structure is also applicable to Port-Gentil.

b/ For Libreville and Port-Gentil. Level of subsidies differs between the two in 1983 and 1985.

c/ Positive value indicates levy to finance the fund. Negative value--in parenthesis--is subsidy provided by the fund.

d/ Includes port taxes, municipal taxes on distribution and storage charges.

e/ Including the taxe complémentaire.

Source: MFBP, mission estimates.

3.40 The net result of these changes is a dramatic shift in the relative weights of taxes and subsidies in the price structure (Table 3.7). There is more emphasis on income generation through a more aggressive fiscal policy (increased "taxe complémentaire") and less emphasis on cross-subsidization among products. The Government can expect to receive up to 167 million CFAF (US$0.5 million) from the "taxe complémentaire".

3.41 These shifts in policy are encouraging, as they indicate a willingness on the part of the Government to make more effective use of taxes and subsidies. The mission believes, however, that there is further scope to simplify the system of taxes and subsidies, and to make their application more economically efficient. The case of gas oil is a good example. Although the product is no longer subsidized through the Stabilization Fund, the final retail price is maintained at half the price of premium gasoline by keeping the tax burden relatively low (26% of the retail price, versus 55% for gasoline). Thus price discrimination in favor of gas oil continues. The objective of keeping the price of gas oil low is to assist small entrepreneurs, industries and transporters. However, given that a dozen large consumers account for almost half of total gas oil consumption, the policy of maintaining an artificially low price is a highly inefficient way of achieving this objective.

3.42 The mission recommends that, as a first phase, the official retail price of gas oil be adjusted (possibly by increasing the "taxe complémentaire" to match that of gasoline) in order that retail prices more closely reflect the relative economic costs of the products. Other mechanisms, such as special vouchers or fiscal measures, be explored to target the intended beneficiaries of any preferential pricing of gas oil. The former action will allow the ratio of the retail prices for gas oil and for gasoline to more closely approximate their relative economic costs, thus aiding demand management of the two products. It should also provide a source of additional government revenues. The mechanisms used to benefit smaller users should be designed to complement the price increase.

3.43 As a second phase, and most importantly, the mission recommends that the Government simplify the current pricing structure, which is unnecessarily complex. This could be done by establishing five major cost categories: ex-refinery price, fiscal levies, freight and Equalization Fund adjustments, Stabilization Fund adjustments, and marketing margins. These items should all be examined under the petroleum product pricing study recommended by the mission (para. 3.31).

3.44 The mission further recommends that the pricing system be improved by instituting a formal mechanism to permit regular consultation and revision of product prices. In the process, the marketing companies should be more directly involved, through the GPP, to provide information on the current marketing and distribution situation and their costs.

IV. ELECTRIC POWER

Introduction

4.1 The monopoly for generating and distributing electric power in Gabon is held by the Société d'Energie et d'Eau du Gabon (SEEG), which is also responsible for water distribution. The bulk of SEEG's activities, costs and revenues are related to electric power. The exact proportion is difficult to calculate as the management and operation of the dual water/electricity systems are highly integrated within SEEG.

4.2 SEEG's operations are grouped according to four physically independent transmission and distribution subsystems (para. 4.4-4.11): Libreville, Port-Gentil, Franceville and the various isolated centers. In addition to the SEEG system, there are a number of individual and/or semi-collective generating facilities in remote villages and on some larger farms. Most of these are relatively small in capacity, although at least one sugar mill has installed a large combined process heat and power generation plant. The contribution of these facilities to total electricity generation in the country is minimal, however.

Main System Characteristics

4.3 The SEEG power system boasts a total installed capacity of 285 MW. Hydroelectric plants account for 56% of this capacity. Total net generation of the system in 1985 amounted to 861 GWh, 78% of which originated from hydroelectric plants. The proportion of hydro to thermal capacity and generation varies markedly among the system's four subsystems. The net generation in each subsystem, for all practical purposes, could be considered either totally hydroelectric or thermal (para. 4.4-4.10). Table 4.1 presents a summary of the main characteristics of the total system and each subsystem.

Table 4.1: MAIN SEEG SYSTEM CHARACTERISTICS, 1985

	Subsystem				
	LBV	POG	FCV	DER	Total
Available Capacity a/ (MW)					
Total	168	57	48	15	285
Hydro	126	0	38	0	161
Thermal	42	57	10	15	124
Peak Load (MW)	87	26	25	8	146 b/
Net Generation (GWh)					
Total	531	158	137	35	861
Hydro	530	0	137	0	668
Thermal	0	158	0	35	194
1982/1985 Average Demand Growth (%/year)	10,2	4,0	7,4	20,8	8,9

a/ In October 1986.
b/ Sum of separated peak loads, irrespective of any coincidence factor.

Source: SEEG.

Generation and Transmission

4.4 The Libreville subsystem (LBV) accounts for approximately 60% of both the total installed capacity and the power generated by SEEG. Two hydroelectric generating plants on the Mbei river form the bulk of installed capacity: Tchimbele, with a 220 million m^3 reservoir, is equipped with three units of 22,800 kW each; Kinguele, downstream, has a negligible reservoir capacity and is equipped with two units of 9,600 kW and two units of 19,200 kW. The diesel-fired gas turbines (2 x 21 MW) have been installed at the Owendo port in Libreville and were brought on-line in 1986.

4.5 The transmission network from the hydro plants consists of three main components. A 225 kV overhead line connects Tchimbele to Kinguele (40 km) and then to the Bissegue substation (Kinguele-Bissegue: 104 km) on the outskirts of the capital. Kinguele is also connnected to the Bissegue substation via N'Toum (Kinguele-N'Toum: 70 km; N'Toum-Bissegue: 35 km) by means of a 90 kV overhead line. Finally, a 105 MVA transformer bank (3 x 35 MVA single phase, plus 35 MVA standy) at Bissegue feeds the 90 kV Libreville subtransmission system.

4.6 The maximum total output from Tchimbele and Kinguele combined is 126 MW under normal conditions, and 108 MW during dry years (assuming a return period of at least 20 years). The average total energy generated annually is 670 GWh, 490 GWh during dry years.

4.7 Under 1985/86 levels of demand (para. 4.13), the gas turbines at Owendo would not be used unless there is a shortage of hydraulically generated energy due to an extremely dry year, or there is need for backup to cover a shortfall in hydroelectric capacity. A capacity shortfall technically could arise from electromechanical outages at one of the hydro plants, or in the unlikely event that one of the 220 kV overhead lines is tripped. In the latter case, LBV's emergency supply capacity would be about 82 MW (40 MW through the 90 kV overhead line and 42 MW from the gas turbines), which is nearly equivalent to the present peak demand.

4.8 SEEG uses a simulation program, Mogador, for managing the operation of the LBV hydro plants. Mogador features a medium-term component for handling the yearly optimization of water use, and a short-term component with a time horizon of several hours for synchronizing the outflows at Tchimbele with the inflows at Kinguele. Management of the reservoirs using Mogador has contributed to the high reliability of the LBV subsystem, and also to avoiding the use of expensive thermal generation.

4.9 The Port-Gentil subsystem (POG) supplies the port city which houses the petroleum industry. Power is generated primarily by two 20.9 MW gas turbines fired with natural gas piped in from offshore oil fields. This capacity easily covers the current peak demand (Table 4.1). An old 5 x 3 MW diesel plant is kept as backup. The generating plant is located on the edge of the city, and thus there is no transmission network.

4.10 The Franceville subsystem (FCV) serves the major urban center in the interior, Franceville, and the mining industry at nearby Moanda. The generating plant consists primarily of the Poubara hydro plants, which include four units of 4,64 MW and two 9.6 MW units. The Moyabi diesel plant (5 x 2.2 MW) has been used only as backup since 1984, when the last of the Poubara units was commissioned. The FCV subsystem has a 63 kV transmission network connecting Poubara to Franceville (21 km) and to Moanda (54 km) via intermediary substations at Mvengue and Moyabi.

4.11 The isolated centers (DER) represent SEEG's administrative and operational grouping of 22 small, physically independent load centers scattered throughout the Gabonese territory. Distances between load centers are usually over 100 km. SEEG is responsible for power supply to all of these centers with the exception of one, which is supplied by Shell Gabon. Installed capacity at each point of the DER subsystem ranges from a mere 120 kW to 1,800 kW; total installed capacity amounts to 10 MW.

Distribution

4.12 SEEG has a total 620 km of 20 kV medium voltage (MV) lines in its distribution systems, 190 km of which are underground. In the DER and FCV subsystems, about 200 km of 5.5 kV overhead lines are also used. The low voltage (LV) lines total 720 km in length, of which 50 km are underground. There are 1,230 MV/LV substations, with total capacity of 363 MVA. All services are equipped with breakers.

Demand Characteristics

Demand Profiles

4.13 Total electricity sales in the SEEG system amounted to 757 GWh in 1985. The LBV subsystem accounts for nearly 60% of total consumption, the DER subsystem for only 7%, and the balance is split evenly between POG and FCV. Systemwide, MV sales account for just over half of total sales. The proportion of MV sales varies widely among the subsystems, however, ranging from a high 88% of consumption in the FCV subsystem to a low 44% in both the LBV and DER subsystems; in the POG, the proportion is only slightly higher than this latter figure, 52%. The largest MV customers include the mining sector, the Présidence, and the oil industry (Table 4.2). Consumption of LV electricity is predominantly in the residential sector, although there is some usage by SEEG itself and in industry. From 1980 until 1986, electricity consumption increased at an average rate of almost 9%/yr (Annex 13). LV customers registered the highest growth rates, 14.5%/yr compared with 4.7%/yr for MV customers.

4.14 Load Curve. In the LBV subsystem, the yearly load factor is 0.69. The daily load curve features an evening peak between 7:00 p.m. and 11:00 p.m. which is 20%-40% higher than the average daytime consumption. There is almost no variation in the daytime load until the evening peak. In the winter months, there is a noticeable post-peak reduction in the night load, which falls to about 75% of the daytime average. Seasonal modulation is small, although there is a load reduction in the summer; a 15% decline is recorded during the month of August when many residential customers go on vacation.

4.15 In the POG and FCV subsystems, the daily load curves have the same general shape, but fluctuate over a smaller range. The summer load is reduced in proportions equal to that in LBV. Yearly load factors are 0.69 and 0.63, respectively.

4.16 The yearly load factor of operating plant in the DER subsystem ranges from 0.25 to 0.60. As a general rule, the larger the load center, the higher the load factor.

Table 4.2: GABON ELECTRICITY SALES - 1985

	Libreville		Port-Gentil		Franceville		DER		Total	
	(GWh)	(%) a/	(GWh)	(%) a/	(GWh)	(%) a/	(GWh)	(%) a/	(GWh)	(%) a/
Medium voltage	211	28	75	10	104	14	7	1	398	53
Low voltage	250	33	70	9	14	2	24	3	358	47
Total	461	61	145	19	118	16	31	4	756	100

Low Voltage Categories	Number of Customers	Percent of Total Consumption
Residential	54,490	38.4
Public Lighting	550	1.4
Industrial	1,040	3.2
Internal Use (Water)	210	2.1
SEEG Personnel	1,860	2.3

a/ Percent of total sales.

Source: SEEG, Annex 12, Annex 15.

Demand Forecasts

4.17 In 1984, SEEG calculated a detailed long-term forecast of electricity consumption throughout the system using several demand trend assessment methods (Annex 16). These forecasts were revised in early 1986 following the oil price drop at the end of 1985 (Table 4.3). The new forecasts indicated a stabilization of the demand in LBV, FCV and POG, followed by moderate growth after 1990. An actual decrease in demand in 1987-88 was possible, especially in the case of POG, where electricity consumption is closely linked to the oil industry, and in LBV, due to the induced macroeconomic effects of the oil price drop. Stagnation of electricity demand in FCV also was anticipated, even though demand in this subsystem is more directly linked to the mining sector than to petroleum. The commissioning of the Transgabonese Railroad would have the most direct impact in this subsystem: the electric cableway which transports 2 million tons of ore annually will no longer be operated, thus reducing the power demand by 10 GWh/yr.

4.18 The SEEG forecast for DER was based on the assumption that there will be no constraints placed on the introduction of new generating capacity in these areas. Under this assumption, electricity demand in DER would grow at about 15% annually (high scenario). The mission adopted the more realistic assumption that further development of

generating capacity would be reduced or halted in the medium term (low scenario). Thus DER consumption would tend towards the maximum energy and demand which could be generated by existing equipment. It is evident from these scenarios that the actual electricity consumption in DER may be constrained, depending on the policy adopted by the Government for introducing new generating capacity (para. 4.38-4.40).

4.19 The mission was of the opinion that the demand trend assessment methods used by SEEG in its demand forecasts were not adequate for projecting future demand. This is because past economic performance, and therefore electricity demand, have been heavily influenced by the evolution of the international petroleum market. The vagaries of international oil prices in the past decade, including two dramatic price increases and the more recent crash, do not represent gross macro-economic/energy demand trends which are likely to repeat themselves in the future. The mission therefore recommended that the SEEG revise its demand forecasts according to a more appropriate methodology, to include:

(a) a disaggregated market survey of each major class of consumer, (in addition to the surveys of large industrial individual consumers) for each of the subsystems; and

(b) a macroeconomic consistency check, based on the most recent macroeconomic projections to be provided by the MEP.

