PN-ACC-217

BULGARIA TARIFF IMPLEMENTATION PROJECT

Electricity and District Heating Tariffs

FINAL REPORT

Prepared Under Contract to

U.S. Agency for International Development

Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics ■ Contract No. DHR-0030-C-00-5016-00

Bechtel International, Inc.

July 1996

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Executive Summary

OVERVIEW

This report describes the Bulgarian Energy Tariff Implementation Project performed by Bechtel, under contract with the United States Agency for International Development (USAID). The scope of the project includes electricity tariffs for the National Electric Company (NEK), and district heating tariffs for Sofia District Heating Company. Project guidance and support has been provided by the Bulgarian Energy Tariff Working Group, made up of representatives from the Committee of Energy (CoE), NEK, the Commission of Prices (CoP), the Ministry of Finance (MoF), and Energoproekt. (Note that in June 1996, the CoE was replaced by the newly established Ministry of Energy and Energy Resources.)

This project has benefited from the open sharing of information and knowledge between the Bechtel team, the Bulgarian Tariff Working Group, Bulgarian industry advisors, the World Bank, EBRD, and USAID. NEK and CoE provided data and analysis underlying the scenario tariffs presented in this report. Our quantitative analysis has advanced on prior work by NEK, Bechtel, and EPS Solutions to develop the IRP Manager computer model of the Bulgarian electric sector. Workshops on the theory and practice of tariff-setting were held in Sofia in October 1995 and February 1996. Arthur Andersen consultants organized portions of the first workshop. Two other reports have been published as part of this project, the Workshop 1 Summary Report (December 1995), and the project Interim Report (February 1996), which is essentially a working version of this Final Report.

The goal of the project is to provide assistance in implementing a cost-based tariff-setting process for electricity and district heating supply, transmission, and distribution services. We present scenario estimates of the level and structure of tariffs based on cost-of-service and marginal cost principles. These analyses are practical illustrations of the tariff-setting process, and the results are useful benchmark comparisons with current tariffs.

KEY RECOMMENDATIONS

At the time of this report, electricity and district heating tariffs to end users are significantly below utility costs to provide the services. Transitioning to cost-based levels will ensure the financial viability of NEK and the district heating companies, eliminate subsidies provided at the expense of future consumers, and minimize price distortions between competing energy sources. Prices should be raised as soon as possible in an orderly transition to cost-based pricing.

The buyback tariff for generation provided to NEK by industrial and combined heat and power producers has recently been increased approaching the short run marginal cost of generation for NEK's system, but is below LRMC. The price increase is an important step towards fair pricing. Fair pricing requires that power producers be compensated for the incremental value they provide to the electricity system.

The cost-based tariff-setting process relies on an institutional framework that generates the necessary tariff data and analysis; regulates according to an open, transparent, and depoliticized

set of rules; and provides proper incentives and rewards for reliable and cost-efficient utility services. In contrast, the current system of direct government control of tariffs too often loses sight of the cost basis for tariffs. We recommend adopting a transparent, regulated, institutional structure with a high degree of autonomy for tariff-setting. Regulatory mechanisms should reward utilities based on performance, and encourage competition where possible.

TARIFF PROCESS

The tariff-setting process illustrated in this report includes the following elements:

- Analyzing the current structures of electricity and district heating tariffs
- Estimating the financial requirements of NEK and Sofia District Heating
- Forecasting the long-run marginal costs of electricity and district heating generation, transmission, and distribution
- Developing tariffs that take into account long-run marginal cost, financial requirements, and social considerations

This tariff process aims to fully recover the costs of owning and operating the utility, while at the same time providing efficient pricing signals to consumers. These objectives are consistent with pricing in a market economy. Cost recovery enables the utility to operate free of deficits and to access international sources of finance for required capital expenditures. Use of marginal cost-based pricing signals promotes efficient utility service consumption levels. Aside from cost recovery and efficient pricing, tariffs must also be designed to address important social equity and economic development issues, such as protecting jobs and assisting economically disadvantaged groups. These considerations necessitate a careful transition to cost-based levels.

Utility tariffs recognize that customers must share jointly in the economic responsibility for equipment which supplies service to more than one customer at the same time. Utility pricing requires allocating the cost-of-service to customers based on the relative usage of the system by each customer. Cost-based pricing requires a tariff-setting framework with the following structure:

- *Classification of customers.* The broad objective for customer class groupings is to aggregate those customers who have reasonably homogeneous load characteristics and associated cost-of-service.
- *Cost allocation to customer classes.* Capital, operating, and financial expenditures are classified as either *demand-*, *energy-*, or *customer-related costs*. These costs are allocated to customers on the basis of usage. Costs for transmission and distribution facilities and losses are higher for low voltage customers who use the entire network than for high voltage customers who use primarily the high voltage facilities. The extent of metering places practical limitations on the cost differentiation that can be captured in tariffs.

- *Tariff design.* Tariff design involves complex judgments and the weighing of sometimes conflicting objectives. Important tariff design issues include the social equity of inter-class and inter-generational subsidies, and price impacts on the Bulgarian economy.

We envision tariffs based on a hybrid of cost-of-service and long-run marginal cost (LRMC). There is the potential to implement any of several alternative tariff designs that recover the overall revenue requirement and, to a greater or lesser degree, meet the condition of marginal cost pricing for incremental consumption. We note that this is a traditional approach to tariff-setting compared to the emerging competitive model that allows market dynamics to set prices for electricity services. We anticipate that as the market economy develops in Bulgaria, the power and heat industries will eventually adopt elements of market pricing.

ILLUSTRATIVE TARIFF ANALYSIS

An important objective of the Bulgaria Tariff Implementation Project is to develop scenario tariff analyses that illustrate cost-based tariffs and provide useful benchmark comparisons with current tariffs. The following sections summarize the assumptions and results for our scenario tariff analysis.

Planning Assumptions

Electricity Demand

With the demise of its centrally planned economy in the late-1980s, Bulgaria experienced two significant drops in electricity demand around 1985 and 1990. Now that the country is transitioning to a market economy, future electricity demand in Bulgaria is difficult to forecast. Electricity demand appears to be on the upswing, having hit bottom during the period 1992-94. Estimates are that within the next 10 years, electricity demand will once again reach the historic maximum levels of the late 1980s. Although the demand forecast used in the tariff project shows a steadily increasing trend, there is the potential for load growth to be offset by reduced usage for electric heating and electric-intensive heavy industry, depending on the pricing and availability of alternative fuels, the prospects for industrial competitiveness, and other factors.

The demand forecast used for our scenario tariff analysis was current at the start of 1996. At the time of this report, demand has been declining, and presumably this decreasing trend will not change through the end of the year.

Figure ES-1 shows forecast annual electric energy demand by customer class. The *overall* demand forecast, which has been used by NEK in its least-cost planning activities with the World Bank, is slightly below the NEK medium scenario, and falls in the mid-range of the high and low forecasts developed in October 1995 by the independent group advising the Prime Minister.

