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INDEPENDENT POWER GENERATION IN BULGARIA: ASSESSMENT OF POTENTIAL, IMPEDIMENTS, AND OPTIONS

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List of Acronyms

ADB	The Asian Development Bank
AyE	Agua y Energia Electrica (Argentina)
BLT	Build, Lease, and Transfer
BOO	Build, Own, and Operate
BOOT or BOT	Build, Own, Operate and Transfer
CAMME	The Compania Administradora del Mercado Mayorista Electrico (Argentina)
CDC	The Commonwealth Development Corporation
CMEA	The Council of Mutual Economic Assistance
CNEA	The National Atomic energy Commission (Argentina)
COE	The Committee of Energy
COM	The Council of Ministers
COP	The Commission on Prices
EBRD	The European Bank for Reconstruction and Development
EC	European Community
"EEE"	An Evaluation of the Effect on the Environment
ENDESA	Empresa Nacional de Electricidad (Spain)
ENRE	The Ente Nacional Regulador de la Electricidad (Argentina)
EWG	Electricity Wholesale Generators (EWG)
EX-IM	US Export Import Bank
FERC	The Federal Energy Regulatory Commission
FSU	The former Soviet Union
GOB	Government of Bulgaria
HIDRONOR	Hidroelectrica Norpatagonica (Argentina)
IFC	The International Finance Corporation
IMF	International Monetary Fund
INI	Instituto Nacional de Industria (Spain)
IRP	Integrated Resource Planning
IPP	Independent Power Producers
MIE	The Ministerio de Industria y Energia (Spain)
MLC	The Municipal Land Commission
MOE	The Ministry of Environment
MOF	The Ministry of Finance
NCW	National Council on Water
NEK	The Natsionalna Elektricheska Kompania
NPC	National Power Corporation (Philippines)
OPIC	US Overseas Private Investment Corporation
PUHCA	Public Utility Holding Company Act
PURPA	The Public Utility Regulatory Policies Act of 1978
QFs	qualified facilities

REDESA	Red Electrica (Spain)
SAL	Structural Adjustment Loan
SE	The Secretariat of Energy (Argentina)
SEGBA	Servicios Electricos del Gran Buenos Aires (Argentina)
SIN	Sistema Interconectado Nacional (Argentina)
T&D	Transmission and Distribution
TDA	US Trade and Development Agency
TPA	Third Party Access
UEFSA	Union Fenosa (Spain)
UNESA	The Unidad Electrica, SA (Spain)
WEM	The Wholesale Electric Market (Argentina)
WASP	Wien Automated System Planning Package

I EXECUTIVE SUMMARY

Assessing the potential impediments and options for independent power in Bulgaria requires reviewing the international experience, evaluating the local independent power market potential, examining the existing policy, regulatory, and institutional conditions, and suggesting approaches to policy and institutional development.

1) The International Experience with Independent Power

Independent power production, or the privately-financed and central utility-independent generation of power, has become a rapidly expanding industry not only in the United States but in many countries in Asia, Latin America, and Europe. In 1992, independent power contributed 62% (or 3,848 MW) of all new capacity additions in the United States. As of 1991, there were about 3,000 independent power projects in the U.S. totaling more than 40,000 MW. It is estimated that of the 542 GW of capacity additions planned in 131 non-North American countries between 1993 and 2000, independent power projects could claim between 80 and 115 GW. The economic and financial advantages of independent power are the driving force behind this expanding new industry: access to private capital, minimized costs due to competition, shift of project risk to the private sector, more rapid integration of optimal power technologies, and expanded use of renewable energy and cogeneration.

The international experience (e.g. in such countries as Poland, Argentina, and Spain) with developing an independent power market provides lessons that should be considered in Bulgaria. As the experience in the United States and emerging economies has shown, the process of attracting private capital into the power sector essentially involves the reduction and management of both country and project risks. The Bulgarian government, the Committee of Energy (COE), and the electric utility (NEK) will have to play an active role in reducing and controlling those risks that a private investor and developer cannot control. Establishing key elements of the policy, institutional, and regulatory framework for independent power plays an important role in the risk mitigation and management process. The contractual commitments that the Government and NEK are willing to offer to private developers are also critical to attracting private financing, because they also reduce the investor's exposure to risk. Ultimately, a private developer and investor must be assured through the policy and contractual framework that NEK is offering a fair power purchase price under fair contractual terms and that the process of selecting a developer will also be fair and transparent.

The international financing of independent power involves structuring and managing both country and project risks in a way that is competitive regionally and globally. Given the current high level of country risk and the lack of a developed capital market in Bulgaria, power projects with international participation will initially require a major role for the multilateral and bilateral financial institutions and a Bulgarian government guarantee of utility

performance. For instance, the European Bank for Reconstruction and Development (EBRD), the World Bank, the International Finance Corporation (IFC), export credit agencies (e.g. US Export Import Bank (EX-IM) or the US Overseas Private Investment Corporation (OPIC)), equipment vendors, and to a small extent, commercial banks could supply the debt financing. The equity investment would come from the foreign investor/developer, a local Bulgarian partner, equipment manufacturers, and possibly the EBRD and IFC. As Bulgaria's independent power market matures and NEK's creditworthiness improves, the need for multilateral and bilateral support and government guarantees will diminish.

2) Independent Power Market Potential in Bulgaria

Independent power in Bulgaria faces clear barriers that will complicate the process of attracting private capital in the power sector:

- Difficult economic structural adjustments: Bulgaria's economic output has experienced a major decline as it tries to make the transition from central planning and communist block markets to free enterprise and international markets.

- Declining power demand and unreliable capacity: The demand for power has also declined leaving surplus capacity, with much of this capacity being unreliable and in considerable need of reconditioning.

- Poor utility financial performance: Electricity tariffs on average still do not reflect the full costs of generation, transmission, and distribution; as a result the electric utility (NEK) is currently not a financially-sound institution.

- Inadequate policy and institutional framework: The policy and institutional framework for independent power is not in place and the legal framework for private investment still requires further modifications.

- High level of commercial risks: Bulgaria is facing high inflation, high interest rates, major unemployment, and unresolved commercial debt negotiations such that most private investors and lenders will be unwilling to make the long-term investment needed by the power sector.

Despite these challenges, various positive conditions and trends in Bulgaria could encourage independent power generation in the coming years:

- Economic adjustment developments: Bulgaria's economic distortions and commercial risks are gradually being reduced through the structural-adjustment loans of the World Bank and International Monetary Fund (IMF) and commercial bank debt negotiations.

- Electric utility financial improvements: NEK is raising its tariffs to reflect the full costs of generation, transmission, and distribution and expects to be financially viable by 1995.

- Foreign investment laws instituted: Bulgaria has enacted laws that establish far reaching rights for private investors, including 100% foreign ownership, national treatment of foreign firms, and free repatriation of profits.

- Investment opportunities in existing capacity: There is a definite need for private investment to rehabilitate or repower existing power plants and cogeneration facilities.

- New capacity needs: When Bulgaria's economy begins to grow again, additional capacity will be needed, including thermal and hydro power plants.

- Independent power policy formulation: The Government has expressed a commitment to encouraging independent power and has begun the process of developing the necessary policy and institutional framework.

Recognizing the difficult economic conditions, sources of financing can be found if the policy and project framework is properly structured. The key components for developing a viable independent power program in Bulgaria will involve two parallel activities: policy development and project development, as discussed below.

Attractive power project development opportunities exist in Bulgaria in various sectors. While Bulgaria has an installed capacity of 12,074 MW, over the last several years the utility, NEK, has had difficulty meeting a system peak of 7,200 MW. This poor performance has been due to aging or technologically-outdated power plants and unreliable supplies of coal. There is a major need for investment to rehabilitate or repower the existing central power and industrial and district heating cogeneration plants. In addition, as power demand increases in the coming decade, major opportunities for building new thermal and hydro power plants will exist. Potential power projects that could attract foreign investors and a preliminary market estimate include:

- Industrial Cogeneration: Rehabilitating one or more major industrial cogeneration projects, such as Chimco Vratsa, Burgas, Vidin, or Kremikovtzi; [600 MW - 2,600 MW]

- District Heating Cogeneration: Rehabilitating one or more of the major district heating plants, such as Sofia or Pernik; [600 MW - 2,500 MW]

- Hydro Power: Private development of one or more of the mini or major hydro sites, such as the sites at Gorna Arda or Sredna Vacha. [400 MW - 2,600 MW]

- Coal-Fired Power Plants: Rehabilitating one or more of the existing coal-fired power plants, such as Maritsa East 1, 2, or 3, Varna, or Russe; [200 MW - 4,500 MW]

- New Generation: Construction of a new combined cycle gas or coal-fired power plant. [1993 - 2000: ~ 880 MW (assuming the intermediate demand growth scenario)]

Feasibility analysis of some of these projects is already underway, and an initial priority ranking of these projects will be included in the least-cost plan that is currently under development.

3) Existing Policy, Regulatory, and Institutional Conditions

The existing policy and institutional framework in Bulgaria is undergoing major changes. Only one statute, the Law on the Environment, has any significant implementing regulations. The power sector regulatory institution is also in a formative stage. The prospects for a broad independent power program will be greatly enhanced as Bulgaria's policy and institutional framework becomes more developed. The key power sector issues that need to be addressed are:

- Energy Legislation: There currently is no comprehensive energy law that addresses the rights of independent generators. A Law on Electrical Energy is being drafted that appears favorable to independent power, however, this Law has yet to be approved by the Parliament.

- Implementing Regulations: Once the Law on Electrical Energy is passed, implementing regulations clearly defining the Law will need to be drafted. These regulations could play an important role in defining such issues as power pricing, project solicitation, etc.

- Legal Recourse: The extent to which there is a reliable system of legal recourse in Bulgaria will also affect the attractiveness of investing Bulgarian power projects. It may be necessary for all parties to an independent power contract to submit to binding dispute resolution by an independent third party, which can be implemented in Bulgaria or in a foreign country.

- Institutional Priorities: An institutional structure and policy favorable to independent power is only beginning to emerge at COE and NEK. There is a need to set specific objectives for COE and NEK against which actual progress can be measured. Other ministries with an important role in power project approval, such as the Ministry of Environment, need to be included in the process in a complementary manner.

- Project Review Process: At present, there is not a clear project approval process that an independent developer can understand and follow. The procedure for project prioritization, selection, negotiation, and permitting will need further definition.

A preliminary assessment of the power sector institutions and the energy bill currently being drafted indicates that a potentially favorable policy and institutional framework is under development.

4) Suggested Approaches to the Introduction of a Policy and Institutional Framework for Independent Power

The Government of Bulgaria, the Committee of Energy (COE), and NEK will need to continue their progress in establishing the necessary policy, regulatory, and institutional framework for independent power. Some of the necessary activities are already underway, particularly electricity pricing reform, energy legislation, Integrated Resource Planning (IRP) analysis, and project feasibility assessments. Additional suggestions are summarized below:

- Strengthen Legislation: Strengthen components of energy and foreign investment legislation to facilitate independent power;
- Establish Regulatory Institution: Establish an independent regulatory institution that addresses independent power and ensure staffing by qualified regulators;
- Draft Regulations: Develop and publish detailed regulations based on the energy law;
- Establish Information Clearinghouse: Establish a central information clearinghouse for Independent Power (IPP) developers;
- Implement Integrated Resource Planning: Use Integrated Resource Planning to establish long run marginal cost and power purchase pricing to guide project selection;
- Define Government Guarantees and Incentives Offered: Establish consistent policy regarding government incentives and guarantees covering utility performance, fuel supply, etc.;
- Define Solicitation Process: Establish the procedure for soliciting independent power;
- Train Negotiations Team: Establish and train a multi-disciplinary review and negotiation team;
- Prepare Standard Small Power Contracts: Provide standard offer contracts for small renewable and cogeneration projects;
- Prepare Terms for Large Power Contracts: Provide standard non-price terms for large projects.

While all elements of the policy and institutional framework described above are necessary in order to enable an active long term independent power market, not all components are essential to develop the initial projects. Independent power projects can potentially move forward in an incomplete policy and institutional framework. In fact, experience in other countries (such as the Philippines, Poland, and Argentina) has shown that promoting specific projects early on can in fact help refine the policy development process.

In order to implement a parallel policy and project development strategy, certain priority elements of the policy and institutional framework need to be developed early on in order to ensure that any proposed independent power projects have an adequate institutional and contractual framework. The near-term key power sector policy framework that needs to be implemented includes the following elements from the above list: establish a consistent policy regarding government guarantees and incentives; establish and train a multi-disciplinary review and negotiation team within NEK, and provide standard non-price terms for large, central, hydro, or cogeneration projects. It may be desirable to also prepare standard offer contracts for small renewable and cogeneration projects. With these basic elements in place, it should be possible to attract independent power investments.

II THE INTERNATIONAL EXPERIENCE WITH INDEPENDENT POWER

1) The Definition of Independent Power

a) Basic Legal and Financial Structure

Independent power represents the financing, construction, and operation of a power generating facility by a company that is independent from the central power purchasing electric utility. The central utility can either be private or government owned, but in both cases is a regulated monopoly. The independent power generator is usually owned by a private company. It is typically an unregulated facility that enters into a clearly-defined power purchase agreement with the utility. By this definition, Bulgaria already has various examples of independent industrial cogeneration and district heating plants at government-owned corporations.

An independent power project (IPP) can: (1) exclusively serve the captive power needs of a particular factory or load (thereby reducing the power requirements of the central utility); (2) meet captive power needs and also generate surplus power and energy for sale to the grid; or (3) be a dedicated power plant for bulk power sales to the grid. Categories 1 and 2 involve some form of cogeneration while category 3 include central power plants ranging in scale from small decentralized generators (e.g. mini-hydro, geothermal, wind, solar, etc.) to large power plants (e.g. coal, oil, gas fired units).

IPPs can be introduced in different ways. At one end of the spectrum, independent power has involved a major restructuring of the power sector, the breakup of generation, transmission, and distribution, and the sale of government-owned power generation and distribution assets to the private sector (as for instance has been implemented in the United Kingdom and Argentina). At the other end of the spectrum, some countries have retained government-control over the main generation, transmission, and distribution system, and have simply entered into power purchase agreements with selected independent power generators (as has been implemented in the Philippines and Spain). Given Bulgaria's expressed near-term requirement to work with the existing government utility, NEK, and the clear objective to attract private capital into the power sector, the focus of this report will be on the latter model for independent power.

Privately financed IPPs are structured as separate companies that involve limited or non-recourse project financing. This method serves to mobilize private capital more effectively by limiting the liabilities of the project owners. In the event of default or bankruptcy, the lenders and investors have no right to the assets of the owners of the company; the only collateral they have is in the assets of the specific project company. As a result, however, lenders require more assurances in the form of contractual agreements, including iron-clad power purchase contracts, and attractive internal rates of return before they are willing to lend to independent power projects.

b) The Process of Independent Power Project Development

The life of an independent power project involves three major phases: development, construction, and operation. Within these phases, some ten distinct steps can be defined.

(1) The electric utility determines the amount and type of capacity needed in its expansion plan through a planning process;

(2) the electric utility obtains and evaluates proposals from prospective developers that are either unsolicited or solicited through a competitive bidding process;

(3) The utility and developer may decide to negotiate an initial letter of intent or memorandum of understanding to define the basic parameters of the proposed project;

(4) The developer performs a detailed feasibility study to define the precise technical and economic characteristics of project;

(5) Detailed legal agreements are negotiated for the purchase of power, fuel supply, construction services, operation & maintenance, etc.;

(6) The developer proceeds to obtain all the necessary permits required, including such issues as land use, environmental emissions, taxes, etc;

(7) Short-term and long-term debt and equity financing is obtained for both construction and long-term capital requirements;

(8) A detailed engineering design of the project is completed;

(9) The power plant is constructed or rehabilitated and commissioned;

(10) The plant is operated, the debt is serviced, and the equity investors earn their return.

Each of these steps represent a milestone or hurdle in the process of developing the independent power project. As shown in Figure 1, at each stage of this process the costs of developing the project increase while the risks of the project failing decrease.

Private Power Project Development Risk and Cost Phases

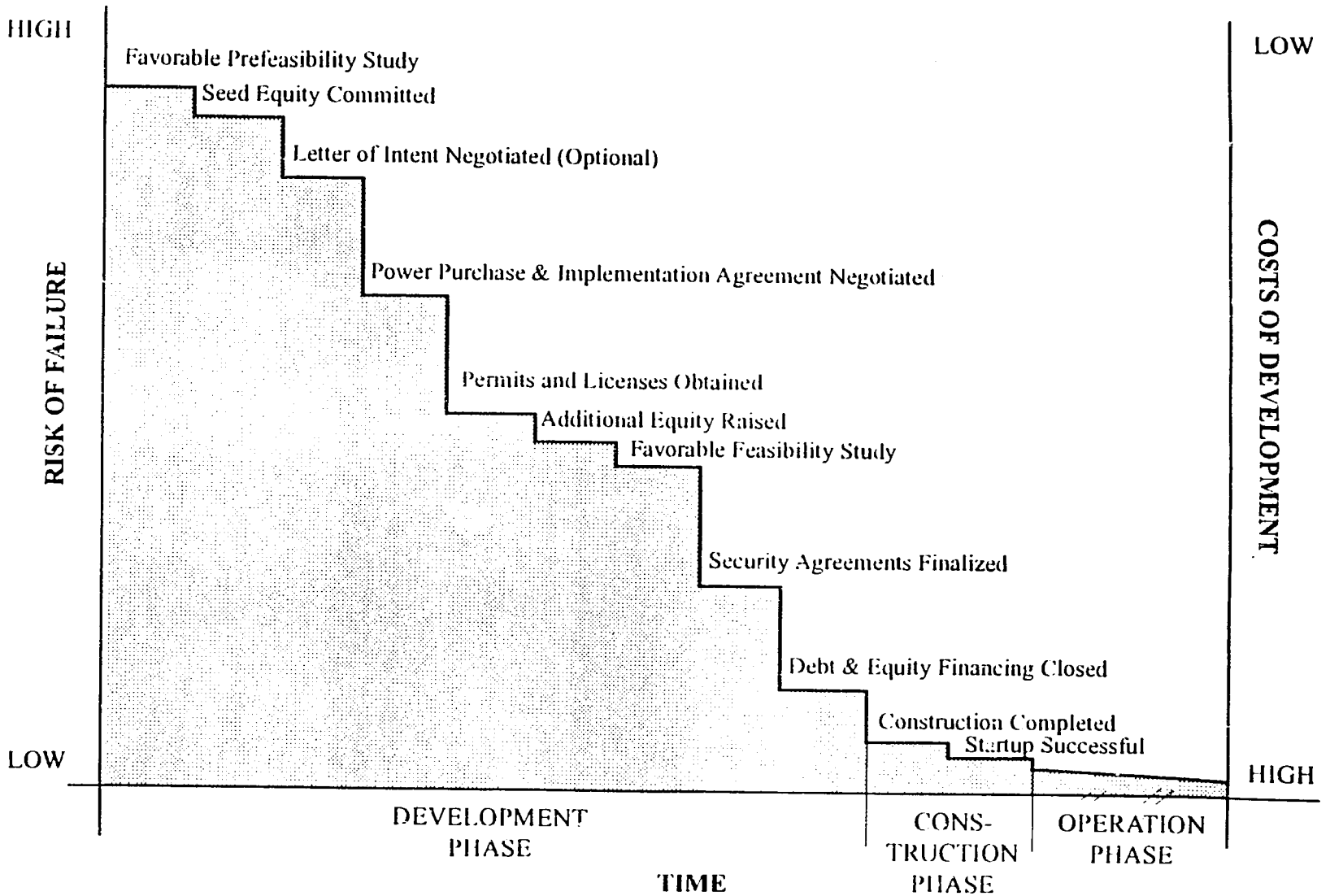


Figure 1

2) The Evolution of Independent Power in the United States

a) Introduction

The U.S. power sector is characterized by a wide array of players, including investor-owned or private utilities, state and municipal utilities, cooperatives, and Federal utilities. Investor-owned utilities provide most of the electric power generated in the U.S., focusing on sales to ultimate customers and secondly on bulk power sales. Federal utilities, on the other hand, focus on bulk power sales to utilities.

The U.S. power sector is regulated at two levels. The Federal Energy Regulatory Commission (FERC) regulates at the federal level, while state public utility commissions in each of the 50 states regulate at the state level. FERC has the responsibility to administer federal laws affecting the electric as well as the gas industry and the transfer of these energy supplies across state borders. The public utility commissions in each state has responsibility for regulating, among many items, the prices of retail sales by electric utilities. There are, in addition, 2,000 local entities which regulate pricing and resource use issues affecting municipal power authorities. In total, there are about 2,050 regulatory entities affecting, in one way or another, the actions of over 3,200 electric utilities.

The Public Utility Regulatory Policies Act of 1978 (PURPA) has had a dramatic impact on the US power sector. The statistics speak for themselves. Over the last ten years after the passage of PURPA, close to 2,500 non-utility projects with a total capacity over 30,000 MW came into operation in the United States. In the next ten years, another 55,000 MW of non-utility power generation could come on line, providing over 40% of all new capacity additions before the end of the century. PURPA allowed non-utilities to invest in qualified facilities (QFs) using cogeneration or select renewable or waste fuels. At this point, over 100 non-utility companies are actively involved in this form of private power generation. In fact, some of these companies are utility subsidiaries because the Congress of the United States allowed utilities to own up to 50% of any QF project, as a quid pro quo for opening the door to non-utilities. The story of how this revolution in the power sector evolved is worth exploring to draw lessons for the development of independent power in Bulgaria.

b) The History of PURPA and Non-Utility Generation

In the late 1970s, the U.S. Government was faced by the energy crisis resulting from the oil price shocks. In an effort to reduce oil imports by eliminating energy waste and promoting the use of indigenous energy sources, PURPA was passed in 1978. The specific objective of this law was to promote the non-utility development of cogeneration and renewable sources of energy. While primarily aimed at fostering energy conservation, PURPA

also put an end to the power generation monopoly of US utilities and opened the door to the de-regulation of that sector.

Prior to PURPA, no unregulated plant could sell power to the grid. The only non-utility-owned power plants were self-generation facilities generally concentrated in chemical production complexes, pulp and paper mills, and some steel mills. These projects produced power for themselves and did not interface with the grid, except in emergency situations. About 7,000 MW of self-generation was in place prior to PURPA, including nearly 5,000 MW of gas-fired or coal-fired capacity; the balance consisted of mostly black liquor units in pulp and paper mills.

PURPA stipulated two conditions that opened up the US power generation sector:

- **First**, it allowed non-utilities (e.g., private companies, equipment suppliers, construction firms) to build and operate certain types of qualifying facilities (QFs) and sell their power output to the grid without being regulated as a conventional utilities.

- **Second**, it required utilities to buy the power from these QFs under certain price conditions.

First, PURPA explicitly exempted QF owners from the regulatory requirements of the Public Utility Holding Company Act (PUHCA). QF owners thereby escaped the burdensome regulatory, reporting, legal, and accounting requirements of PUHCA. Furthermore, QFs were exempted from the rate regulation and other financial reporting regulations of the Federal Power Act. Finally, PURPA exempted QFs from the financial and organizational requirements of the state public utility commissions. These special rights granted to QF owners allowed them to earn an unregulated return on their projects, in contrast to utilities that were subject to rates of returns set by their state public utility commissions.

PURPA allowed non-utilities to build two types of QFs designed to either use an energy-efficient technology (i.e. cogeneration) or help diversify the US power generation mix:

- Cogeneration Projects which simultaneously produce two or more useful forms of energy (process steam, hot water, or process heat) and electricity. Cogeneration projects are energy-efficient since they generate electricity on the margin for as little as 4,000 to 6,500 btu/kWh compared to 9,500 Btu/kWh for a conventional power plant. To qualify as a QF, a cogeneration project must produce at least 5% of its total energy output in the form of useful thermal energy. If that requirement is met, a QF cogeneration project can be of any size and can use any type of fuel.

- Small power projects which produce only electricity but use waste fuels (for example, waste coal, industrial process wastes, or biomass) or renewable energy (for example, geothermal energy, wind power, hydropower or solar energy). To qualify as a QF, a small power project must be below 80 MW.