4.20 A new scenario, which predicts a recession in the electricity subsector, was constructed in early 1987 using a synthetic approach which excludes use of tendencial models, the latter deemed ineffective in the context of Gabon's economic crisis. Nevertheless, SEEG would find it difficult to implement the methodology recommended by the mission. This is due, firstly, to the lack of analytic data on market segments; and secondly, to the fact that the sector operators feel that the MPE's long term economic projections are not made accessible to them. SEEG believes furthermore that macroeconomic models are very difficult to elaborate because of lack of reliable data. A new investment plan, based on the revised (downward) growth scenario, takes into account the modification of the major parameters (para. 4.23; 4.27).

Medium-Term System Development: 1987-1995

4.21 New Generating Capacity. Taking into account the forecasts for electricity demand used by the mission and presented in Table 4.3, the existing generating capacity in the three large load centers (POG, LBV, and FCV) will be sufficient in the medium term to meet electricity needs. SEEG's 1987 revisions are even lower, and thus the conclusion remains valid. The available margin of power and energy for existing hydroelectric capacity in the LBV and FCV subsystems now stands at 26%

Table 4.3: REVISED ELECTRICITY DEMAND FORECASTS: 1986-1995

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
	(actual)									
Libreville										
Net Consumption (GWh)	511	481	481	485	515	545	580	610	650	690
Peak Demand (MW)	85	80	80	81	86	91	97	102	109	116
Port-Gentil										
Net Consumption (GWh)	169	158	158	160	165	170	180	190	195	200
Peak Demand (MW)	28	26.5	26.5	27	28	28.5	30	32	33	34
Franceville										
Net Consumption (GWh)	143	140	140	140	150	160	175	190	205	220
Peak Demand (MW)	26	25.4	25.4	25.4	27.3	29.0	31.5	34.5	37.2	40.0
DER										
High Scenario (GWh) a/	63	63	64	68	76	86	95	110	120	135
Low Scenario (GWh)	63	55	55	55	58	60	61	63	64	64

a/ Assuming some addition to generating capacity is possible.
b/ Assuming constrained consumption due to limits on generating capacity.

Source: SEEG, mission estimates.

and 20% respectively. With these margins, thermal generation is needed only if there is a disturbance in generation or transmission, or under extremely poor hydrological conditions. Once the available margins have been utilized, it still would be possible to meet electricity demand in these subsystems through incremental use of existing thermal capacity. The maximum peak which thus could be accommodated would be 126 MW at LBV and 32 MW at FCV.

4.22 A complementary 12 MW gas turbine (1.2 billion CFAF) could prove necessary for FCV after 1992 to decrease the risks of shortages in dry years. Still, any significant new generating capacity will not be required until after these dates. A final decision on this can be delayed until 1988-89.

4.23 SEEG's 1985 system development plan called for the installation of two new 21 MW turbines in 1992-1994 for Port-Gentil. This reserve was to constitute the second phase in a project to establish an interconnection between the LBV and POG subsystems (para. 4.27). Under the revised 1987 forecasts, the interconnection was scrapped, and a new strategy retained which foresaw separate development of the LBV and POG subsystems. This strategy reflected the uncertainties in 1986/87 about the price of natural gas and its availability at Port-Gentil. Recent natural gas discoveries (para. 2.28-2.31) have made this strategy questionable, and the mission advises that a new optimization of the investment plan be undertaken to incorporate this information (4.27-4.33).

4.24 A 32 billion CFAF development program for the DER subsystem, co-financed by Canada (C$ 32 million), France (4.5 billion CFAF) and the SEEG (20 billion CFAF), had been initiated in 1985. The program included development of the electric power and water supply systems in 24 isolated centers. The scope of the project was reduced to 15 centers in early 1986, to include either electric power or water at each target point, but not both.

4.25 After decreasing the scope of the planned program once more, the Government finalised the conditions for executing the readjusted program in 1987, with financing provided by the Canadians. The Government is still negotiating with the French Government for equipment for centers not included in the Canadian program. The mission recommends nonetheless that the program be prioritized and continued according to an extended schedule. A full economic and financial analysis of the various projects which comprise the program should be undertaken 14/ and the energy demand in targeted load centers re-evaluated (para. 4.33) in order to rank the projects accordingly for completion.

14/ Many of the projects contained in the program are significantly different one another. Some are merely extension projects; others, such as Lebama, are small hydro projects which would displace diesel stations. Thus the analyses must be undertaken project by project.

4.26 Transmission and Distribution. The principal investments to consider in short-term system development are in transmission and distribution for the LBV subsystem. The Bissegue substation transformation capacity at Libreville requires strengthening (2 billion CFAF). A new 225 kV overhead line connecting Kinguele to Libreville is also needed (5 billion CFAF). These investments are intended primarily to improve the reliability of supply. Since system reliability is already quite high, the mission believes that they can be postponed without incurring significant risks to subsystem operations.

Long-Term System Development

4.27 SEEG's initial long-term system development plans were based on the original 1984 demand forecasts (Annex 16). The plan was revised in 1987 to take into account changes in the key parameters and, in particular, uncertainties surrounding availability of natural gas. Since many of the key parameters have changed substantially yet again in the past 12 months, with the discovery of major natural gas reserves, this plan is not likely to be the best solution for system development. SEEG will therefore have to review and re-optimize its existing plans to reflect new gas discoveries, economic constraints, and a new timing.

Interconnection of LBV and POG

4.28 Long-term development of the LBV and POG subsystems should once again be examined simultaneously, as the interconnection between the two is still an option, given the availability of natural gas at Port-Gentil. The interconnection would follow an in-land route, for a total of 407 km of overhead lines (225 kV). The substations would be developed in two stages, allowing a transmission capacity of 40 MW during the first stage and 80 MW during the second. Total cost of the project is 36 billion CFAF (US$102.9 million).

4.29 The studies previously conducted during the planning stages included detailed operation simulations under various scenarios of developing generating equipment. On the Libreville end, this incorporated possible development of hydro sites along the M'Bei, Komo and Abanga rivers. The potential and costs associated with the three most (economically) interesting sites are presented in Table 4.4. On the Port-Gentil end, the addition of two 21 MW gas turbines immediately following construction of the interconnection was considered in some of the scenarios. 15/ The simulations showed that the interconnection

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15/ Generating costs at Port-Gentil were estimated at 15.5 CFAF/kWh in the simulations, given a gas price of 30 CFAF. The total cost rises to between 20 and 25 CFAF/kWh once capital, operating and maintenance costs are added, depending on the discount rate and plant factor used in the calculations.

would be used to transmit power in both directions, thereby delaying the need for larger additions to capacity.

Table 4.4: POTENTIAL HYDROELECTRIC PLANTS NEAR LIBREVILLE

	Kinguele downstream	Kinguele upstream	Ngoulmendjim
River	M'BEI	M'BEI	KOMO
Installed capacity (MW)	30	40	100
Investment costs a/ (million CFAF)	50,000	85,000	130,000
Mean energy (GWh/yr)	210	280	610
Firm energy (GWh/yr)	160	230	520
Energy cost b/ (CFAF/kWh)	37.5	44.4	30.0
Energy cost c/ (CFAF/kWh)	28.6	36.4	25.6

a/ Including an interest rate of 10%/year during construction.
b/ On the basis of the firm energy and calculated with yearly capital and operation and maintenance costs equal to 12% of investments costs, but without price nor taxes and duties.
c/ The same as b/ but on the basis of the mean energy.

Source: SEEG.

4.30 The principal parameters in these previous simulations and their evolution have been modified significantly. With regard to the growth of consumption, the new demand forecasts indicate that the importance of the POG subsystem relative to LBV has decreased. However, future trends for gas prices, another major parameter, are more certain than before, thanks to the oil companies' analyses giving estimates of the cost of supplying gas to SEEG from the new discoveries. Furthermore, it has been shown that, once a timing for the interconnection has been established, gas will be available in the quantities needed (up to 2 billion m^3/yr) for a sufficient period of time (at least 15 years).

4.31 Demand in Port-Gentil can be met with existing capacity until almost 2000. However, demand forecasts indicate that new capacity will be needed in the LBV subsystem by 1996/1997. Without the interconnection, major investments in hydroelectric capacity would be needed in Libreville. The mission therefore recommends that SEEG re-optimize its development plan to account for the availability of gas at Port-Gentil, in order to take a decision by 1989 on the first major investment to be undertaken for system development. This date is crucial, as the lead times are six years for Kinguele downstream and Ngoulmendjim and four years for the interconnection and Kinguele upstream. The lower price of fuel could make the possibility of thermal alternatives more attractive, also, and this should be taken into consideration in the revised plan. If the interconnection is found to still be the optimal first stage for developing the LBV/POG subsystems, construction should begin preferably in 1992, but no later than 1994. In the interim, complementary soil investigations for the hydro sites will have to be completed immediately, so that full information is available for taking an optimal decision.

4.32 For the other subsystems, the timing for deciding on the appropriate sequence for system development is less crucial. The optimum foreseeable development in the FCV subsystem would include (a) a gas turbine operational around 1992 to provide back-up during dry years and/or during hydro/thermo-mechanical equipment outages, and (b) new hydro capacity (possibly Poubara 3) in 1996 or 1997. A decision for the latter would be needed, at the latest, by 1992. In the case of the DER subsystem, development will be a matter of general policy for electrification of isolated centers. Projected economic and financial conditions in the medium- to long-term would prohibit return to any full-scale development of this subsystem before 1991. The investments needed in the other subsystems may push this date back to 1996.

4.33 The mission recommends that the Government review and clearly define its development strategy for isolated centers in the long-term within a sector-wide framework of investment priorities for electrification. The Government should take advantage of this period of slowed development to thoroughly re-assess the energy needs in targeted isolated centers, in conjunction with a full economic and financial analysis of proposed projects in order to set development priorities (para. 4.25).

4.34 The mission estimated in Table 4.5 the investment program for the electricity subsector with or without the Libreville/Port-Gentil interconnection, plus the additional investments needed for developing the isolated centers. Investments for the sector will be reduced significantly in the short-term, but will increase rapidly in the first half of the next decade as existing generating capacity becomes saturated.

Table 4.5: PROJECTED INVESTMENT PROGRAM FOR ELECTRICITY SUBSECTOR 1987-1995
(billion 1986 CFAF)

	1987	1988	1989	1990	1991	1992	1993	1994	1995	Total Investment
Generation and Transmission										
Total with interconnection:	0	0.5	0.5	0	0	5	8	8	26	58
LBV and POG										
- Special studies	-	0.5	0.5	-	-	-	-	-	-	1
- Interconnection overhead lines & substations	-	-	-	-	-	2	8	8	6 a/	36
- Next hydro plant	-	-	-	-	-	-	-	-	20 b/	-
FCV										
- Gas turbine	-	-	-	-	1	2	-	-	-	3
Total without interconnection:	0	0.5	0.5	0	5.5	13	10	15	30	74.5
LBV										
- Special studies	-	0.5	0.5	-	-	-	-	-	-	1
- Kinguele downstream	-	-	-	-	5.5	10	10	10	10 c/	50
- Next hydro plant	-	-	-	-	-	-	-	5	20 d/	-
FCV										
- Gas turbine	-	-	-	-	1	2	-	-	-	3
Distribution	2.0	2.0	2.0	2.0	2.0	2.5	2.5	2.5	2.5	20
Libreville	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	13.5
Port-Gentil	0	0	0	0	0	0.5	0.5	0.5	0.5	2.0
Franceville	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	4.5
Isolated centers	1.5	1.5	1.5	1.5	4.0	4.4	4.8	5.3	5.9	30.4

a/ Complementary substation equipment in 1996.
b/ Timing assumes commissioning in 1999 (gas turbine at Port-Gentil to be commissioned beforehand, with first investments beginning after 1995).
c/ Last part of electromechanical commissioned in 1996.
d/ In the development without interconnection, the next hydro plant would probably be other than Kinguele downstream.

Source: SEEG, mission estimates.

Other Subsector Issues

Electricity Tariffs

4.35 The tariff structure currently used by SEEG is characterized by a declining block rate structure which varies according to the subsystem. One constant LV tariff throughout the SEEG system is the "social" residential tariff, a two block rate for consumers with low demand. The range of the initial block in this tariff was doubled in April 1986 (from 120 kWh to 240 kWh) in an effort to reduce electricity costs of smaller residential consumers. The two MV tariffs include a "subscribed demand capacity" charge for all subsystems except LBV, which instead has peak and off-peak rates.

4.36 Tariff levels are the same in FCV and DER, and generally higher in those subsystems than the tariff levels in LBV and POG. The average price per kWh in 1985, excluding all taxes and other contributions (para. 4.38) came to 42 CFAF. This increases to 43.5 CFAF/kWh if equipment costs are included. By August 1986, the average price per kWh had increased to 46 CFAF.