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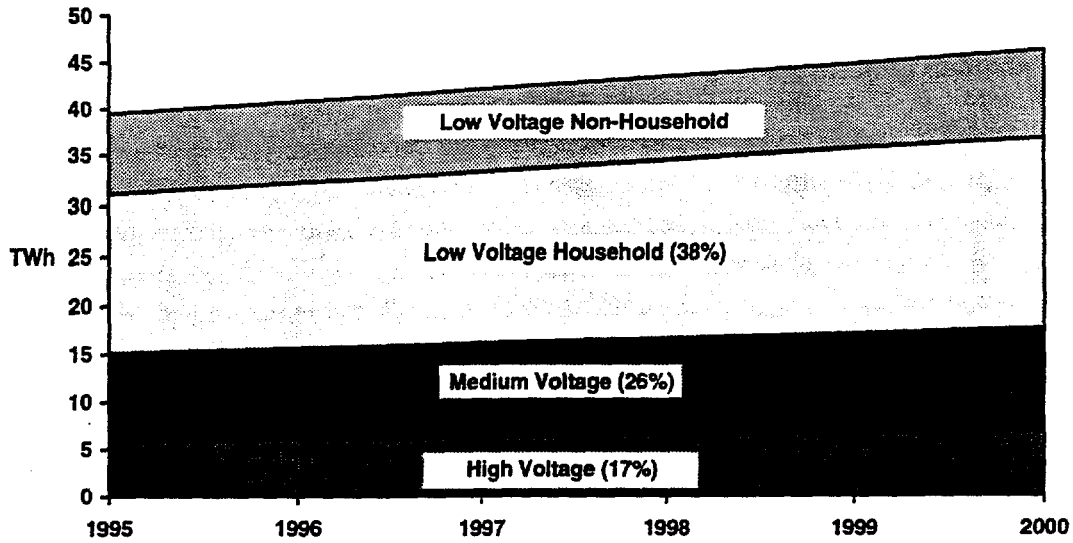

Figure ES-1 Annual Electric Energy Demand Forecast by Tariff Category

Electricity Supply

Figure ES-2 presents the annual electric energy demand/supply balance. This electricity supply plan, together with the associated expansion and replacement plans for transmission and distribution (T&D), underlies the forecast of revenue requirements for fuel, O&M, capital costs and all the other elements of the utility cost structure that are recovered in cost-based tariffs. The electricity plan is modeled in the IRP Manager computer model, which contains demand, supply, finance, and tariff modules.

At the present time, several alternative development plans are under consideration. These plans contain varying timing and need assumptions for several power projects that have been identified for the Bulgarian system. The key developments that will impact tariffs within the next 5 years include:

- Rehabilitation of each of the major coal-fired power plants
- Addition of new peaking combustion turbines
- Timing of the shutdown of Kozloduy Units 1-4

District Heating Supply and Demand

The Sofia system is served by two plants with both combined heat and power (CHP) and heat-only equipment, and two plants with heat-only boilers. District heating plants are fired by fuel oil and natural gas. Most district heating is delivered as hot water, with minimal demand for steam.

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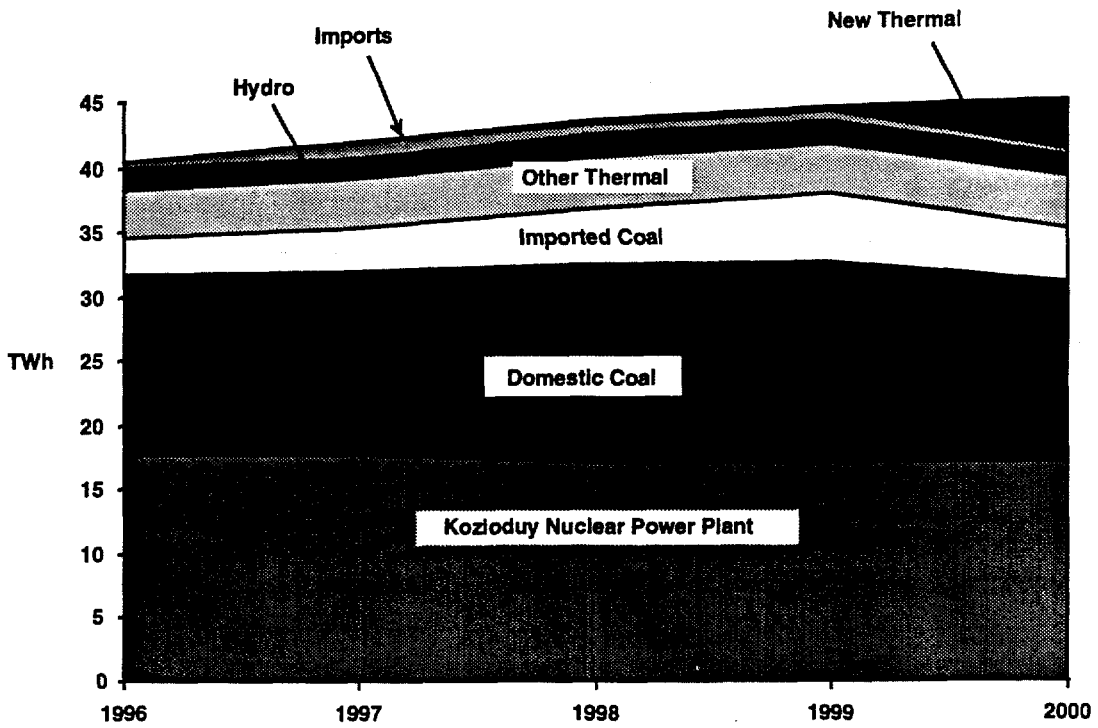

Figure ES-2 Annual Electric Energy Supply Forecast

New district heating demand in Sofia is projected to be offset by decreased transmission losses and by increased efficiency of customer usage. A key uncertainty for district heating supply is the feasibility of combined heat and power plants, specifically the Sofia and Sofia East combined cycle power plants. These plants are included in the electric supply plan in the year 2000, however our analysis of the Sofia District Heating Company does not include these plants because they are not required for heat supply.

Long-Run Marginal Cost (LRMC)

LRMC is made up of two components, marginal energy cost and marginal capacity cost. Marginal energy cost, also known as short-run marginal cost (SRMC), is the change in variable operating costs, such as fuel, to serve a change in demand in any hour. Marginal capacity cost is related to changes in peak demand. Marginal generation, transmission, and distribution capacity costs reflect the need to provide sufficient capacity to meet incremental system peak demand with an adequate degree of reliability.

Marginal costs are used in allocating cost responsibility to customer classes, and in formulating time-differentiated tariff schedules to recover these costs. In theory, strict marginal cost pricing ensures efficient consumption of resources. In practice, strict LRMC pricing is usually adjusted to meet the utility's overall revenue requirements. Thus, LRMC serves as a tariff design guide to reallocate cost-of-service to meet total utility revenue requirements. LRMC and its energy and

capacity components are summarized in Figure ES-3 for electricity and district heating. LMRC is levelized over the 10-year period 1996-2005, assuming a 10 percent opportunity cost of capital.

