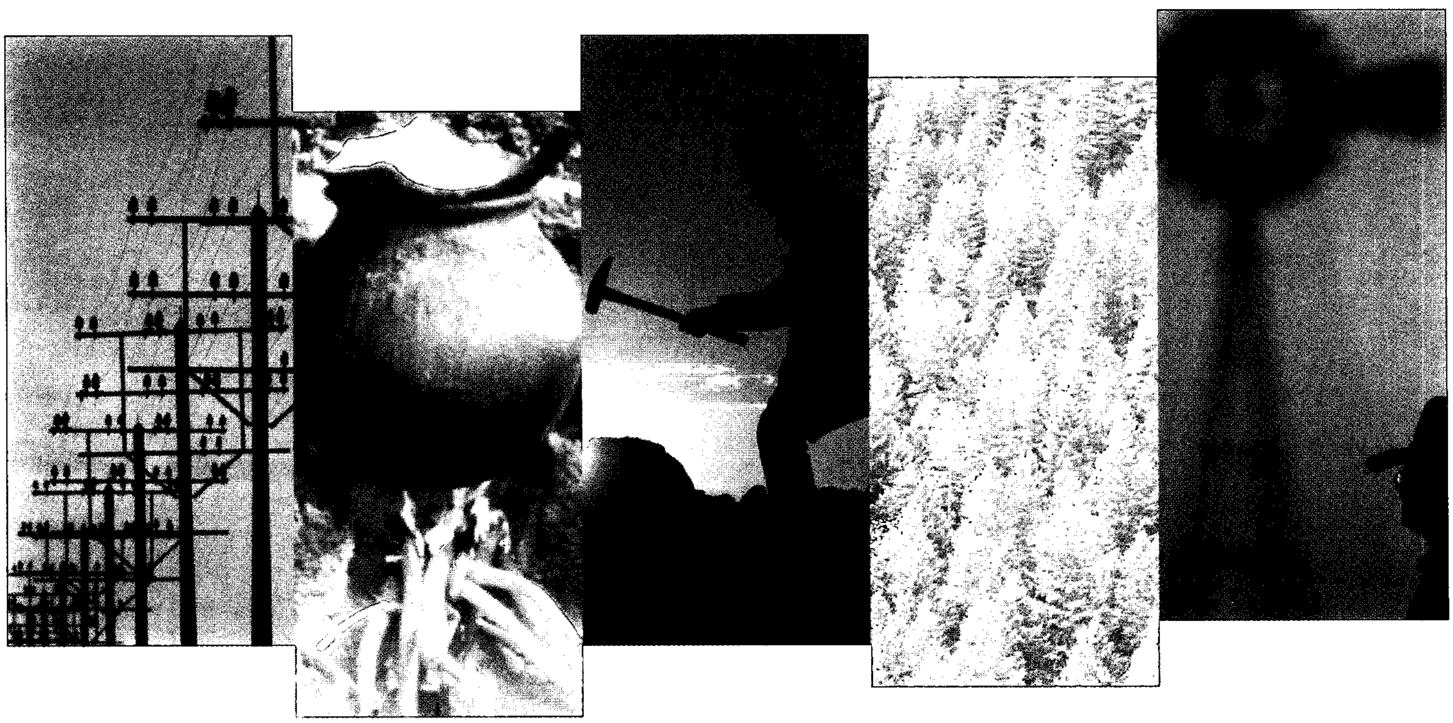
Increasing the Efficiency of Gas Distribution

Phase 1: Case Studies and Thematic Data Sheets

ESM218
July 1999



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JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

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

GOVERNANCE AND OPERATIONS

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

FUNDING

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

FURTHER INFORMATION

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

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Phase 1: Case Studies and Thematic Data Sheets

July 1999

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

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

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Preface

Many client countries with access to natural gas reserves or supply have the potential to construct new or expand existing gas distribution systems, and use this relatively clean-burning fuel to substitute for other energy sources that are more expensive, less reliable, or more polluting. This ESMAP study analyze the technical, institutional, and economic aspects of natural gas distribution systems, including newly constructed ones, to provide developing and restructuring countries with options and recommendations on ways to increase the efficiency of their natural gas distribution systems.

This study included case studies of four distribution systems, in Europe (Denmark), Asia (Turkey), Africa (Tunisia), and South America (Argentina). Each case study was undertaken to draw lessons from each national perspective. The Denmark study was of a publicly owned and heavily regulated newly constructed system in a relatively cold climate. The Turkey study was of a newly built municipally owned utility constructed and operated by a private consortium. The Tunisia study considered a dual power and gas utility, and the Argentina study considered newly privatized distribution utilities coupled with a new independent regulatory authority. The scope of the study, however, did not include an in-depth consideration of the efficacy of distribution systems serving residential customers in climates where heating is not a factor, nor an in-depth consideration of the potential economic or environmental benefits of expanding gas distribution to communities.

This report was prepared by Henri Beaussant, Consultant, and reviewed by Phillip Murray, Gas Specialist from the World Bank's Energy, Mining and Telecommunications Department (EMT). The case studies and research were completed by Messrs. Henri Beaussant, Bent Svensson, Senior Energy Economist, (EMT), and J.F. Guth and J. Engel Consultants.

Acronyms and Abbreviations

avg.	average
BOTAS	The Turleish Gas Transmission Company
CHP	combined heat and power
DH	district heating
DONG	Danish Oil and Natural Gas Company
DR	district regulator
DRS	District regulator stations
DUC	Dansk Undergrunds Consortium
ENI	Italian Gas Company
ETAP	Tunisia State-Owned Oil & Gas Company
GdE	Gas del Estado (Argentina)
GdF	French Gas Company
GFU	Norwegian Joint Gas Negotiating Committee
GOM	gross operating margin
GPA	gas purchase agreement
HGN	Greater Copenhagen Gas Distribution Company
HP	high pressure
IEA	International Energy Agency
IPP	Independent Power Producer
km	kilometer
km^2	square kilometer
LFO	light fuel oil
LP	low pressure
m	meter
m^3	cubic meter
m^3/h	cubic meters per hour
m^3/y	cubic meters per year
mcf	million cubic feet
mmbtu	million btu
MP	medium pressure
n/a	not applicable
NEB	National Energy Board of Canada
NG	natural gas

NG	natural gas
NGF	Natur Gas Fyn
°C	degrees Centigrade
OD	outside diameter
OECD	Organization for Economic Cooperation and Development
PE	polyethylene
PN	primary network
PPI	production price index
psi	pounds per square inch
PVC	polyvinyl chloride
R&C	residential and commercial
SCADA	Supervision Control and Data Aquisition
STEG	Société Tunisienne de l'Electricité et du Gaz
TGN	Gas Transmission Company in Northern Argentina
TGS	Gas Transmission Company in Southern Argentina
UK	United Kingdom
VAT	value added tax
YPF	Yacimientos Petroliferos Fiscales

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Presentation and Main Conclusions

Presentation of the Study

1.1 The general objective of the present ESMAP study was to provide developing countries and economies in transition as well as the donors community with (a) reference information on the technical, economic, and institutional aspects of gas distribution, based on case studies of existing projects; (b) an assessment tool to evaluate the feasibility of gas distribution projects; and (c) options and recommendations on how to increase the efficiency of existing projects and how to achieve better efficiency for new projects. Tentatively, the study is planned to be carried out in two phases. If both phases are completed, the final product will be a handbook that describes (a) how gas distribution is currently handled in different situations and countries and (b) the options and alternatives that the gas distribution industry is currently testing or implementing to enhance efficiency, as seen from the technical, economic, and institutional viewpoints.

1.2 This report presents the findings of Phase 1 (i.e., item (a) in paragraph 1.1). It summarizes the information and data gathered on four case studies, and presents complementary information collected through desk research (within the World Bank, using existing literature and reports) as well as through internal meetings with World Bank staff who are working on gas distribution projects. This interim product consists of the following items:

- Presentation of the study followed by its main conclusions (Chapter 1)
- Set of thematic data sheets (Annex 1) that present, in a comparative manner, the issues and options of the gas distribution industry in four countries (Turkey, Tunisia, Argentina, and Denmark)
- Set of four monographs, one for each of the case studies (Chapters 2 through 5).

Both the monographs and the data sheets are intended to present facts rather than proposals and considerations, but they do include, where relevant, critical reviews of the operations surveyed and preliminary assessments of the major issues faced by the industry. The comments and conclusions of Phase 1 emphasize lessons learned that are of particular relevance and interest within the study's scope and objectives. In-depth analyses, as well as various options that can be developed to address issues that arise with gas distribution, are specifically the purpose and scope of Phase 2, which is to be conducted later.

Phase 1

1.3 The case studies were conducted in four countries (Turkey, Tunisia, Argentina, and Denmark) where gas distribution started recently or where the gas operation underwent a major change recently. Initially, six countries were selected to cover, as much as possible, various combinations of climatic conditions, population and urban densities, age and history of networks, sectoral competition, and institutional environments. Five of the studies were to be conducted in developing countries and one in a newly gasified industrialized country, which was to serve as a benchmark. Due to budget constraints, the number of case studies was reduced to four and it was then decided to alter the methodology, which was based initially on the comparative analysis of a number of specific themes common to each study. The objective of the study was changed to focus on the countries' specific characteristics and highlight those characteristics that make a country's gas experience valuable to the future of the industry. The study thus became more qualitative than quantitative. The main consequence of this modified approach was that it made it difficult to raise, discuss, and compare precisely the same topics in each case study, as the six-country study would have allowed. To make some basic comparisons available, however, chapter 2 presents and compares some options and alternatives selected by the utilities for a number of areas.

1.4 Each of the four countries is remarkable in at least one major aspect of the gas distribution industry, and the scope of the study was to focus on such topics:

In Turkey, the city of Izmit (located 100 km east of Istanbul) has become a booming industrial center where gas distribution is expanding rapidly. Unlike the structure retained in Ankara and Istanbul, where the utility is fully owned and operated by a municipal department, Izmit's local, municipally owned utility, Izgaz, has entrusted a private consortium with the construction and operation of the system from the beginning, which enabled gas distribution to develop on a fast track.

- Tunisia presents one of the few cases of a large-scale dual utility, operated at the country level. Gas is distributed together with electricity, which presents certain advantages in terms of economies of scale, but creates an imbalance between the two activities. In addition, Tunisia has been expanding, although slowly, gas networks since new sources of supply became available in the mid 1980s. The case study focuses on the capital city, Tunis, including the city center and the fast-growing suburb of L'Ariana.
- Argentina completely overhauled the structure of gas distribution by breaking up Gas del Estado, its former state-owned, vertically integrated downstream gas utility, and creating a completely new system, which involved privatization of assets and an incentive-driven regulatory framework coupled with an independent regulatory authority. The case

study was conducted on two of the six new operating companies: Camuzzi, which operates extensive networks in two concessions south of Buenos Aires, covering most of the territory from the capital city to Tierra del Fuego; and Litoral Gas, a smaller utility centered on Rosario, the third-largest city in Argentina.

- Denmark is the latest European country to have launched, in the early 1980s, a new countrywide transmission and distribution system. The downstream gas industry is heavily regulated and operated by public enterprises. The case study focuses on two utilities: NGF, the gas utility of the province island of Funen (Fyn in Danish), and HGN, which is responsible for gas distribution in the Greater Copenhagen area, not including the city.

1.5 Although the methodology was not directed at systematically gathering data to evaluate and compare the characteristics of several distribution systems, it was possible to prepare data sheets and to establish comparisons in six business areas:

- Structure, ownership, and regulation of competition
- Market conditions and market development
- Technical characteristics
- Operation: main characteristics
- Operation: efficiency-oriented methods
- Tariffs and economic regulation.
- Phase 2 (Tentative)

1.6 If undertaken, Phase 2 will lead to production of the final report and meet objectives (b) and (c) of the study. It would address the same areas specified in paragraph 1.5 while providing greater detail and comparative analyses. However, to complement the topics included in the case studies, Phase 2 would also include two additional major areas:

- Economics of gas distribution. This section will discuss the cost of construction and operation of networks versus the operator's expected income, in relation to overall gas demand (i.e., gas uses, unit consumption, and gas prices). The purpose is to address an issue that is critical to client countries in warm climates. It would try to establish a threshold above which gas distribution is expected to be economic, and to review all factors and check the validity of the well-established assumption that gas distribution may not be economical wherever gas is intended to be used only for cooking or water heating or both.
- Presentation of the benefits of gas in economic and environmental terms.

1.7 The Phase 2 report will explore and discuss in more depth several avenues to increase the efficiency of gas distribution, including the following:

- Technical issues (e.g., network architecture, pressure levels, and materials)
- Operational issues (e.g., cost of conventional metering versus flat metering charge versus prepayment metering; and outsourcing)
- Gas pricing principles (e.g., cost-based versus market value)
- Tariff policy (e.g., alternatives for tariff policies and structures: lump sum, flat price, standing cum commodity charges, and block tariff)
- Institutional, regulatory, and ownership issues (e.g., organization of gas distribution; place of distribution in the gas industry; type of franchise; exclusivity; regulatory entity)
- Economic regulation (e.g., price cap versus rate of return).

1.8 Also, the study would benefit from an in-depth section on the lessons learned from previous projects. Through its staff and consultants, the Bank has gained considerable expertise in the preparation and implementation of gas distribution projects, especially in Latin America and Asia, and, more recently, in Eastern and Central Europe.

Main Conclusions

1.9 *Structure and Ownership.* The study of the gas industry in Izmit shows that an important factor, with regard to efficiency, is the status of the operator rather than the structure of the ownership of the assets. Although the gas utilities in Istanbul and in Izmit are both owned by the municipality, they have evolved differently. The gas distribution industry in Istanbul, owned and operated by a municipal company, has lagged well behind its initial development plan for years. In Izmit, on the other hand, where the municipal utility granted, from the very beginning, operation of the system to a private company, the network began to operate and sell gas only 15 months after construction started, well before the end of the three-year construction period. After eight months of sales promotion, 30 percent of the households estimated in the potential market had already secured their connection by paying a deposit that was equivalent to the lump-sum connection fee. This allowed the utility to use the cash received from both the deposits and the first gas bills well before the end of the four-year grace period of the loan that was contracted to finance construction of the network. Considering how vital it is for the utility to increase the connection rate to generate early revenue, the first years of operation are critical in such a capital-intensive project with regard to financial results.

1.10 In this respect, two decisions were instrumental:

- The central government authority (in this case, the Council of Ministers) that granted the operating permit to the utility made it compulsory for the utility to entrust a private operator with the operation of the distribution system.

- The incentive was built into the agreement between the utility and the private operator, whereby the remuneration of the operator was linked to the number of customers connected. Although such an incentive must be carefully monitored by the utility, because the quantity of service lines laid is not the only criterion to generate revenue, the incentive seems to be well designed because the operator will eventually be in charge of both technical and commercial operation of the network.