4.37 Annex 23 describes in detail the tariff structure and levels in use at the time of the mission.

4.38 Although tariff levels are set to reflect the general costs of electricity supply in each subsystem, there is a certain amount of cross-subsidization and a number of specialized costs incorporated into electricity billing. In the LBV and POG subsystems, two line items are added to the basic price of electricity. A "contribution d'équipement" (equipment contribution) covers the capital costs related to the electricity and water distribution networks, which are owned by the municipalities. The "contribution spéciale d'équipement" (special equipment contribution) is used to reimburse the municipality's expenses for use of electricity, particularly public lighting. The customers of the LBV subsystem also are billed for a contribution to an SEEG equipment fund used to cover debt service and investments. This contribution is calculated on the basis of hydro-generation at Kinguele (6.47 CFAF/kWh) and service charges of miscellaneous loans. Income from LV electricity sales in all subsystems except DER is allocated to the "fonds de péréquation" (equalization fund) and "fonds de compensation" (compensation fund) to subsidize the costs of electricity supply in the DER subsystem. Both funds are managed by the Caisse Autonome d'Amortissement. Tariffs in all subsystems include an 8% sales tax (taxe sur le chiffre d'affaires) on consumption.

4.39 Tariff Reform. In 1984, SEEG began a detailed tariff study to complement its 1984-1988 investment plan and further plans for system development into the early 1990s. For LBV-POG, this included the commissioning of the interconnection and two gas turbines during the investment period, plus development of one hydro plant (the timing of

which had not been determined) after 1988. Poubara 3 was planned for FCV, but no major generation projects were envisaged in the DER. The tariff structure which resulted from the study represents a vast simplification of the current tariff structure. Tariff levels incorporate the principles of economic efficiency, subject to the constraints of (a) imposed public service policies, such as geographic cross-subsidies; and (b) revenue generation requirements, to ensure a sufficient gross margin to support the financing of future investments. The study appears to be methodologically sound.

4.40 The final general structure has two principal components, a fixed demand capacity charge (prime mensuelle fixe à la puissance) and a proportional price (prix proportionel de l'énergie consommée) for each unit of energy consumed. The structure is further distinguished according to the following criteria:

(a) the voltage category - HV transmission, MV distribution or LV distribution;

(b) the period of consumption, or time-of-use. This distinction is limited to MV customers, and corresponds to periods determined as peak and off-peak;

(c) the duration of usage of the subscribed demand capacity, by definition the ratio of the energy consumed during a certain period and the contracted demand capacity. In the LV tariffs, this is retained only for customers subscribing to demand capacities of 18 kW or higher;

(d) the subscribed demand capacity (la puissance active souscrite), which is "monitored" through the use of single-setting load limiters, set at the maximum demand requested by the customer. This charge is used as an incentive for more efficient utilization of the customers electric appliances; and

(e) the actual energy consumed. This is the only tariff criteria applied to LV customers who subscribe under the "social tariff", with demand capacities of less than one kW.

4.41 Tables 4.6 and 4.7 present the proposed tariffs and the related LV marginal costs, as presented in the final report of the study (May 1985). Geographic cross-subsidization is maintained for LV tariffs, but eliminated for MV and HV. This action represents a practical compromise between economic and social objectives: the high long-run marginal costs of supply in the DER and FCV are covered by MV and HV customers (who are generally the larger consumers) and large consumers of LV electricity in LBV and POG--yet electricity remains accessible to smaller consumers throughout the country. Once the long-run marginal costs were determined, the basic tariff levels were adjusted according to a factor (le péage) which takes into account the elements of the policy for financing investments. The values in Tables 4.6 and 4.7 assume that this factor is equal to one.

Table 4.6: SEEG TARIFF STUDY - LOW VOLTAGE a/

	National Tariff b/		Long-Run Marginal Costs c/					
			LBV - POG		FCV		DER	
	Demand d/	Energy e/	Demand d/	Energy e/	Demand d/	Energy e/	Demand d/	Energy e/
	(CFAF/kW)	(CFAF/kWh)	(CFAF/kW)	(CFAF/kWh)	(CFAF/kW)	(FCFA/kWh)	(CFAF/kW)	(CFAF/kWh)
Small and Medium Capacity								
Social (1 kW)	--	60.73	--	55.6	--	70.13	--	123.84
Comfort (3 or 6 kW)	1719	48.46	1650	43.87	2612	51.59	2204	108.22
Great Comfort (9 or 12	2309	44.26	2222	39.83	3511	45.20	2958	102.82
Large Capacity f/								
Short duration g/	1418	51.67	1369	46.96	2161	56.48	1821	112.33
General h/	2309	44.26	2222	39.83	3511	45.20	2958	102.82
Long duration i/	3315	40.07	3187	35.79	5042	38.82	4258	97.43

a/ March 1985.
b/ New tariff resulting from the study, to be applied nationally. Based on the long-run marginal costs calculated in the study, equalized geographically and taking into account the SEEG/Government capacity to finance investment plan versus cash generation from from new tariffs. Excludes the Government's share in certain investments in the DER, the consumption tax (TCA) and contributions to the special municipal funds.
c/ As calculated by SEEG according to the long-term generation development plan for each subsystem.
d/ Monthly premium in CFAF/kW of subscribed demand capacity.
e/ Proportional price in CFAF per kWh consumed.
f/ Subscribed demand capacity : 18, 24, 30, 36 kW or more.
g/ From 0 to 120 hours/month usage of the subscribed demand capacity.
h/ From 120 to 240 hours/month usage of the subscribed demand capacity.
i/ Over 240 hours/month usage of the subscribed demand capacity.

Source: SEEG.

Table 4.7: SEEG TARIFF STUDY - TRANSMISSION AND MEDIUM VOLTAGE a/b/
(CFAF)

	Transmission Tariffs			Medium Voltage		
	LEV-POG	FCV	DER	LEV-POG	FCV	DER
Very Short Duration (TCU) c/						
Demand Charge (per kW)	33899	36742	37710	40500	51199	42738
Proportional price (per kWh)						
Peak (7 - 11 p.m.)	90.88	95.78	251.08	107.27	133.46	280.45
Off-peak	26.42	19.16	56.85	26.42	26.70	60.33
Short duration (CU) d/						
Demand Charge (per kW)	50730	55238	59650	60606	76971	67603
Proportional price (per kWh)						
Peak (7 - 11 p.m.)	49.36	46.56	151.27	57.68	64.87	167.34
Off-peak	16.53	9.31	56.85	18.91	12.98	60.33
General e/						
Demand Charge (per kW)	63518	68952	72028	75884	96081	81633
Proportional price (per kWh)						
Peak (7 - 11 p.m.)	34.47	28.90	115.45	39.89	40.27	126.74
Off-peak	12.99	5.79	56.85	14.68	8.06	60.33
Long duration (LU) f/						
Demand Charge (per kW)	77853	84247	84889	93011	117392	96207
Proportional price (per kWh)						
Peak (7 - 11 p.m.)	25.85	18.67	94.72	29.60	26.02	103.26
Off-peak	10.93	3.96	56.85	12.22	5.20	60.33

a/ March 1985.
b/ Does not include consumption tax (TCA) or contributions to the special municipal funds. These prices are not equalized geographically, and reflect the long run marginal costs supplying electricity. Excludes the Government's share in certain investments in the DER.
c/ From 0 to 1000 hours/year.
d/ From 1000 to 2500 hours/year.
e/ From 2500 to 5000 hours/year.
f/ Over 5000 hours/year.

Source: SEEG.

4.42 With demand forecasts now adjusted downward (para. 4.17-4.18), most of SEEG's system development plans will have to be re-optimized (para. 4.31-4.33). The mission recommends that the tariff study be updated:

(a) to incorporate (i) the re-optimized system development plans (particularly as this relates to the calculation of short-run and long-run marginal costs of supply) and (ii) modifications to the load curve and consumption patterns envisaged following the 1986 economic slowdown; and

(b) to ensure adequate cash generation.

Reform of Public Service Regulations

4.43 SEEG's present legal status is that of concessionaire for the operation of the power system. The concession grantors are the municipality, in the cases of LBV and POG, and the state for the other subsystems. The generating plant of the system is owned directly by the Government, which normally assumes responsibility for financing and constructing the infrastructure needed by SEEG's operations, as well as partially reimbursable loans. SEEG is a parastatal enterprise, with the Government holding 63% of its shares, and large private or semi-private companies holding the remainder. No return is realized on SEEG's capital, although some large consumers who are also shareholders (COMUF, COMILOG) are beneficiaries of preferential (low) tariffs. The mission has recommended that this situation be reversed, so that shareholder benefits are realized through return on capital rather than through tariffs (para. 4.47).

4.44 The major advantage of the current public service arrangements is that the Libreville and Port-Gentil municipalities are able to monitor the development of the electricity and water distribution networks within their jurisdictions. The major disadvantages stem from the overly complicated billing and accounting systems needed by SEEG under these arrangements. In general, customer bills are difficult to read. Charges intended to cover investments are not easily decipherable, especially in LBV and POG, where the various funds complicate the billing. The accounting system adopted to keep track of subsystem disparities is characterized by (a) numerous circular inflows and outflows, and (b) imprecise valuation of assets, making it difficult to define the economic return on investments and debt servicing capacity.

4.45 In early 1986, the MEHR considered a proposal to reform the public service arrangements for electricity and water. The primary objectives of the reform are to (a) further unify the electricity subsector, and (b) transform SEEG into an enterprise which will operate with neither loss nor profit. The MEHR's proposal is comprised of three main components:

(a) SEEG will be converted into a public enterprise with 100% of capital held by the Government.

(b) Upon this conversion, all buildings and equipment owned or used by SEEG will become state property.

(c) SEEG will be responsible only for managing the system.

The legal difficulties inherent to these arrangements can be easily accommodated within the framework of the Gabonese law.

4.46 This proposal meets the objective for subsector unification, and should result in simplified accounting and billing of electricity throughout the country. Several major difficulties could arise, however, from the transformation of SEEG into a management company owned entirely by the national Government.

(a) There is a risk that regional/load center-specific inputs needed for efficient management and planning of subsystem distribution will be lost if the municipalities are totally excluded.

(b) There is a risk that the creation of a publicly-owned monopoly for electricity supply will not lend itself to efficient and least-cost supply of power throughout the country. In fact, experience in other countries in Africa and elsewhere shows that total nationalization of public utilities tends to distort incentives for efficient supply.

(c) Electricity investment is likely to become a heavy burden on the Government budget, when some elements should be financed from other sources, especially by consumers.

(d) SEEG will become subject even further to Government administrative rules (e.g., on staff-related issues) that may not be appropriate to a commercial, revenue generating enterprise.

4.47 In light of this, the mission recommends that all proposal for public service reforms within the electricity subsector be revised, preferably following a thorough examination of SEEG's financial situation and a management audit of subsector operations (para. 4.52). In the meantime, the mission advises that SEEG's parastatal status be maintained. Shareholders other than the national government could include the current shareholders, but should most certainly include the Libreville and Port-Gentil municipalities to insure their continued participation in distribution issues. Investment by other entities or individuals, private or public, could also be encouraged. If this status is maintained, preferential tariffs for shareholders should be eliminated; instead, shareholders should be the beneficiaries of any profit realized from SEEG operations.

SEEG's Financial Situation

4.48 A severe cash balance problem caused by arrears and/or non-payment is the most important financial issue for the SEEG in the short term. More than 85% of outstanding billings are attributable to national and local services and the national administration (Table 4.8). Although this is not a recent phenomenon, the problem has mushroomed dramatically since 1981; by mid-1986, arrears amounted to almost 50% of the yearly billing. As a result, SEEG's cash flow has decreased from about 40% of the combined electricity and water turnover in 1980/81 to only 27% in 1985. The situation probably is much worse than it appears, since SEEG owns no capital and pays no depreciation. The expected decrease in electricity demand coupled with short-term difficulties for the national economy can only cause the situation to worsen.

Table 4.8: ARREARS PAYABLE ON SEEG ACCOUNTS
(million CFAF)

Customers	1981	1982	1983	1984	1985
VIP	548	679	1,181	1,950	2,152
Other private	2,250	1,741	1,313	1,375	2,046
Administrations under the state budget	2,550	4,207	5,006	3,190	6,442
Other administrations	1,959	2,547	3,093	3,390	3,381
Municipalities & Communities (Libreville & Port-Gentil excluded)	452	700	298	589	935
Total	7,759	9,874	10,891	10,494	14,956
(% of yearly billing)	(36.4)	(38.5)	(36.7)	(29.6)	(32.9)

Source: SEEG.

4.49 There are certain structural and operational problems inherent to the system which contribute to SEEG's financial difficulties. The demand on the generating system is relatively small and dispersed; thus distribution costs, even in the cities, are quite high. The low generating costs of the hydroelectric plants are offset by the high investment costs of these plants, arising from difficult access to the sites. The isolated centers represent a disproportionate fraction of the overall SEEG budget, relative to the size of installed capacity. Because it is entirely thermal and highly decentralized, the generating costs of this subsystem are more than three times those of the next most expensive subsystem. It would be difficult, if not impossible, for SEEG to correct these factors.