Second, PURPA stipulated that utilities had to buy the power produced by QFs and had to provide non-discriminatory interconnection and back-up service to these QFs. QFs generally sell power under long-term (20 to 25 year) contracts at rates negotiated or competitively bid with utilities and in compliance with avoided cost and other requirements of relevant state regulatory agencies. The approval of the power sale contract and the normal siting and permitting approvals are generally the only extent to which QFs are regulated. As a quid pro quo for "opening up" the power generation monopoly that electric utilities had, PURPA allowed utilities to own up to 50% of QFs provided they did contract to sell power to themselves.

c) The Implementation of PURPA

Several implementation issues quickly arose which had to be dealt with both at the Federal level and at the local level:

- At the Federal level, the Federal Energy Regulatory Commission (FERC) was put in charge of the broad implementation of PURPA and, as such, issued in February 1980 its Order 69. This order, however, left a lot of details to state public utility commissions.

- At the state level, public utility commissions retained jurisdiction over the implementation of PURPA, including deciding:

  - the methodology to be used to set rates for sales and purchases of QF-power;
  - the responsibilities for QF interconnections;
  - the standards for QF system safety and reliability; and
  - the process by which these commissions would resolve disputes between utilities and QF owners.

Nonetheless, some states still felt that PURPA was one more instance of Federal interference. The State of Mississippi challenged the constitutionality of the new law in April 1979. It was not until June 1982 that the Supreme Court of the United States ruled that PURPA was constitutional. Consequently, there was little QF market development between 1978 and 1983.

The most important issue, then, became how to determine the price that utilities should pay for QF power. PURPA just said that utilities should pay no more than their "avoided-cost", a new and vague concept which FERC clarified by stating that the avoided cost should be "an administratively-determined approximation of the incremental costs to an electric utility of electric energy and capacity or both, which, but for the purchase from QFs, such utility would generate itself or purchase from another source." At first, this was interpreted to mean the full marginal cost of building the next power plant, which was generally construed as a large,

expensive, utility-owned power plant. In some cases, this meant paying 10-11 cents/kWh of QF power -- almost twice what utilities would pay for power bought from neighboring utilities.

Although some utilities challenged FERC's "administrative" interpretation, the Supreme Court upheld FERC's authority to endorse the avoided cost approach, stating that the "basic purpose of ....PURPA was to increase the utilization of cogeneration ... and to reduce reliance on fossil fuels" and that "at this early stage of implementation of PURPA, it was reasonable for FERC to prescribe the maximum rate authorized by Congress and thereby provide the maximum incentive for the development of cogeneration and small power production."

Even upheld, the FERC guidelines remained unclear and state commissions developed different methodologies which in some cases were legally challenged as well. For example, New York State declared that there should be a floor of 6 cents per kWh for QF power, a decision which was later repealed. Several states (e.g. Pennsylvania) also said that contracts signed between utilities and QFs were to approved even if they did not quite follow the commission guidelines. Commissions also reacted at different speeds as they faced various utilities with diverse demand and supply situations and different levels of sophistication. In addition, some state commissions (e.g., California and Ohio) had large staffs while others did not have the in-house engineering and financial expertise needed to administer PURPA issues. As a result, only 16 states had issued their regulations by March 1981, the deadline set by FERC. By March 1983, two years later, six states still had no PURPA regulations in place.

While regulators were searching for the best approach, most US utilities were resisting non-utility generation because they resented having to purchase high-priced power from QFs that could be located anywhere and operated by anybody. For most utilities, this smacked of anarchy and, in numerous instances, utilities counteracted by offering discount rates or deferral agreements to industries that were potential cogenerators or by imposing high standby and interconnection rates.

Finally, the pressure of state regulators and the activism of non-utility companies overcame the utilities's opposition in some key states such as California, Texas and Pennsylvania. In these states, non-utility offers started to pour in on a "first-come, first served" basis to take advantage of high-avoided costs. In addition, QFs built then could be amortized over a 5 year period as the result of a new tax law passed under the first term of the Reagan administration. By the mid-1980s, some of these states were swamped by QF offers. For example, over 6,000 MW of offers were signed up in California alone in 1984 and 1985. At that point, utilities and regulators started to search for ways to regain control of the situation by reducing the amount of QF capacity offered with queuing systems and capacity auctions. In essence, utilities were concluding that when there is a high level of QF offers, the avoided cost could be defined as the cost of purchasing additional power from the most competitively priced QF project. In 1984, the idea of issuing requests for QF proposals that could compete against each other emerged in the states of Maine and Massachusetts.

While regulators and utilities were getting their act together, the demand for power was growing in several regions of the United States. Utilities were reluctant to build their own plants for several reasons. Utilities feared major cost overruns; the major failures they had experience in nuclear construction caused some of them to re-examine the assumption that bigger plants were better. They also did not like the high fuel prices and interest rates that were in effect at the time and their balance sheets were often not in a favorable position to take on the risk of new construction.

In this context, US utilities came to realize the advantages of QFs compared to conventional power plants:

- **First**, QFs are small compared to central utility stations. Therefore, QFs better fit the gradual increased demand faced by most US utilities. Being smaller, QFs are also easier to site and permit. In most states, permit reviews are simpler for projects below 100 MW, 75 MW or 50 MW. In addition, industrial cogeneration projects are generally built on existing sites where the incremental water, community, and socio-economic impacts are minimal.

- **Second**, being smaller and easier to site and permit, QF projects can be constructed faster than conventional plants with less chances of incurring cost overruns. A QF project generally can be built in less than 3 years under turnkey contract with price ceilings.

- **Third**, easier to site and less risky, QFs are accepted by financial institutions which are willing to provide project financing by extending highly-leveraged debt on a non-recourse basis. With this type of financing, financial institutions loan the necessary funds against the sole assets of the project, without having recourse to the equity owners of that project. For the lenders, the single most important asset in a QF project is its long-term power sale agreement because it is signed by a utility that is generally considered as a most credit-worthy institution. In the 1980s, QF projects were leveraged up to 85-95%, thus enabling them to produce power at lower costs and still generate higher returns than utility projects leveraged at less than 50-60%. In addition, cogeneration projects, with their higher energy efficiencies, are more cost-efficient than central power plants.

- **Finally**, utilities came to accept that there were knowledgeable, entrepreneurial and efficient non-utility organizations that could run their QFs as reliably as utility-plants. The was a growing recognition that increased competition in power generation led to more innovation in technology, more fuel diversity, and better diversification of risk.

As the need for new power kept growing, FERC proposed a ruling in early 1988 that would have standardized competitive bidding for QF plants. However, several states resisted saying that they wanted the flexibility to design their own QF selection processes and continue

to use them as needed in case-by-case negotiations. Although it failed, the proposed ruling sent the message that competitive bidding was the way to go.

Currently, most US utilities issue requests for competitive bids for a certain amount of non-utility capacity that has to meet certain size, fuel and operation criteria and must come on line within a specified time window. Such bids can be either open or closed bids:

- In open bids, the request for proposal provides an explicit scoring system which is being used throughout the project selection and negotiation process.

- In closed bids, there is no scoring system, although the utility may provide some indications as to the types of projects it prefers.

In both cases, however, utilities are learning how to improve their bid selection process by evaluating QF offers not only on price but also on "quality". To judge the quality" of a QF offer may call for looking at up to 15 - 20 factors such as the use of certain local fuels; the impact on the local environment and economy; the type and reliability of the technology proposed; the timing of the project; its transmission fit; the quality of the planned operation and maintenance contract; and the reputation and track record of the sponsors behind each project. In some cases, the utility will bid its own plant or use as a benchmark a potential contract to purchase bulk power from a neighbor utility.

In this new competitive bid environment, QFs generally sell power at rates between 6 and 8 cents per kWh. At these rates, rates of return on QF projects can range between 15% and 25% depending on the degree of risk, location, and size of the project. To date, over 65 competitive bids have been issued by 48 utilities to request over 19,000 MW of non-utility generation capacity. The market response to these bids has been tremendous: over 1,950 projects were bid for a total in excess of 148,000 MW, that is almost 8 times what was being asked. These bids were issued by all types of utilities, including investor-owned utilities, public utilities and rural cooperatives.

d) The Success of Non-Utility Generation in the US

The combination of increasing capacity needs, the utilities' reluctance to build new plants, and a growing acceptance of QFs by utilities, explains the emergence of a strong non-utility generation industry which has grown by 15% per year over the last ten years. The US QF market took off in 1985 and, since then, annual increases of 3,500 to 4,000 MW per year have been recorded. Year 1990 was a record year with over 6,000 MW of new operational capacity: this included 224 projects for a total investment in excess of $ 8.5 billion.

Overall, more than 30,000 MW of new QF capacity has been developed since 1980, representing over $ 40 billion in investments. QFs have provided about 15% of all the new

power generation capacity installed in the United States since 1980. This proportion has subsequently increased from 25% in 1985 to 53% in 1990.

Today there are close to 3,000 non-utility generation projects in operation, representing a total generation capacity of more than 40,000 MW. This accounts for roughly 6 per cent of the total installed generation capacity in the United States. In 1990, QFs produced the equivalent of $9 billion in electricity sales. At this point, over 85 utilities purchase significant amounts of independent power.

QFs are very diverse in size and type of fuels. Gas-fired cogeneration, however, dominates with 45% of the total non-utility generation capacity in place. Next comes coal-fired cogeneration (15%). Small power projects account for 23% of the existing QF capacity, including projects with a broad slate of energy sources: biomass, waste fuels, hydroelectric power, municipal solid waste, and geothermal, wind and solar energies.

In addition, some 1,500 QF projects were identified as under development, representing potential capacity additions of nearly 70,000 MW, most of which will come on line between 1992 and 1995. This includes over 34,000 MW of gas-fired capacity, 11,200 MW of coal-fired capacity and some 6,000 MW of capacity that will use biomass or waste fuels; the balance (16,700 MW) will rely on renewable energy resources. Note that not all the projects forecasted will succeed; it is estimated that about 50% of all projects initiated eventually fail to be constructed due to their inability to meet various regulatory, permitting, or financial requirements.

In terms of applications, small power projects (most using renewable energy) account for the largest share of QF projects, both operating and under development. The next most intensive QF markets are cogeneration projects found in the chemicals, pulp and paper, and petroleum refining industries; these three industries combined host 18,000 MW of operational non-utility generation and could attract another 17,000 MW of additional QF capacity in the next five years.

Non-utility generation, with its flexibility and quick-on-line capability, will help US utilities meet their capacity needs across the entire country. Up to 200 competitive bids may be issued through 2000, requesting over 45,000 MW of non-utility generation capacity, first on the East Coast, but then spreading to the Southeast and Midwest of the United States, as the demand for new power generation shifts round the country. In most cases, utilities will solicit between 200 MW and 450 MW at a time.

In that context, it is projected that 54,700 MW of non-utility generation capacity will develop through 1999, including 26,200 MW of gas-fired capacity; 15,400 MW of coal-fired capacity industrial cogeneration; 6,500 MW of biomass- and waste fuel-fired capacity; and 6,500 MW of capacity relying on diverse types of renewable energy resources.

Over 9,000 MW of non-utility generation capacity may therefore be in place by 2000. Through 1999, non-utility generation will provide about 46% of the total generation capacity that is expected to come on line. This bodes well for this new industry which is attracting more and more players. As the industry grows at 10% per year, some-non-utility companies will grow large in the 1990s. By 2000, leading players may control the equity of some 3,000 MW of non-utility project. By being involved in up to 40-50 projects in 20-30 states; the portfolios of this major players could then be worth $ 1 billion or more and their annual power sales are likely to exceed $ 1.5 billion.

e) The New Energy Policy Act

A new national energy law, entitled the Energy Policy Act of 1992, which substantially expanded the scope of independent power in the US. This Act signals a new era by offering the following new terms:

- A new category of power plants, Electricity Wholesale Generators (EWG), are exempt from PUHCA and thus have similar status as Qualifying Facilities under PURPA, while they are still subject to the Federal Power Act and state regulatory commissions. There are no explicit fuel or size restrictions for EWGs and they have fewer restrictions on utility ownership.

- Transmission access will be broadened for wholesale power exchanges between utilities and independent power plants. This broader access to the grid will give independent power generators greater rights and opportunities to wheel power to utilities and major customers.

This new law is likely to result in a wide variety of new EWGs emerging on the market. EWG size will at first be limited by the realities of the power plant siting and the sizes of power capacity additions being required by utilities. Thus, most EWGs being developed in the United States over the next four years will likely still be below 400 MW, with 150 MW to 300 MW being quite popular. The competitive market conditions in the U.S. are also leading many developer to pursue major project overseas.

In addition, under the new Act, FERC can order wheeling between utilities, or between QFs or EWGs and utilities, or between QFs or EWGs and major industrial customers as long as the transaction meets four conditions: (1) it involves wholesale power only; (2) it is in the public interest, (3) it does not jeopardize the reliability of the grid, and (4) it involves wholesale power that is transacted at a "just and reasonable" price.

With this new Energy Policy Act, the independent power market in the US is opening a new chapter that will lead to a wider variety of opportunities for independent power generators.

f) Lessons Learned from the US Independent Power Experience

In conclusion, we can say that PURPA has had a positive effect on energy efficiency since cogeneration has inherently higher thermal efficiencies than power-only technologies. In some cases, utilities were forced to purchase relatively expensive power typically from renewable energy power plants; the responsibility for this situation being largely due to poor decisions made by the utilities themselves. PURPA, however, had a good impact on diversity of technology and fuel supply and it has reduced the probability of a single large outage. The impact has also been positive on reducing oil dependence, although the use of indigenous gas has increased. More importantly, however, PURPA has brought on power that was badly needed in some key states and has reduced the capital requirements of several utilities that were not willing to build or were not in a good financial situation to do so. Other points have been learned in the last ten years:

- Non-utility plants can be integrated into a utility system with a reasonable set of interconnection and dispatchability requirements, although dispatchability can remain a problem in some cases.

- Once on line, non-utility plants can be quite reliable.

- Utilities are getting better at calibrating proposals from non-utility generation companies through better negotiations, more thorough due diligence, and by using monetary incentives such as imposing fees for entering the bidding process and imposing penalties for failure to meet operating requirements.

- It is useful to develop clearly defined requests for non-utility power to allow a good negotiation climate.

- It is preferable to adopt standardized power purchase contracts to facilitate negotiations and project financing.

- Utilities need to balance price and quality factors to arrive at the right avoided cost and reflect possible changes in future capacity conditions.

Overall, the non-utility generation experience in the United States is a unique experience of unmatched magnitude in the world. Yet it did not emerge as the result of a drastic and definite intent to deregulate the US power generation sector, but rather as a long-term simmering spin-off of a law aimed at promoting energy conservation in a marginal way. PURPA, however, did succeed in making the US electric industry more competitive, although this process has been long and tortuous in the minds of several non-utility companies.

Looking back over the US experience, one can conclude that to be successful, an independent power promotion program has to meet three conditions:

- It must be clear in its objectives: what level of diversification or privatization is sought? What type of projects are being preferred? Where should these projects be built and when would be the best time to build them? How can power pricing and Integrated Resource Planning be best implemented to meet both economic and social objectives?

- It must foster a climate of trust between the utilities and the private power developers so that projects do proceed on a timely basis and that precedents can be taken for granted. In addition, the sharing of risks must be defined: for example, who is taking the risk for fuel price changes, environmental permit failures or over building capacity?

- It must be accompanied with the right incentives for utilities to participate fully and help contribute to the objectives set forth by the private power program.

These lessons from the US context have played an integral part in the evaluation of Bulgaria's policy and legal framework, as reviewed in Chapters III, IV, and V.

3) Relevant Case Studies of Independent Power Programs in Transitional and Emerging Economies

Three countries have been selected to profile the development of the independent power policy and institutional framework and the commercial market: Poland, Argentina, and Spain. The experience from these countries in combination with the US experience will provide valuable lessons for developing independent power in Bulgaria.

a) Poland

The power system of Poland had a total capacity of 31,390 MW in 1989, composed of some 400 power plants and generating over 125 billion kWh. Eighty-five percent of total power generation comes from coal-fired power plants. The power sector is comprised of 28 power generation companies, 33 electricity distribution enterprises, 4 lignite mining companies, and a wide variety of equipment manufacturers, maintenance organizations, and engineering firms. It is estimated that about 5,100 MW of capacity will be needed by the year 2000 and an additional 8,000 MW to 12,000 MW by the year 2010, with much of this capacity being in the form of rehabilitation and repowering of existing power plants.

Until 1990, the entire power sector in Poland was state-owned, with the exception of a few small hydro power stations. After beginning the transformation of the Polish political and economic system in 1989, it was decided to privatize the state-owned power companies. In 1990, the Parliament liquidated the Power and Lignite Board and began the process of converting all the power companies into independent joint-stock companies. In addition, a new joint-stock company, PSE-SA, was formed to own and operate the high voltage transmission system and the pumped storage power stations. PSE-SA also dispatches the

power stations, prepares load forecasts, and purchases power from the generating companies. The Polish Government will initially own 100% of all the joint-stock companies. It plans to sell off most of the generation companies, but will always maintain a 51% shareholding in PSE-SA.

The regulation of the power sector is expected to be conducted both at the local and central government levels. The activities of the distribution companies are to be under the jurisdiction of local provincial governments, while the PSE-SA will be under central government control. A national regulatory body is to be established to license generation and distribution companies and set wholesale power rates. The legislation implementing this scheme is still under consideration by the Parliament. More recently, the Polish Government has established new policies for energy pricing in order to improve the efficiency of energy supply and use and to mobilize additional capital for investment.

Substantial efforts are underway to eliminate subsidies in the energy sector. The Polish Government has already reduced the subsidies paid to coal miners and transporters. Similarly, the wholesale prices paid to producers of power and heat are being increased. The first energy pricing study has been completed in order to estimate the long-term tariffs. Ultimately, bulk power prices may be regulated by competitive bidding, even on an hourly basis. There is a major commitment to increase retail electricity and heat rates and to eliminate cross subsidies.

With these reforms underway, the Polish Government has begun implementing a program to encourage private investment in the power sector. Several generating companies have already been transformed into joint-stock companies and are now negotiating with foreign companies that propose to form joint ventures with the joint-stock power companies and invest in the rehabilitation of power plants. The joint-stock companies will contribute the value of their plants and the foreign investors will raise new capital on a project finance basis.

In order to finance independent power projects, it is essential that these joint ventures secure long-term revenue from the sale of power (and steam, if any). Therefore, with the assistance of USAID, PSE-SA has developed a model power purchase agreement to govern its purchase of power from the joint ventures. Several power purchase contracts are in the process of being negotiated with different joint ventures. US AID consultants are also representing district heating companies in their negotiations with the joint ventures and advising various ministries of the Government with respect to government guarantees being requested by foreign investors.

The major issues that have arisen in Poland are the same issues that are likely to arise elsewhere in Eastern Europe. The valuation of the joint stock company's existing assets has proven to be a very difficult problem because the public treasury desires a high valuation and the foreign investors fear a high valuation will undermine the bankability of the projects. As a result, independent experts are usually asked to conduct this valuation.

The uncertainty of the future pricing arrangements throughout the power sector has complicated the process. PSE-SA, for example, does not want to agree to a wholesale power purchase price which is higher than that it can collect from the sale of power to the distribution companies. For their part, the joint ventures do not want to invest time and money in the negotiation of "non-price" terms in the power purchase agreement until the purchase price of power is known.

Similarly, the on-going restructuring of the power sector and the possibility of further changes in the regulatory environment have also created difficulties. The Polish Government naturally seeks to avoid undertaking obligations in the various agreements that may be inconsistent with the subsequently imposed rules, and the joint ventures cannot assess the risks which they confront. For example, there is a concern that more stringent environmental laws may be enacted in the near future. Because compliance with these laws could be costly, the joint ventures have asked for protection against such increased costs. The Polish Government, however, does not know if these laws will be applied retroactively, and, if they are, it is unclear which governmental agency should offer protection. Such problems can be minimized if restructuring is completed and a stable regulatory environment is established early.

Assuming these problems are overcome, there will remain a question concerning the availability of Government guarantees. Because the bankability of independent power projects depend on the revenue stream from one or more Government-owned entities, the joint ventures have closely examined the creditworthiness of these entities. To ensure that they receive payment, the joint ventures have requested that the Government guarantee the obligations of the Government-owned companies. Unfortunately, the Government has limited capacity to guarantee obligations, and it must allocate this limited capacity among many different public purposes. This issue is still unresolved in Poland.

As is evident, the independent power policy and institutional framework in Poland is still in the early stages of development. A variety of independent power developers and equipment vendors from the US and Europe have been negotiating joint ventures with the joint stock companies to develop specific projects. While various joint-ventures and power purchase agreements are in various stages of completion, no independent power project in Poland has been successfully financed to date.

b) Argentina

The Secretariat of Energy regulates the power sector and has owned the major utilities. The Secretariat of Energy (SE) is under the jurisdiction of the Ministry of Economy and Public Works and Services. SE regulates electricity supply throughout most of the country and grants and controls electric concessions through the National Directorates for Coordination and Regulation of Prices and Rates for Electricity Planning. The Federal Board of Electric Energy is an advisory body for SE and is made up of representatives from each of the provinces. Under SE, the Ente Nacional Regulador de la Electricidad (ENRE) is responsible for

establishing the basis for tariff calculations, defining the terms for awarding concessions, and safeguarding public safety, environmental protection, and property rights. The government-owned electric utilities that have operated under the jurisdiction of SE are: Agua y Energia Electrica (AyE) (4,818 MW of both thermal and hydro); Servicios Electricos del Gran Buenos Aires (SEGBA) (2,703 MW entirely thermal); and Hidroelectrica Norpatagonica (HIDRONOR) (2,770 MW entirely hydro). The government is in the process of privatizing the generating assets owned by all three of the above utilities.

The President's Office manages the nuclear capacity while provincial utilities are managed by local governments. The National Atomic Energy Commission (CNEA) oversees the construction and operation of Argentina's 1,018 MW of nuclear capacity involving two power plants located in the Central and Lotral regions of the country. Provincial governments own and operate the provincial companies and cooperatives, which represent a total of 729 MW of capacity. The national grid is extensively interconnected. The national electricity grid Sistema Interconectado Nacional (SIN) is based on a network of 500 kV and 200 kV lines that interconnects 90% of the entire power systems (1990), with only the provinces in the far northeast and the south being separate.

The demand for electricity increased by an average of 4.0%/yr over the period of 1970 and 1990, reaching about 40,481 GWh in 1990. Between 1992 and 2000, electricity demand is expected to grow between 4% and 8% per year, depending on economic growth. Total installed capacity is expected to increase from 11,865 MW to 17,421 MW between 1992 and 2000. Some new nuclear capacity and little new thermal capacity is planned. Major improvements in the poor capacity factor for some thermal power plants is expected. The vast majority of the increased capacity will come from three new hydro complexes. This capacity expansion is expected to call for between $6.8 and $10.2 billion dollars of new investment, not even taking into account the privatization investments in existing capacity.

Argentina has come out of a period of hyperinflation that exceeded 1000%/yr and negative GDP growth of -4.0%/yr or less during the late 1980s; a failed war with Britain over the Falkland Islands; and a transition from military to democratic government. President Carlos Menem and his economy minister, Domingo Cavallo, dramatically revamped and stabilized the economy by 1991 through an ambitious economic restructuring involving anti-inflationary monetary policies; deregulation of commerce and financial markets; successive agreements with the IMF; opening of domestic markets to international competition; and extensive privatization of government-owned corporations.

Argentina's privatization program has completed the sale of the telecommunications (ENTel), airline (Aerolineas), and steel (SOMISA & Altos Hornos) corporations as well as various chemical, television, shipyards, subway, financial, and railway companies. In the energy sector various oil and gas companies and electric power and transmission facilities have been privatized. The decision to privatize most of the government-owned companies is designed to attract badly-needed private capital, reduce the government's public debt, encourage competition, and promote economic and technical efficiency.

The process of demonopolizing the power sector was initiated by the Menem regime, which came to power in 1989. This program is based on various pieces of key legislation: Executive Decree #634, the Proyecto de Ley #15336, the Resolution 38/91, and the new Resolution 61/92. The objective of these laws and regulations are to transfer ownership of government-owned utilities and power projects to the private sector, encourage competition where possible, adjust power prices to reflect actual cost of generation, and protect consumers by regulating the tariffs, power quality, and rate of return earned by power companies.