1.11 *Market Development.* In Tunisia, the public utility, Société Tunisienne de l'Electricité et du Gaz (STEG), has not yet developed an efficient gas distribution system, in particular in the residential and commercial markets, including small-scale industry. There are several reasons for this disappointing result. First, a lack of market knowledge and sales objectives prevent the utility from actively promoting sales in areas where gas mains are laid, leading to poor overall penetration and low usage of the existing network. Second, network extensions and service lines are built mainly at the request of potential consumers, but the utility does not take such opportunities to fill in the potential market located in a new project's area. Third, there are positions designated within the organization chart that are not filled; subsequently, field operating units are not staffed adequately with commercial officers or with technical support personnel to perform technical audits and energy assessments. Fourth, the gas tariff structure was designed using the electricity tariff structure as a model, and, thus, gas customers are charged based on the operating pressure of the gas in the main to which they are connected. A formal evaluation of the actual economic cost of gas distribution apparently has not been performed; such an evaluation, together with an in-depth market analysis, are prerequisites to establishing an efficient tariff structure.

1.12 The general reason for such an apparent lack of interest in gas distribution may be related to the status of the gas activity within the utility. STEG is one of the few[1] "dual" utilities; that is, it transports and distributes both electricity and gas. Initially, gas was used primarily in power plants to produce electricity, and most of the utility's management and higher level staff view gas as just one of the raw materials used to produce power. While gas demand now exceeds 2 billion m^3 per year (i.e., 35 percent of the primary energy consumed in the country), gas is not yet viewed as a premium energy source. For example, the internal transfer price of gas to the power plants is one of the best-kept secrets within STEG, which raises concerns about cross-subsidies from the gas activity to the electricity activity. Moreover, STEG has consistently shown a strong reluctance to develop gas deliveries to captive markets, stating that supply constraints would not guarantee the security of supply. This is not a valid argument, however, because additional sources of supply, such as the doubling of the TransMed pipeline,[2] the

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[1] At the country level. Dual or multisector local utilities—often municipally owned and operated—are common in northern Europe and the United States.

[2] The Trans Mediterranean pipeline crosses Tunisia and the Mediterranean Sea from Algeria to Sicily into mainland Italy.

recent development of the Miskar gas field in the Gulf of Gabes, and the interconnection of the northern and southern gas grids within Tunisia, make such alleged supply constraints irrelevant. Thus, further gas development should be based on increased autonomy of the gas activity, including separation of accounts (unbundling), establishment of a key to allocate the costs of the "dual" staff (in particular with regard to distribution), evaluation of the costs of the gas activity, and a new tariff policy, including transfer prices.

1.13 *Operation.* Utilities organize their operations in quite different ways. For example, staff-per-consumer ratios vary dramatically, from 0.7 staff per thousand customers at Litoral Gas (Argentina) to more than 7 staff per thousand customers in the STEG (Tunisia) central gas operation. Although the two ratios cannot be strictly compared because they do not include exactly the same activities (e.g., STEG staff not only control distribution, but also operate the transmission network), it is clear that STEG is not driven by the same quest for efficiency as is Litoral Gas. The recent reorganization of STEG appears to be a positive move, intended to give the districts—the lower operating level—more responsibility in the decisionmaking process. The objective has been only partially achieved, however, because many new positions allocated to the districts are not yet filled, and because the center (the Gas Directorate) has retained positions that should have been transferred to the districts. Some positions are thus redundant between the upper and lower levels. In fact, some positions are redundant within the upper level, in particular, with respect to the definition and implementation of the market development strategy. Overall, STEG's gas activity appears to be overstaffed. While the precise number of staff working for gas distribution cannot be calculated in the absence of an appropriate key to allocate "dual" staff to either the gas or the electricity activity, it is estimated that approximately 800 staff work for the gas activity (i.e., more than 10 staff per thousand customers). This is 3 times the number who work for the Danish NGF, and 8 to 15 times as many who work for Argentinean utilities.

1.14 Whether or not to outsource is one of the decisions that affects the size of the operating crew and the efficiency of the operation. Outsourcing is intended to decrease operating cost while retaining an acceptable level of quality. Gas distribution is to a large extent an "in house" operation, where most tasks are carried out by the operator's own staff. The only tasks that utilities outsource are those that do not require permanent "gas staff" because the tasks either are not specifically related to the gas effort or they do not occur frequently enough to keep dedicated staff busy. Examples of tasks that can be outsourced include the civil works required for network extension, reinforcement, construction of new service lines, and maintenance (e.g., digging, pipelaying, backfilling, and resurfacing). Gas utilities also do not carry out activities that are outside their responsibility, such as carcassing and the installation of appliances[3]. Technical operation is less likely to be outsourced than is customer service, precisely because of its more technical nature. In Argentina, however, some utilities, such as Metrogas in Buenos Aires, have outsourced the "first grade" leak detection survey, while

[3] The utility's responsibility generally ends at the outlet of the meter.

retaining the more critical upper grade levels. This has led to a decrease in the number of house leak detection teams from 100 to approximately 30.

1.15 Customer service is typically an area in which utilities try to increase efficiency by decreasing manpower costs. This is achieved by outsourcing and by implementing efficient technologies. It generally begins by outsourcing meter reading, and then bookkeeping and billing. In Argentina, most utilities outsource these activities, sometimes including activities such as cutting off and reconnecting customers. Litoral Gas uses an external crew of 13 meter readers and 1 supervisor to read 88,000 meters per month (i.e., nearly 300 readings per reader per day), which is high compared with the statistics of most utilities. In Denmark, gas distributors have followed the lead of the water and electric utilities by allowing customers to read the meter themselves and inform the company either by mail or by telephone (one out of four residential customers transmits the data by telephone). Basic customer activities (e.g., bookkeeping; sending and processing self-reading cards; billing; and processing overdue bills) are outsourced at a cost[4] of $11.55 per customer per year, which is comparatively low. One step beyond is prepayment metering, which is already operated to a significant extent by electric utilities, although not in the countries surveyed. The use of such prepayment meters is attractive, but it is currently limited by the high cost of sophisticated electronic equipment, about $180 per meter (i.e., about three times the cost of a conventional meter), although costs are decreasing. The advantages of such a system, however, are tremendous: (a) it decreases the cost of customer service because it eliminates most of the meter reading, bookkeeping, billing, and cutting off and reconnecting tasks; (b) it significantly improves the utility's cash management and decreases the cost of short-term money because the gas is paid for before, not after, it is consumed; and (c) it resolves from the beginning the management of overdue bills and bad debt.

1.16 *Gas Tariff and Economic Regulation.* In this study group, gas tariffs seem to be largely overlooked by the utilities and their regulators. Argentina provided the only example where the design of both the structure and the rates of gas tariffs satisfactorily meet basic requirements. That is, they are based on economic costs; they fit the market's breakdown into real classes of consumers; and, where relevant, they include both a standing charge and a commodity charge. The Argentinean tariff structure is sophisticated in that it includes seven classes of consumers, some with two or three consumption blocks. The amounts of both the capacity and the commodity charges are designed to fit as well as possible the structure of the consumers' demand. This optimizes the utility's revenue (as consumers are not undercharged) and is fair to consumers (as they are not overcharged). This tariff system is not flawless, however. For example, one of the seven tariffs has been incorrectly designed by the regulator: it does not fit any market. It is thus not used by the utilities because applying it would systematically lead the utility to charge a higher gas price than another tariff, one that is correctly designed, that is dedicated to the same industrial category of customers.

[4] All prices are in US dollars.

1.17 Tariffs in other countries are much cruder. The least satisfactory system of those studied was in Turkey, where none of the objectives of a sound tariff policy (as briefly described in paragraph 1.16) are in place. Tariffs are set by the transmission utility that regulates gas tariffs in addition to its original duty as gas supplier. In every gas-supplied area, distribution tariffs are capped at an arbitrary 30 percent on top of the city-gate price, no matter what the actual economic cost of the distribution. Because the Municipality owns the utility and wants to keep gas tariffs low, tariffs in Izmit are fixed at an even lower level than allowed by regulation, i.e., 20 percent above the transfer price; this does allow the utility to take full advantage of the allowed prices. Preliminary calculations show that such tariff structure will make the utility unable to repay the loan that was contracted to finance the construction of the network, not to mention the operating cost. Tariffs include a flat price per m^3 consumed, without a standing charge. Although the tariff designates three classes of consumers, the flat prices for all three classes are almost the same; that is, they do not take into account the structure of the consumption or the quantity of gas consumed.

1.18 Except in Argentina, where the regulator is independent, economic regulation is enforced by a governmental body, whether a ministry or a state-owned utility. While tariff setting and enforcement is quite conventional in Denmark and Tunisia, where the government exercises full control over tariffs, the principle of the Turkish system is simple: prices are set by the municipality where the utility operates, with a cap established by the regulator. Problems arise in implementation. As discussed previously, gas prices in Turkey are not related at all to actual distribution costs for either construction or operation, and the price cap is as arbitrary as the tariffs. Moreover, the regulator is not independent; regulatory activities are carried out by the transmission utility (BOTAS). This situation gives BOTAS complete control of the overall gas industry because it is responsible for both setting and controlling import prices and transmission tariffs and for controlling distribution tariffs.

2

Case 1: Structure and Organization of a New Gas Distribution Project - The Case of Izmit, Turkey

Background

2.1 Izmit is a medium-size city (350,000 inhabitants) located 100 km east of Istanbul at the easternmost tip of the Sea of Marmara. In the early 1990s, in an effort to combat increasing air pollution, five municipalities (local governments) of the Greater Izmit area decided to build a gas distribution system and to set up and operate a natural gas distribution utility. Since 1990, gas had been available to the region via the high-pressure (HP) transmission system that had been built and was owned by BOTAS, the state-owned pipeline company. BOTAS had begun supplying natural gas to industrial customers in the industrialized eastern part of the city. In 1992, a public utility, Izgaz, was established, with a limited equity of $4 million, to distribute gas in the entire Izmit region to industrial, commercial, and residential users. The Izmit municipality holds 99 percent of the equity; the balance is distributed among the four smaller municipalities.

2.2 The project was based on a 1987 market survey and the subsequent basic design, which was revised in 1993. The Ministry of Energy approved the Izgaz plan on two conditions:

- Funding for construction of the network must be obtained through foreign credit that covered the entire cost of the gas distribution project (i.e., no public money was to be used).
- In addition to Izgaz, two separate companies would be set up, one to be in charge of construction of the network and the other to be in charge of technical and commercial operation of the network. Both were to be backed up by experienced foreign gas companies. However, Izgaz would retain control of the project.

Market Base

2.3 The market survey indicated that nearly 92,000 households and approximately 10,000 commercial and industrial establishments were likely candidates for gas connection by the year 2015. Most households were located in apartment blocks, thus giving the future utility a strong market base because block boilers that equip some of the buildings would make conversion faster and cheaper. Also, the resulting dense gas network estimated at 4 meters of pipe per customer would keep construction cost at an acceptable level. In Izmit, as in Istanbul, harsh winters make space heating a primary market for gas; the average number of degree-days (in °C) is almost 1,600, and the average minimum temperature is as low as -6°C. Because building insulation is poor in Izmit, specific gas demand is expected to be high, almost 2,000 m^3/year of gas supplied per dwelling of which 75 percent is used for space heating, which corresponds to approximately 15,000 kWh/year of useful energy required within the dwelling.

Main Technical Features

2.4 The design of the gas network is similar to the design that has been implemented in most European countries since the early 1980s. Gas is supplied by BOTAS through two high-pressure/medium-pressure (MP) city-gate stations, one at the western and one at the eastern tip of the city. A 32-km, primary steel-pipe network, operated at 25 bar (370 psi), in the northern foothills of the city connects the two city-gate stations and feeds the 283-km, secondary polyethylene MP network, which is operated at 4 bar (60 psi). Connection from the street network to the customers is made through 17,000 polyethylene service lines. Gas network operation is monitored through a SCADA system.

Table 2.1: Projection of Gas Demand for Year 2015

	Units	*Gas Demand (million m^3/y)*
Population in the Gas-Supplied Area	398,240	
Number of Dwellings	91,440	
Number of Dwellings that are Flats	86,870	
Projection of Gas Customers and Gas Demand		
Residential	69,200	129.6
Penetration factor	*76%*	
Small Commercial	5,600	11.4
Large Commercial	22	4.9
Industry (BOTAS customers not included)	15	96.5
Total	**approx. 74,800**	**242.4**

Funding

2.5 In 1993, Izgaz obtained from the French government a loan of FRF650 million (about $110 million) to cover the total cost estimate of the project. After a 42-month grace period, the principal and interest were to be paid back in 96 equal monthly installments (8 years). The loan is guaranteed by the Turkish Treasury Department. If Izgaz is unable to fulfill its commitments, the Turkish Treasury will make the payments, and then will withhold some of the annual state contribution to the municipal budget. In Turkey, municipal budgets are financed by the central government. By law however, the central government cannot withhold more than 30 percent of the money it allocates to the municipal budgets, which tends to reduce the strength of the commitment that binds the local government.

2.6 Because the viability of a new gas distribution project is extremely sensitive to the success factor (i.e., the actual gas penetration rate as compared to the planned penetration rate) in the first years of operation, the terms of the loan included two positive components. First, in addition to its main objective, which is to finance construction of the gas network, the loan included a provision for technical and commercial support services to the operating company, in the form of a three-year assistance program to begin the operating activities. Second, only two-thirds of the amount of the loan was intended to fund construction of the network (mains and service lines), while the balance was dedicated to installing internal piping within residential buildings (carcassing). The first component was implemented, but the latter arrangement was canceled, at Izgaz's request, to fund network extensions and thus increase the utility's market base. Thus, customers must finance both the internal piping and the gas appliances, a factor that could reduce the connection rate and alter the economic viability of the project.

Concession and Gas Supply

2.7 When the loan was obtained, Izgaz signed a Concession and Supply Contract with the Department of Energy and BOTAS. The simultaneity of the contractual arrangements was necessary because a concession cannot be obtained if there is no supply agreement. In 1994, the Department of Energy and BOTAS granted to Izgaz an unlimited concession for operating gas distribution in the Izmit region. There is a major obstacle that must be overcome, however, because the territorial boundaries of the concession are not clear. Izgaz is required to supply with gas "at least" all customers "covered in the feasibility study that would make applications." But BOTAS has not relinquished—and does not seem ready to consider relinquishing—the right to supply gas to its industrial customers located in the Greater Izmit area, even if these customers are within the territory of one of the five municipalities involved in the Izgaz venture. Potential conflicts between Izgaz and BOTAS are likely to arise as soon as Izgaz tries to increase its market base, especially in the lucrative industrial sector.

2.8 BOTAS committed itself to supply Izgaz with as much as 160 million m^3/y of gas for five years, based on the estimates of the feasibility study. However, Izgaz is discovering that this amount will soon not be sufficient because large industrial users are making applications. In particular, an electrolysis plant and a paper mill are both applying for 40 million m^3/y each for cogeneration purposes. Their combined consumption would be half of the contractual supply provided by BOTAS. Izgaz is therefore ready to begin negotiating with BOTAS to double the contractual amount.