4.50 Several options are available to SEEG to tackle its financial problems. It has already launched a vigorous collection program for recovering non-payments from small, private customers. This is only a fraction of the problem however, as most of the arrears are attributable to governmental or parastatal bodies. Owing to the structure of the arrearages, the Government could opt to resorb some of the debt. This would be the most politically expedient solution, but could leave SEEG in an untenable position of financial instability.

4.51 Given the limitations inherent to undertaking a comprehensiv· review of the electricity subsector within a short period of time, the mission was not able to explore this problem in more depth. The problems seem to stem primarily from the financial structuring of SEEG relative to the Government. It is an issue which should be given a high priority by Gabonese authorities, as many questions remain unanswered in this assessment. The mission recommends that a full examination of SEEG's financial situation and a management audit of subsector operations be undertaken immediately, the key areas of immediate concern being:

(a) to determine the net financial position of SEEG vis-à-vis the Government, taking into account direct and hidden subsidies, including Government-financed investments, operational subsidies, and preferential tariffs; and

(b) to define a plan for financial and managerial restructuring of the subsector (the former possibly by debt-to-equity exchanges or transfer of assets), with the objective of (i) rectifying the financial situation, (ii) strengthening SEEG's accounting system to ensure that its accounts totally reflect the rate of return on subsector investments and the economic costs of generation, transmission and distribution, and (iii) optimizing the level of autonomy exercised by SEEG in order to promote efficient management and operation of the electricity supply system.

4.52 There does appear to be scope also for SEEG to improve its immediate cash balance through the reduction of some operating costs. Personnel costs, for instance, represent 45% of SEEG's operating expenses. This is a high percentage but can be explained by the capital intensive nature of SEEG's operations (small outlays for fuel, linked to heavy use of hydroelectric generation) and also by the many non-connected distribution points scattered throughout the system. The mission estimates that 500 MW are sold and 39 customers are served per employee. 16/ The managerial and supervisory staff account for 40% of

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16/ These figures cannot be calculated precisely since employees cover both water and electricity operations. The mission's estimates are made using the assumption that 3/4 of personnel's activities are devoted to electricity.

the total 2,040. This is partly due to the double staffing of about 50 key positions with an expatriate and a national undergoing training. The expatriate staff (80 regular employees) is paid according to the same scale as the nationals, but receives additional benefits for housing, home leave, etc. The additional cost represents about 5% of the total personnel costs. The number of expatriates is being progressively reduced, which will produce savings in this area.

4.53 The mission recommends that in addition, all operating costs be reviewed to ascertain their scope for reduction. Other costs should also be examined: maintenance costs are relatively high, but in return the reliability of service in the SEEG system is excellent. Some reduction in maintenance costs could be achieved without substantially lowering the supply reliability. Miscellaneous costs included in SEEG's budget such as training (5%) and public relations and missions (4%) could also be reviewed to determine the scope, if any, for possible reduction. The company is pursuing all effort to bring its operating costs under control.

Table 1: GABON: COMMERCAL ENERGY CONSUMPTION
('000 TOE)

	1978	1979	1980	1981	1982	1983	1984	1985	1986 a/
PETROLEUM PRODUCTS (000 tons)									
LPG	5.25	5.57	6.09	6.73	7.29	8.30	8.90	8.90	9.80
TOE equivalent	5.56	5.90	6.45	7.13	7.72	8.79	9.43	9.43	10.38
Growth rate (%)		6.10	9.34	10.51	8.29	13.89	7.23	0.00	10.11
Avgas	4.81	4.21	2.91	2.60	2.20	1.70	1.60	1.80	1.30
TOE equivalent	4.98	4.36	3.02	2.69	2.28	1.76	1.66	1.86	1.35
Growth rate (%)		-12.56	-30.72	-10.84	-15.32	-22.73	-5.88	12.50	-27.78
Jet A1	73.00	69.02	68.58	75.62	74.83	70.50	78.30	81.50	73.40
TOE equivalent	74.46	70.40	69.95	77.13	76.33	71.91	79.87	83.13	74.87
Growth rate (%)		-5.46	-0.63	10.25	-1.03	-5.79	11.06	4.09	-9.94
Gasoline	44.93	45.69	51.17	53.55	56.83	61.70	62.20	65.30	64.70
TOE equivalent	46.23	47.01	52.66	55.10	58.47	63.49	64.00	67.19	66.58
Growth rate (%)		1.69	12.01	4.64	6.12	8.58	0.81	4.98	-0.92
Kerosene	10.03	8.97	9.68	10.05	10.71	12.00	14.70	15.80	16.60
TOE equivalent	10.15	9.08	9.79	10.17	10.83	12.14	14.88	15.99	16.80
Growth rate (%)		-10.55	7.86	3.79	6.58	12.09	22.50	7.48	5.06
Gas Oil	161.28	160.28	176.88	204.32	207.20	215.30	221.60	234.70	201.80
TOE equivalent	161.28	160.28	176.88	204.32	207.20	215.30	221.60	234.70	201.80
Growth rate (%)		-0.61	10.35	15.51	1.41	3.91	2.93	5.91	-14.02
Fuel Oil	6.08	10.22	33.74	29.51	24.31	24.50	30.40	38.10	28.60
TOE equivalent	5.89	9.91	32.70	28.59	23.56	23.74	29.46	36.92	27.71
Growth rate (%)		68.27	230.11	-12.56	-17.60	0.78	24.08	25.33	-24.93
TOTAL	305.37	303.96	349.06	382.36	383.36	394.00	417.70	446.10	396.20
TOE equivalent	308.55	306.94	351.45	385.12	386.39	397.13	420.89	449.22	399.48
Growth rate (%)		-0.46	14.84	9.54	0.26	2.77	6.02	6.80	-11.19
ELECTRICITY (GWh)									
Total to Internal System	491.20	534.80	566.50	611.80	667.20	729.00	795.10	861.00	873.00
TOE equivalent	42.24	45.99	48.72	52.61	57.38	62.69	68.38	74.05	75.08
Growth rate (%)	13.91	8.88	5.93	8.00	9.06	9.26	9.07	8.29	1.39
TOTAL COMM CONS (000 TOE)	350.79	352.93	400.17	437.74	443.77	459.83	489.27	523.27	474.56
percent change		0.61	13.39	9.39	1.38	3.62	6.40	6.95	-9.31

a/ Preliminary estimates.

Source: Mission estimates, DGH, SEEG,

Table 2: AVERAGE ANNUAL GROWTH
(% per year)

	78-81	79-82	80-83	81-84	82-85	78-85	79-83
Elec	9.18	7.96	8.06	8.85	8.92	9.05	8.22
Pet Prod	7.97	6.04	6.85	4.65	3.96	5.68	5.39
Total	7.79	6.19	6.94	5.20	4.59	5.96	5.68

Annex 2

INVESTMENT EXPENDITURES FOR PETROLEUM EXPLORATION, 1977-1985
(In million CFAF)

	GULF	MARA/ VALMAR	ELF	SHELL	INA	BP	BURMAH	AMOCO	TENNECO	AGIP	CONOCO	TOTAL
1977			15,260	2,258								17,518
1978	699		13,482	2,290	164	590						17,225
1979	2,487		18,612	924	3,845	766	3,266					29,900
1980	1,449	125	21,485	1,644	3,197			3,700				30,600
1981	1,013		33,056	700	4,007		7,852	6,524		33		53,152
1982	58		43,799	1,943	2,962			7,623	268	2,404		59,057
1983	369		36,330	3,908			2,512	1,824	1,385	123		46,451
1984			32,733	13,006			3,816	11,239	8,952	1,104		70,850
1985			33,290	12,700			1,611	7,454	36,794	467		92,316

Source: DGH.

Annex 3

GABON - WELL DRILLING HISTORY, 1976-1985

Year	Wells drilled		Meters drilled			Dry Holes	
	Exploration	Development	Exploration	Development	Total	Exploration	Development
1976	16	24	36,117	65,452	101,569	12	2
1977	17	13	40,132	39,239	79,362	15	1
1978	15	15	35,155	33,160	68,315	10	2
1979	21	16	50,141	43,036	93,177	13	2
1980	16	24	35,543	52,485	88,028	8	2
1981	27	41	69,113	90,262	159,375	20	7
1982	20	40	43,702	85,937	129,639	11	5
1983	18	33	36,716	70,082	106,798	10	1
1984	22	20	53,026	42,366	95,392	18	2
1985	31	16	77,279	40,191	117,470	27	2
Total	203	242	476,924	562,201	1,039,125	144	26
				RATIO		71%	11%

Source: DGH.

Annex

INVESTMENT EXPENDITURES FOR PETROLEUM DEVELOPMENT, 1976-1985
(million CFAF) a/

	ELF	SHELL	AMOCO	TOTAL
1976	10,708	314		11,022
1977	6,642	537		7,179
1978	19,105	1,769		20,874
1979	16,941	8,000		24,941
1980	34,271	15,662		49,933
1981	84,060	10,767		94,827
1982	76,497	10,158	7,462	94,117
1983	85,515	22,346	33,460	141,321
1984	51,625	17,533	20,421	89,579
1985	46,954	32,896	8,982	88,832

a/ Average yearly exchange rates:
1980 $1 = 211 CFAF
1981 $1 = 272 CFAF
1982 $1 = 328 CFAF
1983 $1 = 380 CFAF
1984 $1 = 436 CFAF
1985 $1 = 450 CFAF

Source: DGH

NATURAL GAS UTILIZATION FEASIBILITY STUDY

DRAFT TERMS OF REFERENCE

I. Reserve Evaluation

A. Review existing data to estimate the size of reserves by field.

B. Estimate investment requirements to appraise and develop these reserves under different scenarios of reserve and production levels. (Alternatively, this could be undertaken in the engineering study under Part III.)

II. Gas Market and Pricing Study

A. Market Survey

1. Industrial-Power Market

Investigate the present fuel consumption of the large industrial consumers within the supply zone. (Large industrial consumer is defined as a consumer with annual fuel consumption of about 2 million liters of fuel oil equivalent per year or more.)

The following information and data should be investigated and gathered from the large industrial consumers:

(a) name, location, ownership;

(b) raw material and product; type and quantity;

(c) present fuel: heating value, price (specify any excise taxes);

(d) storage capacity;

(e) type and general technical specification of the fuel consuming equipment, i.e., boilers kiln, diesel engine, turbine, etc;

(f) fuel consumption: yearly, average daily, maximum daily, maximum hourly;

(g) specify the seasonal consumers, such as sugar factories and period of work;

(h) future expansion plan.

For medium size and small industrial consumers, the above information should be provided for each category of consumer, such as brick kiln, foundries, workshops, etc.

2. Commercial and Household Sectors

(a) identify cities and townships within the supply zone, by location, population, general layout, type of houses and commercial units and development plant;

(b) temperature: mean maximum, mean minimum, seasonal changes, degree days of heating and cooling;

(c) type of fuel and consumption of each sector; specify LPG;

(d) breakdown of household consumption, i.e., space heating, water heating and cooling;

(e) determine the number of potential commercial gas consumers by group, such as bakeries, hotels, etc; and

(f) number of LPG consumers.

B. Consumption Estimates

1. Using the data from the market study and considering the technical feasibility, conversion costs, time required for conversion, the value of gas ("net back"), and minimum reserves to cover project or plant life, estimate the potential for gas consumption (a) for present industrial/power consumption and (b) industrial expansion and potential commercial and household consumption.

2. Also investigate the scope for use and the value of natural gas as a transport fuel or feedstock for production of ammonia/fertilizers and petrochemicals, including preliminary estimates of attending investments required.

C. Pricing

1. Review the existing pricing structure for natural gas and competing energy resources.

2. Upon completion of the engineering study, recommend in broad terms a natural gas pricing structure, taking into account development and delivery costs, costs of conversion, service connection and costs of competing energy sources.

III. Preliminary Engineering Design and Cost Estimates

A. Prepare a broad description and cost estimates of natural gas gathering, transmission, processing and separation and major distribution systems (i.e., pipeline to industrial grid and spurlines to city gate station(s)), consistent with reserve scenarios proposed in the reserve study and the market survey.

B. Estimate the unit and, if possible, marginal costs of producing, transmitting and distributing the gas for various scenarios of reserves.

C. Outline the steps required in implementing such investments.

IV. Feasibility Analysis and Recommendations

A. Evaluate the impact of the gas as a new source of energy in the overall energy supply-demand context.

B. Analyze the petroleum products supply-demand situation before and after gas substitution and present a solution, i.e., by exporting the excess petroleum products and/or changing the refinery's product pattern.

C. If justified, recommend an action plan for developing the gas, including an analysis of provisions concerning gas and condensate in existing production sharing contracts and appropriate price levels for the gas to induce a commercial oil company to develop and produce the gas resources.