The pace of privatization has been dramatic. As of the end of 1992, 3,115 MW or about 26% of the installed capacity in 1992 largely owned by the government had been privatized. The government is aggressively pushing its power sector privatization program and would like to complete the entire power sector privatization program before the end of 1993. While this timetable is likely to slip somewhat, the pace is nonetheless dramatic.

The competitive pricing of power is administered by the new entity, CAMME. The Argentine government set up the Compania Administradora del Mercado Mayorista Electrico (CAMME) as an operational company in August, 1992 to perform a range of power plant dispatching and electric tariff coordinating functions for the Wholesale Electric Market (WEM). While ENRE of the Secretariat of Energy performs the tariff regulatory functions, CAMME is charged with the actual implementation of rate setting. Its key responsibilities include determining the spot market prices based on market and regulatory guidelines, supervising and monitoring the electric system, programming the supply of electricity on a daily, weekly, seasonal, and mid term basis, controlling the system of power plant dispatching, distributing the payments between generation and transmission companies, and administering contracts. The Board of Directors of CAMME is composed of representatives from government, generators, transmitters, and major customers, thereby giving most of the key players in the power sector a role in decision-making.

Power pricing is based on separate spot and bulk contract markets. There are two parallel markets for power, the spot and bulk contract market. Large industrial customers have begun to enter into long-term contracts with specific generation companies. The remaining power is supplied on the spot market, where prices are determined by the mean fuel cost of the most expensive unit in operation and the cost and probability of a loss of load at any given time. The economic dispatch priority will tend to favor hydro generation first (when available), then nuclear, and finally fossil generation. In the first few years since its inception in 1992, the spot market will account for a major volume of power flowing between generator and consumer. It is expected, however, that the system will eventually mature to consist mostly of long-term power contracts and that the spot market will be limited to the purchase and sale of contingency service and surplus power, as is developing in the newly privatized power system in the United Kingdom.

Five power projects have been privatized to date. As of the end 1992, seven major power projects have privatized: Puerto (1,009 MW gas and fuel oil), Costanera (1,260 MW gas and fuel oil), Alto Valle (97 MW, gas), Guemes (245 MW, gas), Pedro de Mendoza (67 MW,

gas and diesel oil), Dock Sud (211 MW, gas and diesel oil), and Sorrento (226 MW, gas and fuel oil). All of these project have been thermal plants located in the greater Buenos Aires, Neuquen, Salta, and Sante Fe regions. A total of 3,115 MW or about 26% of the total 11,865 MW installed in 1992 have been privatized. Foreign developers from Europe and the US have made major power investments. Power project bids often required assuming repair and debt liabilities as well as allowing for a small share of employee ownership. The percent of the project sold never exceeded 90%, since 10% was always reserved for the employees. In some cases such as with Puerto, Costanera, and Guemes, the government retained 20% for possible later sale. In addition to the cash investment, developers also sometimes agreed to make investments in repair and assume certain amounts of outstanding debt.

Selection of winning bids has been based on price and qualifications. While the particular terms for each power project sale is confidential, it would be fair to say that the most important criteria for the selection of winning bidders was (a) the technical and managerial capabilities of the bidder to operate the project (so as to qualify for a short list of bidders) and (b) the price offered. In setting the offering price, bidders would naturally have examined the age, efficiency, reliability, and other performance characteristics of each unit as well as the personnel requirements, fuel costs, generation cost, dispatch potential, potential sales price, etc. Interestingly, the bidders came up with a wide range of offering prices. Bids for Puerto ranged from between US $43 and $92 million, for Alto Valle ranged between US $12 and $22 million, for Guemes ranged between US $53 and $87 million. In all cases the highest bid won. These wide spreads in the offering price indicate there were major differences in the bidders' estimated value for these projects.

There are no major constraints to accessing financing. Many investors have quickly responded to the favorable business climate in Argentina. In 1992 alone, over US$ 1.4 billion of direct investment in Argentina's electricity generating and transmission/distribution assets have been made by broad range of international and domestic investor and lender groups. The political and financial risks in Argentina have declined markedly since the unstable periods of the 1980s. Foreign commercial and investment banks such as the Bank of Boston, Citibank, J.P. Morgan, Chase Manhattan, First Boston Group, Paribas, ING, etc. are all players in this rapidly developing power project privatization market. Nonetheless, there is a note of caution. Obtaining long-term debt financing will probably require credit support from government agencies or multilateral development banks. While capital is quickly returning to Argentina, only three to five year terms are currently available; it may be several more years before long-term debt becomes available. Local financial markets are not particularly familiar with non-recourse project financing terms, so presently most investment capital is coming from outside the country.

c) Spain

The power sector in Spain is centrally regulated by the Ministerio de Industria y Energia (MIE). In 1985, the government nationalized the main high-voltage grid, creating Red

Electrica (REDESA) which is 51% controlled by the government. As owner of the main grid, REDESA and the government control the central dispatching system, determining which plants will generate power and when. In theory, dispatching is based on cost of generation and availability criteria, while in practice preference is given to domestic coal fired-plants. All the electric utilities in Spain (both government and privately owned) are members of a central utility industry organization, called the Unidad Electrica, SA (UNESA). While power planning is initiated by each individual utility, considerable coordination is managed by MIE and UNESA. MIE determines the uniform electricity price throughout the country based on a standard cost recovery methodology, regulating revenue transfers between utilities to make up for differences in the cost of generation.

Spain had a total installed capacity in 1990 of 43,490 MW, with 16,103 MW of hydro, 7,363 MW of nuclear, 9,362 MW of domestic coal, 1,314 MW of imported coal, 6, 574 MW of oil, 1,320 MW of gas, and 1,454 MW of self-generation. The Spanish power sector was originally composed of a relatively dispersed group of some 21 largely privately-owned companies that generated and distributed power in respective territories. Since 1985, a consolidation began with a government-sponsored asset swap, where some of the financially strong utilities acquired assets in the weaker companies. In the past two years, this consolidation has accelerated when most independent utilities were subsumed by Empresa Nacional de Electricidad (ENDESA) or the Iberdrola group through mergers, takeovers, and share acquisitions. The 100% government-owned Instituto Nacional de Industria (INI) owns 75% of ENDESA (with the remainder being publicly traded). Proposals that the government sell off more of its share in ENDESA to reduce the national debt are unlikely to take place and certainly would not lead to the government reducing its ownership share below 51%. Iberdrola, on the other hand, is an investor-owned consortium (involving the merger of Iberduero and Hidroelectrica Espanola). Two smaller independent power companies also remain, Union Fenosa (UEFSA) and Hidroelectrica del Cantabrico. In terms of 1991 installed capacity, ENDESA has 43.8%, Iberdrola has 36.4%, UEFSA has 11.9%, and Hid. del Cantabrico has 3.4%.

The primary motivation for the above-mentioned consolidation has been to make the Spanish power sector more financially viable and competitive in the unified European market. With the EEC's new policies regarding Third Party Access (TPA) and a general opening of the power markets to greater competition, the Spanish power sector recognizes that it needs to consolidate into larger companies to compete against the large mostly government-owned utilities on the continent.

Between 1991 and 2000, the National Energy Plan calls for the addition of 8,377 MW. Total installed capacity in 1990 was 43,490 MW and the expected installed capacity in 2000 will be 51,450 MW. This expansion plan assumes an annual growth in power demand (adjusted for the energy program) of 4.03% between 1990 and 2000, with the major increase being in the transport, residential, and commercial sectors. This growth in demand and capacity expansion is regarded by some to be optimistic, given the slowdown that has been taking place in the Spanish economy (real GDP growth has declined from 5.2%/yr in 1988 to an estimated

1.7%/yr in 1992). This expansion plan expects there to be a substantial increase in the relative share played by gas-fired and self generation and a decline the relative role for nuclear and oil.

National policy on the development of private power has only focused on promoting hydroelectric power and industrial cogeneration. The government has not encouraged or even permitted private development of independent thermal power plants. Between 1982 and 1988 various laws and regulations have been passed that actively promote industrial cogeneration. A national law has been established that gives cogenerators the right to sell power back to the grid if the cogeneration facility exceeds a combined electricity and thermal heat rate of 5700 kJ/kWh or an efficiency of about 63%. The law establishes a simple equation for calculating the buy-back rate at between 85% and 95% of the industrial rate, depending on whether firm capacity is guaranteed or not.

About 2,450 MW of industrial cogeneration expansion is anticipated between 1990 and 2000. The rapid expansion of cogeneration is due to: (a) an ambitious new policy to promote industrial cogeneration, (b) high industrial tariffs , and (c) limited installed cogeneration capacity to date in Spain (i.e. only about 3% of total electricity production versus about 15% in most industrialized countries).

Prior to 1986, only 750 MW of cogeneration capacity was installed in Spain. Very few of these projects are selling electricity back to the grid. Between 1986 and 1992, there have been 85 new industrial cogeneration projects with a total capacity of 871 MW installed, more than doubling the capacity in as little as six years. Seventy five percent of these projects have a capacity of less than 10 MW while only 3 projects or 4% of all projects have a capacity in the range of 50 to 80 MW. A substantial number of these new projects have involved incremental sales of electricity to the grid. Of the 871 MW installed between 1986 and 1992, 54 projects or 63.5% of all projects involve simple gas turbines with 16.5% involving combined cycle systems, and 13% steam turbines. This trend is a reflection of the overall trend in Europe and Spain towards using gas to reduce environmental emissions and to capitalize on the low costs and high efficiencies of new combustion technology.

Unlike its neighbor, Portugal, where large scale BOT power projects have been tendered, the Spanish government and electric utilities have traditionally been opposed to opening the market to major independent power projects. With the government owning a majority of the power sector and there being entrenched political and economic interests, the general assumption has been that the IPP market is unlikely to develop any time soon. A recent announcement, however, by the Secretary of Energy, Ramon Perez Simarro, has shed more light on the Ministry of Industry and Energy's (MIE) plan to submit an ambitious new law to the parliament that would call for an opening of the power sector to bulk independent power generation. Secretary Perez Simarro proposes in the new electric power law to maintain the existing central power planning system, to separate generation from transmission and distribution (T&D) in a way that maintains the government monopoly control over the main transmission and dispatching network, and introduce greater competition in the

generation sector by allowing independent bulk power generators to undercut the electricity tariffs established by the MIE. If independent producers can profitably sell power at prices lower than the established tariff, the Secretary Ramon Perez would like to give them the right to access the grid.

The European Commissions proposal for Third Party Access (TPA) is a key component of the European government's plan to open the market to competition. Strong opposition to the European Commission's TPA proposal has been mounted by the continental members of Eurelectric (the European electric power industry association). The major case against TPA forcefully argued by Eurelectric is that free competition will threaten the reliable supply of power, could lead to greater volatility in electricity prices, would require a wide array of burdensome new regulations, and could possibly compromise efforts to reduce the environmental impact of power generation. While it is acknowledged that competitive power markets could lead to lower prices in the near-term for large (e.g. industrial) customers, opponents charge that a free power market would raise electricity prices for small (e.g. residential) customers (as has occurred in the United Kingdom). Opponents try to cast the independent power experience in the United States and the United Kingdom in a negative light, citing these markets as not being examples worth emulating.

The free market proposal in this pending new Spanish electricity legislation will need to pass parliament and could face stiff opposition. In the Spanish market, the government-owned ENDESA and other elements of the government are opposed to opening the market to bulk independent power generation. On the other hand, the privately-owned Iberdrola supports an opening of the market; they see free competition as in their best interest since the current rate-setting and dispatching system is regarded as favoring ENDESA. The submission of the new electricity law has been delayed for many months, it is unclear whether the law will be submitted and voted on before the general election the government must call before October, 1993. Even if the law is largely accepted, it is unlikely that the market will result in the open competition found in the United Kingdom or lead to truly competitive large tenders.

The Spanish economy, the eighth largest of the industrialized countries, experienced real GDP growth of 5.2%, 4.8%, 3.6%, and 2.4% from 1988 to 1991, respectively. This growth was approximately 1% higher than the average economic growth in the European Community. In 1992 the estimated growth rate is lower, but still a positive 1.7%. Moderating growth in 1992 and in the future reflects weaker international conditions as well as specific Spanish monetary policies. There are no appreciable shortages or barriers to raising capital for projects with an attractive return on investment, due to a favorable investment climate and continued strong economic growth (GDP growth: estimated at 1.7%/yr for 1992). While short-term prime lending rates were in the 16% range in 1990 (due to efforts to restrain an economy and credit supply that has been expanding too rapidly) these rates have been declining to reaching 13.8 in 1992.

Given the high electricity prices in Spain (e.g. 1989 industrial rate for 10 MW, 50 GWh/yr load is 8.7 Pesetas/kWh or ~ 9.3 cents/kWh), returns on investment in cogeneration projects are very attractive. The government cogeneration development company, IDAE, has estimated internal rates of return between 20% and 65% for cogeneration projects and has been aggressively developing projects to capitalize on these attractive opportunities. The major utility groups, ENDESA and Iberdrola, are both expanding into the cogeneration business as well.

4) Structure and Sources of Independent Power Financing

Privately financed IPPs typically are structured as separate project companies that raise their capital on a non-recourse project financing basis. This method serves to mobilize private capital more effectively by limiting the liabilities of the project owners. In the event of default or bankruptcy, the lenders or investors have little or no right to the assets of the owners of the company; the only collateral they have is in the assets of the specific project company. For this reason, the financing of independent power involves carefully defining and structuring a project so as to properly manage and minimize its risk of failure. With an effectively defined and structured power project, it is possible to attract the investors that would be willing to accept the risk and reward profile of their particular investment.

a) Independent Power Ownership and Financial Structures

The structure of a non-recourse financed independent power project is shown in Figure 2. According to this widely-applied model, a developer would establish a project company in Bulgaria dedicated to the financing, construction or repowering, and operation of a specific power project. The sources of financing would be from senior and subordinated debt and from equity in the form of preferred and common stock (as discussed below). In the international market, various types of loan guarantees and risk insurance are often required by lenders and investors.

As shown in Figure 2, this project company would enter into a clearly-defined power purchase contract with NEK that spells out NEK's power purchase rate over a period of approximately 20 to 25 years. Power purchase rate, fuel price, inflation adjustments, terms for penalties or bonuses, etc. would be specific elements of this contract. Given NEK's limited creditworthiness at the present time, it is highly likely the developer would seek specific Bulgarian government guarantees of NEK's financial commitments to pay under this power purchase agreement. The power purchase contract and guarantees are part of a carefully structured security package (with the government, lenders, fuel suppliers, plant operators, contractors, etc), as shown in Figure 3. The developer would need to obtain these agreements to reduce and distribute the project's risk so that financing can be obtained. [See Chapter V, Recommendation 6]

Private Power Project Financing

For a Build, Operate and Transfer (BOT) Power Project

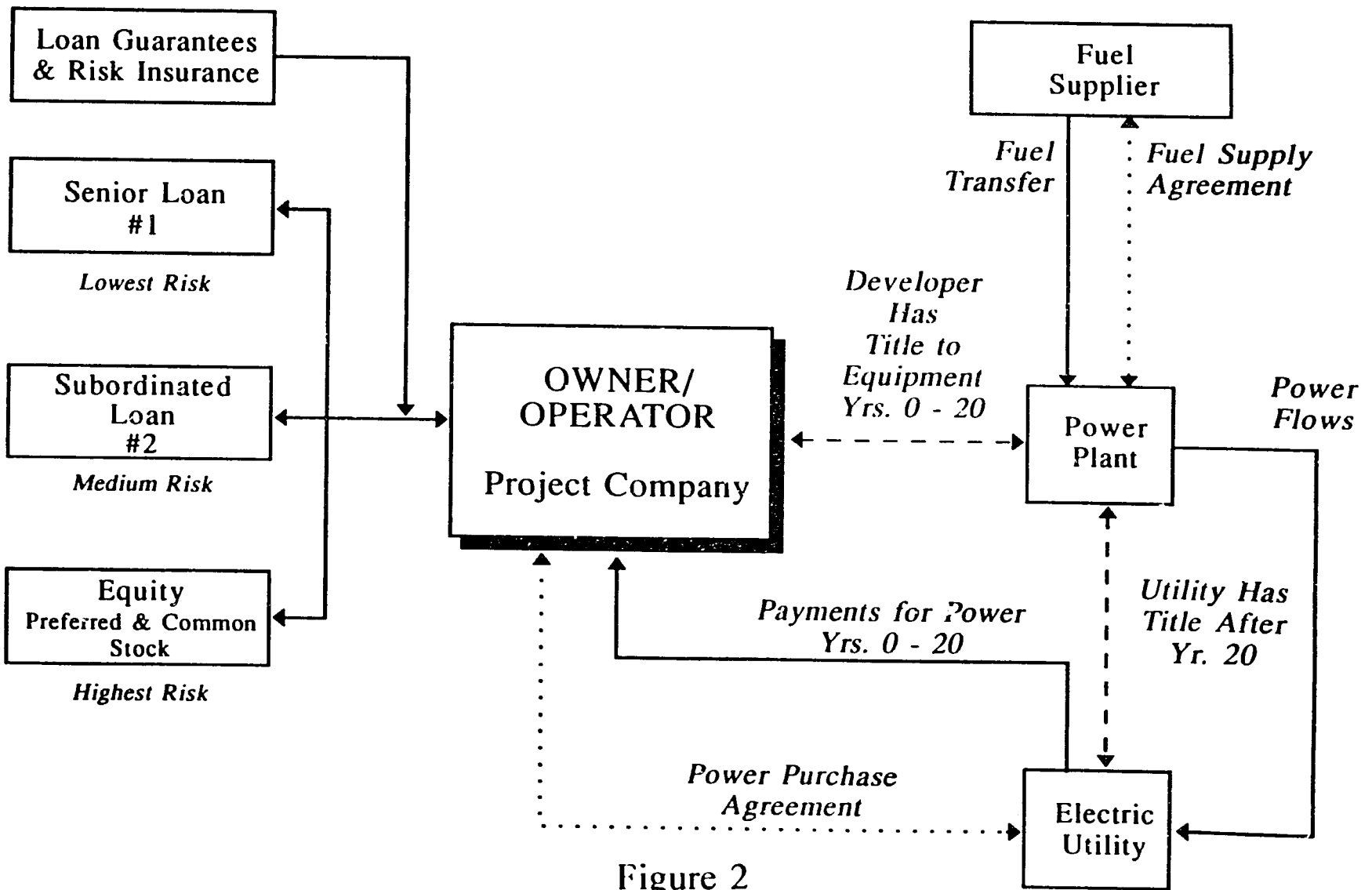


Figure 2

Security Package for a Private Power Project

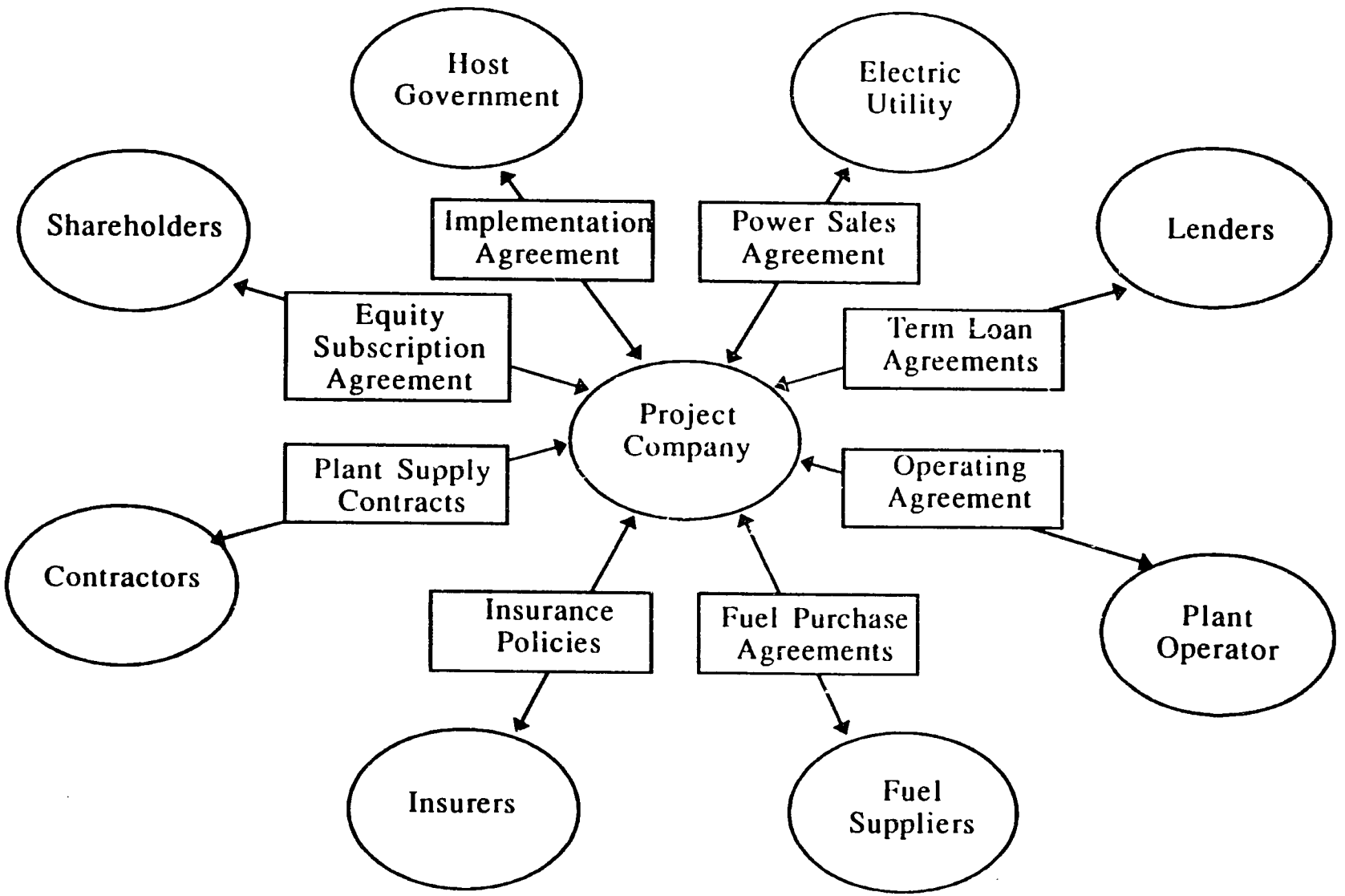


Figure 3

91.e

The long-term ownership structure of international independent power projects has been based on different models commonly called BOO, BOT, and BLT.

* Build, Own, and Operate (BOO): The private developer finances, builds, owns, and operates the project for the entire serviceable life of the power plant without ever transferring ownership to the utility.

* Build, Own, Operate, and Transfer (BOOT or BOT): The private developer finances, builds, owns, and operates the power project for a prescribed term of about 20 years. After this period in which the debt has been serviced and the equity investors have earned their return, the ownership of the project is transferred from the private developer to the electric utility.

* Build, Lease, and Transfer (BLT): The project developer finances and builds the project and then leases it to the utility in exchange for an agreed upon rent or lease payment. Leasing is particularly favored in those countries which have constitutional restrictions on private ownership of a power plant.

The most common models being applied to independent power projects in emerging and transitional economies is the BOO and BOT framework.

b) Sources of Financing

With thorough analysis of a good power project and a favorable power purchase contract and other agreements in hand, the developer should be able to raise capital necessary to finance the project. The two sources of capital for financing any project are equity and debt capital:

* Equity Capital: Internationally, equity investors typically supply about 20% to 30% of the project investment requirements. The equity investor takes on a major portion of the project's risk because his return on investment over the life of the project is a function of the project's financial performance.

* Debt Capital: Debt capital is supplied by a bank through a loan or from the sale of bonds and typically supplies about 70% to 80% of the project's capital requirements. The debt investors take less risk because they have first rights to any liquidated collateral in the event of project failure. For their lower risk exposure, debt investors are offered only a lower fixed return over a typical 10 to 20 year term.