Construction

2.9 The Construction Contract is part of the Implementation Agreement that was signed at the end of 1994 between Izgaz and the consortium selected to build the network. The consortium includes three main partners: an engineering company, a pipelaying company, and a contractor for civil works. All three employ 125 staff for the duration of the three-year project (July 1995–July 1998). The pipelayer leads the consortium and issues the bills for Izgaz's approval. The consortium's scope of work includes the regular tasks of a turnkey contract: detailed engineering; supply of required materials and equipment; construction of the gas distribution system, including service lines (not carcassing); and supervision and quality control. The consortium also pays expenses related to the service contract (i.e., the operator's expenses, see para. 2.11 below).

2.10 The utility has approximately 30 staff members, 20 of whom are directly involved in the project:

- Technical group (10 staff members) monitors the consortium's construction activities and systematically checks gas installations within buildings to make sure they meet safety regulations.
- Project group (10 staff members) processes all payments requested by the consortium as well as Izgaz's own payments, and does the accounting.

In addition, Izgaz handles relations with municipal and state authorities; in particular, it provides the consortium with all required digging permits and follows up with external entities, such as the highway and railway authorities. Because the objective of the project is to reduce air pollution in areas around the Sea of Marmara where pollution level is deemed too high, all foreign equipment and materials to be incorporated in the works are imported free of taxes and custom duties.

Operation

2.11 The second component of the Implementation Agreement is the Service Contract, which has a duration of 49 years. To implement the contract, an operating company, Dogaz, was established under Turkish law in November 1996. In addition to the foreign partners of the consortium, it includes the French gas utility, Gaz de France, as the operator, and several small private Turkish firms. The objective is to help the utility start operating (especially sales promotion) as soon as the sections of the network are commissioned, while the network is still under construction. The early setup of the operator enabled the utility to collect down payments from future customers at an early stage and to keep pace with the construction of the network. During the first three years of the service contract, when actual revenue from gas sales is negligible, Dogaz's resources are provided by the consortium under the terms of the construction contract. During this period, Dogaz's remuneration is a function of the amount of pipe already commissioned and the number of customers connected. Izgaz's participation in Dogaz resources includes providing, at no charge, the required office space, warehouses, and yards.

2.12 Dogaz activities began in November 1996, 15 months after construction started. At that time, the first portion of the secondary network was commissioned and handed over to Izgaz with connected customers that had already begun to receive gas. The main activities at the start are conducted by 45 staff members:

- Sales development (tariff policy, door-to-door canvassing, and public information).
- Customer management (meter reading, gas billing, and cash collection).
- Operation and maintenance of the distribution system.
- Training of professional personnel.

Tariff Policy

2.13 *Gas Tariffs.* Tariffs are set by the gas distribution company and are regulated according to the national regulation, which states that the average distribution margin cannot exceed 30 percent of the gas purchase price from BOTAS at the city-gate station. With few exceptions, however, all gas utilities in Turkey, including Izgaz, apply a single flat rate per m^3 of gas delivered; that is, the rate does not vary with the class of consumer or with the amount of gas actually consumed. In addition, Izgaz does not take full advantage of the price-cap system because it charges only 20 percent above the gas purchase price for distribution cost, presumably for political reasons. Preliminary calculations indicate that this tariff policy cannot generate enough revenue for the operation's sustainable development and that the policy needs fundamental changes to both the rates and the structure. The following major issues must be addressed:

- The gas rates will generate less than $6 million per year after sales have reached a plateau, and much less than that during the buildup period. Such revenues are far too low to cover the repayment of the loan and the utility's operating costs.
- Non-differentiated tariffs between classes of consumers prevent the utility from fully recovering the actual distribution cost from its various customers. It sends the wrong signal to the customers who are, in effect, being subsidized, allowing them to develop bad usage habits that become difficult to break, in particular where the utility is municipally owned. It also creates cross-subsidies between classes of customers, in this case, from the industrial sector to the households, which prevents industrial customers from benefiting from the actual lower gas cost.
- Flat rates do not reflect the actual cost of service because they do not clearly identify the fixed charges and the variable costs. Both residential

and industrial tariffs should be two-tiered and include (i) a standing charge that covers the depreciation of the facilities as well as those operating costs that are independent of the amount of gas actually consumed (e.g., meter reading and billing); and (ii) a commodity charge that covers most of the utility's purchase price of the gas. Standing charges should reflect the actual economic "responsibility" of each class of consumer in the fixed delivery cost of gas, while the price of the gas commodity charge should reflect the cost variations generated for the gas supplier (BOTAS) by the utility's seasonal, weekly, or daily load variations.

2.14 Gas purchase and sales prices, expressed in Turkish lira, are revised every month to take into account the high rate of inflation (80 percent per year). Gas is sold by BOTAS in US dollars, and is expressed in local currency using the conversion rate at the time of invoicing. Izgaz's tariffs, although slightly lower, are similar, in terms of both structure and level, to the tariffs established by the other gas utilities. Regular rates range from $0.23/m^3 in Istanbul to $0.26/m^3 for the top tier in Eskisehir. Except for EGO in Ankara where public institutions are charged a higher rate, all utilities charge one single flat rate to all classes of customers. Only BOTAS in Eskisehir differentiates tariffs according to consumption level, although large customers are inexplicably charged a higher rate.

Table 2.2: Izgaz Gas Tariffs (including 15 percent VAT)

Class of Consumer	*Gas Tariff ($/m^3)*	*Gas Tariff ($/mmbtu)*
Residential (up to 300,000 m^3/y)		
Cooking Only	0.22	6.75
Cooking and Water Heating	0.22	6.75
Cooking, Water Heating, and Space Heating	0.22	6.75
Commercial (up to 300,000 m^3/y)	0.22	6.75
Industry (from 300,000 m^3/y)		
Firm (all classes)	0.21	6.43
Interruptible (all classes)	0.19	5.82

2.15 *Charges.* New customers must provide funding for the carcassing of the building, where applicable, and for the gas appliances. In addition, the utility charges new customers various fees to cover non-gas-related items, first at the time of subscription and then with every bill. These charges are not regulated. The subscription package includes (a) a lump sum connection fee of $90, plus a 15 percent VAT; (b) an advance payment representing two months of winter consumption; and (c) a start-up fee of $8.The connection fee is intended to cover the cost of the service line, and the amount is independent of the actual number of customers supplied through the same service line (i.e., a service line supplying the boiler of a 50-dwelling apartment block will earn the utility 50 times the connection fee). If the customers also use gas for water heating and cooking, they will not be charged an additional fee for individual uses.

2.16 Service fees appear on the bimonthly bills. They include a monthly fee for meter rental, $2.33 for a regular residential meter; a finance charge to cover the currency's depreciation, which is incurred by the utility between the time it pays BOTAS and the time the utility is paid by the customers (this represents about two months of consumption); and a monthly fee to cover management costs ($0.33).

Customer Service

2.17 Customer service is carried out by Dogaz staff. Dogaz does not subcontract tasks to external companies, except civil works (excavation) and office cleaning. The transfer of title and the limit of the utility's liability takes place at the outlet of the meter, or at the building's front wall where the meter is located within the premises (e.g., in apartment blocks). Regular tasks of Dogaz personnel include the following:

- Meter reading is carried out every two months; except for industrial clients, whose meters are read every month. The meter reader delivers the bills to the clients because the postal service is not reliable.
- Gas billing is carried out by staff who are in charge of the reception desk and updating files.
- Payments are received by a cashier and processed by the accountants. Customers may also transfer money to a dedicated Izgaz account. To cope with inflation, customers are allowed a short seven-day period to settle their bills.

Gas Sales Promotion

2.18 Setting up the Izgaz operating company within months of construction start-up and giving it the resources necessary to effectively start operation proved instrumental in Izgaz's rapid attainment of a significant market base, even before the work was completed. Within the first year of sales promotion Izgaz signed up 26,000 customers—and secured their related connection fees—which represents 24 percent of the total potential market that was estimated at the year 2015 horizon. It is estimated that an additional 15,000 customers will have been connected by the time network construction is complete. The method used to pay Dogaz (see paragraph 2.11) provides an efficient incentive to connect as many clients as possible from those that were identified in the market survey. In this effort, Dogaz salesmen visit every identified large consumer, including industries, commercial and public buildings, and large apartment blocks. They also advertise in newspapers and at public demonstrations and have opened a customer center. As long as the network construction proceeds, the consortium will construct the service lines. Based on the onsite market survey performed beforehand, the operator can keep pace with the consortium's pipelaying schedule and provide it with standard detailed designs and corresponding lists of materials that have been prepared for each type of service line, based on the gas capacity required by the customer, up to 800 m^3/h. Such on-time operation enables the consortium to build the service lines required at the time the street network is laid, which generates significant savings of both time and money, and secures revenue for the utility as early as possible.

3

Case 2: Issues and Options for a Developing Gas Utility - The Case of Tunis, Tunisia

Gas Supply and Demand

3.1 Tunisia is a small country (9 million inhabitants) with a fairly rich gas industry. Gas distribution began in the 1920s when the Tunis town gas plant began to manufacture town gas, mainly for the residential sector's cooking needs. In 1954, natural gas production was launched at the small Cape Bon field, located 60 km northeast of Tunis, where gas was used to supply local industries and was shipped to Tunis to feed the town gas plant. With a yield of less than 1 million m^3/y, the field is now almost depleted. In 1972, associated gas from the jointly operated[5] El Borma oil field, located on the Algeria-Tunisia border in southwestern Tunisia, was shipped 300 km to Gabes to supply a conventional steam-turbine power plant and local industries. The remote location of the field and the increasing demand in Gabes for gas to produce power prevented the gas pipeline from being extended to the country's populated northern areas. Since 1982, production at El Borma has declined, with a yearly production of approximately 140 million m^3.

3.2 New gas sources opened up in the mid 1980s, when the first intercontinental gas pipeline (TransMed I, Algeria to Italy) crossed the Mediterranean Sea from Cape Bon to Sicily in 1985, passing through a 200-km section across Tunisia. Together with a significant increase in scale, the TransMed brought two additional gas sources (albeit one in physical terms) to Tunisia:

- A transit fee of royalty gas paid by the gas purchaser, equivalent to 5.25 percent of the amount of gas transiting through Tunisia, as measured at the Algeria-Tunisia delivery station. The gas can be taken in cash or in kind; the monthly decision belongs to Tunisian authorities, who carefully monitor the price of gas versus the price of high-sulfur fuel oil to make the appropriate decision. The implementation of the second, parallel gas line (TransMed II) increased the amount of royalty gas available to approximately 900 million m^3/y.

[5] With Algeria's Sonatrach.

- Commercial gas purchased from Algeria that complements the royalty gas. The amount of commercial gas purchased varies according to the amount of royalty gas taken in kind; on average, it accounts for about the same amount as the royalty gas (i.e., approximately 1 billion m^3/y).

3.3 In the early 1990s, the declining gas production at El Borma and increasing power-generation requirements led Tunisia to develop new gas sources throughout the country. The long-awaited Miskar gas field, located offshore in the Gulf of Gabes, was put on line in 1996, and the northern and southern high-pressure (HP) transmission grids were connected by construction of a 200-km "missing link." Thus all gas sources are now linked with all major potential consumption centers located on the Mediterranean seaboard.

3.4 The Tunis gas network was supplied with town gas for nearly 70 years. When Cape Bon natural gas became available in 1955, gas-cracking was substituted for coal distillation. Subsequent conversions (naphtha from 1970 to 1985, then cracking of Algerian gas) allowed gas customers to remain supplied with town gas until the plant was shut down in 1989, after the old network and the customers' gas appliances had been converted to use natural gas. Not until the mid 1980s did natural gas start to be distributed in Tunis's northern suburbs and in the highly touristed areas of Hammamet and Monastir, where it supplies numerous hotels and restaurants, but few households. At present, gas is supplied to 70,000 residential and commercial customers in 10 of the country's 34 "Distribution Districts," which are concentrated in the Tunis (80 percent), Hammamet/Cape Bon, and Sousse/Monastir areas. Total gas sales in the districts is 180 million m^3/y, of which 100 million m^3/y (5 percent of total gas demand in Tunisia) is sold to residential and commercial customers. Gas distribution networks (MP 4 bar, as well as LP) total 1,700 km, fed by a 330-km basic grid (higher MP, 20 bar)

Structure and Organization of the Gas Industry

3.5 Tunisia's gas and electricity industry structure dates back to the former colonial power. Both activities are integrated into one state-owned company, Société Tunisienne de l'Electricité et du Gaz (STEG), which operates across the country under monopolist regulation. Hence, the monopoly gas distributor is also the country's monopoly electricity distributor. Gas exploration and production is conducted by external, private companies (with regard to new production sites), although a state-owned oil company, ETAP, holds the state's interests and purchases gas from the producers. STEG operates under the supervision of the Ministry of Industry's Energy Division, and policies and operating strategies are set at the ministry level.

3.6 STEG is not operated as a quasi-private firm. It has no mandate to provide an economic return on its assets or on the capital invested in it by the state; rather it is operated to provide a service to the community and to cover its capital needs with its own resources, within the context set by government policy and the explicit requirements of multilateral financial institutions. Such objectives have enabled STEG to achieve remarkable results with regard to electricity (e.g., rural electrification programs have enabled more than 80 percent of rural households to be connected to the grid, among the highest rates in the developing world, including emerging economies). On the gas side, gas consumption exceeds 2 billion m^3/y, thus accounting for 35 percent of the primary energy supply and 12 percent of the final energy demand. Gas, however, is still not considered an autonomous activity. Seventy-five percent of gas consumption is dedicated to power generation, and that percentage is likely to increase with the introduction of gas-based IPPs (Independent Power Producers). STEG continues to show reluctance to develop gas for captive markets, in particular the residential and commercial sectors, because of alleged supply constraints.

3.7 Several aspects of the utility's structure and organization, as described in this chapter, lead one to view STEG as an "electricity utility with a gas activity," led by a strong "electricity culture," rather than a balanced electricity-gas enterprise. Such aspects include STEG's reluctance to develop gas activities beyond power generation and large industrial end users and the lack of autonomy of the gas activity. These features are apparent in the company's general objectives and results, and they translate into weaknesses in the organization of the gas activity as well as in its day-to-day operation. Although some of the problems identified may also be present in the electricity activity, they are more likely to adversely affect the operation of the "minor" gas activity of the company and the morale of its staff.

3.8 STEG's control of both the electricity and the gas distribution networks has advantages and disadvantages, as shown in Table 3.1.