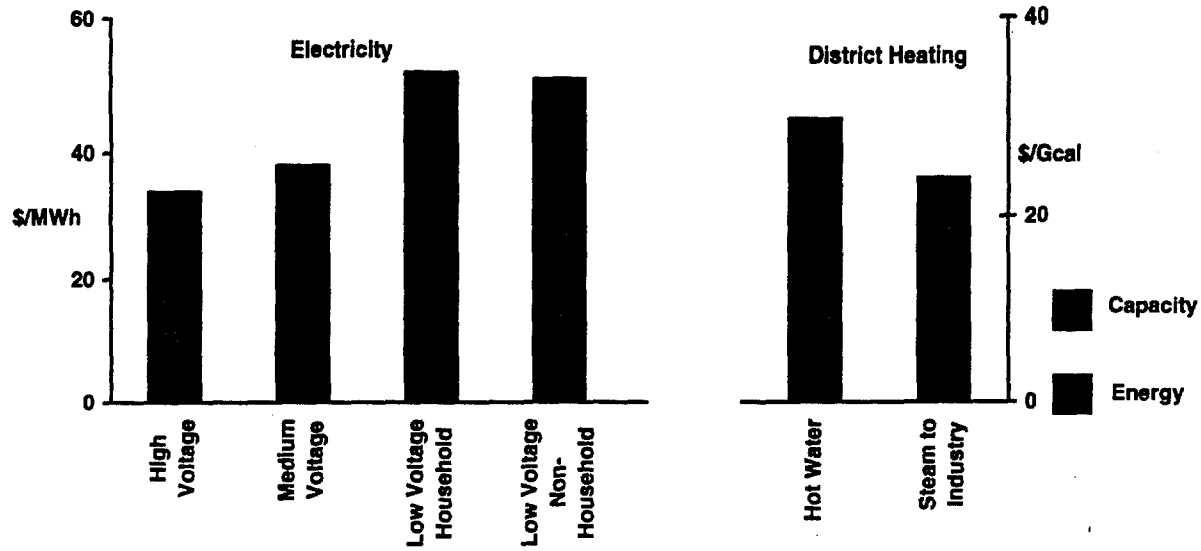

Figure ES-3 Capacity and Energy Components of LRMC

Cost-of-Service

Cost-of-service is the utility's financial requirements for meeting customer service requirements. Cost-of-service is an *average* cost, as distinguished from *marginal* cost. It includes the utility's operating expenses, depreciation, return on assets, taxes, and the amortization of system expansion projects. Tariffs usually are set at levels that allow the utility to collect its cost-of-service without generating either financial surplus or deficit. For both NEK and Sofia District Heating, allowance for depreciation is a key issue, because book depreciation is currently inadequate for the financial requirements associated with plant replacement due to the effects of hyperinflation of the Bulgarian currency.

The cost-of-service scenarios developed in this report are distinct from official reported accounting cost. First, we consider cost-of-service on a *forward-looking* basis, rather than *historic*. Second, we develop financial scenarios that assume the utilities will be fully funded, in contrast to the existing poor financial condition of both NEK and Sofia District Heating. We note that official accounting statements indicate that NEK is profitable and that Sofia District Heating, like most district heating companies, is unprofitable, requiring direct government subsidies. But the official statements present a distorted view of real costs. Depreciation is understated in real terms due to the effects of hyperinflation. Reported energy production costs do not reflect the subsidies to domestic lignite producers that are provided by the government. In addition, there is no accounting for costs associated with nuclear plant decommissioning and nuclear waste disposal.

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Electricity Cost-of-Service

Our hypothetical financial scenario for NEK provides sufficient funds to meet operating expenses, expand and replace plant as required, and provide for nuclear decommissioning and nuclear waste disposal. The financial scenario aims to meet appropriate targets for cash flow, capitalization, and return on asset base. The methodology involves treating depreciation as a variable that is optimized to ensure adequate revenues to meet the utility's financial requirements. The resulting increase in the depreciation allowance implies a de facto asset revaluation. The implied asset value is cross-checked to ensure that it is not overstated relative to historic measures of true asset value.

Financial requirements associated with system expansion are financed with a mix of up to 50 percent debt, with the rest from retained earnings. The portion of debt in NEK's capitalization is built up significantly, on the premise that the utility is currently well under its "debt capacity." However, increased debt in the utility sector must be considered within the larger context of ongoing initiatives to control public-sector debt obligations.

The scenario forecast of electricity cost-of-service is compared with LRMC and September 1995 tariffs by customer class in Figure ES-4. September 1995 tariffs have been converted to dollar equivalents using an exchange rate of 67 levs per dollar. We estimate that the levelized cost-of-service for electricity sales for the period 1996-2000 is $43 per MWh, compared to LRMC of $49 per MWh and the September 1995 average tariff level of $26 per MWh.

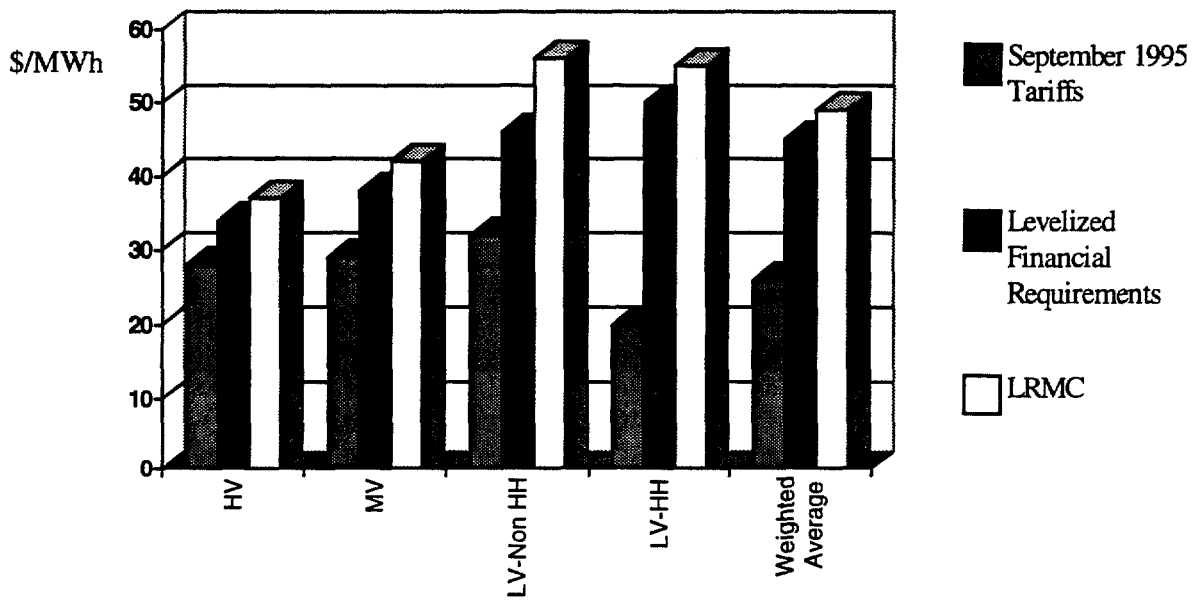

Figure ES-4 Comparison of September 1995 Electricity Tariffs, Financial Requirements, and LRMC

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District Heating Cost-of-Service

Hot water tariffs for the Household and Public Sector – Budget Categories, based on LRMC, will be adequate to meet the financial requirements of Sofia District Heating only if:

- Depreciation reflects asset revaluation
- The buyback rate for electricity is increased to the electric generation system LRMC
- Non-payment problems are avoided
- The relatively minor consumption of steam is priced at LRMC

District heating cost-of-service is estimated at about $29 per Gcal for hot water, which is close to estimated LRMC. The September 1995 tariff is $12 per Gcal, about 40 percent of the cost-of-service.