The scrutiny a proposed power project receives in raising the equity and debt financing is the most critical phase in the development of an IPP. There typically are two stages of financing a power project: construction and operation. Construction financing covers the one to four years typically required to complete the construction of a conventional thermal or

hydro power plant. During this phase the project is not earning a return, since it is not selling any power. A turn-key construction contractor is typically required to take on the construction risk and commit to completing the project on a fixed price basis. Once the power project has been commissioned, the operation phase of the project is financed over a period of 10 to 20 years. At this stage, the owner and operator of the project assume the operation risk and are earning the revenues needed to service the debt and pay a return to the equity investors.

One of the major hurdles of successfully financing an independent power project is satisfying the requirements of the lenders. The ratio of debt to equity varies based on the risk in a particular market. During the highly favorable US independent power market conditions of the 1980s, some projects were financed with 100% debt. Today in the US market, at least 10% equity is required, with 20% being common. In the riskier markets of the developing and transitional economies, equity requirements of 20% to 30% can be expected. In these riskier markets, developers will require higher returns on equity than is currently earned in the US. Given that lenders are supplying between 70% to 80% of the financing, they will subject any project to very close scrutiny before agreeing to lend.

Given the size and complexity of many independent power projects, financing often involves the syndication of debt from multiple sources. For sizeable power projects, it is not uncommon for various multilateral, bilateral, and commercial financial institutions to syndicate their debt financing into a carefully structured package. While these arrangements serve to diversify the risk across multiple institutions and leverage each bank's limited resources, the process of structuring the financing can be significantly delayed. As it is often said, "time is money." If the process of negotiating a project and raising financing is unduly burdensome, the ability to successfully implement projects will be constrained. Many of the policy and institutional recommendations raised in Chapter V of this report will facilitate independent power by reducing real and perceived risks and procedural delays in raising financing.

The main question is what sources of capital would be interested in investing in a Bulgarian IPP. Two major risk factors are typically considered: country risk and project risk. Country risk typically involves such political risks as war, insurrection, expropriation of assets, inconvertibility of currency, and exchange rate volatility. Project risk typically involves construction cost overruns or delays, poor power plant performance, non-compliance with power purchase or fuel supply contract, etc. With the necessary legal contracts, project risk is usually considered manageable by a developer. Country risk, on the other hand, represents a danger of failure that the investor has much greater difficulty controlling. Country risk ranking services such as Euromoney and Institutional Investor grade most of the countries worldwide according to a range of economic and financial indicators. For instance, Euromoney uses 9 criteria that include economic data, political risk indicators, debt indicators, access to bank finance, access to short-term finance, access to international bond and syndicated loan markets, access to and discount on forfeiting, credit ratings, and debt in default. For instance, Bulgaria had a listing of 118 out of 169 countries in the March 1993

edition of Euromoney. This rating reinforces the earlier conclusion that Bulgaria's credit risk would be regarded as unacceptable for most commercial banks at this time.

In emerging and transitional economies, the primary source of debt and some equity capital is from the multilateral and bilateral institutions. Commercial banks are often very hesitant to take on the risk in these markets without a major involvement of the multilateral and bilateral institutions. The International Finance Corporation (IFC) (which is part of the World Bank Group) and the European Bank for Reconstruction and Development (EBRD) are two key contenders for providing debt financing for independent power projects in Bulgaria. Bilateral institutions such as the Export Import Banks of such countries as the US and Japan have been involved in financing independent power projects. Political risk insurance (against expropriation, insurrection, and inconvertibility) and loan guarantees are typically sought from bilateral agencies, such as the US Overseas Private Investment Corporation (OPIC) and the US Export-Import Bank (EX-IM). Foreign and domestic commercial banks are likely to play only a small role in the early independent power projects in Bulgaria, particularly with current Bulgarian interest rates (greater than 60%) and short terms (less than one year).

To illustrate how independent power projects are financed, it would be worth providing an example. Given the rapidly growing demand for power and the major financial constraints, Asia in general and the Philippines in particular has been the site for some of the first major IPPs. A newly-financed project of particular note is the 700 MW coal-fired Pagbilao power project in the Quezon Province of the Philippines. This project is jointly being developed by Hopewell Holdings of Hong Kong (an infrastructure project developer), Mitsubishi Corp of Japan (a power equipment vendor), and Black & Veatch International of the US (an engineering construction company). This project is being built under a 25 year Build, Operate, and Transfer (BOT) agreement with the Philippine National Power Corporation (NPC). The NPC agrees to buy power from the developer under a take-or-pay power purchase agreement, with NPC also supplying all the fuel (coal) for the project.

The financing of the Pagbilao power project is of particular interest. The total project cost is $888 million, with about 75% being financed from debt sources and 25% equity. $535 million of the debt financing is being jointly supplied by the Export Import Banks of the US and Japan. This project could be a trend setter in that it is the first time the US and Japanese export credit agencies have jointly-financed a major project. The remaining debt is being furnished by the International Finance Corporation (IFC), the Asian Development Bank (ADB), and the Commonwealth Development Corporation (CDC). The project developer, Hopewell is supplying $200 million or 77% of the equity financing, with the IFC, ADB, and CDC also providing some equity.

As will be the case in Bulgaria, multilateral and bilateral sources of financing played an important role in the Pagbilao power project development. While developers and equipment suppliers are willing to put their capital at risk, commercial banks will likely be slow

to participate in the early stages of an independent power market in emerging or transitional economies.

5) Independent Power Lessons Applicable to Bulgaria

a) Benefits of Independent Power

The policy motivation behind promoting independent power in different countries can vary significantly. In developed countries, the objective has typically been to promote competition, efficiency, and the integration of a more diverse array of generation technologies and fuels. In developing and transitional economies, the goal has included the above objectives but has been primarily to attract private capital into a financially constrained power sector. The benefits of independent power to Bulgaria are at least fourfold.

i) Access to Private Capital. The attraction of both foreign and domestic private capital will increase investments in Bulgaria and reduce the debt burden of the NEK. By integrating Bulgaria's power sector into the international capital markets, the ability of NEK to modernize and meet its expansion plans will be enhanced.

ii) Transfer of Optimal Technologies. With the infusion of foreign investment will come the application of state-of-the art technologies that will enable the Bulgarian electric company (NEK) to improve the quality of service and operate in a more efficient and environmentally-sound manner. In addition, with private investments will come improved business management and accounting practices and expanded training and development of Bulgarian workers.

iii) Expanded use of Renewable Energy and Cogeneration. An independent power policy framework will induce private companies and industry to cost-effectively expand Bulgaria's indigenous renewable energy and cogeneration capacity in a way that could reduce Bulgaria's dependence on imported energy and hard currency requirements. These facilities could provide electricity at a price that is below NEK's avoided costs and would offer environmental benefits.

iv) Competition Leading to Minimized Costs. The competition fostered by independent power not only induces private developers to generate power at competitive costs but also provides important benchmarks for the NEK in determining the costs of new generation capacity.

The effective restructuring of the Bulgarian power sector from central planning and subsidies to market economics and financial viability will be greatly facilitated by the above benefits.

b) Essential Independent Power Policy and Institutional Conditions

The transmission of electric power represents a naturally-monopolistic market that must be subject to government regulation to prevent a utility from earning excessive monopoly profits. The policy and regulatory framework defined by the government and the electric utility are critical factors in establishing the price of electric power and therefore the return on investment in power projects. Independent power developers and investors therefore examine the policy, institutional, and regulatory framework before making investments in a particular country's power sector. On a contractual basis, individual projects can be developed without the entire policy and institutional framework being in place. Nonetheless, in order to develop a mature and competitive independent power industry with a diverse array of participants, this framework will be essential.

In the increasingly global marketplace, countries must compete against each other to attract the necessary capital and power project development capability. The independent power policy and institutional framework of Bulgaria relative to other countries worldwide will play a critical role in determining the success of Bulgaria's independent power program. The key lessons learned from the experience in other countries in general and the specific case studies described above point to three important independent power policy conditions.

- **Fair Process:** The process of selecting specific developers and projects needs to be as fair and transparent as possible. The developer and investors should be given a clear idea of who the key decision makers are and what specific requirements must be met. If the process is overly confused or political, it is unlikely that NEK will attract the kind of quality developers and investors it wants.

- **Fair Price:** The power purchase price offered by the utility needs to be fair and reflect the market price for generation. Unlike a government-owned utility, an independent developer cannot subsidize or reallocate costs of generating power. Without a fair market rate for the power, the independent generator will not be able to earn the revenues needed to service its debt and earn the required return to its investors.

- **Fair Terms:** The terms of the power purchase contract and other agreements need to incorporate certain other key elements necessary to reduce risks that the investors or lenders are unable or unprepared to take. The contract term needs to be of sufficient length (typically 20 - 25 years for a thermal project, and longer for a hydro project) in order to enable the project owner to service its debt. The structure of the buy-back rate and the energy and capacity commitments need to be spelled out clearly. The developer needs to be given appropriate guarantees that the government and utility will honor all its contractual and incentive commitments.

These three points summarize the essential elements of an effective independent power policy and institutional framework. These issues will be addressed in greater detailed and applied to the Bulgarian context in Chapters IV and V.

III. INDEPENDENT POWER MARKET POTENTIAL IN BULGARIA

1) Status of Bulgaria's Economy

a) Macro-Economic Conditions

During the communist era between World War II and the fall of the Soviet Union in 1989, Bulgaria made a major transition from an agricultural to an industrial economy. This economy, however, was largely dependent on subsidized energy from, and on markets in, the former Soviet Union (FSU). The collapse of the old communist order and the Council of Mutual Economic Assistance (CMEA) has hit Bulgaria with a double crisis. As energy prices quickly approached world market levels, Bulgaria's highly-inefficient economy has been hit with a dramatic increase in energy-related costs. At the same time, the markets for Bulgaria's traditional products have dropped precipitously, as the economies of the FSU and the Eastern Bloc have experienced economic decline. Bulgaria has been forced to follow the pattern throughout much of the Eastern Bloc, i.e. a dramatic decline in GDP. In 1990, Bulgaria's GDP declined 11.3% and in 1991, GDP declined a further 22.9%. These GDP figures, however, should be used with caution. The true size of Bulgaria's GDP is in question; estimates are that some 20% - 40% of total economic output is in the informal sector, and thus is not officially recorded.

According to US Department of Commerce statistics, inflation was around 50% in 1990 declining to around 35% in 1991, only to rebound to an estimated 65% in 1992. According to the EBRD, it is estimated that inflation will increase to between 80% and 120% in 1993. A large part of this inflation, however, is due to price increases mandated by the government to reduce or eliminate subsidies. This type of inflation is regarded as temporary and should result in a subsequent decline in inflation. Given the high inflation rates, commercial banks are only lending over short terms not to exceed one year and at high interest rates of over 60%.

A distortion exists in the freely floating Bulgarian leva exchange rate. Despite strong inflation, the leva has not devalued appreciably. Between 1991 and 1993, the leva has only depreciated from around 18 levas/US$ to around 25 levas/US$, despite annual inflation of between 35% and 80% during this same period. This distortion in the exchange rate is in part attributed to a low demand for dollars resulting from Bulgaria's economic downturn, the lack of disposable income on the part of many Bulgarians, and the high Bulgarian interest rates. Under these current conditions, foreign companies have had no problem repatriating profits or revenues in hard currency. When the economy turns around, however, a significant correction in the exchange rate could occur.

Bulgaria's foreign debt had doubled between 1985 to 1990, reaching about US$ 11 billion in 1991. Over 80% of this foreign debt is owed to commercial banks. Bulgaria has successfully renegotiated its sovereign debt with the Paris Club, but remains at an impasse regarding its commercial debt with the London Club (primarily to banks from European

countries such as Austria, Germany, etc. and with only a small US bank component). Bulgaria's commercial debt is currently trading at around $0.18 to the US dollar. To date, a major impasse exists between the debt price the commercial banks want and what the Government of Bulgaria is willing to agree to. In the absence of a resolution of these debt negotiations, commercial banks will be very reticent to lend beyond the usual short-term trade financing.

The major multilateral lending institutions are active in Bulgaria. As part of a radical and comprehensive reform program launched by the coalition government in 1991, the IMF provided a US$ 279 million Stand-by Arrangement for an external contingency mechanism to maintain crude oil and natural gas prices. Also in 1991, the World Bank agreed to a US$ 250 million Structural Adjustment Loan (SAL) and a Technical Assistance Loan of US$ 17 million. Total IMF and G-24 financial support in 1991 was about US$ 1.6 billion. The IMF is negotiating with the Government of Bulgaria on further assistance that will help it in its negotiations with the London Club on the commercial debt. The IMF is pushing the GOB to keep the inflation rate below 50% - 60% and the GDP decline below 5%, which is well below the 80% - 120% inflation and 10% to 15% GDP decline expected for 1993.

In April 1993, the Bulgarian Cabinet approved a three year investment program totaling 93,499 million leva (approximately US$ 3.6 billion) between 1993 and 1995. Approximately 60% (59,106 million leva) of this budget will come from external sources, with the World Bank, EBRD, and European Investment Bank making substantial commitments. This program has identified 49 priority projects in bridges, water supply, rail transport, health care, environmental protection, electric power engineering, etc.

b) Overall Business Climate

Over the past two years, the difficulties of converting an inefficient industry based on former communist block markets to markets in the West, the ensuing decline in Bulgaria's GDP, the high inflation and interest rates, the unresolved commercial bank debt negotiations, and the very limited and short term commercial lending clearly pose formidable barriers to investment. The general recession in the world economy and the Gulf and Yugoslavian wars have also particularly hurt Bulgaria's prospects for a quicker transition to a market economy.

While the current business investment climate is facing difficulties, Bulgaria has very attractive prospects in the future. Bulgaria has enacted laws that establish far reaching rights for private investors, including 100% foreign ownership, national treatment of foreign firms, and repatriation of profits (these laws are discussed in greater detail in Chapter IV). Bulgaria is endowed with a strategic trading position on the Balkan Peninsula, a well educated and skilled work force, certain elements of a good infrastructure, rich agricultural land, and attractive tourist resorts in the mountains and along the Black Sea.

Like most Eastern European countries, Bulgaria has embarked on a privatization program. The Privatization Agency has been established with a staff dedicated to identifying and packaging the most attractive companies for public sale. The focus of this privatization program has been on those light manufacturing and agricultural industries (e.g. food processing, electronics, textile, etc.) that are potential export businesses which would earn the foreign exchange needed by foreign investors. As is true throughout Eastern Europe, the progress in privatizing companies is proceeding more slowly than hoped. Nonetheless, the first recent privatization of a "maize" (corn chip) products company, Tsarevichni Produkti, was sold to the Belgian company G.R. Amylum N.V. (80%), the United Bank of Bulgaria (18%), and company employees (1%) for US$ 45 million. This first privatization is seen as a promising development that hopefully will set a trend. The Privatization Agency expressed a particular interest in expanding industrial cogeneration at specific steam requiring industries being privatized. It has been reported that this maize company just privatized in fact has a cogeneration plant that the new owners do not want to use and which they would be willing to sell to an independent developer.

2) Overview of Bulgaria's Power and Energy Sector

a) Existing Energy Resources

Bulgaria is endowed with limited energy resources and has typically had to import about 80% of its total energy needs. The country has only a very limited amount of oil, significant reserves of low grade brown coal, and some hydro resources.

Reserves of oil and gas have been declining and are currently at an estimated 3 million tonnes of oil equivalent, which would provide only about 3 months coverage at Bulgaria's current consumption levels. Exploration for oil around the Black Sea coast holds some hope of expanding these reserves.

Coal reserves at currently active coal mines are at about 2.6 billion tonnes, with lignite accounting for about 90% and sub-bituminous and bituminous coal comprising about 10%. The bituminous coal is dispersed and generally uneconomic to extract. The lignite reserves, on the other hand, are mostly concentrated at Maritsa East (southeastern Bulgaria). These reserves are found in relatively favorable mining conditions: easily accessible terrain, low overburden to lignite ratio, thick seams, and no groundwater problems. These lignite reserves are sufficient to meet the fuel requirements of 2,300 MW of power generating capacity at three power plants (Maritsa East 1 - 3) and a briquette factory for about another 75 years. This lignite, however, is of poor quality with a heating value of 1,500 kcal/kg and 2% sulfur. The Bobov Dol 630 MW power plant is located at an indigenous brown coal mine south of Sofia. Imported black coal from the Ukraine currently supplies the Varna (1,260 MW) and Russe (400 MW) power plants, with other sources being explored.

There are significant hydropower resources that remain to be exploited. With 1970 MW of current installed hydro capacity, Energoproekt estimates that this represents only about 33% of the total exploitable resource. It is estimated that about 2,800 MW of economically exploitable capacity remain to be developed at various micro, mini, and large hydro sites. As is typical with hydro, this capacity experiences seasonal fluctuations due to rainfall and has limited dispatchability. Nonetheless, the availability of precipitation is heaviest during the NEK's highest winter power demand period.

Oil, gas, and coal prices were heavily subsidized during the old communist era. While these subsidies have been reduced substantially, particularly for oil, some level of subsidy still exists. The World Bank in its 1992 Energy Strategy Study points out that the price for the most economic Maritsa East coal is $0.6/GJ, while the real cost of production is about $1.1/GJ. On the other hand, the cost of imported natural gas from Russia is considered to be higher than the world market price. The World Bank points out that Bulgargaz was paying US$104 per thousand cubic meters for gas from Russia in 1991, when the world price was closer to $90 - $95 / 1000m3. This distortion is attributed to a non-cost based mechanism for pricing gas that is vulnerable to fluctuations in index prices based on fuel oil and the dollar/leva exchange rate. The World Bank views these continuing distortions and subsidies in energy prices as not sending the right price signals in the Bulgarian energy sector.

b) Existing Power Capacity

The Natsionalna Elektricheska Kompania (NEK) is responsible for generating, transmitting, and distributing electricity to the entire country of Bulgaria. The Committee of Energy (COE) is the Bulgarian government committee which overseas NEK, the district heating companies, and the coal mining sector. Although the NEK is still wholly-owned by the government, efforts are being made to make it a profitable, financially independent organization that could be privatized in the future.

NEK provides electric power from a diverse fuel mix that in 1991 included 3,760 MW of nuclear power, 2,440 MW of indigenous lignite power, 1,970 MW of hydropower, 1,560 MW of imported coal power, and 630 MW of indigenous brown coal capacity. A listing of the name, size, and fuel of the major power plants is found in Table 1. Of the total installed electric generating capacity in Bulgaria, 86.6% is owned by NEK (10,460 MW); 4.8% by independent, limited liability district heating companies (1045 MW); and 8.6% by industry (577 MW). In all, a substantial proportion of NEK's generating capacity (over 13%) is provided by independent power producers (IPP's).

While NEK has 12,074 MW of total installed capacity at its disposal, over the last several years it has had difficulty meeting a system peak load of 7,200 MW. Most thermal plants are aging and poorly maintained, resulting in production at only 60 - 80% of their design output. Coal supplies from the former Soviet Union have been unreliable, as have been supplies from Bulgaria's own coal mines. Safety problems at the Kozloduy nuclear plant have

NEK INSTALLED AND OPERATIONAL POWER CAPACITY 1992			
Thermal Plants	**Fuel**	**Operational Capacity (MW)**	**Installed Capacity (MW)**
Maritsa East I	lignite	172	200
Maritsa East II	lignite	1,080	1,230
Maritsa East III	lignite	780	840
Varna	imported coal and gas	1,260	1,260
Bobov Dol	brown coal	570	630
Russe	imported coal	310	400
Total Thermal Plants		4,172	4,560
Kozloduy Nuclear Plant		1,811	3,760
Hydropower		1,600	1,970
Total Capacity		7,583	10,290

SOURCE : NEK, 1993

Table 1

required the shutdown of two units so that new safety equipment can be installed. And finally, production from hydro plants has been affected by a period of dry weather. In 1992, a total of 38.24 TWh was generated. NEK generated 30.88 TWh. District heating plants and industrial generators produced 4.66 TWh and the remainder, 2.70 TWh, was imported from other countries.

c) District Heating and Industrial Cogeneration

Most major cities and towns in Bulgaria have well-developed district heating systems. These systems provide steam and hot water to industries and households. Like the power plants, many of the systems are old, poorly maintained and have inefficient boilers and distribution systems. Boilers in the larger systems run on natural gas, fuel oil or coal and associated generators provide electricity to the grid under contracts with NEK. A summary list of the 10 major district heating plants that have power generation facilities is found in Table 2.

Likewise, there are some 9 major industrial cogenerators with a capacity greater than 10 MW, as shown in Table 3. These include large petroleum and petrochemical plants, two chemical plants, a metallurgical plant, a tire and fabric plant, and a fertilizer plant. Fuels for these cogeneration plants include gas, coal, and fuel oil. These cogeneration facilities primarily produce steam for the thermal loads of the factories and generate power as a byproduct for reducing part or all of the power demand from NEK. Some of these cogenerators sell surplus electricity back to the grid.

A visit to two of the cogenerators (i.e. the Kremikovtzi steel mill and the Chimco Vratsa chemical plant) revealed that some cogenerators only meet part of the captive electricity needs with no sales to the grid. Kremikovtzi is able to generate power cheaper than NEK due to the availability of low cost gas byproducts from steel production. Expanding cogeneration to generate excess power for sales to the grid was deemed presently uneconomic at Kremikovtzi, since it would require supplementing the limited by-product gas supplies with high-priced imported gas. At Chimco Vratsa the economics of cogeneration just to meet captive needs is barely viable given the high natural gas prices, possible generation inefficiencies, and the relatively low NEK tariffs. Nonetheless, NEK indicated that some of the cogenerators are delivering surplus power to the grid. These cogenerators include Burgas, Devnia, Svishtov, NHK Pleven, and Vidin.