GABON: SOGARA PRODUCTION 1975-1985

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
CRUDE THROUGHPUT ('000 tons)	906.27	980.97	844.64	970.72	743.20	794.36	689.63	616.88	519.91	580.85	642.47
PETROLEUM PRODUCTS ('000 m3)											
LPG ('000 tons)	4.99	5.36	3.97	5.80	3.14	4.69	4.55	5.25	3.93	5.64	7.30
TOE equivalent	5.29	5.68	4.20	6.14	3.32	4.96	4.82	5.56	4.16	5.97	7.73
Gasoline - Regular	125.11	119.26	100.29	103.97	72.75	37.06	32.26	24.99	13.75	15.40	10.94
Ton equivalent	88.08	83.96	70.61	73.19	51.22	26.09	22.71	17.59	9.68	10.84	7.70
TOE equivalent	90.63	86.39	72.65	75.32	52.70	26.84	23.37	18.10	9.96	11.15	7.92
Gasoline - Premium	53.92	70.78	63.46	78.12	68.30	67.14	67.02	57.51	59.54	64.37	74.03
Ton equivalent	39.36	51.67	46.33	57.03	49.86	49.01	48.92	41.98	43.46	46.99	54.04
TOE equivalent	40.50	53.17	47.67	58.68	51.31	50.44	50.34	43.20	44.72	48.35	55.61
Kerosene	121.26	130.94	108.97	131.06	113.40	101.60	110.93	113.73	85.51	102.62	109.87
Ton equivalent	96.52	104.23	86.74	104.33	90.26	80.87	88.30	90.53	68.06	81.68	87.45
TOE equivalent	97.20	104.96	87.35	105.06	90.90	81.44	88.92	91.17	68.54	82.26	88.07
Jet A1											
Ton equivalent	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOE equivalent	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Naptha							0.88	15.71	11.45	12.27	17.69
Ton equivalent	0.00	0.00	0.00	0.00	0.00	0.00	0.64	11.42	8.32	8.92	12.86
TOE equivalent	0.00	0.00	0.00	0.00	0.00	0.00	0.66	11.76	8.57	9.18	13.23
Gas Oil	271.51	291.00	263.52	304.33	214.26	222.21	268.57	230.70	212.65	229.47	265.34
Ton equivalent	233.50	250.26	226.63	261.72	184.26	191.10	230.97	198.40	182.88	197.34	228.19
TOE equivalent	233.50	250.26	226.63	261.72	184.26	191.10	230.97	198.40	182.88	197.34	228.19
Fuel Oil	391.45	480.64	361.31	395.13	325.92	321.25	261.50	220.39	171.22	193.61	210.90
Ton equivalent	352.31	432.58	325.17	355.62	293.33	289.13	235.35	198.35	154.10	174.24	189.81
TOE equivalent	341.39	419.17	315.09	344.60	284.23	280.16	228.05	192.20	149.32	168.84	183.92
Bitume ('000 tons)	0.52	5.36	13.03	7.44	3.74	7.68	5.70	10.91	12.25	10.54	8.23
TOE equivalent											
TOTAL											
Ton equivalent	815.28	933.42	772.47	865.13	675.81	648.57	637.15	574.43	482.68	536.21	595.58
TOE equivalent	808.50	919.63	753.59	851.52	666.72	634.95	627.13	560.38	468.15	523.10	584.68
REFINERY CONSUMPTION ('000 tons)	51.72		39.09	50.02	35.74	37.42	26.32	23.14	22.47	27.67	28.00
REFINERY LOSSES ('000 tons)	39.27	47.55	33.15	55.56	31.66	108.37	26.17	19.32	14.76	16.97	18.89
in percent of throughput	4.33	4.85	3.92	5.72	4.26	13.64	3.79	3.13	2.84	2.92	2.94

a/ To August 31, 1986

Source: Mission estimates, DGH, DGE.

Annex 7

BEICIP SCENARIOS FOR PETROLEUM PRODUCT DEMAND

Table 1: DEMAND PROJECTIONS FOR PETROLEUM PRODUCTS - HIGH AND LOW GROWTH SCENARIOS

Product	Unit	1983	1988		1995	
			High	Low	High	Low
LPG	t	8,313	12,200	10,940	19,600	15,510
Regular & Premium Gasoline	m^3	81,777	110,000	93,500	150,000	103,000
Aviation Gas	m^3	2,422	2,000	2,000	1,500	1,500
Jet Fuel	m^3	88,180	97,000	86,000	122,000	88,000
Kerosene	m^3	16,000	17,850	18,450	16,000	16,350
Gas Oil	m^3	254,500	288,600	234,600	385,400	294,800
Fuel Oil	t	24,463	40,800	31,400	55,000	40,000
Bitumens	t	9,894	15,000	12,000	21,000	17,000
Lubrificants	t	8,935	10,000	8,500	12,000	10,000

Source: BEICIP.

Table 2: DEMAND PROJECTIONS FOR PETROLEUM PRODUCTS MEDIUM GROWTH SCENARIO

Product	Unit	1983	1985	1988	1990	1992	1995
LPG	t	8,313	9,700	12,200	13,600	15,200	17,560
Regular and Premium gasoline	m^3	81,777	92,000	110,000	114,500	119,100	126,500
Aviation Gas	m^3	2,422	2,250	2,000	1,850	1,700	1,500
Jet Fuel	m^3	88,180	91,600	97,000	99,200	101,500	105,000
Kerosene	m^3	16,000	16,700	17,850	17,350	16,900	16,200
Gas Oil	m^3	254,500	258,050	288,600	302,500	317,000	340,100
Fuel Oil	t	24,463	30,000	40,800	42,600	44,500	47,500
Bitumens	t	9,894	11,700	15,000	16,050	17,200	19,000
Lubrificants	t	8,395	9,000	10,000	10,300	10,600	11,000

Source: BEICIP.

PETROLEUM PRODUCT DEMAND AND INVESTMENT REQUIREMENTS

Table 1: DEMAND PROJECTIONS FOR PETROLEUM PRODUCTS
LOW GROWTH SCENARIO

Product	Unit	1988	1990	1992	1995
LPG	t	10,940	12,100	13,350	15,510
Regular and Premium gasoline	m^3	93,500	96,100	98,800	103,000
Aviation Gas	m^3	2,000	1,850	1,700	1,500
Jet Fuel	m^3	86,000	86,600	87,100	88,000
Kerosene	m^3	18,450	17,800	17,200	16,350
Gas Oil	m^3	234,600	246,750	264,300	294,800
Fuel Oil	t	31,400	33,650	36,050	40,000
Bitumens	t	12,000	13,250	14,600	17,000
Lubrificants	t	8,500	8,900	9,300	10,000

Source: BEICIP.

Table 2: ESTIMATED STORAGE REQUIREMENTS FOR SECURITY INVENTORY AND RESERVE INVENTORY

	Required Security Inventory	Daily Peak Volume	Security Inventory	Practical Available Capacity	Needed Extra Storage for Security Inv.	30 days Inventory	Extra Storage needed for 30 days	25 days Inventory	Extra Storage needed for 25 days
	(days)	(m^3/day)	(m^3)	(m^3)	(m^3)	(m^3)	(m^3)	(m^3)	(m^3)
Owendo									
Gasolines	16	305.0	4,880	2,435	2,445	9,150	7,386	7,875	5,984
Kerosene	16	50.0	800	—	—	1,500	—	—	—
Jet	16	428.0	6,848	8,780	—	12,840	6,116	10,700	3,487
Gas Oil	16	472.0	7,552	5,925	—	14,160	9,058	11,800	6,572
Fuel Oil	21	125.5	2,635	3,000	—	3,765	841	3,125	137
Lambarene									
Gasolines	9	25.5	229	255	—	765	561	637	420
Kerosene	9	18.5	166	125	47	555	473	462	370
Gas Oil	9	119.5	1,075	1,190	—	3,585	2,634	2,987	1,976
N'djole									
Gasolines	10	31.4	314	1,305	—	942	—	785	—
Kerosene	10	21.6	216	535	—	648	124	540	—
Gas Oil	10	113.0	1,130	6,715	—	3,390	—	540	—
Moanda									
Gasolines	9	37.4	336	1,435	—	1,122	—	935	—
Kerosene	9	14.4	129	—	—	432	—	360	—
Jet	9	22.1	199	475	—	663	—	552	—
Gas Oil	9	174.7	1,572	1,935	—	5,241	3,636	4,367	2,675
Mayumba									
Gas Oil	25	8.1	202	250	—	243	—	202	—
Port-Gentil									
Gasolines	9	106.0	954	1,435	—	—	—	—	—
Kerosene	9.5	48.4	460	—	—	—	—	—	—
Jet	9.5	36.3	344	2,680	—	—	—	—	—
Gas Oil	7	653.0	4,571	7,645	—	—	—	—	—
LPG	60	300.0	1,800	300	1,500	2,000	17,30	—	—

Source: Mission estimates, BEICIP, DGH.

REGIONAL PETROLEUM PRODUCT PRICE STRUCTURE

Table 1: PRICE STRUCTURE FOR PRODUCTS PASSING THROUGH THE GAMBA DEPOT
April 10, 1986
(CFAF/hl)

	Premium	Regular	Kerosene	Gas Oil
1. Base Price Ex-Port-Gentil	26,807.00	26,307.00	7,607.00	13,707.00
2. Port-Gentil Harbor Fee	225.00	45.00	45.00	45.00
3. Tax on #2 (8%)	18.00	3.60	3.60	3.60
4. Port Tax	100.00	100.00	100.00	100.00
5. Transport P/G-Gamba	1,408.00	1,408.00	1,408.00	1,408.00
6. Tax on #5 (8%)	112.64	112.64	112.64	112.64
7. User Fee - Gamba depot	354.00	354.00	354.00	354.00
8. Tax on #7 (8%)	28.32	28.32	28.32	28.32
9. Discharge/unloading	50.00	50.00	50.00	50.00
10. Equalization Subsidy/Tax	(1,495.96)	(1,291.56)	(1,401.56)	(1,207.56)
11. Price ex-Gamba Depot	27,607.00	27,117.00	8,307.00	14,607.00
12. Delivery charge	225.00	225.00	225.00	225.00
13. Tax on #12 (8%)	18.00	18.00	18.00	18.00
14. Retail margin	850.00	850.00	850.00	850.00
15. Retail price	28,700.00	28,210.00	9,400.00	15,700.00
16. Price per liter	287.00	282.00	94.00	157.00

Source: Direction Générale des Caisses de Stabilisation et de Péréquation.

Table 1: PRICE STRUCTURE FOR PRODUCTS PASSING THROUGH THE SECONDARY DEPOT OF LAMBARENE
April 10, 1986
(CFAF/hl)

	Premium	Regular	Kerosene	Gas Oil
1. Base Price Ex-LBV/POG	26,807.00	26,307.00	7,607.00	13,707.00
2. Port-Gentil Harbor Fee	225.00	45.00	45.00	45.00
3. Tax on #2 (8%)	18.00	3.60	3.60	3.60
4. Port Tax	100.00	100.00	100.00	100.00
5. River Transport	1,072.50	1,072.50	1,072.50	1,072.50
6. Tax on #5 (8%)	85.80	85.80	85.80	85.80
7. CNI Tax on #5 & #6 (2%)	23.16	23.16	23.16	23.16
8. User Fee - Lambaréné	303.88	303.88	303.88	303.88
9. Tax on #8 (8%)	24.31	24.31	24.31	24.31
10. Discharge/unloading	50.00	50.00	50.00	50.00
11. Equalization Subsidy/Tax	(1,202.65)	(1,148.25)	(1,208.25)	(1,008.25)
12. Price ex-Lambaréné depot	27,507.00	26,817.00	8,107.00	14,407.00
13. Delivery charges (to city)	225.00	225.00	225.00	225.00
14. Tax on #13 (8%)	18.00	18.00	18.00	18.00
15. Municipal Tax	250.00	250.00	250.00	250.00
16. Retail margin	850.00	850.00	850.00	850.00
17. Retail price	28,850.00	28,160.00	99,500.00	15,800.00
18. Price per liter	288.00	282.00	94.50	158.00

Source: Direction Générale des Caisses de Stabilisation et de Péréquation.

Table 3: PRICE STRUCTURE FOR PRODUCTS PASSING THROUGH THE MAYUMBA DEPOT
April 10, 1986
(CFAF/hl)

	Premium	Regular	Kerosene	Gas Oil
1. Base Price Ex-Port-Gentil	26,807.00	26,307.00	7,607.00	13,707.00
2. Port Gentil Harbor Fee	225.00	45.00	45.00	45.00
3. Tax on #2 (8%)	18.00	3.60	3.60	3.60
4. Port Tax	100.00	100.00	100.00	100.00
5. Transport P/G-Mayumba	1,408.00	1,408.00	1,408.00	1,408.00
6. Tax on #5 (8%)	112.64	112.64	112.64	112.64
7. User Fee - Mayumba depot	553.12	553.12	553.12	553.12
8. Tax on #7 (8%)	44.24	44.24	44.24	44.24
9. Discharge/unloading	50.00	50.00	50.00	50.00
10. Equalization Subsidy/Tax Mayumba	(1,711.00)	(1,606.60)	(1,516.60)	(1,516.60)
11. Price Ex-Mayumba Depot	27,607.00	27,017.00	8,407.00	14,507.00
12. Delivery charges to city	225.00	225.00	225.00	225.00
13. Tax on #12 (8%)	18.00	18.00	18.00	18.00
14. Retail margin	850.00	850.00	850.00	850.00
15. Retail price	28,700.00	28,110.00	9,500.00	15,600.00
16. Price per liter	287.00	281.00	95.00	156.00

Source: Direction Générale des Caisses de Stabilisation et de Péréquation.