Table 3.1: Pros and Cons of STEG's Dual Activities

Pros	*Cons*
Network understanding and potential for cross selling or targeting of clients	Potential for unclear objectives, inadvertent (or intentional) cross-subsidization between energy sources
Economies in reading of meters, billing and collections	Economic and cultural domination of one activity over the other
Easier effective execution of government energy policy	Unclear performance evaluation in operational and financial terms
	Bureaucratic barriers to the development of optimal resource allocation
	Potential for developing a staff-centered rather than a client-centered culture
	Potential difficulties in developing any future privatization policy beyond plant level

The Reorganization

3.9 Since 1990, a new organization has slowly been put in place in an attempt to transfer some management and decisionmaking responsibility from the center to area levels. The present organization of STEG's gas and electricity operations, lowest to highest, from district to region to central services to headquarters, partly hierarchical and partly decentralized, is a result of the decision to decentralize the previously rigid structure, which was based on a Gas Division of which the Central Services is the "rump", and to bring operational people into closer contact with the customers. One noticeable measure was to give the districts (see paragraph 3.11) some responsibility for significant input into network planning and administration, following which they therefore developed their own staff function at a local level. These staff functions cover a number of the areas already or previously covered by the Central Services function, which has been orienting itself more into longer term network planning, reporting to the headquarters.

3.10 STEG's decentralization process into a district-based or customer-centered organization is only about half complete. Therefore, the present structure does not always lead to effective efforts toward corporate goals, which leads to under-utilization of time and resources.

Districts

3.11 The lowest level in the gas organization is the district. The district is a "dual" level, where both gas and electricity operations are conducted. The district controls the final distribution of gas and electricity to the end-client base, including the HP and medium-pressure (MP) lines to industrial and commercial clients and the low-pressure (LP) lines to small industrial, commercial, domestic clients; administers the client base (reading of the gas and electricity meters, which all clients have, and client billing and collections); and ensures maintenance of the distribution network under its control. The district also executes the network development plans approved in the planning process.

Regions

3.12 Above the districts in the hierarchy are the two gas regions (North and South), which have no billing or profit-and-loss functions. The regions are responsible for maintenance and extension of the transmission network to the point where it enters the district and also play a major role in the network planning process and its execution. The *Plan Directeur* (master plan) is developed by the regions using input from the Central Services Department and the districts. The regions, through the contracting system, have indirect input into investment in the distribution networks administered by the districts. STEG developed a list of approved contractors who carry out most of the network construction. The work is done through framework contracts with different contractors. These contracts are administered through the regions, but the districts are responsible for supervising the work.

Central Services Department

3.13 The Central Services Department (*Direction Gaz*, Gas Directorate) has a large staff unit of 500 people, which performs network planning and general analysis functions. Potential network extensions are studied in this unit, which evaluates the demand for the extension requests submitted by the districts.

Headquarters

3.14 The headquarters operation heads the districts directly and receives the input from the Central Services unit; the regions do not have true supervisory roles. The headquarters unit is the only unit with a full balance sheet and income statement responsibility. All finance functions are centralized within the headquarters.

Technical Issues

Network Design

3.15 The conceptual design of gas distribution networks (e.g., layout structure, design pressures, materials, and sizing) generally follows the modern philosophy and rules implemented in most Western European gas countries; that is (a) a regional primary distribution system (operating at 20 bar [300 psi]) supplies industrial customers and local utilities through district regulators (DRs), and (b) gas is then distributed to residential, commercial, and small industrial customers via MP distribution networks (operating at 4 bar [60 psi]). The Tunis LP old town gas network is fed by the 4-bar system to ensure gas supply while the older system is progressively rehabilitated or replaced. Electro-welded polyethylene (PE) technology was adopted in 1988 and already represents 60 percent of the network. PE pipes are manufactured in Tunisia; fittings and welding machines, as well as meters, meter boxes, and regulators, are imported.

3.16 Alongside adoption of modern techniques, STEG is still designing MP networks like older LP networks (i.e., local networks are strongly meshed). Such design was intended to equalize the low operating pressure in the LP networks to avoid excessive pressure drops and to avoid interrupting too many customers' supply if there was an incident. Systematic interconnection, however, typically entails increasing the length of gas mains by 10 to 15 percent, thus increasing construction costs. Today, the use of MP networks and the ability to repair polyethylene mains quickly make such precautions unnecessary. Therefore, it is recommended that future networks be of the branch-type or "dead end", with a branch serving about 400 to 500 clients. Ring mains connect the branches, which are equipped with valves that are normally closed but that can be quickly opened to feed the branches from another side in case of temporary interruption of the normal supply.

Commercial and Marketing Issues

Sales Promotion

3.17 Both gas and electricity activities are still governed by the search for technical excellence, which although a valuable quest is done at the expense of sales development and market expansion. Moreover, in the present organization, gas is sold and distributed mainly by staff who has experience with electricity and who are not fully aware of the potential for gas. Since 1991, districts have established Gas Technical Units to manage the technical aspects of gas distribution, but there are no commercial units in either the districts or in the Distribution Department. The only executives in charge of the commercial aspects of distribution are the district managers, whose education and experience are in electricity and who cannot and actually should not dedicate much time to the gas activity, because it should be done by gas specialists.

3.18 To promote the use of gas would require the following:

- Market surveys must be systematically conducted within each district to develop and maintain a reliable database.
- Input from the databases must be used to prepare regional and local development planning (see paragraph 3.19).
- Evaluation and selection criteria must be established to assess the economic viability of projects.
- Commercial teams must be established in the districts to perform the tasks described in (a) through (c), carry out onsite techno-commercial visits, and monitor market evolution.
- The Distribution Department must have a commercial division to establish commercial policy, including a tariff policy, and to ensure consistency between commercial activities performed at the local level.

Development Planning

3.19 Gas development planning is neither comprehensive nor consistent. New projects that entail network extensions are generally the result of requests to the districts by developers or residents associations to supply existing or new housing developments, genuinely small projects. The decisions to extend networks or not are made after a specific evaluation on a case-by-case basis; they are not based on a comprehensive master plan. Therefore, such decisions do not take into account the future gas requirements of the area. The following three inefficiencies arise from this lack of development planning:

- Gas mains are designed and sized to supply only the housing project for which they are requested. The small-size pipes and district regulators used to meet the needs of only one specific housing project can become bottlenecks in the future, making it necessary to build a new network in parallel when demand increases or to drop a new project where supply is not available.

- Subnetworks are scattered throughout the district's area, which significantly increases the average network length per customer ratio. In Tunis, the average length of network per customer (14 m and 21 m in the urban districts of Tunis Center and the Tunis suburb L'Ariana, respectively) seem high when one considers the medium to high population density of the area. District regulators are scattered throughout the area, which leads to an excessive number of regulators, while their average throughput is well below their design capacity. In the Greater Tunis area, 50 DRs are operated for an overall peak flow rate of 20,000 m^3/h (i.e., 400 m^3/h per station on average), while regular, commercial DR sizes range from 2,500 to 5,000 m^3/h. At 27 percent, gas penetration in the area is still low. Considering the rather low average unit consumption (740 m^3/y on average in the residential market) that results from mild climatic conditions, the load per meter of network (49 m^3/y per meter) appears insufficient to make the operation profitable.

- Project costs are high because smaller, non-integrated projects prohibit economies of scale on materials and equipment as well as on mobilization and demobilization time. Works are awarded to contractors who have registered with STEG, without systematically tendering at the area or country levels. Costs follow a standard price list that is based on the costs of previous projects. Because these previous projects were small, unit prices are high.

3.20 Most projects are reviewed and decided on at the district, rather than the center, level, although the center is theoretically responsible for evaluating all network extensions. The districts—and the center as well—are not equipped with appropriate guidelines to evaluate projects that would enable decision-makers to assess a project's viability and rank the potential of various projects. The main—if not the only—selection criterion appears to be how much money remains of that allocated to new investment in the beginning of the fiscal year. To eliminate these inefficiencies, network planning should be conducted in a more active fashion, following a four-step process:

- Draft a grid of evaluation (a matrix), for new and rehabilitation projects, that leads to a solid understanding of both construction and operating costs, and enables to evaluate the projects' viability.
- Ensure that there is a clear understanding of "who does what" between districts and the center.
- Establish regional and local master plans as bases for medium- and long-term development planning.
- Set mandatory bidding procedures that must be used for all projects whose costs are above a certain threshold.

Gas Pricing and Tariff Policy

3.21 The current gas tariff policy was modeled after the electricity tariff structure; thus, tariff levels are set according to pressure levels, not according to classes of customers or consumption patterns. Such tariffs (a) do not provide the utility or the customers with the proper signal that would inform them about the actual economic cost of supplying gas and (b) may lead to price distortions. In addition, nontariff rates, such as connection rates, are high and do not seem to reflect the real economic costs; also, they cannot serve as incentives for potential customers to get connected. Finally, transfer prices within STEG from the gas activity to the power activity are not transparent, which raises concerns about possible cross-subsidization of power by gas.

3.22 Restructuring STEG's pricing policy would allow the utility to do the following:

- Establish a clear connection between the structure and levels of tariffs and the real economic costs; thus sending the correct signal to the customers and to the utility.
- Encourage gas use by mitigating the burden of one-time charges, such as connection fees.
- Ensure sound financial income to the gas activity.

Financial and Management Issues

Accounting and Budget Control

3.23 The district keeps monthly and annual accounts based on execution orders for each type of activity within its purview. Accounts are segregated between electricity and gas for the clearly separate tasks, although the joint tasks of meter reading, billing, collections, and general administration are aggregated at the district level. An accounting is produced where the execution orders for the gas activities are aggregated, although these do not represent what would normally be called an income statement in international parlance. An income statement is produced and variances from the budget are noted; however, the joint costs including meter reading, billing, and collections are not taken into account in this statement. There are no asset or liability accounts generated at this level and therefore there is no asset or liability responsibility beyond the execution of collections.

3.24 While the district produces monthly management information system input that includes variances from the annual budget, these variances are not treated as they would be in a commercial organization; rather, they are merely the subject of an annual descriptive review called the *Rapport annuel d'activité* (Annual Activity Report). Despite the lack of a true gas district income statement, it seems that the computerized records that are maintained could be combined for different gas districts through an allocation of joint (mixed) costs to the gas activity. Such an allocation-based district income statement is developed in the normal course of business by STEG. However, the district managers do not have this tool to measure their own unit's performance, nor does the headquarters have such a tool to evaluate the range of strategies implicit in the different developments pursued by different districts under the planning system.

3.25 Such an allocation-based income statement diverges from a true income statement approach in the following ways:

- Gas purchase costs are allocated to the districts in a manner that is not directly determined by gas sales volumes. This seems to be due to the interconnections of the network across district boundaries, which makes true input-output measurements impossible.
- Depreciation costs for the networks are allocated from the corporation as a whole because the districts do not have a balance sheet of assets under their management, apart from the incremental investment in the network, itself allocated in the central planning process on an annual basis.
- Because the districts do not have balance sheet responsibility, it follows that a similar allocation problem exists for the large financing costs of STEG.

Performance Evaluation

3.26 STEG should develop some profit-and-loss responsibility at the different levels of the company to guide it in a more explicit manner to developing marketing responsibilities in the districts, as well as in prioritizing distribution investments. Without a planning system linked explicitly to performance evaluation of the districts there is no practical way for top management to assure the state shareholder that assets are being applied effectively. However, in certain areas of the company there is an understanding of the profit center approach and agreement that such information could assist district-level decision-makers in the planning and evaluation of their and their subordinates' performance.

3.27 STEG faces an important challenge to improve its gas distribution districts, which currently perform at a less-than-adequate level. A company's orientation and culture is a determining factor in its long-term returns and in its long-term survival in a capital-short environment. Developing strategies, however, is both a financial and political decision. Such a decision is financial in that for a company to generate adequate returns over the long term, generating such returns must be a corporate objective and must be a criterion upon which unit performance is monitored and upon which management and employees are rewarded. The decision is political in that profit responsibility is clearly placed with those in charge of implementing corporate objectives, and the performance of responsible individuals can be measured.

3.28 Implementation of a profit-centered management structure implies a strategic restructuring that that will complement the operational restructuring that STEG has already undertaken to put itself in closer touch with the end customer. It would involve a process of pushing decision responsibility down into the districts, and would require training in the use of decision tools for district managers. It would probably also involve a major reduction of staff positions within the corporation as a whole as these roles are integrated into "line" roles within the districts or the regions.

Toward an Independent Gas Utility?

3.29 Despite the sizable—and flexible—amount of gas made available from Algeria through the TransMed pipeline and the additional gas from the Miskar gas field, STEG continues to show a strong reluctance to develop its market base on a larger scale. In particular, developing gas use in the residential and commercial sectors as well as in the industrial sector has long been considered undesirable because a single, foreign source of supply could not ensure security of supply in case of a major breakdown at the production level or along the transmission system. Most of the approximately 2 billion m^3/y of gas used in Tunisia is still dedicated to generating power in conventional, dual-fuel facilities about 76 percent in 1995. The percentage of gas used for power generation is likely to increase as gas-based IPPs develop. At the other end, households and commercial users account for no more than 5 percent of the gas consumption, while small- and medium-size industry does not exceed 8 percent of gas sales.

3.30 Considering the factors mentioned in paragraph 3.29 and STEG's electricity-oriented culture, it is likely that Tunisia's gas industry will not be able to fully develop unless the gas activity loosens its ties with the electricity activity and becomes more autonomous. The current external supply conditions make a move toward an independent gas utility achievable. With the supply from the Miskar gas field and the doubling of the TransMed pipeline, not to mention the ENI-sponsored Libya-to-Italy project, the security of supply is real and is better than the situation in many countries where gas has acquired a more significant position, such as in Southeast Asia. Increasing gas consumption for power generation would give the gas utility the strong, reliable market base that it needs to safely develop new business. Developing gas sales into highly rewarding markets, such as the residential and commercial sectors, some specific industries, as well as cogeneration, would provide the utility with reasonable margins provided that the current tariff policy is improved to reflect the actual gas value as well as real gas delivery costs. A new institutional framework would be needed to fill the regulatory vacuum of certain aspects of the gas and electricity activity, such as the lack of concession/license agreement, and to establish rules to govern competition, access to the market, and the remuneration of the operators.

4

Case 3: Gas Distribution Regulatory Framework The Case of Argentina

Industry Structure

4.1 Before privatization, Gas del Estado (GdE), Argentina's state gas company, had a monopoly on natural gas operations throughout Argentina, and thus carried out all downstream gas activities (transmission, distribution, and sales). GdE bought gas from Yacimientos Petroliferos Fiscales (YPF), at that time the state oil and gas company (now privatized), and from private producers in Neuquen and in the North and South areas of Argentina. At the time of privatization, gas consumption was approximately 22 billion m^3/y. In the winter, however, incremental demand for space heating from households far exceeded the amount of gas available, and supplies were frequently curtailed, which was one of the main reasons for privatization. GdE operated a 12,000-km transmission grid that linked all three major production areas to the distribution units, which were scattered throughout 18 of the 23 provinces. This included the Greater Buenos Aires area, which was responsible for more than one half of the country's gas consumption. Extensive distribution networks, including regional transmission lines and spur lines operated by the distribution units, totaled 60,000 km.