The current power sales terms between NEK and industrial or district heating cogenerators are not sufficiently attractive to induce investments in new cogeneration capacity. The power purchase contracts are for no longer than one year and offer prices below NEK's full cost of generation (these contract terms are discussed in greater detail in Chapter IV). Under these one year contracts, the district heating or industrial cogenerators are not obliged contractually to meet availability or reliability criteria or to generate minimum levels of

BULGARIAN DISTRICT HEATING PLANTS WITH ELECTRIC POWER GENERATING CAPACITY	
Town	**Installed Capacity (MW)**
Sofia	95
Plovdiv	65
Russe West	3
Pleven	24
Shumen	12
Traicho Kostov	132
Sliven	22
Kazanlak	10
Gabrovo	12
Republika	88
TOTAL	463

SOURCE : COMMITTEE OF ENERGY, 1992

Table 2

MAJOR INDUSTRIAL COGENERATION PLANTS IN BULGARIA - 1991

No.	Name of Power Plant	Fuel (MW)	Installed Capacity (MW)	Maximum Available Capacity (MW)	Annual Electricity Output (GWh)	Annual Heat Output (Tcal)	Annual Fuel Consumption Thous.tce
1	NHK - Burgas	residual, natural gas	257	160	949	3046	568 119
2	Devnia	imp.coal, residual	219	100	634	3200	207 18
3	Swishtov	imp.coal	120	60	498	435	250
4	Kremi-kovtzi	natural gas	112	80	527	795	282
5	NHK - Pleven	residual, natural gas	60	45	291	1194	127 50
6	Vidin	imp.coal	60	50	273	567	283
7	Vratza	natural gas	60	40	200	1258	198
8	Stara Zagora	lignite, natural gas	48	32	52	835	67 84
9	St.Kara-zhiev	residual	26	10	43	703	92

SOURCE : NEK, 1992

Table 3

energy. Under these conditions, these facilities could not be regarded as firm capacity that is dispatchable by NEK and thus could not expect payments for capacity delivered.

d) Expected Needs for Electricity and Capacity

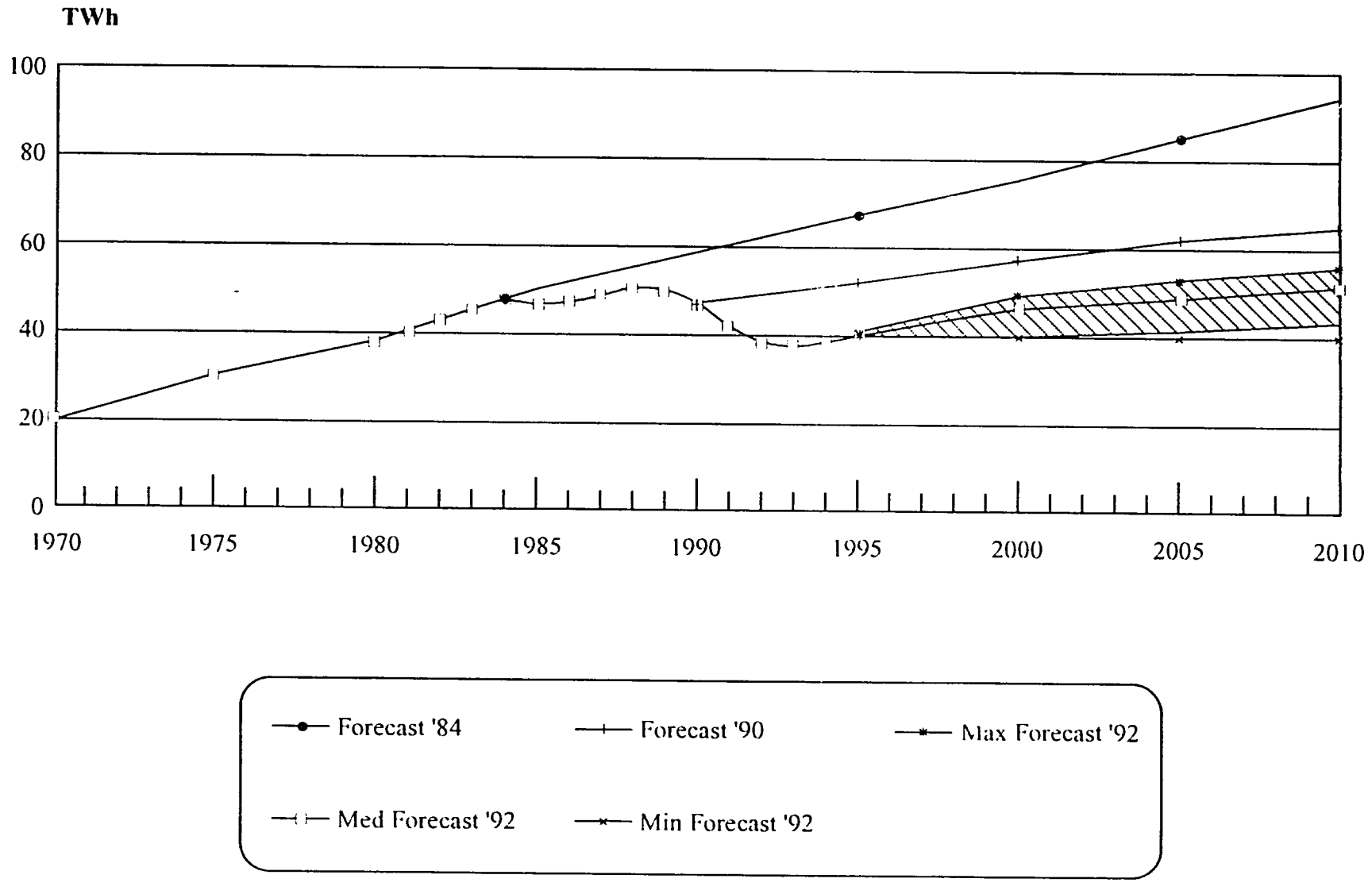
i) Electricity Demand Forecast

As occurred in many of the planned economies of Eastern Europe and the former Soviet Union, there was rapid development of the power sector in Bulgaria through the mid to late 1980's to accommodate an expanding but inefficient heavy industrial base. The sudden transition to market economics, the collapse of former communist bloc markets, and the wars in the Gulf and Yugoslavia have led to a dramatic decline in economic and industrial output and electricity demand over the past several years. Electricity demand is expected to "bottom out" in 1992 and 1993 and then begin increasing slowly.

The graph found in Figure 4 shows NEK's different demand forecasts scenarios based on projections made in 1984 (under the old communist order), 1990, and minimum, intermediate, and maximum projections in 1992. As this graph shows, there was a dramatic decline in electricity demand below the 1984 projections, with two precipitous drops around 1985 and 1990. The forecast of electricity demand found in Table 4 (which was prepared by the World Bank and accepted by NEK) is very close to the intermediate demand forecast shown in Figure 4 and appears to be a reasonable forecast of electricity and peak power capacity demand between 1992 and 2010. Therefore, we have used the 1992 intermediate demand forecast is used in the capacity expansion plan discussed below.

Load forecasts should be used with caution. Economic predictions are especially hazardous for Bulgaria and other Eastern European countries because there is no experience with large scale conversions from planned to market economies. It is too early to know whether various industries could become competitive on the world market. Major shifts could occur from energy-intensive industries like chemicals and metallurgy to lighter industries that are less energy-intensive. Furthermore, the current forecast does not account for price elasticity and so the impact of household consumption on load could be overestimated. In addition, the potential impact of demand-side management or energy efficiency programs is uncertain. Use of these forecasts for investment decisions involves considerable risk, which both NEK and IPP developers must consider.

Bulgaria Electricity Demand Forecasts



Source: NEK, 1992

Figure 4

HISTORY AND MEDIUM FORECAST OF ELECTRICITY DEMAND		
YEAR	TWh	MW
1989	48.64*	8332*
1990	45.91*	NA
1991	41.00*	NA
1992	38.22*	6870
1993	38.30	6840
1994	38.50	6870
1995	40.50	7230
2000	46.00	8070
2005	49.00	8600
2010	52.00	9120
* Actual		

Table 4

ii) Capacity Expansion Plans

NEK has prepared an expansion plan projecting capacity installations and needs between 1993 and 2010, as shown in Table 5. This expansion plan is based on the intermediate electricity and peak power demand forecast accepted by the World Bank and NEK, as discussed above. This capacity expansion includes projects currently being implemented by NEK, including the completion of the Chaira pumped storage facility which will provide 864 MW of peaking capacity and the Maritsa East II, (Unit 8) coal plant which will provide 210 MW of base load capacity. These two projects have been funded by the World Bank and the European Bank for Reconstruction and Development, respectively.

Based on the medium demand forecast, NEK's current generation expansion plans forecast the need for 880 MW of new capacity by the year 2000 and 3,940 MW by 2010. Options for meeting these capacity requirements include the use of indigenous coal, indigenous hydro, imported coal, imported gas, and nuclear. Specific options will be discussed in the next section. After the year 2000, NEK's alternate plan recommends that consideration be given to construction of a new nuclear facility and a major hydropower facility on the Danube River.

Capacity Balance Forecast for Bulgaria Power System

(Megawatts)

Source Types	Year					
	1993	1994	1995	2000	2005	2010
Electricity demand (TWh)	38.0	38.5	39.5	46.0	49.0	52.0
Peak load (MW)	7100	7000	7180	8210	8750	9280
Existing NPP	2600	2600	2600	2600	2600	2600
Existing TPP	4937	4917	5226	5195	5155	5145
Existing HPP	1200	1200	1200	1200	1200	1200
Chaira project	200	400	400	800	800	800
Required new construction	0	0	0	880	1620	2320
Total available capacity	8937	9117	9426	10675	11375	12065
Reserve compared to peak load MW	1837	2117	2246	2465	2625	2785
Reserve compared to peak load %	25.9	30.2	31.3	30.0	30.0	30.0

NPP: nuclear power plants
TPP: thermal power plants
HPP: hydro power plants

Source: NEK, 1992

Table 5

The World Bank recently prepared a report entitle Bulgaria Power Demand and Supply Options (May 1993) with the International Energy Agency for the G-7. This study was requested by the G7 in 1992 to examine alternative energy sources for replacing the less safe nuclear plants (VVER 440 model 230s) in Eastern Europe and the former Soviet Union. Bulgaria has 4 VVER 440 model 230 units # 1 - 4 at its Kozloduy plant with a capacity 1,760 MW out of the total plant capacity of 3,760 MW. The possible phase out of nuclear power capacity has significant implications for electric power planning and the potential role of independent power. Independent power developers are unlikely to have a role in nuclear generation. The phase out of some fraction of the nuclear capacity will create a greater demand for alternative power, which could open up significant IPP opportunities.

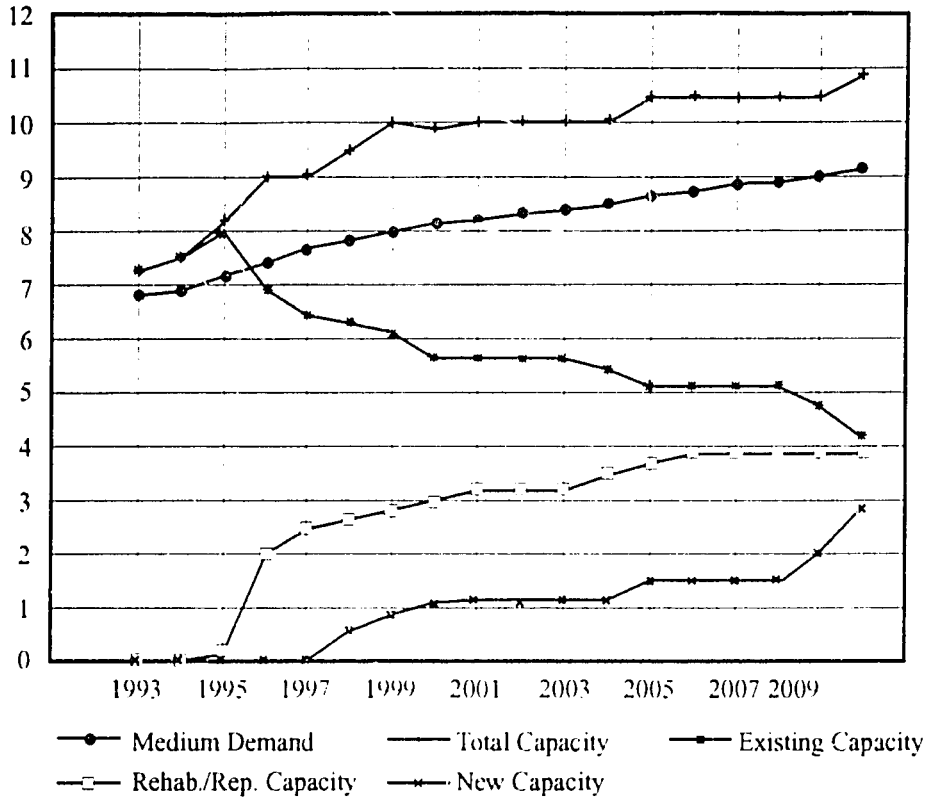
In this study, the World Bank developed various capacity expansion and investment projections using the Wien Automated System Planning Package (WASP) least cost expansion planning model. These forecasts were based on three different electricity demand projections and six difference nuclear power scenarios, ranging from shutting down all six units at Kozloduy immediately (Scenario 0) to keeping all units operational through the end of their designed life (Scenario 5). The scenarios involving continued nuclear power plant operation require between $678.0 and $1,566.8 million investments to upgrade the safety and performance of these units. The Bulgarian government has agreed to reduce its dependency on nuclear power over the long term.

The least cost alternative to nuclear power and option for capacity expansion involves the addition of new gas-fired combined cycle generating units at existing or new district heating and industrial cogeneration facilities. The installed cost for this new combined cycle capacity at existing cogeneration sites is projected to be between about $200/kW and $500/kW. The Government of Bulgaria has been concerned about the increased reliance on imported gas that these facilities would require. At their request, this study ran a scenario that limited gas imports for power and district heating to about 2 billion cubic meters per year (approximately current levels) and thus effectively eliminated the least cost expansion option involved gas-fired combined cycle systems. According to the World Bank analysis, this restricted gas consumption scenario effectively increased the cost of supplying power by about 3% - 8% (depending on demand and nuclear phaseout assumptions). The Government of Bulgaria will need to decide whether this possible increase in the cost of capacity expansion is justified to reduce dependence on imported gas.

The World Bank analysis concludes that the least cost alternative in the near-term involves investments in rehabilitating and repowering existing thermal power plants and district heating and industrial cogeneration facilities. Bulgaria's demand and capacity balance between 1993 and 2010 is shown in Figure 5 under two difference scenarios: (1) for a complete nuclear shut down (Scenario S-0) and (2) a complete nuclear rehabilitation (Scenario S-5). As is evident in these charts, by the year 2000, power and cogeneration plant rehabilitation/repowering could potentially contribute between 2,000 and 3,000 MW. In contrast, only 0 to 1,000 MW of new capacity additions are indicated.

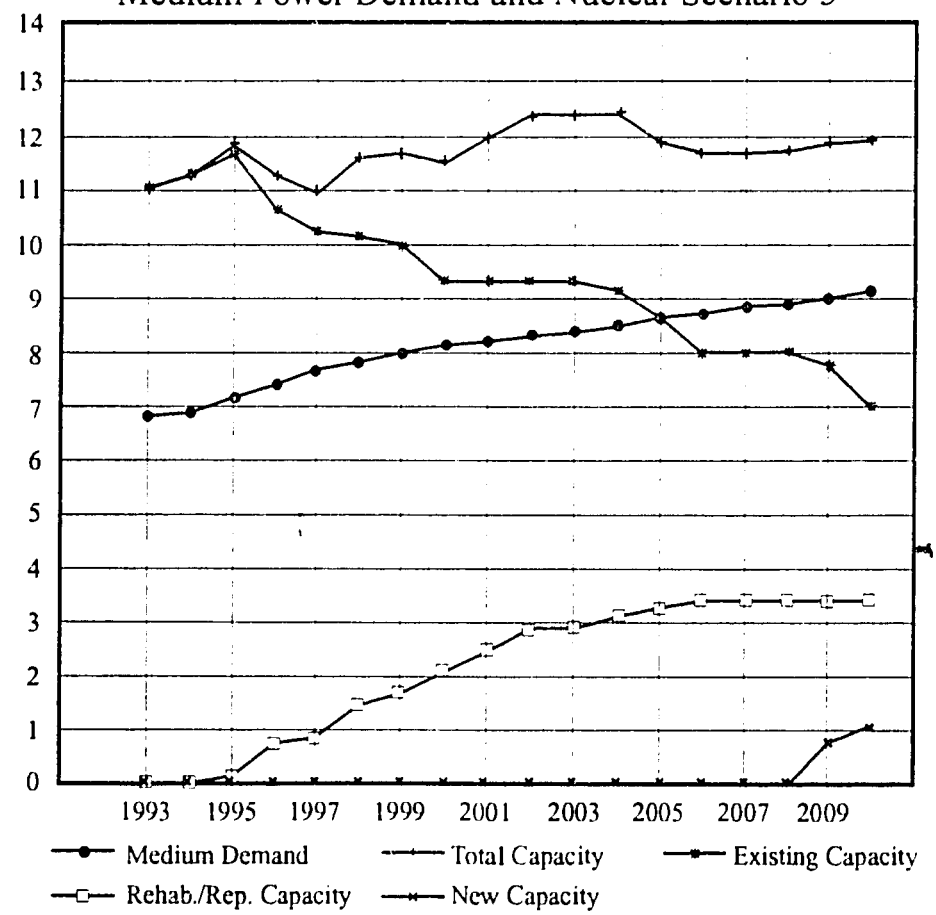
Bulgaria: Demand - Capacity Balance

Medium Power Demand and Nuclear Scenario 0



Bulgaria: Demand - Capacity Balance

Medium Power Demand and Nuclear Scenario 5



Source: World Bank, *Bulgaria Power Demand and Supply Options*, May 4, 1993.

Figure 5

The analysis prepared by the World Bank is preliminary and will be refined by additional demand side and least cost utility planning being implemented. US AID and the European Community (EC) are currently cooperating in the development of a least-cost power supply plan for Bulgaria. This study will bring together a number of studies in an effort to provide a more comprehensive plan for generation expansion and demand-side management. A clear definition of the least cost expansion options will result from this ongoing analysis.

One of the studies that will be included in the least-cost plan is a detailed feasibility analysis of the rehabilitation of six thermal power plants. This study is funded by the US Trade and Development Agency (TDA) and is being implemented by Bechtel. The upcoming report will provide useful information on potential rehabilitation, repowering, and retirement of the major central thermal power plants.

When it is completed, the least-cost plan will provide a very detailed analysis of electricity demand and options for capacity expansion and demand-side management. It is important to note that if Bulgaria experiences low economic growth, demand-side management and energy efficiency measures prove effective, and some 450,000 households are successfully converted from electricity to gas heating (i.e. the low demand forecast scenario), no additional capacity expansion will be required until the year 2000 and possibly as late as 2005. The uncertainty in the demand forecast and expansion plans requires that such plans be continuously updated to reflect current economic and electricity demand data. The focus under most scenarios will be on the rehabilitation and repowering of existing thermal units, whether they be central power plants or industrial and district heating cogenerators.

e) Financial Status of Power Sector

i) electricity pricing

The average electricity tariff is set by the Council of Ministers (COM), with the Commission on Prices (COP) and the Committee of Energy (COE) defining the structure of the tariffs (for a further discussion of these institutions, see chapter IV). In May 1990, a uniform tariff structure was instituted that is consistent with the principles of marginal cost pricing. This tariff differentiates customers on the basis of high (> 35 kV), medium (10 kV - 35 kV), and low voltage (< 10 kV) levels and according to different times of the year (winter and summer) and different times of the day (peak, day, and night).

There have been major increases in the average tariff from 0.0524 leva/kWh in late 1990 to 0.64 leva/kWh in January 1993. In May 1993 a further tariff increase was instituted as shown in Table 6. According to the World Bank, this May 1993 increase has raised the average tariff to about 2.9 cents/kWh. This rate is still considered too low. The World Bank and NEK have agreed that before September 1, 1993 the average price will be increased to 3.5 cents/kWh. After more detailed financial and cost analysis has been performed (which is expected before September 1994), the average price will be set at the greater of the long run

NEK ELECTRICITY TARRIFS MAY 1993 (leva/kWh)						
Time of Day	**Winter Period**			**Summer Period**		
	Level of Voltage			**Level of Voltage**		
	hv	mv	lv	hv	mv	lv
Peak	1.472	1.527	1.598	1.284	1.324	1.389
Day	0.799	0.826	0.863	0.691	0.716	0.750
Night	0.359	0.407	0.427	0.340	0.351	0.369
One-scale Measurement	1.187	1.225	1.285	1.032	1.064	1.116
The approximate exchange rate in May 1993 was is 26.4 Leva per US$						

SOURCE : NEK, 1993

Table 6

marginal cost or the average price necessary for NEK to achieve a debt service coverage ratio of 1.5.

Residential household tariffs are substantially lower than for all other customers due to a major subsidy. While industrial tariffs have approached NEK's cost of generation, residential tariffs have been significantly lower. In the May 1993 tariff increase, residential rates were increased 50% while industrial rates were only raised 5.5% to partially reduce this cross subsidy. Household consumers, however, are being hard hit by these rate increases, given the low wages of many Bulgarians (particularly senior and other citizens on fixed incomes). There are discussions of providing some kind of social safety net to help those residential customers most in need. Given the very limited financial resources of the government, the source of funds for such a program is hard to identify.

ii) utility financial performance

In the long term, the government may consider privatizing NEK. Currently, however, the financial performance of NEK and the lack of an appropriate energy policy and institutional framework would make NEK less attractive to investors. Over the past few years, NEK has been operating with inadequate cash flows and high current liabilities. In 1992, NEK had losses of 2.45 billion leva on total revenues of 15.40 billion leva. In 1991, losses were around 1.39 billion leva on total revenues of 9.56 billion. These losses are being covered through state support. The Ministry of Finance (MOF) has given NEK a timetable in which to eliminate this need for state subsidies. The goal agreed to between the MOF and NEK is that by 1995, NEK will be earning a positive net income and that state subsidies will end. The World Bank and NEK are working together closely to achieve this objective.

Given the recognized inability of NEK to service its debt, most of its earlier liabilities were forgiven and removed from its books. Without having to service its debt on the amortization of previous installed capacity, it will be significantly easier for NEK to turn a profit in the near-term. However, as additional investments in repowering, rehabilitation, or new capacity are required over the coming years, NEK will need to raise its tariffs to reflect the capital recovery costs. Even after all of the tariff increases made so far and contemplated before the end of 1993, an independent power purchase rate based at or below the existing industrial tariff may not be sufficient to enable an independent power developer to recover the full capital, operating and maintenance, and fuel costs of a new power installation. This actual cost of generation issue will need to be examined closely as COE's and NEK's independent power policy framework is developed.

The current goal is to establish the needed policy and regulatory framework so that appropriate tariffs and price signals can be established in the market place. In addition, assistance is being provided to COE and NEK in applying market-oriented financial and accounting principles. The schedule of these activities should put NEK in a relatively attractive condition by early 1995. By developing a favorable independent power policy

program in parallel with these activities, it is very conceivable that independent power projects could be successfully initiated within this time frame.

3) Review of Potential Independent Power Configurations

There are various configurations and options for independent power development that could occur in Bulgaria. These include:

- Industrial Cogeneration: Those industries that particularly require substantial quantities of steam or hot water for their production process (e.g. pulp & paper, petrochemical, steel, food processing, etc.) are prime candidates for cogeneration and independent power.

- District Heating Cogeneration: District heating plants that supply steam and hot water to municipalities and industry are also prime candidates for cogeneration and independent power.

- Thermal and Hydro Plant Repowering: Existing thermal and hydro power plants that are in need of considerable rehabilitation or repowering could be sold in part or in their entirety to private developers, who will make the necessary improvements and/or expansions.

- New Thermal and Hydro Power Projects: New capacity requirements could be supplied by private developers building new thermal and hydro power projects.

District heating systems and industrial cogenerators may offer the opportunity for providing increased capacity and energy to the grid either through repowering existing facilities with expanded power output capacities or through construction of new generating plants at new industrial sites. Industries could be encouraged to self-generate and reduce power demand through appropriate power pricing terms. The viability of cogeneration projects clearly depends on the commercial viability of the underlying industrial or district heating business and on the power purchase contract terms offered by NEK (i.e. buyback rate and contract term).

Some of the existing thermal power plants are in major need of rehabilitation or repowering in order to optimize their technical and financial performance. The Government of Bulgaria is severely constrained in its ability to finance these improvements and may want to attract private capital for this purpose. In order to induce the private sector to invest, NEK may wish to consider selling all or part of some of these thermal power plants. A joint venture between NEK and a private developer could be proposed or the power plant could be sold to

the private sector outright. New stand-alone independent power plants built by private developers, when needed, could sell electricity to NEK or directly to large retail customers.

The development of Bulgaria's substantial indigenous hydro resources could also present attractive opportunities for independent power developers. Energoproekt's Hydropower Division has performed an extensive study of the potential for new hydro development. There are major hydro sites being developed such as the Chaira pumped storage hydro plant being completed with funding from the World Bank. Energoproekt has identified about 155 mini-hydropower sites totaling 2,599 MW and 738 micro hydro sites totaling 215 MW. Some of these sites have as much as 1000 feet of head, which could result in a very attractive installed cost per kiloWatt.

The long term need for major new central station power capacity using coal, oil, gas, and hydro after the year 2000 will also lend itself to independent power development. By this point, some smaller IPPs should have been developed thus establishing the procurement, contractual, and permitting precedent.

4) Estimate of Bulgaria's Independent Power Market Potential

The ability to make a market estimate for independent power is constrained by two major uncertainties. First, the demand for electricity and the power expansion needs are unclear due to Bulgaria's difficult economic transition. With the recent declines in electricity demand and surplus capacity of variable reliability, Bulgaria could possibly postpone making major new investments in the non-nuclear power sector for a few years. Within the next 5 to 10 years, however, major new investments in cogeneration and power plant rehabilitation and expansion will be required. Second, the extent to which a favorable business investment climate for independent power will develop is unclear. Independent power developers will only play a role in new capacity investments if the Government of Bulgaria, COE, and NEK implement policies and pursue strategies that encourage and facilitate private investment (as explored in Chapters IV and V). Given that these policies are in the formative stage, there is considerable uncertainty as to their outcome.