Table 4: PRICE STRUCTURE FOR PRODUCTS PASSING THROUGH THE NDJOLE DEPOT
April 10, 1986
(CFAF/hl)

	Premium	Regular	Kerosene	Gas Oil
1. Base Price Ex-Port-Gentil	26,807.00	26,307.00	7,607.00	13,707.00
2. Port-Gentil Harbor Fee	225.00	45.00	45.00	45.00
3. Tax on #2 (8%)	18.00	3.60	3.60	3.60
4. Port Tax	100.00	100.00	100.00	100.00
5. River Transport	1,518.00	1,518.00	1,518.00	1,518.00
6. Tax on #5 (8%)	121.44	121.44	121.44	121.44
7. CNI Tax on #5 + #6 (2%)	32.79	32.79	32.79	32.79
8. User Fee - Ndjolé	303.88	303.88	303.88	303.88
9. Tax on #8 (8%)	24.31	24.31	24.31	24.31
10. Discharge/unloading	50.00	50.00	50.00	50.00
11. River Equalization Subsidy/Tax	(1,593.42)	(1,589.02)	(1,599.02)	(1,399.02)
12. Price Ex-Ndjolé depot	27,607.00	26,917.00	8,207.00	14,507.00
13. Delivery charges	225.00	225.00	225.00	225.00
14. Tax on #13 (8%)	18.00	18.00	18.00	18.00
15. Retail margin	850.00	850.00	850.00	850.00
16. Retail price	28,700.00	28,010.00	9,300.00	15,600.00
17. Price per liter	287.00	280.00	93.00	156.00

Source: Direction Générale des Caisses de Stabilisation et de Péréquation.

Table 5: PRICE STRUCTURE FOR PRODUCTS FROM MOANDA DEPOT THROUGH NDJOLE
April 10, 1986
(CFAF/hl)

	Premium	Regular	Kerosene	Gas Oil
1. Cost Price (Ndjolé)	27,607.00	26,917.00	8,207.00	14,507.00
2. Transport Ndjolé-Moanda	4,403.00	4,403.00	4,403.00	4,403.00
3. Tax on #2 (8%)	352.24	352.24	352.24	352.24
4. Losses in transit (on #1+2+3)	293.19	286.54	100.22	100.31
5. Financial charges on security stocks 13% at 60 JHT	566.24	550.92	213.30	349.94
6. Customs credit tax (5%)	10.02	10.02	3.34	
7. User Fee - Moanda depot	400.90	400.90	400.90	
8. Tax on #6 (8%)	32.07	32.07	32.07	32.07
9. Retail margin	850.00	850.00	850.00	850.00
10. Equalization Subsidy/Tax	(6,157.66)	(5,935.69)	(5,505.07)	(5,740.13)
11. Price ex-Moanda depot	28,357.00	27,847.00	9,057.00	15,257.00
12. Transport (depot to city)	225.00	225.00	225.00	225.00
13. Tax on #11 (8%)	18.00	18.00	18.00	18.00
14. Municipal Tax	250.00	250.00	250.00	250.00
15. Retail price	28,850.00	28,360.00	9,550.00	15,757.00
16. Price per liter	289.00	283.00	95.50	158.00

Source: Direction Générale des Caisses de Stabilisation et de Péréquation,

PETROLEUM PRODUCT TRANSPORT COSTS

Table 1: REIMBURSEMENT FROM THE NDJOLE DEPOT
(CFAF/liter)

Towards:	Distance (Km)	Transport costs (T.T.C.)	Reimbursement			
			Premium	Regular	Kerosene	Gas Oil
Akieni	625	62.44	60.01	58.01	58.51	60.01
Ayem	113	11.29	7.86	7.86	7.36	8.86
Bitam	383	38.26	34.83	34.83	34.33	35.83
Boue	247	24.68	21.25	21.25	20.75	22.25
Franceville	536	53.55	51.12	49.12	49.62	51.12
Koulamoutou	384	38.36	38.93	36.93	34.43	35.93
Lastourville	353	35.26	32.83	30.83	31.33	32.83
Makokou	351	35.06	31.63	31.63	31.13	32.63
Makambo	526	52.55	49.12	49.12	48.62	50.12
Minvoul	423	42.26	37.83	38.83	38.33	39.83
Mitzic	190	18.98	15.55	15.55	15.05	16.55
Moanda	476	47.55	60.75	58.53	54.25	56.66
Mouanna	462	46.15	43.72	41.72	42.22	43.72
Oyem	308	30.77	27.34	27.34	26.84	28.34

Source: MFBP.

Table 2: REIMBURSEMENT FROM THE MAYUMBA DEPOT
(CFAF/liter)

Towards:	Distance (Km)	Transport costs (T.T.C.)	Reimbursement			
			Premium	Regular	Kerosene	Gas Oil
Mebamba	239	23.88	21.45	21.45	21.45	21.45
Mbigou	325	32.47	30.04	30.04	30.04	30.04
Mimongo	347	34.67	32.34	32.34	32.34	32.34
Moabi	204	20.38	17.95	17.95	17.95	17.95
Moulia	280	27.97	25.54	25.54	25.54	25.54
Ndende	204	20.38	17.95	17.95	17.95	17.95
Tchibanga	114	11.39	8.96	8.96	8.96	8.96

Source: MFBP.

Table 3: REIMBURSEMENT FOR TRANSPORT FROM THE DEPOTS AT MBINDA AND MOANDA (CFAF/liter)

From MBINDA towards:	Distance (Km)	Transport costs (T.T.C.)	Reimbursement Premium	Regular	Kerosene	Gas Oil
Moanda	104	10.39	18.06	18.05	14.62	15.95
Comilog	104	10.39	6.79	6.89	6.89	6.89
From MOANDA towards:						
Akieni	149	14.89	11.46	11.46	10.96	11.46
Bakumba	55	5.49	2.06	2.06	2.06	2.06
Boumango	169	16.08	13.45	13.45	12.95	13.05
Franceville	60	5.99	2.65	2.65	2.15	2.65
Koulamoutou	193	19.28	15.85	15.85	15.35	15.85
Lastourville	123	12.29	8.86	8.86	8.36	8.36
Lekoni	158	15.78	12.35	12.35	11.85	12.35
Sosuho	50	5.59	2.16	2.16	1.66	2.10
Mounana	20	2.00	(1.43)	(1.43)	(1.93)	(1.43)
Mvengue	45	4.50	1.07	1.07	0.57	1.07
Okondja	248	24.77	21.34	21.34	20.84	21.34
Pana	283	28.77	24.84	24.84	24.34	24.84

Source: MFBP.

Table 4: REIMBURSEMENT FROM THE LAMBARENE DEPOT
(CFAF/liter)

Towards	Distance (Km)	Transport costs (T.T.C.)	Reimbursement Premium	Regular	Kerosene	Gas Oil
Fougamou	92	9.19	5.76	4.76	3.76	5.76
Mebamba	310	30.97	27.54	26.54	25.54	27.54
Mandji	170	16.98	13.55	12.55	11.55	13.55
Mayumba	477	47.65	44.22	43.22	42.22	44.22
Mbigou	397	39.66	36.23	35.23	34.23	36.23
Mimongo Yeno	419	41.86	38.43	37.43	36.43	38.43
Mimongo Mbigou	475	47.45	44.02	43.02	42.02	44.02
Moabi	291	29.07	25.04	24.64	23.64	25.64
Moulia	200	19.98	16.55	15.55	14.55	16.55
Ndende	273	27.27	23.84	22.84	21.84	23.84
Sindare	97	9.69	6.26	5.26	4.26	6.26
Tchibanga	363	36.26	32.83	31.83	30.83	32.83

Source: MFBP.

Table 5: REIMBURSEMENT FROM THE LIBREVILLE DEPOT
(CFAF/liter)

Towards:	Distance (Km)	Transport costs (T.T.C.)	Reimbursement Premium	Regular	Kerosene	Gas Oil
Lambaréné	235	23.48	20.26	22.16	21.96	20.56
Medouneu	218	21.78	10.85	10.75	9.55	10.15
Ndjolé	224	22.38	18.16	20.06	19.86	18.46

Source: MFBP.

Annex 11

PRICE STRUCTURE FOR BUTANE SOLD IN LIBREVILLE AND PORT-GENTIL
March 18, 1985
(CFAF/t)

1. Ex-refinery price	99,000
2. Landing Tax	1,000
3. Discharge fee (2% of 1 + 2)	2,000
4. Entry duty (25% of #1)	24,750
5. Tax 10% of #1 and #4	12,375
6. "Taxe complémentaire" 5% of #1	4,950
7. Customs tax 0.8% of #1	792
8. Treasury tax 2% of #4, 5, 6 and 7	86
9. Depot User's Fees	25,378
10. Tax 8% of #9	2,030
11. Exit price at dépôt	172,361
12. Bottle maintenance	34,383
13. Amortization of bottle costs	34,320
14. Transport to city	9,781
15. Tax on transport to city 8% of #14	782
16. General charges	18,405
17. Financial charges 1.2% of #4, 5, 6, 7 and 8	515
18. Profit	17,500
19. Stabilization subsidy	5,953
20. Wholesale price	294,000
21. Retail margin	26,000
22. Retail price per ton	320,000
23. Retail price per 12.5 kg bottle	4,000

Source: MFBP.

ELECTRICITY SYSTEM DATA

Table 1: SUMMARY OF BASIC DATA

	1975	1980	1985
Installed capacity (MW)	101.1	209.0	251.9
Hydro	47.7	121.8	163.8
Thermal	53.4	87.2	88.1
Generation (GWh)	253.0	566.5	861.3
Hydro	143.3	415.8	667.7
Thermal a/	109.7	150.7	193.6
Losses	36.6	68.4	104.4
Sales (GWh)	216.4	498.1	756.9
HV and MV	122.2	309.5	398.4
LV	94.2	188.6	358.5
Customers	19,390	33,100	58,506
HV and MV	172	310	360
LV (Total)	19,218	32,790	58,146
Residential	18,425	31,860	56,652
Public Lighting	157	185	538
Industrial	636	765	956

a/ Including purchases from Shell Gamba (2.3 GWh in 1985).

Source: SEEG.

Table 2: MAIN POWER SYSTEM CHARACTERISTICS, 1985

	Libreville	Port-Gentil	Franceville	Isolated centers	Total
Available capacity a/ (MW)	168	57	48	5	285
Hydro	126 b/	0	38	0	161
Thermal	42	57	10	15	124
1985 Peak Load (MW)	87	26	25	8 c/	--
Net Generation (GWh)	531	158	137	35	861
Hydro	530	0	137	0	668
Thermal	0	158	0	35 d/	194
Sales (GWh)	461 e/	146	119	31 e/	757
HV & MV	211	75	104	7	398
LV	250	70	14	24	358
Number of customers	37,968	8,845	3,059	8,633	58,506
HV & MV	252	44	42	21	360
LV	37,716	8,801	3,017	8,612	58,146
Average Demand Growth 1982 to 1985 (%/yr)	10.2	4.0	7.4	20.8	8.9

a/ In October 1986.
b/ Only 108 MW are available in dry years.
c/ Sum of individual peak loads; not occuring simultaneously.
d/ Including 2 GWh purchased from SHELL.
e/ Figures for N'Toum included under Libreville totals.

Source: SEEG.