4.2 In 1992, GdE was split into ten utilities, including two transmission companies (TGN in the north and TGS in the south) and eight distribution companies; in early 1993, GdE was privatized. During this period a regulatory framework was established, which became effective in January 1994. The structure of the gas industry in Argentina following privatization is described in the following paragraphs.

Production

4.3 Privatization has not altered YPF's dominant position. Before privatization it held more than 80 percent of the natural gas reserves and production. Since privatization YPF produces approximately half of the Argentinean gas, and imports gas from Bolivia. However, bilateral agreements with other, smaller companies give YPF actual control of about 70 percent of the gas production. Until 1993 wellhead prices were determined by YPF and were uniform throughout Argentina. YPF increased the wellhead price from $0.97/mcf to $1.15/mcf in the Neuquen basin. In recent years, price differentials at the wellhead have developed between the Neuquen Basin and the North and South areas. The price differential now reflects the city-gate price at Buenos Aires minus transportation costs from the wellhead. Because Neuquen is closest to Buenos Aires the netback is higher in Neuquen ($1.35/mcf) than in the remote Tierra del Fuego, where it has remained at the former regulated price (i.e., $0.97/mcf).

Table 4.1: Price of Gas at Wellhead
(Average for each area $/1,000 m^3)

Gas Fields	*Winter 1994*	*Summer 1994*	*Winter 1995*	*Summer 1995*
Neuquen	43.55	42.07	47.61	45.03
Noroeste	40.60	38.75	44.29	42.07
Austral	35.43	35.43	35.80	35.43

Source: Enargas.

Transmission

4.4 The two transmission companies operate on a contract carriage basis with a first-come/first-served priority; they are not allowed to buy or sell gas. Transmission rates are regulated with price-cap formulas. Firm and interruptible tariffs are available and they vary with the distance the gas is transported. The charge is reviewed every five years. Transmission companies do not benefit from regional monopolies: anyone can build and operate a transmission line from existing sources into markets already supplied. To avoid discriminatory behavior and conflicts of interest, limitations on ownership structures were introduced. Distributors and producers cannot own more than 30 percent of the shares of a transmission company. Consumers have the option of contracting with the transmission company for transportation of direct purchased gas, or they can build their own transmission pipeline.

Distribution

4.5 The territory covered by GdE for 18 of the 23 provinces was broken down into eight distribution concessions, each concession covering a certain number of provinces, except for Buenos Aires. Because of its large geographic extent and huge market base, the Greater Buenos Aires area was split into two distribution areas, one exclusively urban, the other including large tracts of suburban and undeveloped areas. A ninth and the last concession was awarded in 1997 to cover the remaining five northern provinces, where gas is not yet distributed, to start a small-size propane-based operation. Distribution companies have regional monopolies, but they have neither physical nor commercial exclusivity to service large consumers in the area. A consumer that receives more than 10,000 m^3/day is allowed to contract directly with a producer if cheaper gas is available. A consumer also can bypass the distribution company both commercially, by using the distribution company's pipelines and paying a distribution fee, and physically, by constructing its own, dedicated pipeline. The rates of the distribution companies are regulated by a price cap. In the case of commercial bypass, the distribution company charges the gas user the full distribution rate applicable to the class of customers to which that user belongs, minus the average cost of gas supply sold by the producers and the transportation fee. This rate is fully negotiable within the price cap. There is no other way to determine the distribution fee because there is no distribution tariff per se. Conversely to the transmission tariffs, what is regulated by the regulator in the distribution activity is the end-user tariff, not the distribution margin.

Government

4.6 The government's role was reduced from an operational role to a regulatory role, and a gas law was passed that established a regulatory board for the downstream gas sector.

Regulator

4.7 The privatization of GdE was based on Law 24076/92. The law also established the framework for the new industry structure, tariff principles, and the regulator (Enargas). The missions of the regulator include the following:

- Protect consumers' rights.
- Promote competition and stimulate investments.
- Promote more efficient operation, free access, and nondiscriminatory use of natural gas.
- Ensure tariffs for transportation and distribution are fair and reasonable.
- Encourage efficiency and rational use of gas.

4.8 The regulator's responsibilities are solely within the downstream gas sector. Decree 1738/92 details the regulator's powers in relation to the transmission and distribution companies, licenses, exclusivity, and limitations on ownership.

4.9 The structure of Argentina's gas industry is basically sound. Production, transmission, and distribution are vertically separated and the end users have a variety of options for gas supply. The government has only a regulatory role.

Economic Regulation of Gas Distribution: Adjusted Price-Cap Method

4.10 The price formula caps the price charged to the final consumers. The final price is calculated according to the following formula:

Maximum price = Gas purchase cost + Transmission cost + Distribution margin

where:

- The gas purchase price at the wellhead is negotiated between producers and purchasers (i.e., either distribution companies or large customers).
- The transmission charge is a price-capped fee consisting of a charge per m^3 only. All capacity is sold as firm capacity and the tariff model was originally calculated based on a fixed costs allocation and on three days of

peak demand. The tariff consists of a charge for each unit of transportation capacity in each of the transportation tariff zones, plus actual compression fuel. This tariff is a maximum tariff that cannot be discounted on a discriminatory basis.

- The transmission companies also offer an interruptible transmission service that cannot be discounted. It is a tariff per m^3 of gas transported.

In addition to distribution margins, the price charged for service lines, as well as nontariff charges, are regulated. Such charges include those for installation and removal of meters, connection/disconnection/reconnection fees, and interest rates on late payments.

Remuneration of the Operators

4.11 Enargas estimated the cost of capital on the basis of the Weighted Average Capital Costs method. The cost of debt is estimated as the sum of the sovereign risk and the rate of return of a risk-free asset (US Treasury bonds: 6.39 to 6.75 percent) over the average life of distribution and transmission companies, respectively. The sovereign risk was estimated to be 6.17 to 6.47 percent, resulting in an estimate of 12.56 percent for transmission and 13.02 percent for distribution companies, respectively.

4.12 The returns for equity and debt are determined separately. The cost of equity is determined by the following factors:

- Rate of return of a risk-free asset.
- The market risk in the gas sector and a risk premium for investments in the Argentinean gas sector.
- A sovereign risk premium for Argentina.

This results in a nominal cost of equity of 15.39 to 18.06 percent for distribution companies and 14.31 to 16.29 percent for transmission companies. The cost of equity is higher for distribution companies than for transmission companies because the distribution companies have a higher market risk. In total, the real cost of capital after taxes was estimated to be 11.3 percent for transmission companies and 13.1 percent for distribution companies. This factor is used as the discount rate for evaluation of expansion projects (K-factor).

4.13 The tariff (except for the production price index [PPI] adjustment) is to be revised after five years. The revision formula takes into account three factors: the variation of the US PPI (reviewed every six months), an efficiency factor (X-factor), and an investment factor (K-factor):

$$P_1 = P_0 + US\ PPI - X\text{-}factor + K\text{-}factor$$

Performance Indicators for the Distribution Sector since Privatization

4.14 Since implementation of the regulatory framework, transportation fees and distribution prices have been regulated and, therefore, have not changed. The other important evaluation criteria are (a) the quality of service, in particular with regard to the continuity of supply, and (b) the development of networks, market base, and gas sales. In both respects, privatization of the gas industry, combined with implementation of the regulatory framework, is considered a success after three years.

Continuity of Supply

4.15 The effort put forth by the owners of the privatized transmission companies to eliminate bottlenecks within the transmission grid has improved the continuity of supply. During the past three years, peak transit capacity has increased 22 percent, reducing the peak winter suppressed demand by 75 percent of what it was during the last days of GdE's monopoly.

Table 4.2: Nominal Capacity in Transmission System
(million m³/day)

	Dec. 1992	*Dec. 1995*	*Index*	*Increase (million m³/day)*		
			(Dec. 1992 = 100)	*1993–94*	*1995*	*Cumul.*
TGS[1]	47.1	56.9	120.8	8.1	1.7	9.8
TGN	24.6	30.3	123.2	3.6	2.1	5.7
Total	**71.7**	**87.2**	**121.6**	**11.7**	**3.8**	**15.5**

[1] Includes regional transmission pipelines. Source: Enargas.

Table 4.3: Suppressed Demand Due to Lack of Transmission Capacity

	1993	*1994*	*1995*
Volume of Suppressed Demand (million m³/day)[1]	21.4	2.2	5.1
Index (1993 = 100)	100	10.2	23.7
Suppressed Demand as a Percentage of Gas Inlet into the System	34.4	3.5	7.6
Average Temperature (°C, Buenos Aires)	9.5	10.7	9.6

[1] Large customers, winter period (average June–August) Source: Enargas.

Network Extensions

4.16 In just three years (1993–1995), an additional 20,000 km of distribution mains were laid in the eight distribution territories, representing a remarkable 30 percent increase since 1992. This was achieved in compliance with the program of expansion included in each concession agreement known as "mandatory works," whereby the new concessionaire agreed to develop the market, in addition to providing network reinforcements and safety measures. Network extensions, however, are not financed only by the utilities. In some provinces, contributions by the utilities account for only about 10 percent of the cost. Most extensions are financed primarily by the provincial governments, as they were under the former GdE system, from a tax levied on gas sales. This tax, which averages approximately 10 percent, varies among the provinces. The other source of funding is "associations of neighbors" who request the extension. If necessary, funds from two or all three sources are combined to fund the extension.

Table 4.4.Expansion of Distribution Network, 1992–95 (km)

Distribution Company	*Situation end 1992*	*Expansion 1993–95*				
		1993	*1994*	*1995*	*Cumul.*	*%*
Metrogas	11,191	11,828	12,294	12,820	1,629	14.6
Ban	13,943	15,668	16,566	17,341	3,398	24.4
Pampeana	12,957	15,132	17,144	18,056	5,099	39.4
Litoral	4,747	5,547	6,330	6,751	2,004	42.2
Sur	8,098	8,860	9,577	10,607	2,509	31.0
Centro	6,055	7,539	8,538	9,137	3,082	50.9
Cuyana	5,330	6,027	6,525	6,815	1,485	27.9
Gasnor	4,445	4,818	4,999	5,127	682	15.3
Total	66,765	75,599	81,973	86,654	19,889	29.8

Source: Enargas

Market Base

4.17 Between 1992 and 1995 the number of customers increased by 554,000, more than a 12 percent increase.

Table 4.5: Number of Customers 1992–95
(thousand)

	1992	*1993*	*1994*	*1995*	*Cumul.*
Residential Customers	4,351	4,522	4,716	4,842	491
Total Number of Customers	4,522	4,739	4,947	5,076	554
Percentage Variation	--	4.1	4.4	2.6	12.2

Source: Enargas

Gas Sales

4.18 The new utilities' success in improving continuity of gas supply and availability does not carry over into the development of gas sales. The two-year (1993–95) increase in gas sales was less than 7 percent. Only the industrial sector showed a significant increase (19 percent); gas sales to the residential sector increased by a mere 2 percent. The variation of the gas demand of the power stations cannot be taken into consideration as it heavily depends on climatic conditions: e.g., rainfall above average fills dams and increase the amount of power generated by hydro schemes, thus decreasing the dispatch of thermal power plants. Two factors may be involved in the disappointing gas sales to the residential sector. First, while the industrial sector is quick to react when security of supply is clearly established, the response time of the highly dispersed residential market may be much longer. In addition, the utilities mentioned previously contribute only limited funds to the network extensions, and therefore have little incentive to develop sales in the new extensions. This places the financial burden of "filling in" the network on the associations of neighbors and the provincial authorities, which are not equipped for such a task.

Table 4.6: Gas Delivered per Customer Category, 1993–95
(million m^3)

	1993		*1994*		*1995*		*Variation (%)*	
Category	*Volume*	*(%)*	*Volume*	*(%)*	*Volume*	*(%)*	*1994–95*	*1993–95*
Residential	5,637	25.8	5,651	25.5	5,760	24.7	1.9	2.2
Commercial	969	4.4	975	4.4	1,041	4.5	6.8	7.4
Industrial	7,644	35.0	8,684	39.2	9,112	39.1	4.9	19.2
Power Stations	5,932	27.2	5,216	23.5	5,912	25.4	13.4	(0.3)
NGV	760	3.5	940	4.2	1,007	4.3	7.0	32.4
Others	884	4.1	687	3.1	485	2.1	(29.4)	(45.2)
Total	21,827	100.0	22,154	100.0	23,317	100.0	5.3	6.8

Source: Enargas.

Current Issues

Application of the Principle of Pass-Through

4.19 Theoretically, distribution companies should be allowed to pass through to the customers both the gas purchase costs and the transmission charges, and thus have full flexibility within the price cap. In fact, however, the regulator, in addition to its activities related to economic regulation, also must approve some activities of the distributors. An example is the allocation of transportation charges on customer groups. The regulator has decided that the allocation of gas costs and transportation costs should be the same (i.e., the transport mix should be similar to the gas mix). This means that the distributor utility of, say, Buenos Aires that purchases gas from several different areas with different transportation costs cannot systematically allocate to the residential customers the cost of the gas that comes from the farthest basin (hence, the highest transportation cost) and allocate to the industrial customers the gas that comes from the nearest basin, just in order to be more competitive in the industrial market. If the split between "far" gas and "close" gas is, say, 30/70, then separate each market, residential and industry, must be charged an average transportation cost that represents 30 percent of the "far" gas and 70 percent of the "close" gas.

4.20 Also, the pass-through of gas purchase costs has been unduly restricted in cases where the regulator judged that the distributors had not purchased the cheapest gas available in the market. For example, a distributor was not allowed by the regulator to pass through a price increase of gas purchased under a long-term contract because, at the time of increase, cheaper gas was available since it was the beginning of the summer season and spot-market gas was then cheaper than long-term gas. The distributor was allowed to pass through the price increase only at the end of the summer period, several months later, when spot gas became more expensive than long-term gas. The distributors argued that it was a short-term view to penalize them for buying long-term gas rather than spot-market gas and that they required a portfolio of different contracts, short-term and long-term as well, with different price indexation formulae and linkages. They considered that the price of the contract is only one parameter in the package, and that their competitiveness should not be judged only from the spot market price parameter.

Expansion of the Network (K-factor)

4.21 During the first five-year period to the end of 1998, networks were extended in accordance with the expansion programs submitted by bidders during the privatization process. From 1999 on, network extensions will be reviewed using the K-factor, which, once established, will not be altered during the subsequent five-year period. Thus, expansion of the network during the next five years is directly related to the K-factor. Utilities have expressed concerns about the rigidity of this procedure, which will make it necessary to plan, schedule, and estimate the cost of the extensions that will be constructed during this period well ahead of time. In addition, because the K-factor will be fixed for five years, the utilities claim that they may purposely underestimate expansion programs to reduce their risks, thus limiting expansion to what is absolutely necessary.