Given these caveats, it nonetheless is possible to provide an estimate for the independent power market and describe the potential independent power opportunities that could potentially develop. As discussed in the capacity expansion plan section and shown in Figure 5, the World Bank estimates that between 0 and 1,000 MW of new capacity will be added between 1993 and 2000 and between 2,000 MW and 3,000 MW will need to be rehabilitated or repowered (based on the extremes of nuclear power scenarios 0 through 5). Assuming the most likely moderate nuclear power scenario # 3, this report estimates that investments totaling about $ 521 million will be required for power capacity rehabilitation and repowering and $474 million investments will be need for new capacity between 1993 and 2000.

Given the capital constraints of the GOB, it is fair to assume that some proportion of those additions will be offered to the private sector. The extent to which private investors will respond will depend on government policy, the overall investment climate, and the extent to which Multilateral Banks and Export Credit Agencies join the private sector in enabling the first precedent-setting independent power projects. A summary of these potential opportunities is discussed below and is provided in Table 7.

a) District Heating and Industrial Cogeneration

Private cogeneration could play an important role meeting the expanded capacity requirements in the near-term. In addition, as Bulgaria considers its economic development future, cogeneration could play an important part in improving the economic viability of certain industries and the district heating sector. For example, agricultural and food processing products are expected to be a major export industry for Bulgaria. Food processing and fertilizer plants both have a strong potential for cogeneration which could make these industries more competitive internationally.

Preliminary analysis is being conducted to determine the repowering and expanded cogeneration potential at the existing industrial and district heating cogeneration sites. In the World Bank G7 report, preliminary analysis has been performed based largely on the application of fluidized bed or combined cycle technology. This report indicates the potential for expanding the installed industrial cogeneration capacity to be around 560 MW to about 2,570 MW at the Burgas refinery, Kremikovtzi steel mill, Chimco Vratsa chemical plant, and the Stara Zagora fertilizer plant.

At the major district heating plants, the potential for expanding cogeneration from a total of about 610 MW to about 2,460 MW has been identified, with particular focus on the Sofia, Kostov, Pernik, Plovdiv, Avram Stoianov, Pleven, and Shumen district heating plants. Through US Trade and Development Agency funding, Gilbert Commonwealth of the US is currently undertaking feasibility studies of three district heating plants. This analysis will be a valuable first step in determining the potential for private investment. There has been discussion of transferring ownership of some district heating plants from COE to the respective municipalities. Given the major rehabilitation and repowering needs of these plants and the financial constraints at both the federal and municipal levels, private investment and management could be greatly needed.

If all these industrial and district heating cogeneration projects proved feasible, the potential for expanded cogeneration at these existing plants would total around 3,800 MW. This additional capacity would be able to supply most of the 4,820 MW of new capacity that the intermediate growth expansion plan calls for between 1993 and 2010. However, the expanded use of natural gas that many of these cogeneration projects call for has generated substantial debate. Many utility officials interviewed want to avoid increasing dependence on imported Russian gas, particularly at the current high price in Bulgaria. In addition, NEK

BULGARIA POWER PROJECT INVESTMENT OPPORTUNITIES

Estimates: June 1993

Power Facility Name	Existing Installed Capacity (MegaWatts)	Potential New or Repowered Capacity (MegaWatts)
Thermal Power Plants		
Maritsa East 1	200	200 – 250
Maritsa East 2	1,245	1,245 – 1,455
Martisa East 3	840	840
Varna	1,260	1,260
Russe	400	400
Bobov Dol	630	630
District Heating Cogeneration Plants		
Russe	270	340
Sofia	125	345
Kostov	186	870
Pernick	155	130
Plovdiv	60	260
Pleven	36	295
Shumen	18	160
Industrial Cogeneration Plants		
Burgas	220	1,082
Kremikovtzi	60	486
Chimco Vratsa	60	284
Stara Zagora	48	720
Devnia	60	616
Hydro Power Plants		
Danube River		400
Gorno Arda		175
Sredna Vacha		100

Source: World Bank, Bulgaria Demand & Supply Options, May, 1993; Energoproekt

Table 7

would prefer to see imported gas used to convert 450,000 residential homes from electric to gas heating (thereby reducing their winter peak demand).

b) Coal-Fired Power Plant Rehabilitation and Repowering

Power project rehabilitation involves repairing and replacing components of an existing design, while repowering involves a substantial reconfiguration and possible expansion of a power plant using improved technology. Major opportunities for both rehabilitation and repowering exist in Bulgaria.

Most of the major thermal (coal-fired) power plants in Bulgaria are in need of some form of rehabilitation or repowering, as is being studied by Bechtel in a Trade & Development Agency (TDA) funded feasibility study. This need is partially based on the age of the units and particularly on the type of technology used and the conditions they have had to operate under. Assuming that the useful life of these Bulgarian coal-fired units is 30 years, units totaling roughly 370 MW would need to be retired between 1993 and 2000. While thermal plants in the US can have a longer useful life, the Bulgarian coal-fired units have been subject to much harsher conditions and involve technology that is less well adapted to the efficiency and environmental criteria Western countries are stipulating as conditions for power sector loans. The power plant units that will exceed a 30 year life between 1993 and 2000 are 4 lignite-fired units totaling 200 MW at the Maritsa East 1 power plant and the 3 lignite-fired units totaling 170 MW at the Maritsa 3 power plant.

The coal-fired power plants that could be considered for replacement and repowering between 2000 and 2010 would add up to over 1,400 MW (again assuming a 30 year life). The power plant units that will exceed a 30 year life between 2000 and 2010 and thus are major candidates for retirement or repowering are 4 lignite-fired units totaling 600 MW at the Maritsa East 2 power plant, 3 imported coal and gas fired units totaling 630 MW at the Varna power plant, and 3 imported coal fired units totaling 170 MW at the Russe power plant. Clearly, the results of the TDA Bechtel study will better clarify the options regarding retirement and repowering of these units.

In order to attract private capital into rehabilitating/repowering existing power plants, NEK may need to consider selling off part or all of particular power plants or entering into joint ventures as is being implemented in Poland. Private developers and investors are unlikely to want to invest in a power plant that they do not have sufficient ownership and management control over. Selling part or all of a power project could also be a way for NEK to raise capital for various purposes.

The indigenous lignite burning power plants at the Maritsa complex (Maritsa 1 -3 power plants) are in considerable need of reconditioning and repowering. The poor quality of the lignite at Maritsa and the labor problems at the coal mines could be addressed by a

Bulgarian government / private investor partnership that would provide the appropriate clean-coal technologies and labor management plan.

The two coal-fired power plants that are burning imported anthracite coal from the Ukraine, Varna (1,260 MW) and Russe (400 MW), are in better condition but still call for significant repowering. The reliability of coal supplies from the Ukraine has been a problem so analysis is being conducted on converting the boilers to burn imported sub-bituminous coal from Africa or Asia. If a reliable supply of coal is found that matches the boiler configuration, private investors might be more interested in these facilities.

The Maritsa East 1 power plant (200 MW) presents an interesting repowering case because it also supplies steam to the country's only major briquette factory. The Bobov Dol power plant (630 MW) has depleted its local source of coal and is being considered for boiler modification to burn blended coal or low sulfur imported coal.

A summary of the three power projects, Maritsa East 2, Varna, and Bobov Dol that the World Bank study identified as prime candidates for repowering is found in the Appendix. When TDA and Bechtel publish the results of their feasibility studies of repowering of all six thermal plants, the results of this analysis will reveal which projects have the best return on investment.

c) Hydropower

It is not expected that any of the existing hydro plants will be retired (some are about 30 to 35 years old) but investment in upgrading to increase efficiency could be attractive. Energoproekt has identified about 2,800 MW of new, potentially-exploitable hydro resources. These new sites could offer some interesting investment opportunities. The NEK is interested in jointly developing with the Rumanians 400 MW of hydro capacity at Nikopol-Turnu Magurele and Silistra Kalarash on the Danube River. Other major hydro sites to be developed include about 175 MW at Gorna Arda and about 100 MW at Sredna Vacha. Given that the hydro generation would typically be during the peak winter demand months, these projects may fit into the least cost plan in an optimal way.

Given the high costs of developing a power project, foreign developers are likely to be primarily interested in the mini-hydro and larger hydro projects exceeding 5 MW to 10 MW. Many of the pre-closing development costs are the same for small projects as they are for larger projects, while the profits and revenues earned are a function of size. Developing a micro-hydro project on the scale of 100 kW would not generate the revenues typically required by a foreign investor to justify the project development costs.

d) New Capacity Additions

As discussed in the previous section, NEK has prepared an expansion plan based on low, intermediate, and high demand growth scenarios. Given the uncertainties in the world and the Bulgarian economy and power sector, these expansion projections are uncertain and will require careful examination and updating. These new capacity projections, nonetheless, do provide an estimate of the possible opportunities for new independent power project development.

If the intermediate demand growth scenario proves correct, 880 MW of new capacity will be required between 1993 and 2000. There is a range of options on how to supply this new capacity, if needed. One option for NEK would be to expand the capacity at the Kozloduy nuclear power plant. Given the difficulty Bulgaria will have in obtaining the financing for this expansion and the fact that it is unlikely that nuclear power could be developed under an independent power scheme, the focus of this discussion has been on conventional thermal and hydro facilities. The most attractive opportunities could be for expanded coal-fired, combined cycle gas-fired, and hydro project development both at central power plants and cogeneration facilities in industry and at district heating plants.

Over the long term, increased electricity demand and more plant retirements will definitely require the construction of new generating facilities. If the intermediate electricity demand growth scenario proves correct, the NEK expansion plan calls for 3,940 MW of capacity between 2000 and 2010. It is very likely that the Bulgarian economy will be on a sound market-based footing by this period and that economic growth could be strong.

There is a wide range of options for supplying these longer-term capacity requirements. At a later date, nuclear power may have found greater favor in the international community, given the growing air pollution concerns. Given the extensive development of Russia's large reserves of oil and gas, the expanded power capacity using these relatively clean fossil fuels may well be increased. Bulgaria's coal reserves and poor coal quality could well inhibit a significant expansion beyond current capacity levels with further imports of higher grade coal.

e) Power Export Markets

Over the long term, COE and NEK might consider the potential market for exporting power to those neighboring countries that are deficient in power. The Bulgarian power transmission system is interconnected with all neighboring countries, including the Ukraine, Romania, Turkey, Greece, and Yugoslavia. Given the existing 750 kV and 400 kV link with the Ukraine, and the 400 kV links with all other neighbors, the basic infrastructure is in place (while transmission capacity may need to be expanded).

Bulgaria occasionally has been importing about 800 MW of capacity from the Ukraine during periods of peak demand, with about 4 - 5 TWh of electricity being imported yearly.

Trade with Romania remains limited given this country's economic and power sector problems and power exchanges with Yugoslavia has been stopped by the current international embargo. Bulgaria is currently negotiating with Greece and Turkey for enhancing their cross-boarder interconnections, expanding exchanges of power, and possible synchronization. Preliminary indications are that Greece and Macedonia could be potential power markets, if Bulgaria is able to develop capacity at a competitive price in the Balkan market.

f) Power Project Prioritization

The procedure for evaluating power project investments should utilize a rigorous Integrated Resource Planning (IRP) process. In this manner, the most appropriate and least cost options will be developed. A key determinant for project selection will be how the power plant meets the load profile in terms of supplying peaking, intermediate, or base load capacity. The installed capacity ($/kW) and life cycle power costs ($/kWh) for each power project opportunity will also be essential factors in project selection. A summary of the installed capacity and life cycle costs of different power technologies based on the US and international market is found in Table 8.

Given the installed and generation costs of different technologies, it is likely that the first investment to consider will be demand side management options under $300/kW, then possible cogeneration and thermal plant repowerings in the range of $200/kW to $400/kW. For new generation options, hydro may provide economic generation at particular sites identified by Energoproekt. While hydro in the US ranges from between $2,000 to $3,000/kW, the high head sites in Bulgaria could reduce capital costs significantly. The choice of the optimal technologies and fuels will become clear after the IRP process has been implemented.

GENERATION SUPPLY OPTIONS ESTIMATES OF INSTALLED AND LEVELIZED COSTS		
	RANGE $/KW	TOTAL LEVELIZED COST ¢/KWH
Combustion Turbine	275 - 500	11-16
Diesel Generator	375 - 1,005	9-26
Combined Cycle	500 - 800	5-6
Pulverized Coal w/ Flue Gas Desulferization	1,420 - 2,410	6-9
Atmospheric Fluidized Bed Combustion	1,600 - 2,600	6-8
Wood Fired Steam	2,700	7-8
Conventional Hydro	1,945 - 3,300	N/A

Source: Central Maine Power, Stone & Webster, and Electric Power Research Institute, 1993

Table 8

IV. EXISTING POLICY, REGULATORY AND INSTITUTIONAL CONDITIONS AFFECTING INDEPENDENT POWER DEVELOPMENT IN BULGARIA

1) Overview of the Existing Policy and Regulatory Framework

The existing statutory framework in Bulgaria is undergoing major changes. Only one statute, the Law on the Environment, has any significant implementing regulations. The prospects for a broad independent power program will be enhanced as the Bulgaria's laws and regulations become more developed. Nevertheless, a preliminary assessment of the power sector institutions and the energy bill currently being drafted indicates that a favorable policy and institutional framework is under development.

While it is important for the long term development of an active private power market in Bulgaria that the legislative and regulatory framework evolve from the current transitional phase to a more stable system, that evolution can be aided and even accelerated by the parallel development of specific projects. At this early stage, if NEK were to implement an informal developer selection process involving negotiations with about 3 or 4 different companies, it could ensure that these first projects are relatively competitive. By proceeding with one or more IPPs, actual experience is gained that will contribute to improving the policy and institutional framework. This issue is discussed in the conclusions to this section and the recommendations in Chapter V.

An overview of the principal Constitutional provisions and statutes affecting private power development is provided below with comments on what changes might improve the overall policy and legal framework.

a) Relevant Constitutional Provisions

i) Private Property Article 17 provides that the right to property shall be guaranteed by law and that private property shall be inviolable. Expropriation can be done only after fair compensation is assured in advance. A bilateral investment treaty with the US signed in September, 1992 should provide additional assurance to US investors.

ii) Energy Sector Article 18 identifies the activities which are to remain as Governmental monopolies. Water resources, mineral resources and parks, for example, continue to be under the exclusive control of the national government. With the exception of the use of nuclear energy, the energy sector is not so identified.

iii) Environmental Protection Article 15 states that Bulgaria shall ensure the protection of the environment and the conservation and sensible utilization of the country's natural and other resources. In addition, Article 5 provides that international instruments ratified by and in force with respect to Bulgaria have the effect of domestic legislation, and

they supersede any domestic legislation stipulating otherwise. Bulgaria is a party to a number of international agreements on environmental issues, as discussed in Section IV(1)(b)(ii) below.

iv) Site Acquisition Article 21 of the Constitution restricts the use of arable land to agricultural purposes, absent exceptional circumstances and need, and Article 22 prohibits foreign individuals and entities from owning land in Bulgaria (but Bulgarian companies with up to 100% foreign ownership apparently can own non-agricultural land; see Section IV(1)(b)(iii) below). Leasehold interests and ownership of structures by foreign individuals and entities are not prohibited.

b) Relevant Legislation

The Law on Electrical Energy (currently in discussion draft)

This Law would require the "State Body on Energy," referred to in this report by its current name, the Committee of Energy or COE, to oversee the generation, transmission, distribution and use of electrical energy by the NEK. The Law contemplates that the COE will be charged with the protection of consumers and of the public interest, including determinations of need and of the cost effectiveness of generation expansion plans. Regulation of prices to consumers, however, is proposed to be made by a "Commission on State Energy Regulation" made up of representatives of several Ministries and other entities with an interest in energy prices. The "Inter-institutional Commission on State Energy Regulation," a temporary commission which would be responsible for the fairness of retail prices pending enactment of the law, is being authorized as of the date of this report. These entities are described in greater detail in Section IV(2)(a) below.

The current version of the draft Law indicates that a favorable policy framework in terms of power purchase pricing and terms will be offered to independent power generators to fill future needs for additional capacity. It requires the COE to create conditions to enhance competition in the generation of electric power and to create preferential conditions for the production of power by IPPs. The law contemplates a certification process for IPPs, in which applicants will be required to demonstrate that:

(1) they are compatible with the approved long term plan for production and transmission of energy;
(2) they have coordinated their planning with the local authorities, the Ministry of Environment (MOE) and the National Council on Water (NCW);
(3) their pricing is in the interest of consumers; and
(4) the public has been informed (detailed requirements for public involvement in the environmental review process, described in subsection (ii) below, will presumably satisfy this criterion).

Clearly, the manner in which these requirements are applied will have an important effect on the commercial environment for private power in Bulgaria.

Given the short history of the institutions which would be involved with the implementation of this statute and the evolving and dynamic nature of regulation in this sector in countries throughout the world, it is reasonable to expect that international sources of capital will be concerned about arbitrary or capricious administration of the Law's policies. A number of the recommendations in Chapter V of this report are intended to address these concerns.

While the current draft does not distinguish between small power producers, cogenerators and other independently-owned generators, if so desired, such a distinction can be made in either the implementing regulations under the Law or in the Law itself. A number of jurisdictions, including the United States, has incorporated such a provision in its legislation. Such a distinction would encourage small independent power production through standard offers that conform to least cost planning principles but establish a standard avoided cost rate and simplify the contracting process for projects under 100 MW. [See Chapter V, Recommendation 9]

ii) The Environmental Protection Act

The Environmental Protection Act was passed in 1991 and amended in 1992. It is a comprehensive environmental statute of broad applicability which establishes the rights of the citizens to a clean environment, to information on issues affecting the environment (Article 9), and to environmental impact assessments prior to construction, reconstruction or expansion of a wide range of projects, including power projects (Article 20).

As discussed in greater detail below, the Law affords the Ministry of the Environment (MOE) substantial authority to achieve its goals. No construction can be started until the MOE has approved the form and substance of the associated environmental impact assessment. Article 28(2) provides that the Minister of the Environment may suspend the regulations of other Ministries and Municipalities when they contravene the prescriptions of the Law, and Article 28(1) authorizes the Minister or the Regional Environmental Inspectorates to suspend or stop industrial activities which impact assessment established as damaging or threatening damage to the environment.

<u>Point Source Emissions -- Air:</u> Bulgaria has adopted emission standards for stationary sources. The standards for power generating facilities are not technology-specific, but rather are based on size categories (in MW) and fuel type. The Law requires sources to pay user charges in proportion to their emissions at or below the published standards for the emitting facility. Emissions exceeding the standards are subject to penalties in amounts up to 30 million Leva (approximately $1.2 million) per month.

Ambient Standards -- Air: In addition to source emissions standards, Bulgaria has stringent ambient air quality standards modeled on those of Germany. They stipulate maximum allowable concentrations, over 30 minute and 24 hour averaging periods, for 171 categories of pollutants. The standard for particulates is comparable to that of the US, but the standards for SO2 and CO are almost an order of magnitude more stringent. Bulgaria is a signatory to the Helsinki Protocol on SO2 and a Sofia Protocol on NOx, and the Vienna convention and the Montreal Protocol on protection of the ozone layer. It is, for example, required by the Helsinki Protocol to reduce its SO2 emissions by 30% from 1980 levels by the end of 1993. Bulgaria's ambient standards govern a wide range of pollution in addition to air quality, including noise and odor pollution. MOE, however, has not yet established a permit system for air pollution discharges.

Because the ambient air quality standards are generally perceived as unrealistic, and given the current state of the economy, there is now little or no effort to enforce them. However, in addition to the penalties described above, there is authority for the assessment of civil penalties against individuals for the violation of environmental laws and regulations (Article 32). Moreover, Article 29 of the statute requires a polluter to remedy any damage it causes with compensation at least equal to the cost of repair. Article 353bis of the Penal Code, which provides that persons who conceal or falsify information resulting in material damage to the environment or to human health will be liable to fine and imprisonment for up to five years, applies only to government officials.

Ambient Standards and Point Source Emissions -- Water: Ambient water quality standards have also been established for three classes of receiving waters, Class I for drinking water quality, Class II for recreation and fishing, and Class III for irrigation. Direct discharges to surface waters must meet the Class II standards. The MOE is currently putting in place a permitting system for discharges to waters. There are also two standards for the discharge of waste to sewerage systems, depending on whether they are served by treatment facilities.

Environmental Impact Assessment: While most existing sources have not yet felt the impact of the Environmental Protection Act and associated regulations, the MOE has established a detailed environmental impact assessment procedure, called an Evaluation of the Effect on the Environment ("EEE") study, pursuant to Article 20 of the Environmental Protection Act. It will serve for all practical purposes as a comprehensive permit review procedure. Most importantly, it gives the MOE great discretion and final authority over the approval of new power generation facilities. It requires the evaluation of the effect of a broad spectrum of activities (including the construction, expansion, reconstruction and conversion of power generation facilities) on air, water, land, flora, fauna, "protected areas," landscape, people, residential settlements and cultural heritage.

Thermal power stations with 300 MW or greater capacity are under the exclusive jurisdiction of the MOE. Other "industrial" electrical generation facilities, hydroelectric facilities and overhead transmission lines are under the MOE's jurisdiction if their impact extends beyond the Regional Environmental Inspectorate in which they are located, if they

discharge more than 30 liters per second of waste water, if they burn more than 750 kg of waste (averaging period not specified), or if the value of the project exceeds 50 million Leva ($2 million). Otherwise, they are under the jurisdiction of the Regional Environmental Inspectorate. Article 20 requires that assessments of "large" polluting facilities must be made at least once every five years.

EEEs must be prepared by experts, who must certify that they are professionally competent and that they have no direct interest in the facility and have not participated in its design. Article 23 requires that the MOE, or the Regional Environmental Inspectorate if it has jurisdiction, review the EEE and organize a public meeting on at least one month's notice to interested parties. It will issue its decision within three months of the hearing. Appeals may be lodged within 14 days, or within 30 days for projects of national significance. The statute requires the reviewing authority to prohibit the implementation of projects for which the assessment is not complete or is negative, or which are not equipped with the necessary pollution control equipment. Finally and importantly, the statute provides that the state is responsible for the cost of remediation of pre-existing pollution at industrial sites.

It should be noted that this Law does not supersede the many other environment-related statutes, dating back to the 1950's, which remain on the books. It has been estimated that over 120 of such laws are in force, including seven of potentially direct relevance to independent power development. However, the relationship of the new statute to the old statutes is not yet clear. In addition, other new environmental statutes dealing specifically with air, water and soil pollution are now being prepared. It is expected that they will expressly supersede some, but not all, of the prior legislation. Regulations dealing with environmental audits of existing facilities are also being prepared.

iii) Property and Resource Rights Legislation

<u>Law on the Ownership and the Use of Agricultural Lands:</u> Articles 31 and 33 of this Law establish the Ministry of Agriculture and the Municipal Land Commissions as the jurisdictional authorities over land ownership issues. This law's primary thrust is the restitution of farmland to those owning it prior to collectivization, or to their heirs. It also prohibits the ownership of (but not the lease of) arable land by foreign individuals, foreign companies and domestic entities with more than 50% foreign ownership. However, the use of arable land for other than agricultural purposes is strongly discouraged by both the statute and the Constitution (Article 221bis of the Penal Code provides for fines and up to three to five years' imprisonment for persons, presumably but not explicitly government officials, permitting non-agricultural uses of agricultural land). Therefore, the development of new power facilities on land which is classified as arable is unlikely. However, the definition of arable land in Article 2 of the law specifically excludes land within community boundaries, forest domains (which should be distinguished from agricultural land which has been reforested), and land on which industrial, commercial, and energy facilities and their yards and ancillary facilities have been built.

There is an expectation that the Parliament will soon consider the enactment of similar legislation for the restitution of expropriated forest land. Although forest land is not afforded the same constitutional status as arable land, use for industrial or commercial purposes is strongly discouraged.

In the past decades, many of the industrial facilities now being privatized were sited on agricultural land. Apparently they are now properly classified, along with the underlying real property, as state assets under the Law on Conversion and Privatization of State Owned Enterprises. The definitional provisions of the two statutes, however, leave some ambiguity on this issue. The boundaries between the industrial and agricultural properties also are likely to be subject to some dispute.