Assessment of September 1995 Tariffs

Table ES-1 summarizes key characteristics of existing electricity and district heating tariffs, including the tariff categories in use in Bulgaria, seasonal and time-of-day differentiation, September 1995 tariff levels, and the ratio of September 1995 tariffs to LRMC. Electricity and district heating are subject to "fixed" pricing, which is the highest level of control by the CoP. Besides electricity and district heating, natural gas is the only other commodity in the fixed category. Non-budget commodities have been placed in the category of "supervised" prices, freeing them of rigid price control, but still subject to regulatory oversight by the CoP.

Existing Electricity Tariffs

We make the following observations on existing electricity pricing levels:

- The average tariff level in September 1995 was $26 per MWh. In March 1996 this was raised to $30 per MWh, and another price hike to $35 per MWh has been proposed for July 1996. In May 1996 the Bulgarian leva lost over one-third of its value, affecting the dollar conversion of the existing leva-based tariffs. Due to these dynamics, it is difficult to determine dollar equivalents. Throughout this report we have chosen to make comparisons with the September 1995 tariff levels converted using an exchange rate of 67 levs per dollar.
- The existing electricity tariff structure is appealing for its simplicity, yet at the same time it captures essential differentiation of season, time-of-day, service voltage level, and customer class.
- September 1995 electricity and district heating tariffs are significantly below the cost-of-service and LRMC estimates developed in this report. Households receive the major share of these inter-generational subsidies. The proposed July 1996 tariff level of $35 per MWh is 80 percent of LRMC.

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Table ES-1 Structure of Bulgarian Electricity and District Heating Tariffs

Tariff Category	Time-of-Day	Season	Classification	% of 1994 Sales	September 95 Tariff	% of LRMC
Electricity (NEK)					**$/MWh**	
High voltage (>110 kV)	Peak Daytime Nighttime	Summer Winter	Fixed	17	27.2	77
Medium voltage (1 to 110 kV)	Peak Daytime Nighttime	Summer Winter	Fixed	26	28.5	67
Low voltage (<1 kV) – non-household	Peak Daytime Nighttime	Summer Winter	Fixed	38	31.5	60
Low voltage – household	Daytime Nighttime	None	Fixed	19	19.6	38
District Heating (Sofia District Heating Co.)					**$/Gcal**	
Industrial steam	None	None	Suprvsd	6		100
Hot water:						
Public sector – non-budget	None	None	Suprvsd	16		100
Public sector – budget	None	None	Fixed	10	12.1	40
Household	None	None	Fixed	68	12.1	40

- The estimated time-of-day and seasonal differentiation in LRMC is significantly different from the existing tariff structure. The proposed July 1996 increase may provide an opportunity to adjust not only average tariff levels, but also seasonal and time-of-day differentiation proportionate to LRMC.
- At present (and at the time this report was prepared), the price paid by NEK for electric generation from industry and district heating companies is lower than the estimated value of that generation.
- Recently, the price has been increased to exceed short run marginal cost.

Existing District Heating Tariffs

Industrial and public sector non-budget district heating tariffs, which have been freed of rigid price control, have reached full LRMC. Tariffs for household and public sector budget district heating sales, which account for 78 percent of Sofia District Heating Company's sales, are approximately 40 percent of LRMC. Low prices to the subsidized categories, combined with inadequate metering and control, severely limit the utility's ability to provide effective pricing signals to consumers.

TARIFF REFORM PROGRAM

Transition to Cost-Based Tariffs

Current electricity and district heating tariffs to end users are significantly below utility costs to provide the services. This has the effect of deferring costs into the future. Continuing this practice will drive up the future revenue requirement per unit of sales, and at some point it may exceed LRMC, which in turn will encourage reduced consumption to less than economically optimum levels, creating the opposite of the current overconsumption. Pricing above LRMC is unstable because some customers reduce consumption and others having energy supply alternatives leave the system. The remaining customers pay more, creating a price-spiraling effect. Prices must be increased to cost-based levels as soon as possible. The alternative is either government subsidization or continued decapitalization of the utility at the expense of future consumers who will have lower quality or higher priced utility services.

Tariff Indexation

An electricity tariff indexation formula has been proposed in Bulgaria to automatically increase tariffs in response to increases in cost-of-service. This is a promising approach to depoliticize tariff adjustments. The formula uses weighted indexes to adjust prices. Coefficients for the indexes are roughly consistent with the underlying utility cost structure: 20 percent for international currency exchange rate, 40 percent for Bulgarian inflation, 20 percent for imported nuclear and coal fuel prices, and 20 percent for domestic coal prices. (At the time of this report, simpler but similar indexation formulations are being considered.)

We expect that the indexation approach will serve its intended function provided that the initial starting point is a cost-based price, and the underlying cost structure of the utility remains relatively stable. An alternative indexation approach involves separate formulas for operating expenses and capital-related expenditures. This alternative recognizes that costs for these two categories increase in differing proportions with demand growth.

Pricing Reform

We make the following recommendations for pricing reform:

- Transition to cost-based levels to ensure the financial viability of NEK and the district heating companies; eliminate subsidies provided at the cost of future consumers; and minimize price distortions between competing energy sources.
- Adopt efficient tariffs designed to recover the overall utility revenue requirement and to meet the objectives of LRMC pricing. In general, this means cost-of-service tariffs with LRMC-based allocation of costs to time-of-day, season, customer class, and capacity- and energy-related components. For both electricity and district heating, strict LRMC pricing is an option based on the empirical finding that LRMC and cost-of-service revenues would be similar.

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- Focus programs to protect the poor on benefits for those with the greatest need, and at the same time preserve marginal cost-based pricing signals for consumption. It is not possible to adapt Bulgarian electricity and district heating tariff structures to meet both requirements. Direct subsidization of the poor is an alternative to subsidized utility tariffs.
- Ensure that the power generation buyback tariff for industrial and combined heat and power producers reflects the incremental value of that power to the NEK system. Further investigation is required to determine "fair" pricing; however, it is known that pricing should fall within the range defined by NEK's SRMC and LRMC.

Institutional Strengthening

There is strong capability within the Bulgarian electricity and district heating industry organizations which analyze demand, supply, finance, and tariffs. However, some additional institutional strengthening is advisable. We recommend that Bulgaria:

- Adopt a transparent process for setting electricity and district heating tariffs
- Adopt transparent processes and roles at NEK and the district heating companies for developing and implementing the information and analysis required to set tariffs to end consumers and to CHP and industrial power producers
- Develop organizational units within the utilities to support tariff design and revenue requirements modeling and data flow
- Establish the role of the tariff regulator, with transparent objectives for cost-based pricing and social programs
- Establish the relationships between the regulator and the utility
- Provide public participation in the tariff process, to ensure that the voice of the customer is reflected in tariff design and social programs
- Provide regulated performance incentives to encourage utility and industry organizations to achieve cost and environmental objectives
- Adopt marginal cost-based transfer pricing mechanisms between operating organizations as a means of encouraging efficient budgeting and cost control
- Encourage competition and private company participation in the electricity and district heating industries, as a means of introducing market pressures to reduce costs

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Section 1

Introduction

1.1 PROJECT BACKGROUND

The Bulgaria Energy Tariff Implementation Project is funded by the U.S. Agency for International Development (USAID). Project guidance and technical support is provided by a Bulgarian Working Group made up of members of the following Bulgarian organizations:

- Committee of Energy (CoE), which is replaced in July 1996 by the newly established Ministry of Energy and Energy Resources (MEER)
- National Electric Company (NEK)
- Ministry of Finance
- Commission on Pricing (CoP)
- Parliamentary Commission for Energy and Natural Resources
- Energoproekt

1.2 PROJECT OBJECTIVES

The objectives of the project are to:

- Investigate the existing cost and pricing of electricity services
- Develop the level and structure of tariffs based on long-run marginal cost (LRMC)
- Develop a financial analysis process and scenario estimates for NEK's financial requirements
- Make recommendations on a tariff process that considers LRMC, NEK's financial requirements, impacts on energy-intensive industries, and protection of economically disadvantaged groups
- Support institutional development through a training program in the above areas

1.3 CONTENTS OF THIS REPORT

The tariff process illustrated in this report includes the following specific tasks:

- *Evaluate energy demand.* We present an analysis of current electricity consumption and future demand projections, select an existing overall forecast, and disaggregate the forecast by voltage level of service.
- *Evaluate supply systems.* We analyze the existing and projected electricity supply system and associated investment requirements and operating costs. We model the electric power system and develop capacity- and energy-related costs by time-of-day and by season.

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- *Evaluate existing tariffs.* Existing tariffs are evaluated relative to projected cost-of-service and LRMC.
- *Evaluate LRMC.* We develop marginal costing for generation, transmission, and distribution services. These components, adjusted for network losses, are used as building blocks to develop LRMC by voltage level, time-of-day, and season.
- *Evaluate cost-of-service.* A financial analysis determines the minimum revenue requirements for the financial viability of NEK. A cost allocation process is used to assign cost-of-service responsibility for revenue requirements to customer classes.
- *Tariff design.* We evaluate several alternative tariff designs that recover overall cost-of-service and, to a greater or lesser degree, meet the objectives of LRMC pricing. Transitional pricing is developed to reduce the impact of price changes on customer groups, especially residential consumers.

1.4 OBJECTIVES FOR TARIFFS

The tariff process presented in this report has a cost-based orientation, which is appropriate for tariffs in a market economy. Cost-based pricing provides the foundation for the utility to operate the electricity system free of deficits and at the same time finance required capital expenditures. Investors and lenders need assurance that the utility's revenues will support return on investment and debt coverage. The objectives for electricity tariffs include:

- Provide clear economic signals to customers on the long-run marginal costs of electricity. Marginal cost pricing promotes efficient consumer behavior for consumption of electricity services.
- Differentiate tariffs to the degree practical. Efficient pricing recognizes separate pricing for capacity and energy, time-of-day, season, service voltage, and customer class distinctions.
- Provide adequate funds to operate the power system and provide a reasonable return on investment.
- Address social equity and economic development issues such as protection of economically disadvantaged groups and consideration of economic competitiveness. This may require that cross-subsidies are phased out over a period of time and that financial objectives are met on a multiyear rather than annual basis.

1.5 OVERVIEW OF THE TARIFF PROCESS

1.5.1 Tariff Concepts

The price of any product sold in the marketplace evolves from the cost of producing and delivering that product to the consumer. In the case of utilities, the pricing problem is further complicated because customers must share jointly in the economic responsibility for equipment

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which supplies service to more than one customer at the same time. Utility pricing requires allocating the cost-of-service to customers based on the relative usage of the system by each customer.

Traditionally, the utility's allowed revenues are set to recover its embedded cost-of-service. In this report we consider embedded cost-of-service on a forward-looking basis. We establish a process to evaluate the utility's future embedded costs associated with capital expenditures, operating expenses, and financial requirements. We also establish a process for forecasting marginal costs. Marginal costs, modified to conform to revenue levels based on embedded costs, are used to indicate directions in which tariffs might be modified in the interests of economic efficiency.

From a practical standpoint, we envision electricity tariffs based on a hybrid of cost-of-service and LRMC. Based on the forecasted relationships between LRMC, financial requirements, and current tariffs, the potential exists to raise tariffs to cost-of-service without exceeding LRMC. This suggests that there is the potential to implement any of several alternative tariff designs that recover the overall revenue requirement and, to a greater or lesser degree, meet the objectives of LRMC pricing.

The tariff-setting process developed in this report is a traditional approach compared with the emerging competitive market model implemented in the United Kingdom, Norway, and other countries. The competitive model emphasizes market dynamics, and tariffs and transfer prices reflect marginal costs, not necessarily embedded costs. At the current time in Bulgaria, utility structures do not conform to the competitive model, and this accounts for the emphasis in this report on a conventional tariff-setting approach. The conventional cost-based approach is used widely throughout the world; however, it is not currently the standard in Bulgaria, where the government sets utility prices to achieve social goals.

1.5.2 Classes of Customers

Tariffs cannot be established individually for each customer, even though the cost of serving them may vary somewhat from the customer class norm. As a practical matter, tariffs are developed for groups of customers. The broad objective for customer class groupings is to aggregate those customers who have reasonably homogeneous load characteristics. There are distinct differences in the patterns of use set by these groups, and thus the cost-of-service varies for each group. The major customer groupings are:

- Residential service
- Commercial service, frequently divided into small and large commercial, and including a wide range of business and service activities
- Industrial service

The Bulgarian tariff classes essentially recognize each of the major categories. There are four customer classes, high voltage (industrial), medium voltage (industrial and commercial), low

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voltage non-household (commercial), and low voltage household. These tariff structures are appealing for their simplicity without compromising essential customer differentiation.

1.5.3 Allocation of Costs

The concepts of *demand-, energy-, and customer-related costs* are used throughout the cost allocation process and, in turn, in the rate design procedure itself. Prior to the allocation of costs to customer classes, a preparatory step is the development of demand-, energy-, and customer-related cost components. Many utilities maintain a comprehensive system of accounts identifying the cost components of all capital and operating expenditures. The following examples illustrate the concept of cost components:

- The cost of high voltage transmission facilities are identified as a capacity-related cost, because the facilities are designed to meet the system peak capacity demand.
- Fuel costs are energy-related.
- Distribution facilities dedicated to serving the needs of particular customers are generally customer-related.

Once the utility's cost components are identified, each cost component is allocated to customer classes based on *causality*. Energy-related costs are allocated largely in proportion to the amount of energy consumed by each class. Customer-related costs are assigned on the basis of number of customers and maximum demand, after first making direct assignments of those costs which are identified with specific customers or classes. Capacity-related costs are allocated based on class contribution to peak-period system demand.

1.5.4 Metering Requirements

Metering limitations determine the degree of detail that can be built into tariff design. In Bulgaria, one- and two-zone meters are used for households, and one-, two-, and three-zone meters are used for non-households. (The third zone measures demand during a short duration system peak period.) Most large customers have multi-zone meters. Use of two- and three-zone meters allows allocation of capacity-related costs to the peak period. The one-zone meter does not allow tariff design to include time differentiation of energy- and capacity-related cost components.

1.5.5 Tariff Design

Tariffs are differentiated by customer class because each class consumes a distinct set of electricity services. Tariffs include energy components to bill customers for time-differentiated energy consumption, and capacity components to bill for contribution to system peak demand. Tariffs reflect the fact that costs for transmission and distribution facilities and losses are higher for low voltage customers who use the entire network than for high voltage customers who use

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primarily the high voltage facilities. Allocation of cost-of-service to customer classes is an accounting process. Tariff design is a more complex process involving judgment. Depending on tariff objectives, there are many possibilities for assigning cost-of-service to tariffs.