Table 3: INSTALLED CAPACITY AND GENERATION

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Total Installed Capacity (MW)	101.1	106.1	162.4	167.0	167.6	209.0	219.2	221.0	228.4	239.5	251.9
Hydro	47.7	52.3	57.0	76.2	76.2	121.8	121.8	121.8	131.4	141.0	163.8
Thermal	53.4	53.8	105.4	90.8	91.4	87.2	97.4	99.2	97.0	98.5	88.1
Total generation (GWh)	253.0	327.8	431.2	491.2	534.8	566.5	611.8	667.2	729.0	795.1	861.3
Hydro	143.3	161.8	299.4	348.0	389.5	415.8	459.5	502.9	546.5	612.9	667.7
Thermal	109.7	166.0	131.8	143.2	135.3	150.7	152.3	164.3	182.5	182.2	193.6
LBV Installed Capacity (MW)	50.8	50.8	50.8	70.0	70.0	115.6	115.6	113.2	113.2	113.2	129.4
Hydro	38.4	38.4	38.4	57.6	57.6	103.3	103.2	103.2	103.2	103.2	126.0
Thermal	12.4	12.4	12.4	12.4	12.4	12.4	12.4	10.0	10.0	10.0	3.4
LBV Generation (GWh)	131.8	164.4	250.5	293.9	313.4	328.7	367.2	396.2	434.9	483.2	442.3
Hydro	128.2	161.3	241.2	283.5	309.6	326.7	356.4	396.0	431.5	482.9	530.4
Thermal	3.6	3.1	8.6	10.4	3.8	2.0	1.8	0.2	3.4	0.3	0.3
POG Installed Capacity a/ (MW)	-	-	-	56.8	59.8	62.8	62.8	62.8	62.8	61.3	59.8
Generation b/ (GWh)	98.0	104.0	114.0	117.8	111.7	123.8	128.4	140.2	148.5	151.9	157.8
FCV Installed Capacity (MW)	-	-	-	-	-	-	31.2	33.8	42.0	51.6	47.8
Hydro	9.3	18.6	18.6	18.6	18.6	18.6	18.6	18.6	28.2	37.8	37.8
Thermal	-	-	-	-	-	-	12.6	15.2	13.8	13.8	10.0
FCV Generation (GWh)	-	-	-	-	-	-	99.2	110.6	121.3	130.7	137.3
Hydro	14.8	51.9	58.1	64.5	79.9	89.0	94.2	106.9	115.0	129.9	137.3
Thermal	(2)	(2)	(2)	(2)	(2)	(2)	5.0	3.7	6.3	0.8	0.0
DER Installed Capacity a/ (MW)	-	-	-	-	-	-	8.6	8.6	10.7	13.4	14.9
Generation (GWh)	6.2	6.8	8.2	11.5	12.9	14.3	16.2	19.2	23.0	27.2	33.3

a/ All thermal.
b/ Included in DER.

Source: SEEG.

CHARACTERISTICS OF INSTALLED HYDRO AND THERMAL PLANT

System	Name	Type of Units	Number of Units	Unit rating	Total installed capacity	Commissioning Years	Unavailability rates a/		
							Maintenance	Forced outages	Total
				(MW)	(MW)		(%)	(%)	(%)
LBV	KINGELE	Hydro	2	9.6	19.2	72 - 73	4.4	0.7	5.1
			2	19.2	38.4	75 - 78	3.7	0.6	4.3
	TCHIMBELE	Hydro	3	22.8	68.4	80 - 85	3.6	1.6	5.2
	OWANDA	G.T.	2	20.8	41.6	86	-	-	-
POG	-	G.T.	2	20.9	41.8	77	7.2	0.8	8.0
	-	Diesel	5 b/	3.0	15.0	69 - 76	2.7	2.7	5.4
FCV	POUBARA 1	Hydro	4	4.64	18.56	75 - 76	3.9	0.5	4.3
	POUBARA 2	Hydro	2	9.6	19.2	83 - 84	2.0	5.3	7.3
	MOYABI	Diesel	5	2.2	11.0	77	-	-	-
		Diesel	2	1.4	2.8	65 - 66	-	-	-
DER	-	Diesel	-	-	15	-	-	-	-

a/ Mean value from commissioning to end of 1985 for hydro plants and mean value for 1985 for thermal plants.
b/ Six twin units out of which two have only one motor left available.

Source: SEEG.

ELECTRICITY DEMAND: 1980-1985
(GWh)

	1980	1981	1982	1983	1984	1985	Average Annual Growth 80-85 (%)	82-85 (%)	84-85 (%)
Total	498	533	586	639	697	757	8.7	8.9	8.6
MV	309	332	347	367	383	399	5.2	4.8	4.2
LV	189	201	229	273	314	358	13.6	16.1	14.0
Libreville	274	296	325	359	400	442	14.6	10.8	10.5
MV	141	158	164	173	185	196	6.8	6.1	5.9
LV	133	137	161	187	215	246	13.1	15.2	14.4
Port-Gentil	114	117	129	133	140	146	5.1	4.2	4.3
MV	76	74	75	76	75	75	-0.3	-0.1	0.6
LV	38	43	53	57	65	70	13.4	9.8	7.7
Franceville	81	91	100	110	114	119	8.0	5.7	3.7
MV	74	83	91	100	103	104	7.2	4.5	1.4
LV	7	8	9	10	11	14	15.0	16.1	24.5
Isolated Centers	29	30	33	37	43	50	11.5	15.4	16.8
MV	18	17	17	18	20	22	4.3	9.6	10.3
LV	11	13	16	19	23	28	20.2	21.0	23.0

Source: SEEG.

ELECTRICITY CONSUMPTION AND SALES BY VOLTAGE AND TYPE OF CONSUMER, 1985 a/

Voltage	Category	Tariff	Number of customers b/	Sales		Average consumption per customer	Invoicing		Average KWh rate
				(MWh)	(%)	(kWh/year)	(billion CFAF)	(%)	(CFAF/kWh)
MV	General tariff	E4	305	93,145	12.3	306,400	5,042	15.9	54.1
	Special tariffs	-	50	288,433	38.1	5,769,000	7,485	23.6	26.0
	Internal sales	-	5	16,916	2.2	3,383,000	--	--	--
	Total	-	360	398,497	52.6	1,106,900	12,527	39.6	31.4
LV	Social residential	ES	4,655	5,357	0.7	1,151	250	0.8	46.7
	Residential	E1+E2+E3+E9	49,835	285,031	37.7	5,719	17,129	54.1	60.1
	Public lighting	E6+E7	545	10,720	1.4	19,670	504	1.6	47.1
	Industrial	E5+E8	1,040	24,352	3.2	23,415	1,189	3.8	48.8
	Internal sales	-	215	15,555	2.1	72,349	--	--	--
	SEEG Personnel	-	1,860	17,462	2.3	9,388	65	0.2	3.7
	Total	-	58,145	358,475	47.4	6,165	19,137	60.4	53.4
TOTAL	General Total	-	58,505	756,972	100.0	12,940	31,664	100.0	41.8

a/ Taxes and "contributions" excluded.

b/ Rounded to the nearest multiples of 5.

Source: SEEG.

SEEG DEMAND FORECAST - 1984

In SEEG's 1984 demand forecasts, several demand trend assessment methods were used.

A1 - Logarithmic extrapolation of past trends

A2 - Linear extrapolation of past trends

A3 - Exponential extrapolation of past trends

B -Use of a log function, taking as a basis past trends, final assessed consumption per consumer and the forecasted trend of the total class of consumers involved, actual and projected

C - Specific market surveys of large consumers

Three forecasts were worked out using different scenarios based on the length of the recorded period used for the extrapolation, or the type of extrapolation selected (A1, A2, or A3).

The tables in this annex present the general features of the forecasts based on the "average" scenario. The phrase "service rate" means the number of service per one hundred inhabitants; "SEEG use" means both the consumption by SEEG personnel and the SEEG own consumption for tis operations (water service).

Table 1: SEEG FORECAST FOR LIBREVILLE, 1984

	Trend estimate	1988	1990	1995
Population (10^3)	-	273	295	359
Service rate	-	10.8	11.5	13.0
Residential specific consumption (MWh/year)	-	9.4	9.7	10.6
Total consumption (GWh)	-	548	628	856
LV Consumption (GWh)	-	321	381	559
Residential	B	276	330	494
SEEG use	A2	21	24	32
Public lighting	A1	8	8	9
Industrial	A2	17	19	24
MV Consumption (GWh)	-	227	247	296
Private use	A2	214	233	281
SEEG use	C	13	14	15

Source: SEEG.

Table 2: SEEG FORECAST FOR PORT-GENTIL, 1984

	Trend estimate	1988	1990	1995
Population (10^3)	-	97	104	122
Service rate	-	10.1	10.7	11.9
Residential specific consumption (MWh/year)	-	9.4	9.6	10.6
Total consumption (GWh)	-	173	191	242
LV Consumption (GWh)	-	97	114	169
Residential	B	92	109	155
SEEG use	A1	3	3	3
Public lighting	A1	1	1	1
Industrial	A2	1	1	1
MV Consumption (GWh)	-	76	78	82
General private	A1	15	16	19
3 large companies	C	58	58	58
SEEG use	C	3	4	5

Source: SEEG.

Table 3: SEEG FORECAST FOR FRANCEVILLE, 1984

	Trend estimate	1988	1990	1995
Total consumption (GWh)	-	139.2	145.3	163.0
LV Consumption (GWh)	-	13.6	15.2	19.1
Residential	A2	9.0	10.1	12.6
SEEG use	A2	2.2	2.4	3.0
Public lighting	A1	0.9	1.0	1.3
Industrial	A2	1.5	1.7	2.2
MV Consumption (GWh)	-	125.6	130.1	143.9
General Private	A1	21.9	23.9	29.3
3 large companies	C	103.7	106.2	114.6

Source: SEEG.

Table 4: SEEG FORECAST FOR ISOLATED CENTERS, 1984

	Trend estimate	1988	1990	1995
Total consumption in centers (GWh)	A3	67.2	97.8	246.3

Source: SEEG.

Annex 17

HYDRAULIC POTENTIAL

The hydraulic potential of Gabon presently is assessed to be 4,900 MW and 33,500 GWh/year of which less than 200 MW and 1,000 GWh/year currently are harnessed (less than 5%).

A very large range of sites are available, from ones convenient for micro or mini-power plants, up to sites where several hundreds of MW power plants can be installed.

The following table displays the most important sites where some studies have been undertaken.

	Number of main sites	Power (MW)	Energy (GWh/year)
Libreville Region	13	763	4,640
River MBEI	3	121	610
River KOMO	5	312	1,980
River ABANGA	3	245	1,510
Others	2	85	540
South East a/	8	638	4,770
High OGOOUE	4	322	2,335
Others	4	316	2,435
Other regions b/	8	3,325	9,540

a/ Region of Franceville, South East of Lastourville.
b/ Mainly in the center of the country.

Source: SEEG.

Annex 18

SEEG PERSONNEL

Table 1: SEEG PERSONNEL BY FUNCTION a/

	Managerial Staff	Supervisory Staff	Labour	Total
Total	231	530	1,279	2,040
Electricity	49	151	535	735
Water	13	35	206	254
Both	169	344	538	1,051
Electricity Subsector	49	151	535	735
Generation	33	98	179	310
Distribution	2	43	171	216
Both	14	10	185	209

a/ September 1986.

Source: SEEG.

Table 2: GEOGRAPHIC BREAKDOWN OF SEEG PERSONNEL

	Managerial Staff	Supervisory Staff	Labour	Total
Total	231	530	1,279	2,040
Head offices	181	286	468	935
Libreville	14	83	291	388
Port-Gentil	13	50	175	238
Franceville	10	35	90	135
Isolated Centers	13	76	255	344

Source: SEEG.

Annex 19

SEEG CUSTOMERS: 1975-1985

Table 1: NUMBER OF MV CUSTOMERS: 1975-1985

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Libreville	99	110	147	-	198	212	210	218	223	243	249
Port-Gentil	45	46	47	-	44	42	39	39	36	43	44
Franceville	-	-	-	-	-			34	42	41	42
						55	59				
Isolated Centers	-	-	-	-	-			28	22	24	25
Total	-	-	-	-	-	310	308	318	323	351	360

Source: SEEG.

Table 2: NUMBER OF LV CUSTOMERS: 1975-1985
(thousands)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Libreville	12.8	14.6	18.9	-	19.8	21.7	23.2	26.8	30.9	34.5	37.7
Port-Gentil	3.6	3.8	4.2	-	4.4	4.8	5.4	6.3	7.4	8.1	8.8
Franceville	-	-	-	-	-			1.8	2.0	2.4	3.0
						6.3	6.9				
Isolated Centers		-	-	-	-	-		5.8	6.5	7.5	8.6
Total	-	-	-	-	-	32.8	35.6	40.7	46.8	52.4	58.1

Source: SEEG.

Annex 20

SEEG OPERATIONAL EXPENDITURES a/
(million CFAF)

	1984	1985
Billing (without taxes)	38,764	49,027
Electricity and water sales	31,594	37,883
Equipment contributions	2,633	4,478
Special contributions	1,701	2,439
Miscellaneous works	1,890	2,923
Miscellaneous activities	904	1,304
Operational expenses	28,129	34,501
Procurement (including fuel)	9,087	10,737
Transportation	736	815
Personnel	10,877	12,845
BIC	338	412
Maintenance under the equipment contribution	327	564
Maintenance and consumption under the special contribution	1,701	2,439
Miscellaneous services	3,272	4,138
Insurances and miscellaneous contributions	515	691
Taxes	600	674
Interests	676	1,186

a/ Both water and electricity.

Source: SEEG.

SEEG: PAST INVESTMENTS

The figures given in the tables below cover SEEG's investments for both electricity and water supply. The mission estimates that electricity represents approximately 75% of total investments. Table 1 show past investments undertaken by concession (outside the private ownership of SEEG). Since these figures vary considerably from year to year, a running four-year average is given so that general trends can be more easily noted.