4.22 Another issue deals with application of the K-factor. How should new capacity be priced? Should the cost for expansion of the system be paid for by the new users only, "incremental" pricing, or should it be paid for by all users through a common increase of the average tariff, "roll-in" pricing? The K-factor was designed to allow roll-in tariffs; by allowing the operators to use the K-factor, all tariffs in the distribution area will be increased.

4.23 The economic efficiency of roll-in versus incremental tariffs should be viewed in context with the issue on resale of capacity (see paragraph 4.24). If a secondary market for capacity is available, so that distribution companies and other shippers with firm transportation contracts have the right to resell the capacity, then no customers would be interested in paying an incremental tariff for expansion of existing capacity so long as the tariff is lower than the incremental costs.

Resale of Capacity

4.24 The market for secondary capacity has not emerged since privatization of the natural gas industry. As discussed previously, there is no excess capacity in the transmission systems during the winter season—although suppressed demand has significantly decreased—and all transport capacity is contracted on a long-term basis as firm capacity (primary market). The issue is whether the right to resell seasonal, temporary excess capacity (secondary market) should be with the distribution companies and other shippers or with the transmission companies, and how this secondary market should be priced.

4.25 In countries that have allowed open access to gas pipelines, such as the United States and Canada, it took several years for a secondary market for transport capacity to develop. In 1993 the US Federal Energy Regulatory Commission—the US regulator—mandated that open-access interstate pipelines allow shippers to release or resell their firm capacity. Several fundamental rules apply to the capacity release program. Most important, all releases are subject to price ceilings and floors that are equal to the pipeline's maximum and minimum tariff rate. Long-term releases, if not made at the maximum pipeline tariff rate, are subject to open bidding; short-term releases may be arranged directly between the releasing and the replacement shipper. In Canada, the National Energy Board (NEB) originally allowed resale of capacity at or below the regulated tariff. After introducing flexibility to change delivery points and backhaul gas, the NEB removed the prohibition on trading capacity above the regulated tariff. According to the NEB, this reduces the need to construct additional capacity, improves the ability of the industry to deliver gas at the lowest cost at all times, and helps indicate when system expansions are required (i.e., when the price in the secondary market exceeds the firm transportation tariff for a prolonged period of time).

4.26 The Argentine model operates with a mechanism for the first resale of capacity and a mechanism for resale of capacity through a bidding process organized by the administrator for resale of capacity. The tariffs for the first resale of capacity cannot exceed the tariff approved by Enargas between the reception point and the exit point agreed to in the original contract. The regulation specifies which tariffs are to be used if the delivery point is upstream or downstream in relation to the original contract.

Is the Regulator Overdoing?

4.27 By law the regulator is responsible for regulating the downstream gas activities, and only them, while production prices are negotiated, i.e., they are be set by the market. In reality, however, one gas producer, the privatized YPF, actually controls the market and the market does not operate as it should in setting prices. Several utilities have expressed concerns about the regulator trying to indirectly regulate gas production through, and at the expense of, the regulated utilities. The previous discussion (see paragraph 4.20) about the regulator not allowing companies to pass through their cost in some cases is considered by some utilities an attempt to indirectly curb production prices, thus, a de facto conflict between the regulator and a producer rather than between the regulator and the utility.

5

Case 4: Developing Natural Gas in a Strongly Regulated Environment - The Case of Natur Gas Fyn (NGF), Denmark

Structure of the Gas Industry

5.1 In Denmark, gas is produced domestically at two fields that had been operated for several years for oil extraction by the Dansk Undergrunds Consortium (DUC).[6] When the government decided in the late 1970s to develop the gas associated with the oil and to sell it on the domestic market, the state-owned Danish Oil and Natural Gas company (DONG) was awarded the sole concession for importation, storage, transportation, and bulk sale of natural gas throughout Denmark. In 1979, DONG signed a long-term supply contract with DUC to deliver 55 billion m^3 during the period 1984–2009 (i.e., 2.5 billion m^3 per year in an average plateau year). It also signed a short-term import contract with Germany to supply DONG with gas before the Danish offshore gas production and transmission facilities become operational, so that gas distribution could start as early as possible.

5.2 At the same time DONG started to design and construct a high-pressure (HP) gas transmission system across Denmark, from fields located in the Danish offshore section of the North Sea to eastern Denmark (Copenhagen), and south to north across the Jutland peninsula. Limited exports to Sweden (Malmo) across the Smaller Belt were also considered. With regard to gas distribution, the country was divided into five regions that encompassed all Danish territory except for the City of Copenhagen, which was already supplied with town gas, and some remote islands. To remain consistent within a strongly regulated energy sector, it was decided that gas distribution would be operated by local government-owned companies. In each region, all interested municipalities were invited to become joint owners of the gas utilities, with unlimited liability and an unlimited right to operate.

5.3 Because south Jutland was scheduled to be the first region to receive natural gas, the first company to be established was Jutland Syd Naturgas, in 1979. In 1982, oil and gas pipelines from the North Sea came ashore on Jutland's western coast

[6] A private consortium including Shell, Texaco, and the Danish firm A. P. Muller.

and Germany began supplying natural gas to DONG at Jutland's southern border, enabling Jutland Syd Naturgas to start its distribution operation. The second region covered Funen, an island located between the mainland (Jutland) and the larger island of Zeeland. Municipalities in Funen established Natur Gas Fyn (NGF) in 1980. As DONG continued to lay a pipeline across Funen, NGF carried out the project's engineering in 1981, launched the network's construction in 1982, and started gas distribution in 1983.

5.4 In 1982, DONG's transmission line crossed the Larger Belt separating Funen from Zeeland. In 1982 and 1983, the other three regional companies were established. Naturgas Sjelland covered most of the island of Zeeland, except for the City of Copenhagen and the Greater Copenhagen area. HNG (in the Greater Copenhagen area), and Naturgas Mit-Nord (in the middle and northern Jutland), started natural gas distribution as DONG lines were commissioned. The City of Copenhagen, where town gas had been distributed for decades, was not constituted as a gas region and the local utility continued to distribute town gas manufactured from coal or oil. A few years later, when DONG started to crack natural gas, the City of Copenhagen became a direct client.

Gas Supply

5.5 With regard to natural gas, Denmark is less endowed than other countries sharing the North Sea shelf, such as the United Kingdom (UK) and Norway. Oil and gas reserves are located in a series of fields located in the westernmost tip of the Danish offshore zone, off the western coast of Jutland, near the border with the UK zone. Gas has been produced in the fields of Tyra and Harald, complemented by that from South Arne in 1997. Two new fields (Siri and Lulita) were to be put on stream in 1998. Although continuing gas exports to Germany was questionable due to increasing domestic gas demand, until now domestic gas reserves have been allowed to supply the Danish market and to be exported to Sweden and northern Germany. Gas production and sales have been steadily increasing since the distribution companies began to operate. Exports to Sweden started in 1985. Security of supply was reinforced two years later when DONG commissioned the first gas storage facility (Ll Torup) in northern Jutland (400 million m^3), followed by a smaller facility in Zeeland near Copenhagen (Stenlille) in 1994. In 1989, DONG signed a second long-term supply contract with DUC, which increased the amount to be delivered to DONG from 2.5 to 4.7 billion m^3/y during the period 1990–2012. Exports to Sweden were increased to 1.1 billion m^3/y from 1993 on. Also in 1993, DONG signed a third long-term supply contract with DUC, which specifies an additional quantity of 1.5 billion m^3/y to be delivered to DONG between 1997 and 2006.

5.6 DONG has already committed most of the 7 billion m^3/y that it can receive from DUC until 2006. During this period DONG plans to sell 4 billion m^3/y on the domestic market and to export 3 billion m^3/y to Sweden (approximately 1 billion m^3/y) and Germany (approximately 2 billion m^3/y). The increase in Danish consumption is expected to continue during the coming years, which makes it necessary for DONG to find additional sources. As an example, the additional new unit planned at the large

CHP[7]-plant Avedoereverkaet at Copenhagen will use a minimum of 600 million m^3/y. A new marine pipeline between the South Arne field and the gas treatment plant at Nybro, on the western coast of Jutland, will be put on stream in 1999, with a capacity of 13 million m^3/day (4.7 billion m^3/y in full swing). Because the additional 50 percent transmission capacity makes new storage capacity less critical, the development of the planned third storage facility at Toender has been postponed for at least ten years. For the first time, however, DONG is considering obtaining gas from nondomestic sources, and is negotiating with GFU, the Norwegian joint gas negotiating committee, for purchase of natural gas from Norway.

Market Base

5.7 Denmark, with a population of 5.5 million and an area of 44,000 km^2, is a small country by European standards. The average population in the region of each distribution utility is less than 1 million. Denmark is a mature country demographically, and energy demand by the residential and commercial sectors has remained steady because the two energy crises of the 1970s led to significant reductions in space heating requirements, which was a result of improved insulation of buildings and houses. However, climatic conditions (e.g., 2,940 degree-days in the island of Funen) keep per unit consumption by households high, approximately 2,080 m^3/y in the Greater Copenhagen area. Outside Copenhagen, an overwhelming proportion of the population lives in single-family households (99 percent in Funen), which leads to even higher per unit consumption.

5.8 As usual with a new product, natural gas had to develop a market while competing against other energy sources that were already in place when gas distribution started. In Denmark, as in most northern European countries in the early 1980s, the other major sources were district heating, often being produced in conjunction with power in cogeneration plants, heating oil, and sometimes coal. The main concern of the central government and of the municipalities, who generally operate the cogeneration plants, was to keep control over the process and not allow gas to compete head to head with existing energy sources, in particular, with district heating. Another concern was to keep the cost of gas networks as low as possible, and thus to minimize both the length of the street network and the number of service lines. From a financial perspective, local governments involved in the newly established gas utilities wanted to maximize gas penetration to repay the loans and get a fair return on their highly capital-intensive investment.

5.9 A strong monopoly regulation was issued, whereby all municipalities wishing to be served with gas—therefore, having provided equity in a gas distribution company—had by law to separate their territories into three heating zones: a district heating (DH) zone, a natural gas (NG) zone, and an open zone. The DH zones and the NG zones were to be energy-exclusive (i.e., only one source of heating was allowed), while the third was to be kept open. In the DH zone natural gas was not allowed to enter except to supply the DH plant and a few small industries where DH was not in competition with gas. The NG zone was devoted to natural gas, and district heating was

[7] Combined heat and power.

not allowed. In the open zone all energy sources were allowed to compete, including, but not limited to, district heating and natural gas. In smaller municipalities without district heating, gas was allowed throughout the city. The geographic designation of the DH and NG zones was based on existing energy patterns and on a decreasing household density criterion, with the most capital-intensive energy system, district heating, being allocated the densest areas.

5.10 Being awarded an exclusive distribution right means that the utility must comply with "public service" rules. For example, in an NG zone, the gas distribution company must serve all clients who want to be connected because both district heating and electric heating are banned, and the only alternative is oil. It is the responsibility of the utility to make it as economical as possible. In an open zone, the utility has the right to not extend its network if such an extension is not deemed profitable. Penetration factors depend heavily on zoning. NG zones in Funen represent a mere 37,000 households and about 20 percent of the entire area and gas penetration has reached 73 percent of these. Conversely, in open zones gas is almost completely absent.

The Distribution System

Network Architecture

5.11 While designing their distribution systems the gas utilities were allowed to adopt whatever operating standards system they desired. Safety and environmental regulation, however, were established at the national level using as references regulations already in place in other European gas countries, which led in certain areas to overregulation. In Funen, the distribution networks are fed from DONG's trunkline through six delivery stations, owned and operated by DONG, that meter the gas delivered and HP gas to supply NGF's primary medium-pressure (MP) network. This 300-km steel primary MP system brings gas to communities as well as to isolated larger gas consumers.

5.12 When it was being designed in the early 1980s there was a question about whether the primary MP system should be designed to operate at a 25-bar or, a cheaper, 19.5-bar maximum pressure. Based on a market survey, the 25-bar pressure design was eliminated because it was believed that it would not bring significant savings in materials or construction costs, since pipe sizes could have been reduced, but valves would have been more costly. The 25-bar system also would have made operation more complicated and costly because pipe pigging would have been compulsory. This decision has proved shortsighted because actual demand is now twice the amount that was estimated in the beginning of operation. While unexpected increase in demand can generally be met by adding a few district regulator stations, the main issue arose recently from the large, unexpected development of gas demand for co-generation, which requires that the gas used in gas turbines be delivered at a pressure higher than that designed (typically, 25 to 30 bar) to avoid costly recompression at the user's facility. NGF is therefore considering progressively upgrading its primary network to bring it to a 25-bar operating pressure.

5.13 As in most European countries, Denmark's secondary MP system is constructed of polyethylene (PE) pipes operated at 4 bar (60 psi). The extensive network is now more than 1,650 km long. Because gas must be transported long distances due to the area's low population density, the average size of PE pipes is unusually large to compensate for pressure drop. Although 60 percent of the network is made of small-diameter pipes (63 mm [2 inches] OD[8] or less) delivered on drums, larger pipes (up to 225 mm OD) are also used.

Construction Costs

5.14 Average unit construction costs on a per-meter basis are lower than what prevails in Europe. Laying pipes across mostly rural and suburban areas enables the utility to take full advantage of the lower construction cost of laying PE pipe. In open land, the cost of laying PE pipe ranges from $40 (for 63 mm diameter) to $90 (for 225 mm diameter) per meter. In urban areas, the cost is 45 to 25 percent higher, respectively, mainly due to the slower construction pace and the need to resurface roads and walkways. Steel-pipe networks are much more expensive, costs ranging from $120 to $260 per meter for 4-inch diameter and 16-inch OD pipe, respectively. The average construction cost per meter of network[9] is thus $110. However, the low population density means that the length of pipe necessary to supply each customer is large. In Funen, the average is 60 meters of pipe per customer (in comparison, the average is "only" 32 meters per customer in the Greater Copenhagen area), which makes the overall cost of the Danish gas networks among if not the highest in the world on a per customer basis.[10] Based on 1996 costs, the average cost of connecting one customer is $7,800, including service line and meter. Considering a cost of $5,000 for a single-family house's internal installation,[11] the total cost to make a customer ready to use gas is almost $13,000.

Gas Sales and Market Development[12]

Funen

5.15 Overall, gas sales total 300 million m^3/y. Residential and commercial customers account for about one-third of the total, as does the industrial sector comprised of small- and medium-scale industry supplied by the distribution system. District heating plants and power generation, including cogeneration at DH plants, and greenhouses make up the balance. NGF supplies slightly more than 27,000 customers. Within the residential and small commercial category, the large majority are "class A" customers—

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[8] Outside diameter.

[9] All street network (i.e., including district regulators, but not service lines).

[10] In southern European countries, where urban density is much higher, ratios range from 2 meters (in very dense city centers) to 20 meters (in suburban, single-family house areas).