Several other laws for the purpose of restitution have also been enacted: for nationalized immovable property; certain nationalized property; and certain shops, workshops, warehouses and pharmacies. There are other laws, such as the 1951 Law on Contracts and Obligations, which have potential relevance to site acquisition. An exhaustive review of such laws is beyond the scope of this report, and in any event this law and many others are expected to be repealed if and when a new law on the same subject is passed by the Parliament.

iv) Privatization and Investment Legislation

Foreign Persons' Business Activity and Foreign Investment Protection Act: This law provides foreign individuals and foreign domiciled entities the right to do business in Bulgaria on equal terms with Bulgarian entities. Article 7 further provides that foreign persons are entitled to most-favored-nation treatment if an international agreement so provides (the U.S Trade Agreement became effective in 1991 and includes a most-favored-nation clause).

Foreign individuals and entities can freely open bank accounts, deal in securities, convert leva into dollars and repatriate both income and capital. Under Article 5 they can own improvements to real property and they can lease land, but neither foreign persons nor domestic entities with majority foreign ownership can own agricultural land. There is no apparent restriction on the percentage of foreign ownership in a Bulgarian company owning non-arable land. A 100% foreign-owned company with Bulgarian domicile should therefore be able to own industrial assets, including the real property.

Article 12 provides that claims can be secured by pledge or by mortgage, although Article 11 also requires foreigners to register their investments assets, and changes thereto, with the Ministry of Finance.

The provisions of this Law also govern labor and social insurance issues. They stipulate that an employment contract will provide the basis for the relationship between employer and employee, and, to the extent issues are not covered in the contract, the Bulgarian legislation

shall govern. However, certain basic contractual issues (hours, minimum wage, termination notice and payment, occupational hazard protection) must conform to Bulgarian Law.

Law on Transformation and Privatization of State-Owned and Municipal Enterprises: The scope of this law is the privatization of industrial, commercial, construction and transportation companies. It therefore is relevant mainly to IPP participation in industrial cogeneration. It may also be relevant to investments in refurbishing utility-owned plant. It provides for privatization through the sale of state enterprises, either before or after their conversion into commercial companies.

Large state-owned (as distinguished from municipally-owned) companies whose book value of fixed assets is over 10 million Leva will be privatized by the Privatization Agency, with the approval of the Council of Ministers in the case of book fixed assets over 200 million Leva. Companies with a book value of fixed assets at or below 10 million Leva are privatized through the relevant ministry. These smaller companies can also be acquired through lease-purchase arrangements, management contracts with purchase options, installment sales and conditional sales. Municipal companies of any size will be privatized by the Municipality in question.

Decree No. 105 of the Council of Ministers regulates the process for enterprises which are put up for auction, and foreign persons may participate freely in auctions subject to the restrictions on ownership of land.

In principle, it should not be difficult for investors in, and lenders to, independent power projects to obtain clear title to project assets, even those subject to claims of restitution, as sales of property under this statute will in most cases be without encumbrance. However, it appears that Article 18 provides claimants a preemptive right to shares in enterprises built on expropriated or collectivized land, in some cases limited to two months after the promulgation of the privatization decision. A transitional provision also makes voidable a "disposal transaction" of state or municipal property under "apparently unfavorable conditions" after 1989. Land ownership and lien records are addressed in Section IV(2)(e) below.

The first of three parts of a **Commercial Code** has also been enacted by the Parliament. It defines the permissible organizational forms for transacting business in Bulgaria and the associated obligations, rights and procedures. It is generally consistent with western European practice.

v) Conclusions on the Policy and Regulatory Framework

Bulgaria has made a positive effort to establish a favorable legal framework for attracting international capital. The passage of the Law on Electrical Energy will be another important step in that direction. Whether the preference for IPPs contained in the draft Law will attract a broad spectrum of potential investors and thereby create long-term active competition in the power generation sector will depend on several additional factors. These

factors are also relevant, but of less concern, to project sponsors negotiating specific projects in parallel with the efforts recommended below.

The content of the implementing regulations will be an important factor. If those regulations provide prospective independent power investors with an expectation of equitable treatment and reasonable certainty of a rational selection process, one important leg of the policy and regulatory framework for IPP development will be in place. See the Conclusions to the following Section on institutional issues, and Recommendation 3.

A final recommendation concerns the consolidation of the project review process. In light of the uncertainties surrounding existing statutes and their administration, it would be helpful to consolidate the authority for project approval as much as possible. The Certificate of Need does not incorporate the considerations of other concerned agencies. It would be helpful if the COE's statutory authority were expanded to enable it to become a central clearing house for all or most of the permits required, as described in Recommendation 1 of Chapter V.

Most important, it will depend on investors' confidence in a rational and consistent legal and regulatory system. Bulgaria's economy is in a transitional phase, and so are its legislation, regulations and policies. The direction of the policies has become clear, but the legislative basis for implementing those policies is still in a formative stage. A great deal of pre-1989 legislation remains in force, including some which is still relevant to concerns of potential investors. Examples include the 1951 Law on Contracts and Obligations and a series of environmental laws on water, air and land pollution. How those laws relate to recent legislation will require clarification. As noted in the text of this section, a number of the new laws also contain provisions which are also likely to concern potential investors.

The Parliament is currently working on legislation to replace the earlier statutes, and much other new legislation is also in preparation. These efforts are still in a relatively early stage, so it cannot be concluded that a rational and consistent system of laws and regulations is yet in place. The associated uncertainties will make it difficult to attract international capital to the broad power sector in the near term. However, every effort should be made to promptly incorporate the newly enacted statutes and the prior legislation into a consistent framework. [See Recommendation 1 of Chapter V]

To attract international capital there should also be an established and reliable system of legal recourse. A detailed evaluation of the Bulgarian legal system is beyond the scope of this report. However, as with the economy and the legislation, the judicial system in Bulgaria is in transition from serving as an arm of the state to acting as an independent judiciary. It will therefore probably be necessary for all parties to an independent power contract to submit to binding dispute resolution by an independent third party in a neutral jurisdiction, possibly outside of Bulgaria. Such a Provision should be included in the contract forms suggested under Recommendations 9 and 10 of Chapter V.

2) The Existing Institutional Structure

a) Committee of Energy, NEK, and Energoproekt

The COE is appointed by and reports directly to the Council of Ministers. The Parliament also has a **Commission on Energy and Energy Resources**, a 13 member body which provides legislative oversight of the COE and the energy sector generally. The COE is the governmental department charged, among other things, with general oversight of utility operations and encouragement of the independent power sector. In addition to responsibility for the generation, transmission, distribution and use of electric power it is responsible for oversight of the coal industry and the district heating sector, although some of the latter facilities are expected to be transferred to Municipal control. Its functions do not include mineral exploration or oil and gas exploration or production, which are under the jurisdiction of the Ministry of Geology, nor oversight of the petroleum, natural gas or petrochemical sectors, which are under the Ministry of Industry.

A recent organization chart showing the responsibilities and functions of the COE and other agencies with involvement in the energy sector is found in Figure 5. The World Bank recommended, in their April 30, 1992 study of the energy sector, that other energy-related organizations operating under the jurisdiction of the Ministry of Industry and the Committee of Geology (see below), be consolidated under the jurisdiction of a single energy agency. It also recommended that the district heating companies be subjected, along with NEK and Bulgargaz, to the regulatory authority of a newly created energy regulatory authority.

The general functions contemplated for the COE were described in the section "Relevant Legislation -- The Law on Electrical Energy." Specifically, the draft statute provides that the COE will be charged, among other things, with assuring that the electrical energy needs of the nation are met, with stimulating efficiency and economy in the sector, with creating conditions for competition in the production and distribution of power, with creating preferential conditions for IPP supply, and for protecting the interests of consumers, citizens, and the environment.

The draft Law also contemplates the creation of a "Commission on State Energy Regulation" which will be delegated certain of the COE's responsibilities to protect consumer interests. That nine-member commission would consist of three members from the COE (with one serving as Chairman), the Ministers of Finance, Industry, Transportation, Commerce and Social Welfare, along with a representative of the Council of Consumers. Pending passage of the legislation creating this commission, the Council of Ministers recently decided to establish a temporary group called the **Inter-Institutional Commission on State Energy Regulation.** This four-person organization, comprised of the Deputy Ministers of Finance, Industry, Social Welfare and Prices, are delegated the COE's responsibility to protect consumers' interests with regard to the price and reliability of electric energy.

NEK, The Natsionalna Elektricheska Kompania, currently owns over 85% of Bulgaria's electric generating resources and essentially all of its transmission and distribution facilities. Its distribution system serves NEK's consumers through 28 branch organizations. NEK was formed as a joint-stock company in 1991. Its shareholders (currently the sole shareholder is the State, with voting power exercised by the Council of Ministers) elect a Chairman and six members to the Company's Supervisory Board. The Supervisory Board then appoints the six-member Managing Board, including the Company's President and Vice President.

NEK is now, and will be, the purchaser of all power sold to the grid by independents. It has negotiated parallel generation agreements with ten cogenerators and nine district heating plants, aggregating approximately 1000 MW of currently available capacity (a number of small hydroelectric facilities have also signed contracts with the utility, but they do not have consistent provisions). The agreement is a standard form of contract effective for one year. Prices currently paid to the independent suppliers are negotiated within a narrow band equal to NEK's own industrial tariff rate, less 15% to 18% for unavoidable administration costs and losses. A twenty percent premium is due to independent generators when they generate power at the request of NEK and would not otherwise be generating thermal energy for their own needs.

The NEK standard power purchase agreement (as found in the Appendix) contains many terms familiar to independent power developers in the US The provisions of Article 12, which requires payment by the utility on the day following receipt of the invoice, is less familiar. Other provisions commonly required by IPPs and utilities in the US and international market are not included, for several reasons.

First, the complexities associated with mobilizing international capital have been addressed in an earlier section. They obviously have not been relevant to NEK's negotiations with Bulgarian cogenerators to date.

Second, the price structure of the energy sector has historically provided no incentive to the Bulgarian industrial and district heating cogenerators to generate excess energy, and any such energy has been a necessary byproduct of each facility's own energy needs (see, for example, PPA Article 5). NEK should include more stringent dispatch and equivalent availability requirements in future cogeneration contracts.

Third, capital investment at cogeneration plants has been made independent of external power sales considerations, and the retail tariffs (and therefore the buyback rates) of the utility have been set without regard to capital recovery. This has resulted in negotiations based on variable cost-based pricing, adjusted annually to reflect changes in such costs. The determination of the utility's long-run marginal cost, including a capital recovery component, will provide a more realistic price signal to prospective sellers. Those sellers will also require more certainty of capital recovery than can be realized by annual renegotiations, with the associated potential for reductions in capital recovery factors. Independent generators will therefore require contracts with a fixed price component (normally the capacity portion of a

two-part tariff) for a term at least sufficient to retire debt obligations associated with the project.

In developing a new model agreement the utility may require much more detailed information about the design, financing, construction, and operation of an IPP than has been the case in the past. In addition it may require development and operational security deposits from the developer. It should establish clear performance milestones and dispatch, operating reliability, and availability targets which are tailored to the characteristics of the IPP and the needs of the utility. A system of penalties for deficient performance and bonuses for superior performance may also be considered. While the temperature- and part-load-dependent operating characteristics of the IPP's technology are not of direct concern to the utility, dispatch and variable pricing provisions should reflect operating reality. Likewise, capacity and reliability testing and evaluation should be done on a consistent basis for utility plants and IPPs.

One of the most difficult issues to incorporate into the IPP contract in any context is excuse of performance for force majeure, and particularly excuse for fuel interruptions. Again, the IPP should be required to perform with the same assurance of reliability as the utility would reasonably expect from its own units, if similarly situated. One of the primary advantages to a utility of contracting for independent power is the shifting of construction and (usually, non-fuel) operating risk to the IPP. The associated risks are readily controlled by the IPP, so the cost to the utility of that service should be quite small and outweighed by the benefits. It is not recommended, however, to allocate risks to IPPs which are beyond their control or beyond their expertise. The IPPs will then price the risk conservatively, either increasing the real price of power to the utility or leaving the market, leaving the risk with the utility in any event.

While US and international contracts are normally much more complex in structure than the current NEK form of agreement, in most fundamental respects the two are similar. With the above-noted elaborations to define the additional obligations and assumptions of both project as well as certain aspects of political risks by the parties, the NEK form should be readily adapted to future use. [See Chapter V, Recommendation 10]

Energoproekt, established in 1948, has acted as the planning, research, engineering and design group for the COE and NEK. It is in effect a fully integrated design and engineering firm organized into 7 divisions, including hydropower, thermal power, transmission and distribution, nuclear energy, automation, research, and engineering investigations. It has extensive domestic and international experience, having involvement with the design, construction or execution of over 100 major projects around the world.

b) Ministry of Industry

The Ministry of Industry has responsibility for a substantial number of energy-related sectors. The organizational chart found as Figure 6 illustrates the organization of the Ministry. It has Neftochim, which operates a large refinery at Bourgas, and two smaller refineries under its jurisdiction. It also controls petroleum products distribution and transportation fuel marketing through Petrol, and controls natural gas transportation through Bulgargaz, the state pipeline company. Finally, it controls the marketing of household fuels (briquettes, LPG and coal) through Toplivo. Mineral, oil and gas exploration is under the jurisdiction of yet another energy-related organization, the Committee of Geology. The Ministry of Industry has authority over a number of facilities which have a significant thermal load and might prove to have economic cogeneration potential, including the Bourgas petrochemical facility, the Kremikovtzi steel facility, and the Chimco Vratsa fertilizer plant.

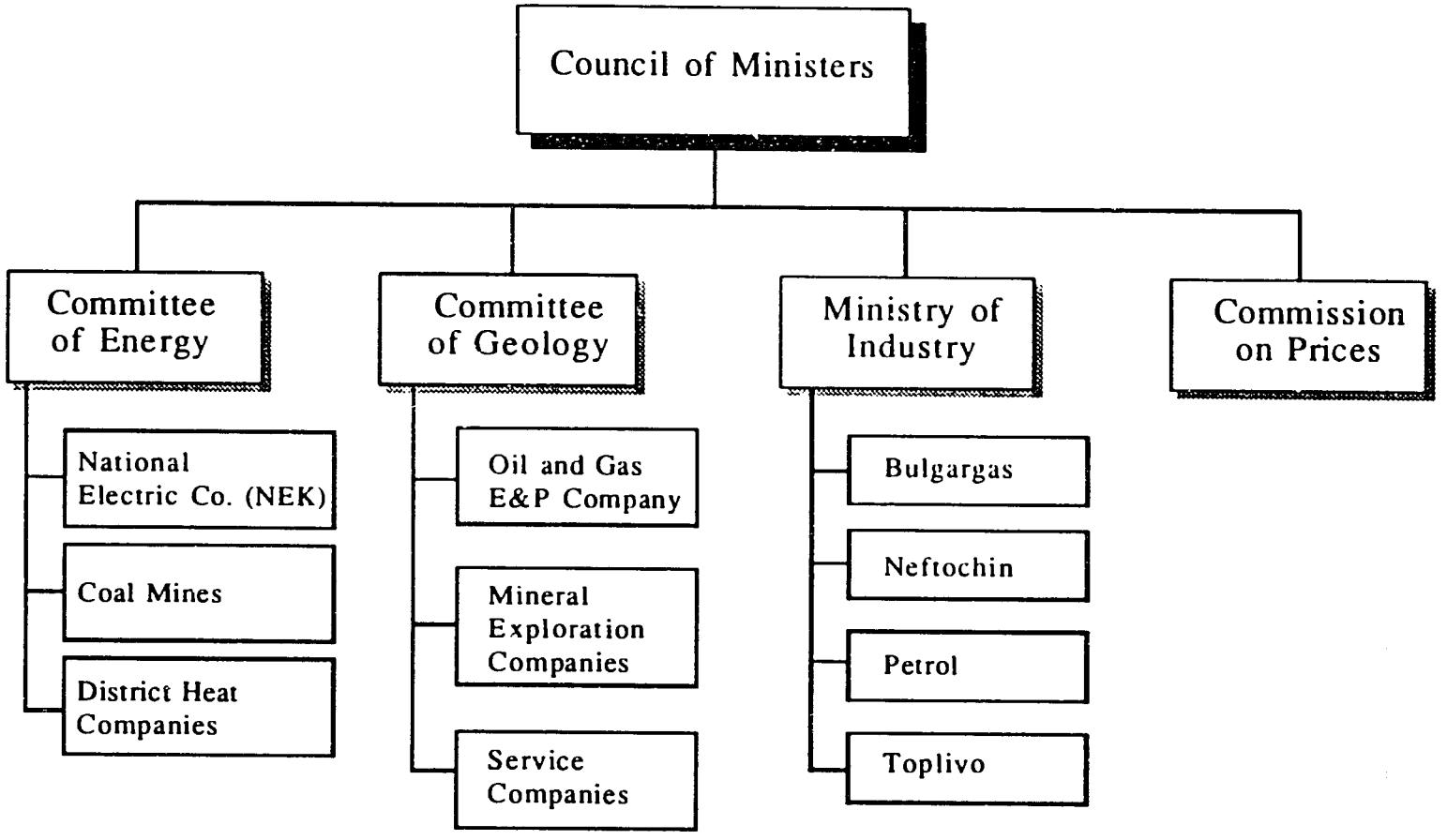
c) Ministry of the Environment

The Ministry of the Environment (MOE) has a broad Constitutional and statutory mandate to establish a clean and healthy environment in Bulgaria. As described earlier, it also has a great deal of discretion under the Law on the Environment in the review of proposed construction or modifications. It maintains headquarters and a research center in Sofia and is organized into six departments, including water, air and soil protection. The Monitoring, Research and Information Center collects and publishes ambient data from its monitoring activities and other sources (the Ministry of Health and the Institute of Hydrology and Meteorology also collect environmental data) in a quarterly bulletin. The MOE is divided for administrative purposes into sixteen regions, called "Regional Environmental Inspectorates," which are responsible for surveillance and enforcement of the Law on the Environment. The regional division boundaries are not coterminous with the administrative Districts described in Section (e) below.

Ambient air data is collected at over 100 sampling locations, 60 of which are operated by the MOE, and almost all of which are located adjacent to urban and industrial complexes. In addition, the MOE has a mobile monitoring lab. Historical data are of questionable value due to irregular or inconsistent sampling and testing procedures. However, the European Community's PHARE program is providing substantial funding for new equipment and training programs and data quality is expected to improve accordingly. However, it will remain difficult to integrate information collected by the various agencies as the nine administrative oblasts, the 16 Regional Environmental Inspectorates and the 28 districts used by the Ministry of Health all have different boundaries.

Water quality data are collected for surface waters at approximately 200 sampling points and at 276 groundwater monitoring points. A hydrogeology handbook is published by the MOE. The MOE also periodically monitors point source discharges.

Bulgaria: Current Organization of the Energy Sector



Source: World Bank, 1992

Figure 6

The process for obtaining environmental approvals was discussed earlier in this report, as were the EEE regulations stipulating the lead jurisdiction for review of environmental impact. Whether it is the headquarters or the Regional Inspectorate, prospective investors should expect significant delays in review due to the enormous responsibilities which are assigned to the MOE staff and the limited resources available to them.

Upon approval of the EEE, application for a construction permit can be made to The Ministry of Construction and Regional Development, which has overall responsibility for building codes and authorizations. For smaller projects of primarily local concern, MOE will likely delegate its authority to the Municipality concerned. For projects of national significance, review and approval will be coordinated from Sofia.

It was noted in the prior section that in addition to the Law on the Environment there are more than 120 older statutes regulating environmental matters, including seven which may be of direct relevance to a proposed power project. While they do not have the strong enforcement provisions of the new law, they technically remain in effect and should be reviewed by prospective investors.

d) National Council on Water

The primary role of the National Council on Water (NCW), which has 12 members representing the large water users of the nation, currently is the preparation of monthly water allocation plans for water resources from 22 multiple purpose dams in Bulgaria. The COE, which controls the impoundments, is responsible for implementation of the plan. The priority of use is as follows: human consumption, livestock consumption, industrial needs, agricultural needs, and power generation. There are recent instances of shortages even for human consumption purposes, and, in fact, in early summer 1993 reservoir levels are critically low.

The issuance of a Certificate of Need by the COE will be conditioned on coordination with the NCW. The siting and design of new thermal plants will certainly have to take into account the occasional scarcity of water for power generation uses. It is unlikely that the NCW would have any objection to a run-of-river hydroelectric facility, or to an impoundment for which the operation would not interfere with downstream allocations. On the other hand, subordination of operation of a new project to the NCW's priorities might well reduce the value of the facility for power generation purposes.

e) Local District and Municipal Governments

Bulgaria is divided into approximately 250 Municipalities, or "Obshtina," each of which has a popularly elected Municipal Council and Mayor. The Municipal Council in turn appoints an administrative staff to perform executive functions for the Municipality. Each Municipality has a property office which maintains records of land divisions and ownership

within its boundaries. However, recordation of mortgages is accomplished at Notarial registries which are maintained in conjunction with, and are located at, the local court for the jurisdiction. While investigations of ownership records should be relatively straightforward in most Municipalities, mortgage records are sometimes incomplete and often not maintained in any systematic fashion.

The Municipal Council has jurisdiction over matters of local interest other than those relating to the restitution of agricultural land. It collects local taxes. It also has the authority to issue bonds. Municipalities are responsible for providing local utility services such as water, waste water and solid waste disposal. They can aggregate themselves to form a special purpose district, or "okolija," which can provide inter-Municipal services such as water supply, waste water disposal, or public transport.

Restitution of agricultural land is under the local jurisdiction of the Municipal Land Commission (MLC), the members and Chairman of which are appointed in each Municipality by the Minister of Agriculture. Each MLC is required by the Law on the Ownership and the Use of Agricultural Lands to maintain a register for all applications for restitution and for all decisions rendered by the MLC.

The Municipalities outside Sofia are aggregated into eight regions, or "Oblasts," which serve as administrative units of the national government. The Governor of the Oblast is appointed by the Council of Ministers for a four year term. The Municipalities comprising Sofia are considered a special region and have a popularly elected Mayor, rather than an appointed Governor.

As noted earlier, the Municipalities may soon be the owners of the district heating plants, They would then be responsible for management or privatization of those assets. The transfer of the district heating plants to the Municipalities is under active debate in Parliament, since most Municipalities are ill-equipped to manage them.

f) Conclusions to the Institutional Structure Evaluation

As noted in the conclusions to the previous section, Bulgaria has taken a number of positive steps in establishing the necessary IPP policy and institutional framework, as found in the leadership being taken by COE and NEK and the draft Law on Electrical Energy. The passage of the Law on Electrical Energy by the Parliament will be an important step in developing an IPP market, particularly with regards to the establishment of an independent regulatory body, but the effectiveness of the draft Law in creating an active long term market will depend on the policy and regulatory factors already cited. IPP developers negotiating specific projects will be equally concerned with institutional attitudes and competence.

The success of independent power will depend to a large extent on the attitudes of the institutions involved. In the US independent power industry development experience, utilities

initially had a bias in favor of building their own plants. Over time they developed an appreciation for role of independent generation. The extent to which the independent power industry develops in Bulgaria will depend on whether NEK sees it in its own interest to encourage this competitive generation market. It is recommended that NEK develop an institutional policy in favor of independent power and specific goals be set for NEK and its negotiating team against which specific progress can be measured. [See Recommendations 6 and 7 of Chapter V]

The use of integrated resource planning techniques to establish pricing and to evaluate proposals will also demonstrate NEK's commitment to a rational and equitable selection process. [See Recommendation 5 of Chapter V]. Further comfort would come from the development of a model contract for large projects addressing the principal non-price terms of concern to investors. [See Chapter V, Recommendation 10; this issue, and the related issues addressed in recommendations 6 and 8, are the most critical for sponsors of specific projects prior to the establishment of a stable and favorable regulatory framework.]

Long term success will also depend on the attitude and authority of the COE. It is ultimately the regulatory authority which must define the policies of the utility sector, and then encourage or enforce compliance with those policies. The development of detailed regulations by or under the supervision of the COE will be an essential element in defining the policies, but the application of those regulations will be crucial to the confidence of the international markets.