Current tariffs in Bulgaria deviate from cost-based tariffs, especially the household tariff, but also other tariffs which in general are below cost-of-service. Subsidized tariffs are used to meet important social objectives, such as redistribution of wealth. However, in the case of Bulgarian tariffs, this is paradoxical because the under-funding from customers is not currently offset by additional revenues from the government, a situation that is unstable and eventually will result in reduced service quality. In general, transitioning to cost-based tariffs as soon as possible is advisable. One of the difficult judgments is how to manage the transition while protecting sensitive customer classes.

1.5.6 Roles of Organizations

Energy prices in Bulgaria are set by CoP. Electricity prices are under the category of "fixed" prices, the most controlled form of price regulation in Bulgaria. The costs reported by NEK are an important input to the cost-setting process; however, there are other equally important inputs. MEER develops tariff policy for the energy sectors. Industries and district heating companies that generate and sell power and heat to NEK are important stakeholders in the tariff process.

The current institutional structure for tariff-setting is broadly characterized as centralized administrative control. It contrasts with the competitive model in which market dynamics influence prices and intervention and regulation are limited to protection of social objectives. The centralized administrative control approach is criticized as ineffective at rewarding organizational efficiency, and has developed a history of establishing unstable market dynamics.

In this context it is worth considering the following Bulgarian examples:

- NEK's capital program is under-funded, and needed replacement and expansion programs are being deferred.
- There is inefficient use of electricity for winter heating due to the low cost of electricity relative to other fuels.
- Electric intensive industries, encouraged by the low prices for electricity, continue to play a major role in the economy despite the country's lack of native energy resources.
- There is an artificial market for Bulgarian coal to fuel power plants. In general, Bulgarian coal is inferior to international coals based on price and contaminant content.

An important step to mitigating these distortions is to reinforce institutional capabilities in tariff-setting. There is a need to further develop the roles and capabilities of the organizations that set

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tariffs, expanding on the foundation already established within groups at NEK and MEER. The following institutional capabilities are required to implement the tariff setting process.

- *Financial planning and modeling.* NEK develops financial plans for up to 5 years. NEK has developed the capabilities to use IRP Manager and other computer models for utility finance, and there is a process for integrating budgets into financial planning.
- *Generation and transmission expansion planning.* NEK has pioneered the use of the IRP Manager Model for developing expansion plans used for forecasting marginal costs and revenue requirements. Although there is significant institutional capability, there are strongly differing opinions regarding expansion and replacement plans for the future. At least part of the controversy can be traced to lack of consensus on the national objectives and financing alternatives for energy developments.
- *Tariff design.* In most countries, both the utility and the regulator have well-defined roles in the tariff design process. Each brings its own perspective on the market impacts and social requirements of tariffs, and the organizations establish a check-and-balance mechanism. In Bulgaria these roles are filled by NEK, MEER, and CoP. There are important concerns that tariff setting is subject to politics and hidden influences, and that financial viability and creditworthiness receive too little attention even at NEK. For these reasons we recommend establishing an *independent* regulatory function, and developing an industry framework aimed as strengthening the market orientation of NEK business units.
- *Budgeting and accounting.* Budgeting is established within the Department of Economic and Budget the regional distribution units and the generating plants at NEK, and budget information is fed upward through the organization to the Corporate Finance Department where it is incorporated in the 5-year financial plan.

1.6 SOURCES OF INFORMATION FOR THE TARIFF PROJECT

We are indebted to the planning personnel at NEK for technical and financial data, and for the IRP Manager Modeling that is used in this report. CoE (MEER) has provided guidance and information on all aspects of Bulgarian tariffs and electric sector development. We have gained insight into a number of electric resource strategies for the energy sector derived from several Bulgarian studies of the sector, including the work of NEK, CoE, Energoproekt, and the independent group advising the Prime Minister.

We have benefited from the work of other consultants and advisors working in Bulgaria, including World Bank, NERA, Arthur Andersen, Central Maine Power, RCG/Hagler Bailly, and PowerGen. The following key documents have been useful for the tariff project:

- *Organization and Policy Formulation for the Bulgarian Energy Sector* (NERA, April 1994)

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- *Protection of the Poor in Bulgaria from the Effects of Sharply Higher Energy Prices* (World Bank, February 1995)
- *Electricity Prices in Bulgaria* (World Bank, December 1994)
- *Bulgaria Energy Strategy Study* (World Bank, December 1991)
- *Staff Appraisal Report: Bulgaria Energy Project* (World Bank, February 1993)
- *Power Complex Rehabilitation Project in Bulgaria* (Bechtel, October 1993)
- *Bulgaria Electricity Study: Management of Electricity Demand* (RCG/Hagler, Bailly, Inc., April 1993)

1.7 GUIDE TO THE FINAL REPORT

The Final Report is organized to answer the following questions:

▪ What are the basic load and resource assumptions underlying the tariff scenarios developed in this report?	Section 2 for loads and Section 3 for resources
▪ How do current tariffs compare with LRMC developed in Section 5 and with cost-of-service developed in Section 6?	Section 4
▪ How are the capacity and energy components of LRMC of electricity supply determined? What is LRMC for the scenario resource plans?	Section 5
▪ How are utility financial requirements determined and allocated to customers in the cost-of-service study? What is the costs-of-service for each of the Bulgarian tariff categories?	Section 6
▪ What are alternative tariff designs that reconcile financial requirements, LRMC and non-cost tariff objectives? What are illustrative tariffs for Bulgaria based on these tariff design alternatives?	Section 7

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Section 2

Review of the Electricity Demand Forecast

The objective of this section is to review the electricity demand forecast used for the scenario tariff analysis presented in this report. This demand scenario is compared with alternative demand forecasts that have been developed in Bulgaria. From the overall demand forecast, we develop separate demand forecasts for each tariff customer class. Customer class forecasts are used to allocate costs to tariff categories in the cost-of-service analysis.

2.1 ELECTRICITY DEMAND FORECAST

Concurrently with the demise of its centrally planned economy in the late1980s, Bulgaria experienced two significant drops in electricity demand around 1985 and 1990. Now that the country has begun transitioning to a market economy, future demand is difficult to forecast. Several significant attempts were made to develop forecasts in the early 1990s by NEK, the World Bank, EBRD, and various consultants. Comparisons of these forecasts show wide variation in expectations at that time regarding the recovery of the Bulgarian economy. Electricity demand now appears to be on the upswing, having hit bottom during the period 1992-94. Estimates are that within the next 10 years, electricity demand will once again reach the historic maximum levels of the late 1980s.

2.1.1 Electric Energy Demand Forecast

The demand forecast used in the tariff scenario presented in this report roughly matches current Bulgarian expectations for demand growth. Figure 2-1 presents a comparison of the following annual energy demand scenarios:

- The scenario used in this report
- 1995 NEK high, medium, and low demand forecasts
- High and low forecasts presented by an independent group advising the Prime Minister in the paper "Strategy for the Development of the Energy Sector of the Republic of Bulgaria" (October 1995)

The figure shows that the demand forecast used for our tariff scenarios is slightly below the current NEK medium scenario and the independent group's high range. The low range forecasts are an interesting point of comparison. These forecasts assume a reduction in electric intensity in Bulgaria, which is currently high by international standards. If tariffs are raised to cost-based levels, it is likely that there will be significant reduction in electric intensive use. There is the potential for reductions in electric heating and electric-intensive heavy industry, depending on the pricing and availability of alternative fuels.