Table 1: PAST INVESTMENTS - CONCESSIONS
(billion CFAF)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Current Value of Investment	7.7	8.5	4.1	21.4	5.3	22.6	7.3	3.3	6.6	8.8	7.6
Present Value (1985 CFAF)	17.6	18.5	8.4	42.3	9.3	36.9	10.9	4.3	8.0	9.4	7.6
Average for Four Preceeding Years (1985 CFAF)	9.8	13.6	11.6	21.7	19.6	24.2	24.8	15.4	15.0	8.1	7.3

Source: SEEG, mission estimates.

At the end of 1985, SEEG's own assets (as opposed to those operated by SEEG under concession arrangements) amounted to 39 billion CFAF. Major capital investments in the past 10 years include the installation of a gas turbine plant at Port-Gentil (the only large generating facility privately owned by SEEG) in 1976-1977 (10 billion CFAF), and construction of new headquarters in Libreville and miscellaneous office buildings in other towns in 1985 (18 billion CFAF).

Table 2: ELECTRICITY SUBSECTOR INVESTMENT PROGRAM - 1987-1995
(billion CFAF)

	Total investment	1987	1988	1989	1990	1991	1992	1993	1994	1995
GENERATION AND TRANSMISSION										
With interconnection		0	0.5	0.5	0	0	5	8	8	26
Libreville and Port-Gentil										
Special studies	1	-	0.5	0.5	-	-	-	-	-	-
Interconnection overhead lines and substations	26	-	-	-	-	-	2	8	8	6 a/
Next hydro plant	-	-	-	-	-	-	-	-	-	20 b/
Franceville										
Gas turbine	3	-	-	-	-	-	3	-	-	-
Without interconnection		0	0.5	0.5	0	5.5	13	10	15	30
Libreville and Port-Gentil										
Special studies	1	-	0.5	0.5	-	-	-	-	-	-
Kinguele downstream	30	-	-	-	-	5.5	10	10	10	10 c/
Next hydro plant	-	-	-	-	-	-	-	-	5	20 d/
Franceville										
Gas turbine	3	-	-	-	-	-	3	-	-	-
DISTRIBUTION		2.0	2.0	2.0	2.0	2.0	2.5	2.5	2.5	2.5
Libreville	-	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Port-Gentil	-	0	0	0	0	0	0.5	0.5	0.5	0.5
Franceville	-	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
ISOLATED CENTERS	-	1.5	1.5	1.5	1.5	4.0	4.4	4.8	5.3	5.9

a/ Complementary substation equipment in 1996.
b/ Assumption for commissioning in 1999 (GT at Port-Gentil to be commissioned beforehand, with first investments beyond 1995).
c/ Last part of electromechanical commissioned in 1996.
d/ Assumption. In the development without interconnection, the next hydro plant would probably be another than Kinguele downstream.

Source: Mission estimates.

Annex 22

SEEG ORGANIZATION CHART

The following organization chart displays past and present situation. The figures on the right are the number of personnel, as of September 1986.

DG	Direction générale (General Management)	171
	Etudes générales (Development studies)	7
	Contrôle de gestion (Management supervisions)	8
	Service Juridique (Lawyer questions)	25
	CDM	60
DI	Direction de l'Informatique (Data Processing)	42
DTE	Direction Technique de l'Equipement (Project Department)	50
DAC	Direction Administrative, Comptable et Financière (Administration, accounting, finance)	38
DIC	Direction Commerciale (Sales)	271
DP	Direction du Personnel	54
DEX	Direction de l'Exploitation (Operation)	
	Common services	209
	Libreville	388
	Port-Gentil	238
	Franceville	135
	Isolated centers	344
		2,040

SEEG TARIFFS
(mid-1986)

"Tarif Social" (Social Tariff)

This LV tariff referred to as "E5", applicable up to 4 kVA, is the same all over the country. It features two blocks:

0 to 240 kWh/month ..... 37.04 CFAF/kWh
Over 240 kWh/month ..... 76.39 CFAF/kWh

The bills are charged with the 8% TCA (income tax).

Other LV Residential Tariffs in Libreville

In Libreville, four other LV residential tariffs are used: E1, E2, E3 and E9.

Tariff E9 is for air conditioning only, and is used by consumers who also have tariff E1 for the other applications (in these cases, the consumers have two meters). This system is being replaced progressively by tariff E3 (with only one meter per consumer). Another tariff, E2, also being phased out, is applicable for all domestic usages. Tariffs 1, 2 and 3 are block tariffs, each block being defined by a number of hours of utilization of the subscribed demand (limited by the breaker setting). The kWh prices are as follows:

Block	Basic price	TCA on basic price	Equipment contribution	Special contribution	Total
E1 0 - 40 h	75.27	6.02	4.01	-	85.30
40 - 130 h	69.66	5.57	-	5.35	80.58
over 130 h	49.31	3.91	-	5.35	56.60
E2 0 - 40 h	75.27	6.02	4.01	-	85.30
40 - 130 h	69.66	5.57	-	8.03	83.26
over 130 h	41.40	3.91	-	8.03	52.74
E3 Same prices as for E2, but with blocks 0-20h, 20-50h and over 50h.					
E9 Single block	41.40	3.31	-	8.03	52.74

Other LV Residential Tariffs in Port-Gentil

In Port-Gentil, there is only one LV residential tariff other than the social tariff, tariff E1, with two blocks only:

Block	Basic price	TCA on basic price	Equipment contribution	Special contribution	Total
E1 0 - 125 h	88.13	7.05	5.76	-	100.94
Over 125 h	39.65	3.17	5.76	5.76	54.34

Other LV Residential Tariffs in Franceville and the Isolated Centers

Here also, tariff E1 is the only LV tariff other than the social tariff. The blocks are the same as in Port-Gentil, and there is no contribution. The prices are the same in Franceville and the isolated centers: for the first block, 98.30 CFAF/kWh and for the second block, 72.70 CFAF/kWh. The 8% slaes tax is added in the billing.

LV Industrial Use

This tariff "5" is a single block tariff with the following prices (in CFAF/kWh):

	Basic price	TCA on basic price	Equipment contribution	Special contribution	Total
Libreville	50.18	4.01	4.01	-	58.20
Port-Gentil	59.28	4.74	5.76	-	69.78

In Libreville and Port-Gentil, there is no contribution, and the common price is 84.80 CFAF/kWh.

Specific LV Tariffs

The two following tariffs also are found, although they are being phased out.

In Port-Gentil, tariff "E7" for private settlements: basic price 66.10 CFAF/kWh, sales tax: 5.29 CFAF/kWh, equipment contribution: 5.76 CFAF/kWh, special contribution: 5.76 CFAF/kWh, for a total of 82.91 CFAF/kWh.

In Franceville and the isolated centers, tariff "E8", for the food industry, has a single block at 50 CFAC/kWh.

MV General Tariff in Libreville

This tariff "E4" is a time of the day tariff, without demand charge. The prices are as follows:

	Basic price	TCA on basic price	Equipment contribution	Special contribution	Total
Peak	62.18	2.49	3.05	3.05	70.77
Out of peak	41.46	1.66	3.05	3.05	49.22

MV General Tariff in Port-Gentil, Libreville and the Isolated Centers

Also referred to as "E4", this tariff is a subscribed demand charge tariff with single kWh price. The prices are as follows:

	Port-Gentil	Franceville and isolated centers
Subscribed demand charge CFAF/kWh/year	20,067.6 + 802.7 sales tax = 20,870.3	20,758
kWh price (CFAF)	50.18 + 2.01 sales tax + 0.87 special contribution = 53.06	75.40

MV Special Tariffs

These tariffs (the most important in MV by the sold energy) are negotiated case by case.

HOUSEHOLD ENERGY

DRAFT TERMS OF REFERENCE

These Terms of Reference are presented by the mission as information. A final version tailored to the characteristics of Gabon's energy sector will have to be defined.

I. The household energy economist should:

(a) collect available and relevant economic data, evaluate existing energy pricing policies, and advise the socio-economic surveyor on economic data to be gathered via the household survey;

(b) determine the economic and financial cost of demand-supply scenarios for electricity, LPG, kerosene, charcoal, firewood, agricultural residues, etc;

(c) assess the economic price of the various fuels and recommend appropriate and phased measures to adjust prices to promote substitution and conservation;

(d) recommend pricing for the substitute fuels, evaluate the pricing of their required cooking equipment (including possible subsidies) and its impact of fuel demand, and determine the cost for each fuel on a per useful MJ basis;

(e) analyze the likely impact of new prices (including subsidies) on disaggregated energy supply, demand, the family budget, foreign exchange, and government budget;

(f) determine the comparative economic benefits of local versus foreign manufacture of new cooking equipment;

(g) prepare economic and financial analyses of all recommended options and policies, rank the options according to their relative economic and financial internal rates of return and net present values, and determine the impact of the proposed policy (or package of policies) on government expenditure, revenues and balance of payments; and

(h) identify support required to ensure successful implementation of the household energy strategy.

II. The petroleum products/distribution specialist should:

(a) review existing and ongoing studies on LPG and kerosene for the household sector;

(b) assess, in collaboration with the stove technologist and the marketing specialist, present supply, storage, distribution and marketing arrangements for LPG and kerosene, and advise on the range and relative priority of technical options (separate as well as in packages) to be considered in developing a program of substitution for LPG, and assess their costs and likely benefits. Special attention should be given to reliability and appropriateness of the distribution system in relation to consumers' fuel purchasing behavior;

(c) determine a phased investment plan required for procurement, processing, handling and distributing LPG and kerosene for the household market, the size of which will be estimated in collaboration with the marketing specialist and the energy economist; and

(d) provide a description and cost estimate for any technical assistance required for program implementation, including supervision of engineering, training of operators and distributors.

III. The marketing specialist should:

(a) identify, in consultation with the stove technologist and local staff, the survey sample and design a consumer acceptability study for improved cookstoves;

(b) train and supervise surveyors, carry out the survey, test social acceptability, and analyze results. Repeat the survey, if adaptations in stove design are indicated;

(c) select, in collaboration with the stove technologist and local staff, the stove designs for dissemination;

(d) evaluate, together with the energy economist, the least-cost financial and economic solutions for meeting cooking needs as well as assess the inherent risks of each option;

(e) recommend, in collaboration with the energy economist, the means of promoting the sale and use of substitute fuels and define their likely consumption area;

(f) evaluate the size, segmentation and location of the market for each fuel; and

(g) implement the recommended program, training and other technical assistance as needed to establish and maintain dissemination.

IV. The stove technologist should:

(a) advise on the range and relative ranking of appropriate stoves for each fuel, as well as determine the need for adaptation of existing equipment or the development of new equipment. If need be, develop in collaboration with local staff such adapted or new stoves;

(b) determine the efficiency and durability of improved three-stone stoves and develop quality controls for construction and use;

(c) identify a small sample of appropriate stoves (based on items (b) and (c)), which will be field-tested in a small control group of consumers to ascertain fuel consumption, time saving, safety, stability, and other consumer (male and female) reactions. The results of this survey will provide inputs of modifying the stove design, if need be, and for narrowing down the range for the final selection of the most appropriate stoves. This survey may have to be repeated more than once;

(d) recommend means of production, procurement of construction materials, provision of training and incentives to artisans/factory if local production is preferable. On the other hand, advise why import or assemblage of stoves is the least-cost solution; and

(e) work in close consultation with the marketing specialist, as well as local staff in the selection, adaptation, and/or development, quality control, market testing, and maintenance of stoves.

V. The soci-economic surveyor should:

(a) review existing studies on household energy consumption and supply, and prepare, in consultation with relevant team members, a detailed list of data requirements;

(b) assist local experts in design of the representative statistical samples for the supply and demand surveys;

(c) design draft questionnaires, in consultation with local experts and team members, for each survey;

(d) advise on the training and supervision of interviewers;

(e) monitor pilot testing and recommend modifications for the large-scale survey;

(f) assist in the design of machine tabulation requests and data compilation;

(g) analyze the results of each survey and supervise preparation of final reports on household energy consumption and supply systems;

(h) develop an information system to keep track of the results of the studies and quality control by means of consumer control groups and permanent monitoring of stove manufacturing; and

(i) evaluate the actual impact of the program and its effect on improving efficiency.

VI. The energy forester should:

(a) identify and describe any present de facto forestry and/or fiscal policy, institutional and planning arrangements drawing upon the material available in studies and from field investigations;

(b) examine the organization of fuelwood supply for each large city in the country. This examination should include: (i) delimitation and mapping of areas for exploitation and those to be protected, including access routes, within a 100-150 km radius about the cities; (ii) quotas for annual exploitation and an exploitation schedule for each area, based on local fuelwood demand and the availability of dead wood; (iii) exploitation specifications for each type of forestry formation, giving priority to collection of dead wood; (iv) potential organization of retailers: village associations, co-ops consisting of several villages, private companies, etc.; (v) placement and management of markets in each area, as well as quotas for each market; (vi) organization of transport between the collection or cutting point and the city markets; and (vii) the potential for improving fuelwood marketing in cities;

(c) design and implement pilot projects among the rural population for promoting rational exploitation of wood resources in the bush; and

(d) calculate the revenues that will accrue as a result of these activities to the government and the village community and suggest mechanisms for the possible use of these revenues to improve the overall performance of the proposed management system.

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