[11] Including gas piping, individual boiler for space and water heating, and radiators. Gas for cooking ranges, which are mostly electric in Denmark (even in gas areas), is not considered.

[12] See also paragraph 6.12.

those who consume less than 6,000 m^3/y. "Class B," those who use between 6,000 and 300,000 m^3/y, includes 850 large commercial and small industries. "Class C" (more than 300,000 m^3/y) includes 85 very large commercial buildings and medium-size industries, where gas is used primarily, if not only, for space heating.

Greater Copenhagen

5.16 With a market base about 2.5 times larger than Funen's, HNG sells 865 million m^3/y to 140,000 customers. Because HNG's area includes a former gas works' territory, a significant number of customers (about 20 percent) still use gas only for cooking, with a very low per unit consumption of 45 m^3/y. Other residential and commercial customers account for about half of gas sales. The other half is consumed by DH, power generation, and large industry.

Gas Pricing

5.17 Gas pricing is another area that reflects the strongly regulated environment of the Danish energy sector, which translates into the following two principles. First, as for other energy sources, gas tariffs for the residential and small commercial sector are the same throughout Denmark (i.e., the "postage stamp principle"). The tariffs are established by the utilities and approved by a board that includes representatives from the consumers, the utilities, and the government. By law, gas tariffs are linked to the prices of oil products through a formula. Maximum gas prices in financial terms (i.e., including taxes) cannot exceed the regulated maximum prices for light fuel oil (LFO) for households, expressed in (net) calorific value. Since introduction of the environmental tax, based on carbon dioxide emissions—approximately 25 percent lower for gas than for LFO—financial gas prices are actually about 4 percent less than LFO prices. Such a policy gives a strong advantage to natural gas operators because overall taxes, such as excise, environmental, and value-added tax are much lower than those that apply to LFO. Economic prices of gas are thus about 75 percent higher than those of LFO.

Table 5.1: Gas, LFO, and Electricity Prices to Small Consumers (end 1996, $ per toe)

Energy	*End-User Prices (including taxes)*	*Taxes*	*Economic Prices (without taxes)*
Natural Gas	853	214	639
Light Fuel Oil	889	522	367
Electricity	2,478	1,426	1,052

Source: IEA/OECD, energy prices and taxes.

5.18 For large commercial and industrial customers, tariffs are published by the Department of Industry, but gas utilities are allowed to grant discounts, or to pay a lump sum, to help potential customers convert their equipment to use gas. Initial contracts are signed for five years and thereafter are renegotiated every two years.

Table 5.2: Economic Prices of Natural Gas in Various Markets (NGF) (mid 1997, $/mmbtu, without taxes)

Markets	*Prices*	*Remarks*
Residential and Commercial	17.29–15.53	Six tariff levels, up to 300,000 m^3/y. First level covers annual consumption up to 6,000 m^3/y
Heat Production	13.19–12.31	Four tariff levels. Thresholds at 0.8, 5, and 15 million m^3/y
Electricity Generation	6.45	One level
Industry	8.79–5.86	Three tariff levels. Thresholds at 0.3 and 0.8 million m^3/y

Operation: Customer Service

5.19 In both Funen and Greater Copenhagen all gas operating activities are concentrated in a single location, the utility's headquarters. In Funen, NGF's central office is located in a remote neighborhood far from the city center of Odense, the province's capital city; there are no branch offices, although the gas area covers 3,800 km^2 (1,500 square miles). In Greater Copenhagen HNG has closed the two regional branch offices, considering that security of operation is ensured because no point of the utility's territory is more than one hour away from Soeborg, the utility's headquarters.

5.20 Both utilities' operating units are adequately staffed, with 96 and 427 persons[13] in NGF and HNG, respectively. Ratios are 3.56 and 3.04 staff per thousand customers, respectively, which is high by European standards, in particular when one considers that the utilities operate modern, efficient networks[14] where routine maintenance is limited. Several reasons may explain this apparent overstaffing. First, with 27,000 and 140,000 customers, respectively, these utilities are small and cannot benefit from economies of scale. Second, the utilities are new, which means that they are already equipped with complete and state-of-the-art technologies, which outside subcontractors would find difficult to supply. Third, the utilities have not finished their growth period (NGF has commissioned 300 km of pipe in 1997); therefore, they still need to retain some technical positions, in particular for network design and construction supervision, which will no longer be required to the same extent once the consumer plateau is reached. Fourth, the institutional environment of the gas industry, based on local government's ownership and job protection, is not conducive to staff reductions, and laying off staff is unlikely.

5.21 Therefore, it seems that improvement in operating efficiency will have to come from gas sales development rather than from cutting costs (e.g., staff reductions).

[13] At the end of 1996.

[14] Although HGN still operates an old, small LP cast iron network (100 km) and 1,000 km of PE pipes inserted in former LP cast iron pipes.

There are, however, opportunities for subcontracting some of the operation activities. In addition to pipelaying and civil works, which are subcontracted by most utilities around the world, NGF subcontracts only customer billing, while HGN entrusts outside contractors with part of the network rehabilitation and off-the-job training. Other possible subcontracting would include some marketing and customer service activities and part of the pipelaying survey.

Metering and Billing

5.22 Gas customers seldom come to the utility's office because all customer service is performed via the telephone or by mail. To decrease the cost of customer service, Danish utilities have simplified meter reading and subcontracted bookkeeping and invoicing. There are no meter readers in charge of the residential and commercial market. Every three months, all "class A"[15] customers are requested to read their own meter and to fill out and mail back the reading card that was mailed to them. Since the end of 1996, gas utilities have adopted the self-reading and voice-response system already in use with most water and electricity utilities. The voice-response system enables customers to transmit the meter readings via telephone. In Funen, about 25 percent of customers call in their meter reading via telephone, while about 70 percent still use the card. Customers have one month to pay, and 97 percent of them pay on time, the large majority using banker's orders. Only 3 percent do not answer initially. When reminded, half of these 3 percent send in their meter reading. For those who do not respond, NGF estimates their bill on the basis of their previous consumption. After a three-week grace period, the utility sends a reminder to those who have not paid. Again, about half of these pay. At the end of a second three-week period the supply is cut off. Out of 27,000 customers, about 120 or 0.4 percent are cut off each billing period. Most are reconnected after payment of a fee; 0.2 percent of total customers never request reconnection

5.23 "Class B" and "Class C" customers also read their own meters, but once each month rather than once every three months. Two hundred such customers are already equipped with a remote meter reading system that will be extended to the entire submarket in the medium term. Preparation and mailing of bills are subcontracted. Unit cost is $12 per year per client. Systematic safety inspections of customers' installations are carried out once every five years, and the meters are actually read on that occasion only. Clients are informed in advance by mail of the date and approximate time of the visit. If they cannot be present they can either ask for another appointment or leave their keys with neighbors. Absences are rare.

Customer Information and Sales Promotion

5.24 Customer information notes are enclosed with gas bills. In principle, the company does not see the customers more than once every five years. The utilities do not carry out sales development campaigns for residential and commercial customers, even in the open zone, because natural gas already has a positive image among the population.

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15 Class A: < 6,000 m^3/y; Class B: 6,000–300,000 m^3/y; Class C: > 300,000 m^3/y

Thus, the utilities believe that sales promotion in that sector would cost more than the return it would bring back. However, the utilities do try to attract large customers, such as industries, district heating companies, greenhouses, and large commercial buildings. The utilities carry out energy assessments at these potential customers' facilities and submit proposals for conversion to gas.

Operating Costs

5.25 Operating activities in 1996, not including commodity cost, cost NGF and HGN $44 million in total (i.e., $263 per customer). Technical operation and maintenance costs represent 60 percent of the total, sales promotion and customer relations costs represent 13 percent, and general administration, including customer service, represents 27 percent. The cost of staffing, at 66 percent, is by far the largest single expense.

Distribution Margin

5.26 Gross operating margin (GOM) represents slightly more than one-half of the utilities' turnover. Due to higher tariffs in the residential and commercial market, a higher share of this market in the overall sales significantly increases the average GOM.

Table 5.3: Share of the Residential and Commercial Market (percent) and Average Gross Operating Margin

	NGF	*HGN*
Share in Gas Sales (percent of volume)	30	47
Share in Gas Sales (percent of revenue)	49	64
Share in Gross Operating Margin (percent of revenue)	63	74
Average Gross Operating Margin ($/mmbtu)	4.87	6.60

5.27 Despite high operating expenses, the large operating margin generated by high end-user prices enable the utilities to dedicate most of the GOM to reimburse the loans contracted to finance construction of the networks. GOM represents 5.3 times the amount of NGF's operating expenses, and 5.6 times HGN's. In addition, the central government reimburses the utilities the value added tax they collect from gas customers on behalf of the treasury to enhance their ability to repay the loans.

Annex

Thematic Summary Sheets

Theme 1: Structure, Ownership and General Regulation

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark (Funen)*
Name	Izgaz	STEG (Société Tunisienne de l'Electricité et du Gaz)	Nine distribution utilities, including Gas Pampeana, Gas del Sur (Camuzzi), and Litoral Gas	Five new utilities, including NGF (Natur Gas Fyn) and HGN (Greater Copenhagen), plus City of Copenhagen
Date Established	1992	mid 1950s. Took over former French utility	Eight in early 1993, from privatized state-owned Gas del Estado; ninth established 1997	1980 for the first five "new" utilities
Operation Started	1995 (when construction started)	At time of transfer; continuation from previous operation under former French administration	End 1992/early 1993 (for the first eight utilities); construction under way in the ninth zone	1982 (when construction started)
Ownership	Public. Municipality of Izmit (99%) and four neighboring municipalities (1%)	Public. State	Private. Some utilities retain minority public ownership (10 to 20%), to be divested soon; utilities include a gas operator and non-gas investors	Public. Local municipalities. Limited to those municipalities that wanted to be connected to the HP gas network
Structure	Joint-stock company	n/a	Joint-stock companies	Municipalities are "jointly and several"; if one fails, the others are accountable

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark (Funen)*
Restrictions on ownership	n/a	n/a	Consumer with direct GPA[1] with producer cannot hold controlling interest in utility operating in the same territory; no broker allowed	n/a
Legal Basis for Operation	Not a legal concession; operating license granted by Council of Ministers	No legal concession (de facto monopoly)	Concessions	Concession
Activities in the Gas Chain	Distribution and sales. Gas purchased from state-owned BOTAS, responsible for imports, transmission, and bulk sales to utilities and large users	Transmission, distribution, and sales. Gas purchased from state-owned oil and gas enterprise (ETAP), including locally produced gas and imported gas	Distribution and sales. Gas must be purchased from producers, not from transmission utilities	Distribution and sales. Gas purchased from state-owned DONG, responsible for bulk purchase (from sole producer DUC), transmission, exports, and bulk sales to utilities and large users
Duration of Concession/Permit	Unlimited	Unlimited (de facto)	35 years (extendible for 10 more years)	Unlimited
Territory	Five municipalities, which jointly own Izgaz	Countrywide	Each utility covers several provinces, except the city of Buenos Aires; all 23 provinces now covered	Province island of Funen

[1]Gas purchase agreement

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark (Funen)*
Exclusive Rights (Commercial)	Only for residential and small commercial customers; BOTAS retains right to sell gas to larger users	Yes	No. Large users (> 10,000 m^3/day) may hold direct GPA with producers; direct customer must pay (negotiated) distribution fee if using the utility's network; discount allowed	Residential and commercial (R&C), small industry: exclusive right to sell heat in "NG zones" (vis-à-vis DH and electricity); exclusive right to supply gas in "open areas"; gas prohibited in "DH areas"; heating oil allowed in all areas
Exclusive Rights (Physical Delivery)	Only for residential and small commercial customers; BOTAS retains right to deliver gas to larger users	Yes	No. Large users (> 10,000 m^3/day) may build a bypass to the transmission line	Same as above
Obligation to Serve	Yes, in the areas covered by the market survey	No	Only if there is a main in the street	Yes, in the "NG zones" (except cooking-only consumers); consumer's contribution requested if connection not economic

Theme 2: Market

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral)*	*Argentina (Camuzzi)*	*Denmark (Funen)*
Population within Utility's Territory	398,000	827,000	3,200,000	5,990,000	450,000
Land Area	35 km^2		143,000 km^2		3,800 km^2
Dwellings	91,440	184,000		2,133,400	203,000 (est.)
Dominant Urban Features	95% of dwellings in apartment blocks (avg. 6.8 apartments per block); strong commercial activity downtown, almost none outside; small and medium industry present in city	Downtown: mix of residential and commercial; L'Ariana suburb: large apartment blocks; limited commercial activity	Largest city: Rosario. Most buildings less than four stories high		99% of dwellings in private houses
Total Customers	74,800	53,330	364,420	1,071,500	27,120
Residential	69,200	49,900	348,500		26,040
Flats	67,800 (98%)	43,500 (87%)			
Private Houses	1,400 (2%)	6,400 (13%)			
Penetration Factor	76%	27% in gas area		53%	73% in "gas area" 13% overall
Commercial	5,600	3,350	15,600		940
Ratio of Commercial to Residential	8%	7%	4%		4%
Industrial	15	85	320		140

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral)*	*Argentina (Camuzzi)*	*Denmark (Funen)*
Service Lines (residential)	16,875	12,610			
Apartment Blocks	15,475	6,210 (49%)			
Private Houses	1,400	6,400 (51%)			
Customers/Service	4.4	7.0			1
Length of Network per Customer (meters)	4.2	16.6	20.9		71.9
Gas Uses	Target is space heating	100% cooking 27% water heating 48% space heating	100% cooking 60% water heating 75% space heating		8% cooking (cooking is mostly electric) 100% heating and water heating
Degree-Days	1,588	n/a	n/a	n/a	2,942
Heating Systems	11% of apartment blocks equipped with central heating	Central heating in some modern, upscale apartment blocks; gas heaters	Gas heaters	Gas heaters	Individual boilers
Load Factor	0.24 (global); 0.17 (residential and commercial)				
Average Yearly Consumption (Residential)	1,870 m^3	740 m^3	Average: 880 m^3; ranges from 500 m^3 (Santa Fe, north) to 1,500 m^3 (Pergamino, south)	From 1,200 m^3 (La Plata, north) to 8,000 m^3 (Tierra del Fuego, south)	3,330 m^3 (including commercial); in Greater Copenhagen, figure for residential only is 2,080 m^3