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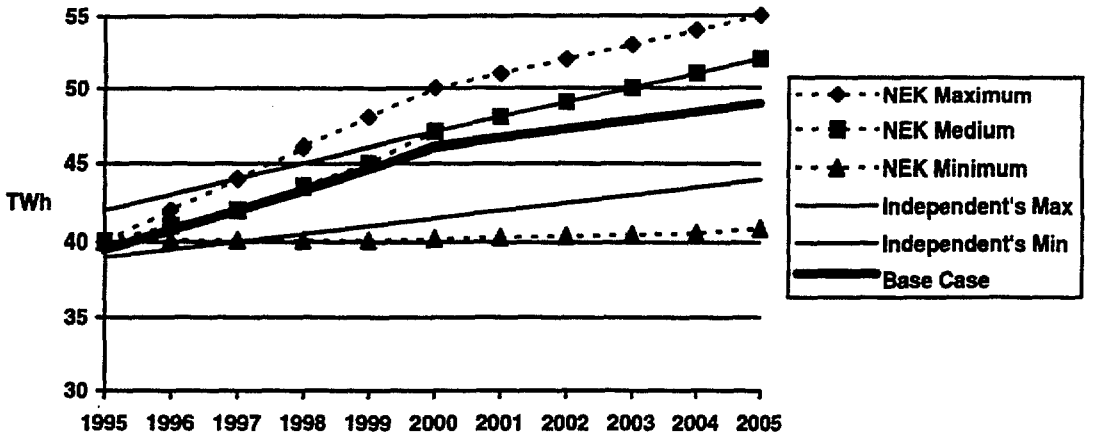

Figure 2-1 Forecasts of Annual Electric Energy Consumption

2.1.2 Capacity Demand Forecast

Figure 2-2 shows the winter and summer maximum megawatt demand forecast for the period 1995-2000. Bulgarian electrical demand is significantly higher in the winter than in the summer. A key factor in the seasonal difference is the electricity used for space heating in the winter. Seasonality in the demand for electricity is a key factor driving seasonal differences in cost-based tariffs.

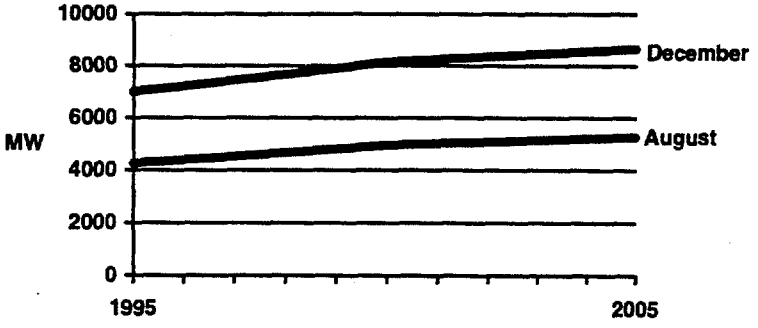

Figure 2-2 Maximum Monthly Capacity Demand

2.2 DEMAND FORECAST DISAGGREGATION BY TARIFF CATEGORY

In the cost-based tariff-setting process, utility revenue requirements are allocated to customers based on the contribution of each customer class to overall system requirements. Customer class groupings are chosen based on similar demand attributes. Thus, for example, households are grouped into a single customer class.

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An important attribute used to group customers is voltage level. The voltage level at which a customer receives electric service affects the network costs and losses that should be allocated to that customer. For example, the costs associated with owning, operating, and maintaining the distribution system are a portion of the cost of serving customers connected at low voltages. In the tariff setting process, it is important to separate each customer according to voltage level to capture the cost of service for that customer.

2.2.1 Methodology and Assumptions

For the forecasts of demand by tariff categories used in this study, we have allocated the overall demand forecast to the following customer classes: high voltage (110 kV and above), medium voltage (< 110 kV and > 1 kV), and low voltage (< 1 kV). Low voltage is subdivided into household and non-household. The ideal demand forecast disaggregation would use separate end-use forecasts for each customer or tariff category. The resulting disaggregated forecasts would be evaluated against historic billing information as a methodological check. We are not able to implement this ideal forecasting process because existing end-use forecasts and historic billing information does not include adequate time-of-day information. NEK has been developing end-use forecasting; however, only partial information is available at the present time.

Without the benefit of end-use forecasts and historic demand information, we make our load forecast disaggregation based on the following basic considerations:

- The overall demand forecast is assumed made up of five basic economic sectors, industry, transport, agriculture, services, and households.
- We develop sectoral electricity consumption based on assumed end uses. Our non-household sectoral forecasts use 1992 sectoral sales statistics, and forecasts of GDP contribution and electricity intensity. This calculation is summarized in Table 2-1.
- The demand forecast for each economic sector is assigned to the four tariff categories based on judgment regarding service voltage levels for typical customers within the sector, as shown in Table 2-2.
- We develop seasonal and time-of-day patterns of electric usage based on the load shape characteristics assumed in Table 2-3. The household load shape is taken to be the residual of the overall load shape and the sum of the load shapes of the non-household tariff category loads. Figures 2-3 and 2-4 depict typical daily load forecasts for each of the four tariff categories for typical winter and summer days.
- We check that the electric consumption in each sector matches historic trends.

Figure 2-5 shows the estimated breakdown in demand by tariff category, HV, MV, LV household, and LV non-household. The household class is the largest (38 percent of total consumption), followed by the MV (26 percent), LV non-household (19 percent), and HV industrial (17 percent of total annual load).

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Table 2-1 Development of Sectoral Forecast

Category	1992	1995	1996	1997	1998	1999	2000		Explanation
Overall Forecast									
Energy	38.2	39.5	40.7	42.0	43.3	44.6	46.0	A_i	
Plant losses	4.0	4.0	4.0	4.0	4.1	4.1	4.2	B_i	
Network losses	4.9	5.0	5.2	5.3	5.4	5.6	5.7	C_i	
Total sales	29.3	30.5	31.5	32.6	33.8	34.9	36.1	D_i	$A_i - B_i - C_i$
Relative GDP Contribution									
Industry	100	90.2	91.0	94.0	97.7	101.7	106.8	E_i	
Transport	100	115.0	118.5	125.0	132.8	141.1	151.4	F_i	
Agriculture	100	81.1	82.3	85.5	89.4	93.5	98.8	G_i	
Services	100	101.2	103.7	108.7	114.7	121.2	129.2	H_i	
Electricity Intensity									
Industry	0.17	0.18	0.18	0.18	0.18	0.18	0.18	I_i	
Transport	0.04	0.04	0.04	0.04	0.03	0.03	0.03	J_i	
Agriculture	0.03	0.03	0.03	0.03	0.03	0.03	0.03	K_i	
Services	0.02	0.02	0.02	0.02	0.02	0.02	0.02	L_i	
Sectoral Breakdown									
Industry	13.5	12.8	13.3	13.8	14.2	14.6	15.1	M_i	$M_{92}*E_i/E_{92}*I_i/I_{92}$
Transport	1.5	1.7	1.7	1.8	1.8	1.9	1.9	N_i	$N_{92}*F_i/F_{92}*J_i/J_{92}$
Agriculture	1.3	1.1	1.1	1.2	1.2	1.3	1.3	O_i	$O_{92}*G_i/G_{92}*K_i/K_{92}$
Services	3.4	3.4	3.5	3.5	3.6	3.7	3.9	P_i	$P_{92}*H_i/H_{92}*L_i/L_{92}$
Households	9.6	11.5	11.9	12.4	12.9	13.4	13.8	Q_i	$D_i - M_i - N_i - O_i - P_i$