To that end, the staff of the regulatory body should be selected and trained to provide full understanding of all issues which may affect utility policy or influence the analysis and decisions of the NEK negotiating team. [See Chapter V, Recommendation 2] Similarly, the NEK negotiating team should be selected and trained to assure their familiarity with the principles and practices of utility operations and power contract negotiations. [See Chapter V, Recommendation 8]

Lastly, the attitudes and capabilities of other governmental institutions will be important. The MOE, in particular, will undoubtedly play an active role in the review of power plant projects. The control of environmental impacts from power plants is a complex and technical matter and is likely to strain the limited resources of that staff. It is in the interest of all concerned to include representatives of other agencies in educational processes which will increase their understanding of the potential and the limitations of power plant emissions controls. Close cooperation between different government agencies on the various permitting requirements for power projects (e.g. environmental, water rights, land use, etc.), will greatly facilitate the process of developing a commercial independent power market.

V. SUGGESTED APPROACHES FOR THE INTRODUCTION OF A POLICY AND INSTITUTIONAL FRAMEWORK TO PROMOTE INDEPENDENT POWER AND PRIVATE INVESTMENT

Bulgaria is currently evolving from a centrally-planned economy to a market economy with a democratic government. The vast majority of relevant statutes and regulations are either newly created or do not yet exist. Even for those which do exist, the institutions which will administer the statutes and regulations are either newly created or are assuming new responsibilities. There is no history, therefore, which prospective investors can evaluate in order to gain confidence in the impartiality of the decision-making process. As a result, it would be desirable to strengthen the policy and institutional framework according to the recommendations discussed below.

1) Strengthen Components of Legislation to Facilitate Independent Power

The current draft of the Law on Energy will, when enacted, establish a favorable policy for the development of independent power in Bulgaria. In particular, it establishes a policy of favorable conditions for independent power, authorizes the execution of long-term power purchase agreements by the utility and establishes relatively clear conditions for the issuance of Certificates of Need.

However, the current draft does not provide for any governmental agency to have authority to issue a final approval on behalf of the Government of Bulgaria. In the US, the state regulatory commission's issuance of a Certificate of Need (or the FERC's issuance of a hydroelectric license) typically signals the satisfaction of all governmental review requirements other than emissions permits and local construction permits. In Bulgaria, there may be Ministries and governmental organizations which have authority over one or more aspects of a proposed project but which are not easily identified by prospective investors. The consolidation of many project review functions through the Evaluation of the Effect on the Environment ("EEE") process is helpful, although that process does not result in a final, determinative authorization to proceed with the project from any organization other than The Ministry of the Environment. It is, therefore, recommended that the EEE determination be made binding on any agency consulted or notified during the EEE process. It is further recommended that one government agency have the responsibility both to identify and coordinate with all jurisdictional authorities not included in the EEE process, and to make a final determination that the governmental approval process is complete. This coordination could logically be accomplished by staff of the regulatory body with the issuance of the Certificate of Need, which would signal the final approval of the project.

Similarly, as noted in the body of this report, there are other statutes which have ambiguities which could inhibit development of an independent power sector in Bulgaria. The privatization law, for example, apparently provides to former landowners preemptive rights

in state or municipal enterprises built on expropriated land, and makes voidable certain "disposal transactions," presumably sales, under "unfavorable conditions." Ambiguities also exist in other statutes, for example the Law on Ownership and Use of Agricultural Lands, which may make it difficult to assure clear title to prospective purchasers of formerly agricultural land. It is, therefore, recommended that a comprehensive review of all Bulgarian laws affecting the environment or property rights be undertaken, with the goal of identifying and clarifying any potential conflicts or inconsistencies.

2) Establish Power Sector Regulatory Institution and Ensure Staffing by Qualified Regulators

The absence of any history of utility regulation in Bulgaria makes it imperative that any such regulatory body be established both with clearly defined functions and authorities, with qualified staff and with resources adequate to fulfill their responsibilities. As the Bulgarian Government completes its deliberations over the regulatory model to be used, a study of necessary resources will need to be performed. Issues to be addressed at a minimum would be:

- Staffing and training of regulatory commission personnel in generation expansion planning and integrated resource planning;
- training of regulatory commission personnel in finance and accounting;
- hardware and software necessary to monitor and corroborate the integrated resource plans of the franchised utilities; and
- training of regulatory commission personnel in utility operational issues.

3) Develop and Publish Detailed Regulations

The evolving and dynamic nature of regulation in the power sector in countries worldwide, combined with the unaccustomed responsibilities of the entities implementing Bulgaria's utility regulatory systems, will give rise to concern by prospective investors about arbitrary or capricious administration of the regulatory policies. It is, therefore, important that the implementing regulations define with precision the requirements, for example, for timing and approval of generation expansion needs. It is recommended that the regulatory body consider requiring significant detail in utility IRP submittals while allowing NEK enough flexibility to optimize the process over time. Such details might include, in addition to the usual procedural guidelines, substantive technical requirements for type, format and availability of data, and modeling protocols, analyses and results.

The regulations will need to also set out detailed requirements for solicitations or proposals to supply additional capacity. These requirements should assure that capacity expansions and renovations are consistent with the Integrated Resource Plan and other policies of the Bulgarian government. Such regulations might prohibit the recovery of capital

investments made by NEK without authorization of the regulatory body and require the solicitation and analysis of alternative proposals prior to authorizing the utility to proceed with its own construction.

4) Establish Central Information Clearinghouse for IPP Developers

In order to counteract the unfamiliarity of many potential investors with Bulgaria and its institutions, it is recommended that the Committee of Energy (COE) or NEK assemble and make available information on the institutional framework, as well as technical data, such as hydrology at prospective hydroelectric sites or thermal demand at cogeneration facilities, which would be of interest to project developers.

COE or NEK would be advised to consider making the information on the utility's least-cost plan assumptions, modeling methodology and results available to prospective investors. Most importantly, this would allow project developers to optimize their project configurations to the needs of (and the benefit of) the utility system. It would also give investors added comfort that the technical and economic evaluation process is handled equitably.

Finally, it is recommended that an information package providing potential power developers with relevant details about conditions in Bulgaria be prepared and distributed on request and at industry conferences.

5) Use Integrated Resource Planning (IRP) to Establish Long-Run Marginal and Avoided Cost pricing and Project Selection

One goal of the IRP planning process should be to establish the power project costs from which project developers as well as utility planners can evaluate the cost-effectiveness of their proposals. It should be recognized that these cost figures will change over time based on the state of technology and market conditions. In the face of uncertainty, the fair estimation of such costs is an essential component of rational utility and IPP decision making. It is also necessary to provide independent suppliers with a fair price for their production while protecting the utility from paying windfall profits to those suppliers.

Proposed projects large enough to have an impact on system economics should be evaluated in the utility's model and compared to the utility's base case plan with respect to economics and reliability.

6) Establish Consistent Policy Regarding Government Guarantees of Utility Performance

Given the limited experience of NEK and other Bulgarian public and private entities in operating as financially sound and independent institutions, it is highly likely that a foreign

investor and developer would require the Government of Bulgaria (GOB) to provide guarantees and other incentives. For instance, the GOB may need to guarantee that NEK will honor its commitments in the power purchase agreement with a developer. Should NEK, for whatever reason, not be able to pay the developer according to the terms of a signed power purchase agreement, the GOB would provide the financial resources necessary to honor the contract. Developers may also seek guarantees from the GOB regarding the performance of government-owned fuel suppliers and the National Bank of Bulgaria. Finally, it is likely that the GOB will be asked for support with respect to foreign exchange availability, force majeure, and other related issues.

Based on the requirements in the international independent power market, the GOB will need to develop a policy regarding what types of guarantees and incentives it is willing to provide. In the early phases of developing Bulgaria's independent power market, it may be necessary to provide substantial guarantees and assistance, but as the IPP market matures and the perceived risks diminish, it would be possible to reduce the type and scope of support offered.

7) Establish Policy for Soliciting Independent Power

NEK may chose to negotiate with the proponents of unsolicited proposals in the early phases of IPP market development in order to overcome the unfamiliarity of project sponsors with conditions in Bulgaria. In more mature market phases and when project precedents have been established, it may be desirable to move to a competitive bidding format. The advantage of competitive bidding is that it can result in lower electricity rates and more favorable terms for the utility and the consumer. Given the substantial costs of preparing an independent power proposal, however, competitive bidding can slow down the project selection process and discourage participation by developers.

8) Establish and Train a Multi-Disciplinary Review and Negotiations Team

In order to protect the purchasing utility's interest while allowing for expeditious selection of project proposals and resolution of unresolved contract issues with their sponsors, it is recommended that a multi-disciplinary review and negotiation team be established at NEK. The team should be comprised of engineers with experience in generation, transmission and distribution operations, fuel procurement, planning and central dispatch. It would also include lawyers specialized in Bulgarian administrative law and procedure. All members of the team would receive training in the principles of contract law and international and project finance.

9) Provide Standard Offer Contracts for Small Renewable and Cogeneration Projects

The development of smaller projects can prove significant to Bulgaria by expanding the use of indigenous energy resources and renewable fuels. However, the transaction costs associated with extended negotiations of price and terms with a purchasing utility can be a major deterrent to potential investors. The elimination of this deterrent through establishment of a "Standard Offer" is recommended.

To implement this recommendation, it will be necessary to establish a class of favored generation technologies and a maximum size for each project which will permit economic development of the resource and the project without adversely affecting NEK's planning or operating characteristics. It will also be necessary to establish a purchase tariff (including terms and conditions) which is structured to assure reliable operation of the facility and pricing which fairly reflects avoided costs. Energy price indexing should be considered, as should capital cost indexing. The terms of the Standard Offer would be non-negotiable; nonetheless the project sponsor would create an effective long-term contract by merely signing and delivering the offer.

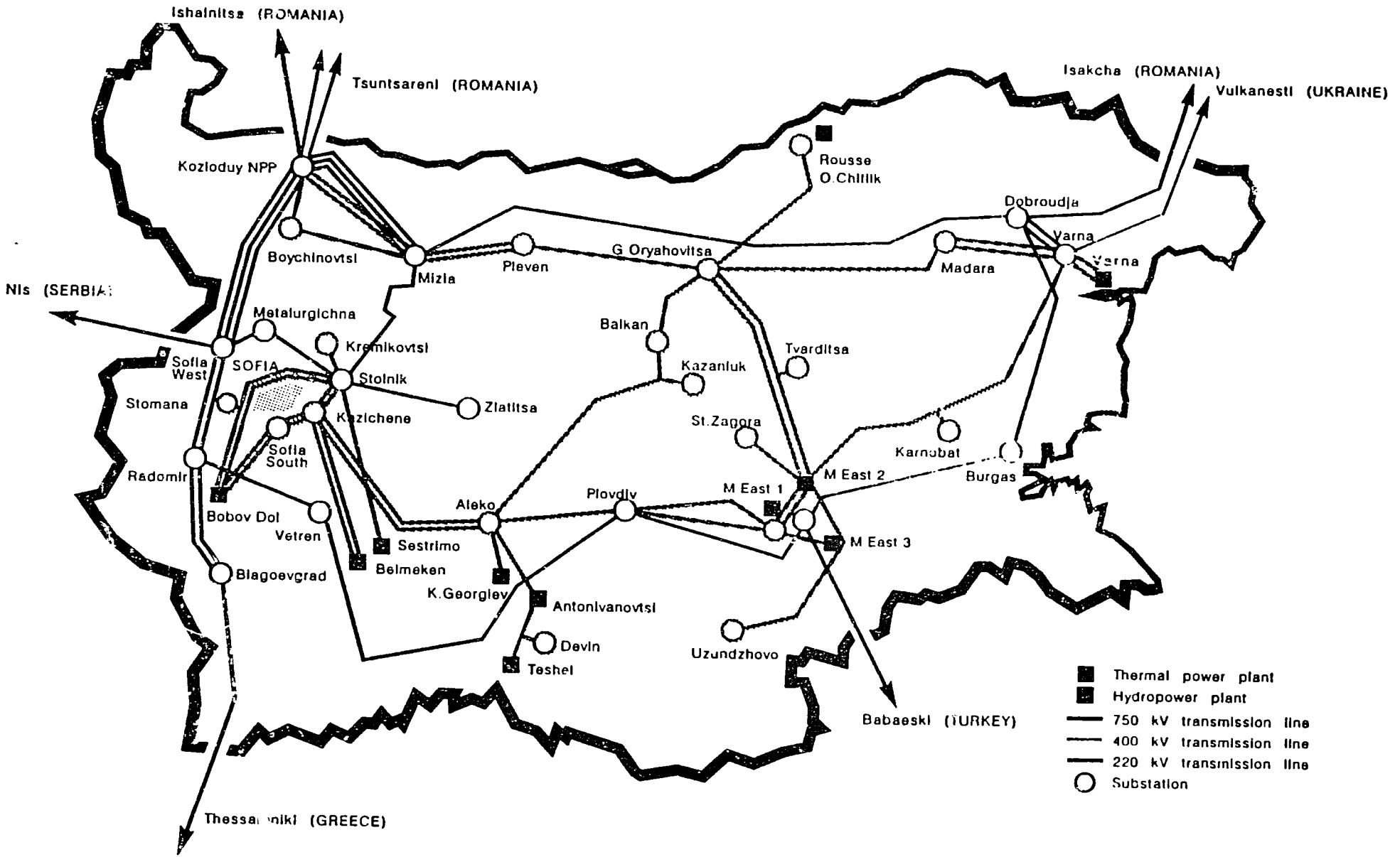
10) Provide Standard non-Price Terms for Large Projects

For larger projects it is not recommended to provide "Standard Offer" contracts. NEK will need to have much more detailed contract provisions and project information because large IPPs can have a material effect on utility system economics and reliability. The non-price terms and conditions under which the purchasing utility proposes to buy power are just as important as the price. The preparation by NEK of a model contract which addresses the principal non-price concerns of investors (such as discussed in Recommendation 6) and allocates risk fairly, could only serve to promote the rapid development of independent power in Bulgaria.

Appendix A

Map of Bulgaria Power System

Electric power system of Bulgaria



Source: NEK

Appendix B

Statistics on Major Power Project Rehabilitation and Repowering Opportunities in Bulgaria

BULGARIA DISTRICT HEATING PLANT REHABILITATION/REPOWERING OPTIONS

District Heating Plant	Retirement Year	Rehab Year	Power After Rehab (MW)	Increase in MW	Rehab Cost $/kW
Sofia					
Unit 4	1994				
Unit 5	1994				
Unit 6	2010	1995	104	99	300
Unit 8	2011	1996	240	220	300
Tsaicho Kostov					
Unit 1	2010	1995	142	122	275
Unit 2	2010	1995	142	122	275
Unit 3	2011	1996	142	122	275
Unit 4	2011	1996	142	122	275
Unit 5	2011	1996	312	257	275
Russe					
Unit 1	1998				
Unit 2	2000				
Unit 3	2010	1995	110	25	225
Unit 4	2011	1996	110	25	225
Unit 5	2013	1998	60	10	315
Unit 6	2015	2000	60	10	315
Shuman					
Unit 1	2010	1995	54	50	482
Unit 2	2011	1996	82	78	488
Unit 3	2011	1996	46	42	472
Republica, Pernick					
Unit 2	1993				
Unit 3	2009	1994	30	10	50
Unit 4	2009	1994	25	5	50
Unit 5	2010	1995	55	15	50
Unit 6	2026				
Pleven					
Unit 1	2012	1997	83	75	466
Unit 2	2012	1997	94	86	473
Unit 3	2013	1998	118	110	486
Plovdiv					
Unit 1	2005				
Unit 2	2011	1995	119	99	308
Unit 3	2009	1994	142	122	275

Source: World Bank, Bulgaria Power Demand and Supply Options, May 4, 1993

BULGARIA INDUSTRIAL PLANT REHABILITATION/REPOWERING OPTIONS

Industrial Plants	Retirement Year	Rehab Year	Power After Rehab (MW)	Increase MW	Rehab Cost $/kW
Burgas					
Unit 1	2012	1997	498	398	300
Unit 2	2012	1997	584	524	289
Devnia					
Unit 2	2010	1995	332	292	340
Unit 3	2011	1996	162	152	344
Unit 4	2011	1996	122	112	357
Kremikovtzi					
Unit 1					
Unit 2	2013	1998	238	193	306
Unit 3	2013	1998	238	228	307
Vratsa	2013	1998	284	244	274
Stara Zagora					
Unit 2	2013	1998	236	224	356

Source: World Bank, Bulgaria Power Demand and Supply Options, May 4, 1993

MAJOR BULGARIAN POWER PLANT CANDIDATES FOR REHABILITATION

Plant	Retirement Year	Rehab Year	Power After Rehab Gross MW	Increase in Output MW	Rehab Cost $/kW
Maritsa East 2					
Unit 1	2010	1995	150	30	141
Unit 2	2011	1996	150	30	141
Unit 3	2012	1997	150	30	141
Unit 4	2013	1998	150	30	141
Unit 5	2014				
Unit 6	2015				
Unit 7	2018				
Unit 8	2022				
Varna					
Unit 1	2010	1995	210	0	221
Unit 2	2010	1995	210	0	221
Unit 3	2010	1995	210	0	221
Unit 4	2011	1996	210	0	141
Unit 5	2011	1996	210	0	141
Unit 6	2012	1997	210	0	141
Bobov Dol					
Unit 1	2009	1994	200	20	173
Unit 2	2010	1995	200	20	173
Unit 3	2011	1996	200	20	173

Source: World Bank, Bulgaria Power Demand and Supply Options, May 4, 1993

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Unit 6	2015				
Unit 7	2018				
Unit 8	2022				
Varna					
Unit 1	2010	1995	210	0	221
Unit 2	2010	1995	210	0	221
Unit 3	2010	1995	210	0	221
Unit 4	2011	1996	210	0	141
Unit 5	2011	1996	210	0	141
Unit 6	2012	1997	210	0	141
Bobov Dol					
Unit 1	2009	1994	200	20	173
Unit 2	2010	1995	200	20	173
Unit 3	2011	1996	200	20	173

Source: World Bank, Bulgaria Power Demand and Supply Options, May 4, 1993

Appendix C

Standard Power Purchase Contract Between NEK and District Heating or Industrial Cogenerators

Standard 1993 Contract
Between NEK and
District Heating or Industrial Cogenerators

Today, 1993, in Sofia, between:
_____, represented by
_____, hereafter called "IPP", on the one side
and Natzionalna Elektricheska Kompania - Joint Stock Company, represented by the Chairman of the Board of Directors DYANKO DOBREV, hereafter called "NEK" concluded this contract, as follows:

I. SUBJECT OF THE CONTRACT

Article 1. Subject of this contract is the insurance of parallel work of the generating capacity of the IPP with the country's electricity system and the purchase of electricity during 1993.

NEK maintains the electricity system in normal condition of parallel work and ensures the supply to the consumers of the IPP in case of failure.

II. TECHNICAL AND ORGANIZATIONAL CONDITION

Article 2. The electricity is scheduled by quarters, months and tariff zones according to the specification which is an integral part of this contract.

In case a change in the quantities of electricity is needed, the parties make the required amendments of the contract not later than 5 days before the end of the respective quarter.

Article 3. The Maintenance and Repair Program of the generators of the IPP with fixed starting dates and length is coordinated with NEK. The changes should be coordinated in writing 5 days before small-scale repairs or 30 days before capital repairs.

Turbogenerators or stream generators can be disconnected and repairs can be conducted after approval of an operational application by the District Dispatch.

Article 4. When requested by the Central Dispatch, the IPP is obliged to change the reactive power of the generators within the limits of their technical specifications.

Compliance with this obligations is ascertained by monthly revision of the meters for reactive energy on the generators of the IPP and of the hourly records of the reactor power in the operational journals of the IPP.

Article 5. The IPP will sell the agreed electricity on the basis of load on the steam extraction according to the characteristics of the turbogenerators which are an integral part of this contract.

Article 6. On request by the Central Dispatch for greater quantities of electricity than produced by the IPP according to the steam extraction by taking into operation additional spare equipment for a definite period of time, NEK pays the additional quantities at a price 20% higher than the average for the month, against an invoice according to the provisions of Article 12.

The two parties are obliged to fix the beginning and the end of such an event in the respective operational journal of the District Dispatch and the IPP.

The quantity of electricity under this article is determined by a bilateral protocol between the respective District Dispatch of NEK and the IPP, which is prepared on the basis of the records in the operational documentation.

Article 7. The IPP is obliged to keep the equipment in good condition, to exercise control and to notify NEK immediately in case of switch-on of the relay protection, automation and signalization of the equipment, related to the functioning of the electricity system, as well as of the communication means and telemechanics.

Article 8. The IPP is obliged to keep in good condition the devices for automatic frequency disconnection and the other automatic regulation devices, so that its own demands, the demands of the clients of the IPP and some important clients of the electricity system are met in case of disconnection of the IPP.

The set-up of the relay protection and automatics, ensuring the combined work of the IPP with the electricity system in normal and emergency regimes, is in the competence of the NEK's bodies and is carried out against payment when caused by changes in the IPP.

The IPP is obliged to follow all NEK's instructions with regard to the relay protection and automatics, including the after-failure tests of these devices.

Article 9. The IPP is obliged to execute the orders, issued by the District Dispatch or NEK, related to the functioning of the equipment which is operationally linked with the District Dispatch and the Central Dispatch, in compliance with the instructions for operational management of the electricity system.

III. MEASURING AND PAYMENT OF ELECTRICITY

Article 10. The purchased electricity will be measured by means of electrometers for active and reactive energy, provided and installed by the IPP on the property borderline between the equipment of the two parties.

The reading of the electrometers is done at 0 a.m. on the first date of each month by authorized representatives of the contracting parties, who draw up a protocol for the purchased during the month electricity.

Testing, regulation and replacement of the electrometers, according to which the electricity is measured and purchased, is carried out at the request of one of the parties in the presence of representatives of both parties.

Article 11. The IPP sell to NEK the contracted quantity of electricity according to the indications of the three-tariff electrometers for the respective month for the tariff zones.

Article 12. The payment for the electricity is effected by direct bank remittance by payment order at prices according to the actual Electricity Tariff.

The IPP is obliged to submit to NEK an invoice for the quantity of electricity sold during the previous month not later than the fifth day of the current month.

NEK submits a payment order to the servicing bank on the day following the day of receipt of the invoice.

In case of delayed payment, NEK pays the central interest rate on the amount due.

IV. PENALTIES

Article 13. In case of violation of Art. 3, Art. 4, Art. 8 and Art. 9 the IPP pays NEK a penalty amounting to 0.05% of the value of the quantity of electricity contracted for the respective month.

Violation of the contract are ascertained by a commission, comprising members of both parties.

Article 14. In case the purchased electricity exceeds or is less by more than 5% than the contracted amount, the IPP pays NEK a penalty for the difference, amounting to 10% of its value.

The IPP assumes no liability for electricity not supplied because of damages in the transmission equipment of NEK.

In cases of natural disaster (acts of God), both parties are exempted from liability.

V. GENERAL PROVISIONS

Article 15. The parties are obliged to exchange lists of the names of the officials, authorized to take operational decisions, as well as of those, responsible for measuring the purchased electricity.

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Article 16. The addresses and the bank accounts of the parties are:

VENDOR:
Company: _____
Headquarters Address: _____
Court of Registration: _____
Number of Registration: _____
Bank Account: _____

BUYER:
NEK Joint Stock Company
Sofia, 8 Triaditza Street
Registered with the Sofia District Court
Number of Registration: 196, volume 5, register II, p. 98
Bank Account: 421 130 165 - 001 - 5, Commercial Bank "Sofia"

If changes in the registration , addresses or bank accounts occur, the parties are obliged to send notification in writing within a period of 5 days.

Article 17. This contract can be amended, supplemented and extended by bilateral written agreement between the parties.

Article 18. Issues not addressed by this contract will be subject to the existing normative acts.

Article 19. Disputes between the parties concerning the implementation of this contract shall be solved by negotiations. When no agreement is reached, the dispute shall be decided upon by voluntary arbitration at the Bulgarian Chamber of Commerce and Industry.

Integral part of this contract are the specification, the repair program, and the regime characteristics of the turbogenerators.

This contract has been prepared in two uniform copies, one for each party, and takes effect on the day of signature.

VENDOR:

_____

_____

BUYER:
NEK
Chairman
/D. Dobrev/