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral)*	*Argentina (Camuzzi)*	*Denmark (Funen)*
Total Gas Sales (million m^3/year)	242	44	2,065	5,380	297
Residential	130	37	272	2,012	90 (including commercial)
Commercial, Small Industry	16	2	303	899	
Ratio of Commercial to Residential	7%	5%	111%	45%	n/a
Industry	96	5	1,104	2,469	113
Power plants	none	none	386		94 (includes DH plants and cogeneration)
Gas transported for third parties (Arg.)			429	1,275	
Yearly Sales/Transportation per meter of network (m^3/y/meter)	768	49	320	224	152
Market Development Plan	During construction, operator (Dogaz) decides on location of street mains and service lines, according to market survey	None. Extensions and connections carried out at customers' request; utility estimates cost and calculates contribution requested from customers	During first 5 years (1994–98), utilities must meet expansion program included in concession terms; focus on filling in to increase yield per meter of pipe; not interested in extensions because tariffs make them not profitable; extensions done at customers' request; must be approved by regulator		Yes, in the "gas zone"; not interested in "open zones" because low population density makes extensions not profitable

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral)*	*Argentina (Camuzzi)*	*Denmark (Funen)*
Financing					
Street Mains, Extensions	Utility	Utility. If extension is required to serve one client (or group of clients), extension is treated like a service line	Three options: (1) utility (seldom), (2) provincial government, using sales tax levied on gas sales, (3) customers' association; can be a mix of two or all three; generally, extension funded by customer with financial help from local government		Utility
Service Line	Utility. Clients' contribution requested through lump-sum deposit of $103, plus $8 for start-up	Utility, with a cap on investment. Clients' contribution makes up for difference where needed, through a complex calculation formula	Clients	Clients	
Meter	Clients	Utility	Utility	Utility	Utility
Carcassing	Clients	Clients	Clients	Clients	Clients

Theme 3: Technical Characteristics

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral)*	*Argentina (Camuzzi)*	*Denmark (Funen)*
Construction Period	Started July 1995; ongoing; completion expected August 1998	1.Old town gas network (1920s), converted to NG (completed 1989) 2.NG extensions started 1984		Average age of networks: 19 years	Started 1983
General Architecture	Standard European design; two pressure levels	Town gas LP; natural gas: standard European design; two pressure levels			Standard European design; two pressure levels; mostly rural and semi-urban
Length of Pipe Network	315 km	894 km	Total = 7,800 km. Distribution = 5,600.Secondary transmission = 1,200	Total = 29,700 km. Distribution: 21,200 Secondary transmission = 5,000 Spur lines = 3,500	1,950 km
Pipes Materials	see below	see below	Secondary transmission: 100% steel Distribution: 68% steel (3,800 km); 32% PE (1,800 km)	10% cast iron; 75% steel; 15% PE. Have removed PVC pipes operated at 1.5 bar (22 psi) as part of the mandatory improvements	see below

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral)*	*Argentina (Camuzzi)*	*Denmark (Funen)*
Primary Networks (PN)	Steel; operated at 25 bar (370 psi)	Steel; operated at 20 bar (295 psi)	Secondary transmission: steel, operated at 16 bar (235 psi)		Steel; operated at 19.5 bar (290 psi); pressure level too low to supply expanding market; PN needs additions/upgrading
District Regulator Stations (DRS)	PN feeds 25-bar/4-bar DRS	PN feeds 20-bar/4-bar DRS			PN feeds 19.5-bar/4-bar DRS
Secondary Networks	MP (4 bar, 60 psi) Polyethylene	MP (4 bar, 60 psi) still built using LP architecture (meshed), which leads to unnecessary extra length (10 to 15%) PE develops since 1988	MP (1.5 bar, 22 psi) Steel and PE	Three town gas networks (cast iron); rest mainly steel; recent extensions in PE, 4 bar	MP (4 bar, 60 psi); average pipe size high due to long distances PE
Service Lines	Polyethylene	Polyethylene			Polyethylene
Peak-Shaving Facilities	No	No	No. Only BAN (utility of northern Buenos Aires) has a 25,000-m^3 liquefied natural gas storage, with 2,000 m^3/hour output		No

Theme 4: Operation: Main Characteristics

Subtheme	*Turkey (Izmit)*	*Tunisia (Tunis)*	*Argentina (Litoral Gas, Camuzzi)*	*Denmark (Funen, HNG)*
Mode of Operation	Contracted out to private operator (Dogaz)	Direct, by utility	Direct, by utility	Direct, by utility
Actual Operator(s)	Day-to-day operation contracted to Dogaz, through 49-year service contract	STEG. Distribution is dual operation (gas and electricity)	Litoral Gas Camuzzi	NGF (Funen) HNG (Greater Copenhagen)
Structure and Ownership of Operating Contractor	Private. Established 1996 under Turkish law; includes French utility (GdF) as operator and partners in the network's construction	Public (State)	Private	Municipalities that decided to be hooked to gas network
Operating Staff (utilities' staff only)	50 staff (Dogaz) plus 30 staff (Izgaz)	Gas Directorate: 480."Mixed" (gas/electricity) staff at other levels; no key to allocate "mixed" staff to gas and electricity activities, respectively	Litoral Gas: 257 Camuzzi: 1,200	NGF: 96 HGN: 457
Operating Ratio (number of utility staff per thousand customers)	0.9:1,000 customers (Dogaz + Izgaz)	Unknown. Considering DG only, ratio is about 7:1,000 customers (including gas transmission)	Litoral Gas: 0.7:1,000 customers Camuzzi: 1.1:1,000 customers	NGF: 3.6:1,000 customers HGN: 3:1,000 customers

Theme 5: Operation: Efficiency-Oriented Methods

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark*
Main Operating Tasks Carried Out by Operator	All except excavations	All except excavations	Maintenance (part)	Most, except excavations, meter reading, and billing (for R&C)
Network Maintenance	Carried out by operator	Carried out by operator	Gas leak survey partially subcontracted	Carried out by operator
Customer Service (Residential and Small Commercial)	Carried out by operator.	Carried out by operator	Subcontracted	Partially subcontracted
Meter reading (Residential and Small Commercial)	Reading done by operator's staff every 2 months; electronic reading transferred to portable terminals	Carried out by operator	Subcontracted. Reading every 2 months. Gas Litoral has 14 readers in Rosario (300 readings per day, each)	Meter read by customer and data sent by mail or telephone to operator
Other Options for Metering	Prepayment metering evaluated in other utilities			
Billing	Every 2 months. Bill is delivered at time of reading due to unreliable postal service	Carried out by operator	Every 2 months; subcontracted	Every 3 months; subcontracted; costs $11.55 per customer, per year
Collection	Customers pay in cash at Dogaz office (one window) or by check; payment must be made within 7 days due to high inflation rate			Check or bank transfer
Extensions	n/a (construction under way)	Carried out by operator	Financed and built by local government or customers through sales tax	Subcontracted

Theme 6: Gas Tariffs And Economic Regulation

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark*
Reference Used to Design Tariff Groups	Economic activity	Pressure level. Tariff grid was designed by STEG after electricity tariff grid	Nothing specific: reference basis is a blend of economic activity, expected consumption level and gas usage, plus a distinctive tariff for piped propane and butane	Economic activity
Number and Types of Tariff Groups	Three groups: Residential and commercial Industry, firm Industry, interruptible	Three groups: HP Primary MP Secondary MP and LP	Seven groups: Residential (R) General, with capacity charge (G) General, without capacity charge (P) Large users connected to distribution network (D); two subgroups: firm (F) and interruptible (I) Same, connected to transmission network (T) CNG Piped propane, butane	Four groups: Residential and commercial Heat production (DH and greenhouses) Power generation (cogeneration at DH and greenhouses) Industry
Geographical Variations	No, within concession limits; but tariffs vary according to concessions	No. Same tariffs throughout Tunisia	Yes, because end-user tariffs include the distance-based transportation tariff component	No. Same tariffs throughout Denmark

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark*
Tariff Structure	In each tariff group: one flat price per m^3 delivered; no standing/capacity charge	HP and MP1: three-tier: fixed subscription charge; capacity charge; commodity charge MP2/LP: two-tier (no subscription charge)	Very sophisticated. All tariffs include two or three components: All tariffs include an "invoice charge" Tariffs R and P include a "minimum amount billed" Tariffs P and G have two (G), and three (P) consumption blocks Tariffs G and F (large users, firm) include a capacity charge (in m^3/day) Tariffs I (interruptible) and CNG only include the commodity charge (for I, it is identical to F)	Several blocks in each tariff group (excluding power generation), according to yearly consumption; 14 blocks in total; for each block: one flat price per m^3 delivered; no standing/capacity charge
Consumption Threshold/ Ceiling to Access a Tariff	Industry: over 300,000 m^3/year	No	Tariff G: 1,000 m^3/day Tariff F: 10,000 m^3/day Tariff I: 3 million m^3/year	R&C: less than or equal to 300,000 m^3/y
Currency Hedging	No, in spite of high inflation rate that alters rates of exchange (loan is expressed in French currency)	No	Yes. Tariffs are expressed in "pesos convertibles," indexed on US dollar	No

Subtheme	*Turkey (Izmit)*	*Tunisia*	*Argentina*	*Denmark*
Adjustment to Inflation Rate	Tariffs revised every month	No	Tariffs are adjusted every 6 months to US inflation rate, according to US PPI variation	No
Relation to Economic Costs	No	No	Yes	No. Gas price (financial) must be equivalent to price of other fuels, including DH, on a per calorie basis; actually slightly cheaper due to lower environmental tax
Who Sets Distribution Tariffs	Municipality where the utility is operating	Government. Tariffs technically designed by STEG	Regulator	Utilities
Who Enforces Tariffs	State-owned supply and transmission utility BOTAS	Government	Regulator	Regulatory board
Flexibility	Price cap at 30 percent above transfer price from BOTAS to distributor	None	Price cap. Discounts allowed, in particular where there is a commercial bypass	None
Regulation	Distribution margin capped at 30% of delivery cost par BOTAS at CGS; in fact, gas is sold at only 20% above BOTAS price due to political interference	Tariffs prepared by STEG; fixed by government	Theoretically a price cap. Actual practice is that (a) gas purchase price not always passed through and (b) cap based on maximum rate of return	Tariffs fixed by government (as for all energy prices)

Joint UNDP/World Bank
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

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Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90

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

EAST ASIA AND PACIFIC (EAP)

Region/Country	Activity/Report Title	Date	Number
Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
	Institutional Development for Off-Grid Electrification	06/99	215/99
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84

Region/Country	Activity/Report Title	Date	Number
Bangladesh	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
	Environmental Issues in the Power Sector (English)	06/98	205/98
	Environmental Issues in the Power Sector: Manual for Environmental Decision Making (English)	06/99	213/99
	Household Energy Strategies for Urban India: The Case of Hyderabad	06/99	214/99
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazakhstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
	Natural Gas Upstream Pricing (English and Polish)	08/98	206/98
	Energy Sector Restructuring Program: Establishing the Energy Regulation Authority	10/98	208/98
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Slovenia	Workshop on Private Participation in the Power Sector (English)	02/99	211/99
Turkey	Energy Assessment (English)	03/83	3877-TU

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MIDDLE EAST AND NORTH AFRICA (MNA)

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

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean - Status Report (English and Spanish)	12/97	200/97
	Harmonization of Fuels Specifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH

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Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
	Reform and Privatization in the Hydrocarbon Sector (English and Spanish)	07/99	216/99
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

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Sub Andean	Environmental and Social Regulation of Oil and Gas Operations in Sensitive Areas of the Sub-Andean Basin (English and Spanish)	07/99	217/99

GLOBAL

Region/Country	*Activity/Report Title*	*Date*	*Number*
	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
	Rural Energy and Development Roundtable (English)	05/98	202/98
	A Synopsis of the Second Roundtable on Energy Efficiency: Institutional and Financial Delivery Mechanisms (English)	09/98	207/98
	The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank: A Carbon Backcasting Exercise (English)	02/99	212/99
	Increasing the Efficiency of Gas Distribution Phase 1: Case Studies and Thematic Data Sheets	07/99	218/99

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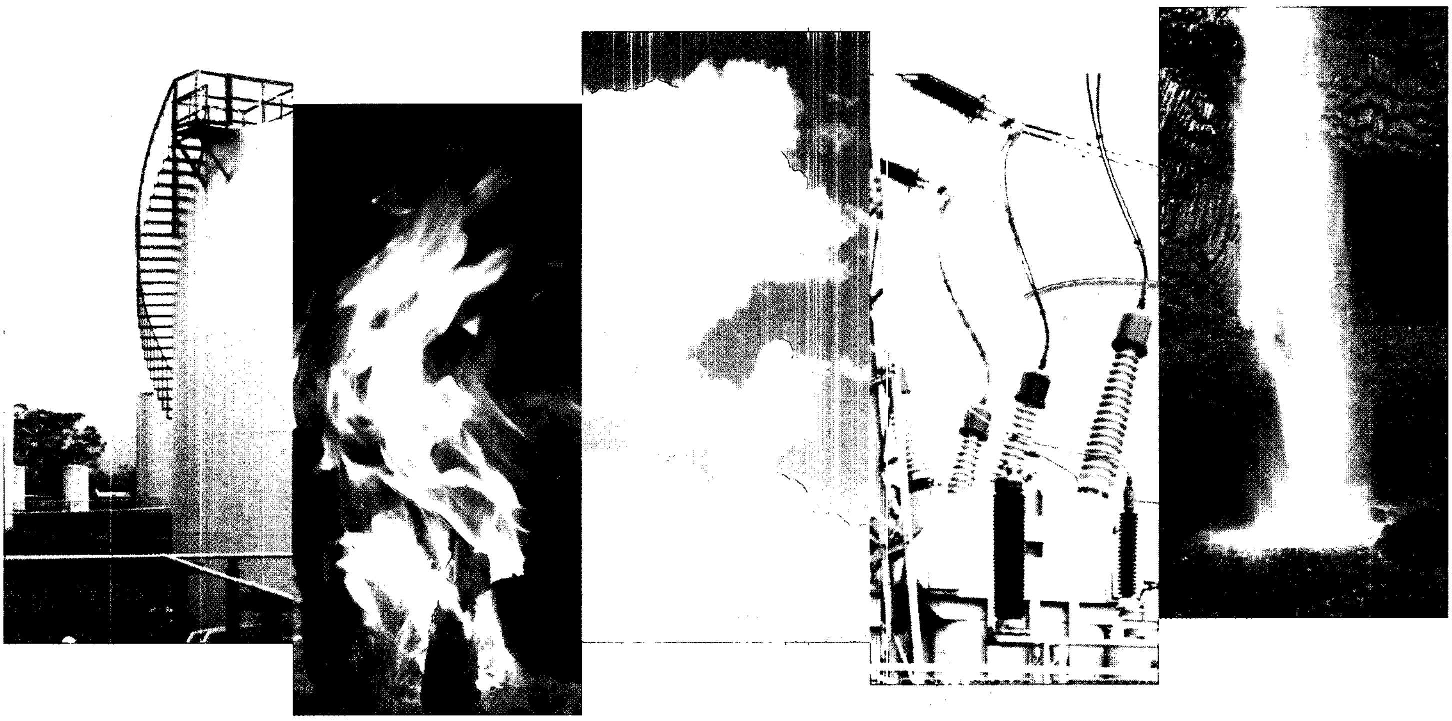

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