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Table 2-2 Assumed Service Voltage Levels by Economic Sector

Sector	High Voltage (%)	Medium Voltage (%)	Low Voltage (%)
Industry	40	50	10
Transport	0	80	20
Agriculture	0	20	80
Services	0	0	100
Households	0	0	100

Table 2-3 Load Shape Assumptions for Non-Household Tariff Categories

Category	Hours	Load Factor (%)
High Voltage		
1st shift	40	100.0
2nd shift	40	95.0
3rd shift	88	92.7
Medium Voltage		
1st shift	40	100.0
2nd shift	40	85.0
3rd shift	88	78.2
Low Voltage		75.0

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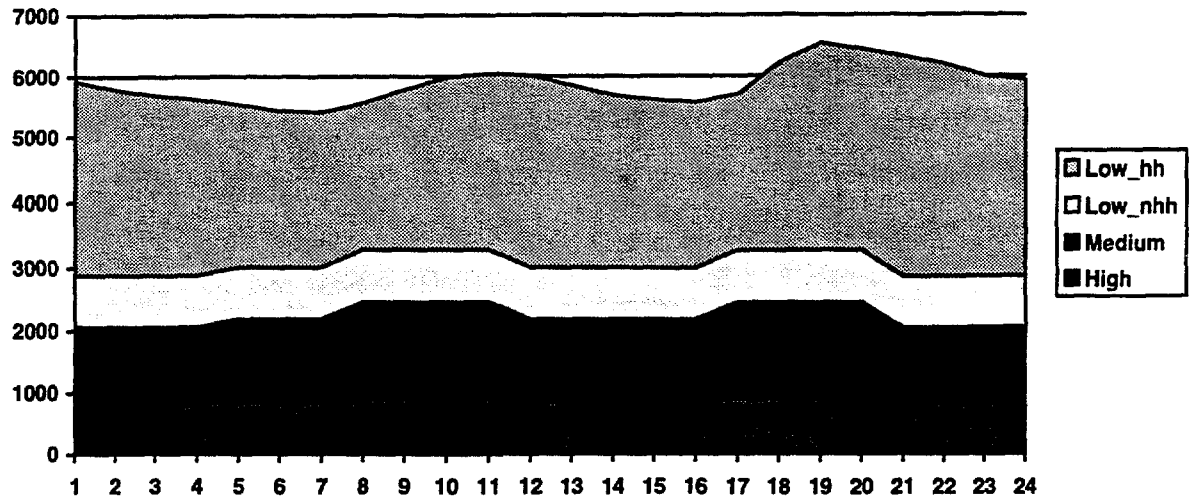

Figure 2-3 Demand by Tariff Category for a Typical Winter Day January 1995

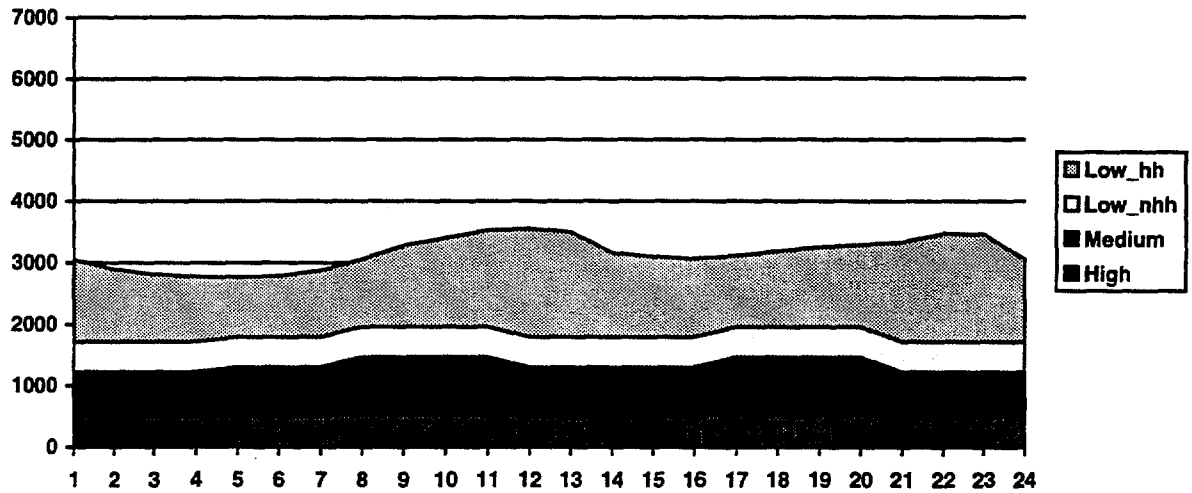

Figure 2-4 Demand by Tariff Category for a Typical Summer Day July 1995

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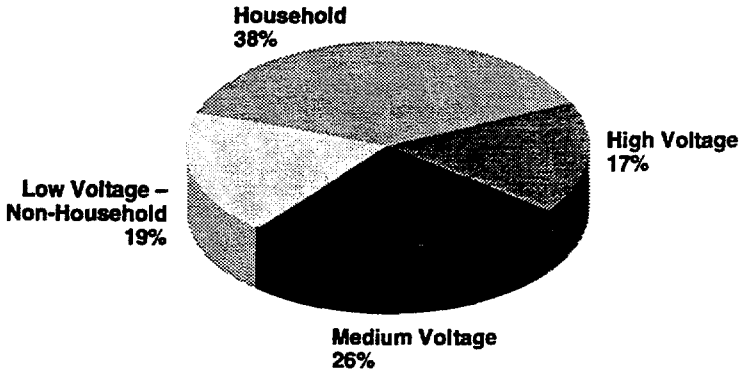

Figure 2-5 Contribution to Electricity Demand by Tariff Category

2.2.2 Losses by Tariff Category

Facilities associated with each voltage level serve customers connected at that voltage level as well as customers at lower voltages (e.g., the medium voltage system serves MV customers as well as LV customers). Therefore, network facilities required at a particular voltage level, and associated costs for these facilities, are dependent on sales and losses at the service voltage level *plus* sales and losses at lower voltage levels. Figure 2-6 depicts this interrelationship, based on the loss assumptions shown below. The resulting loss responsibility and generation requirements by tariff category for 1995 are shown in Table 2-4.

The demand forecast by tariff category uses the following loss assumptions:

- Plant losses: 9 percent of gross system electric energy requirements
- High voltage system losses: 2 percent of energy passing through the high voltage network
- Medium voltage system losses: 5 percent of energy passing through the medium voltage network
- Low voltage system losses: 15.7 percent of energy passing through the LV network

Table 2-4 Loss Responsibility by Service Voltage Level – 1995

Service Voltage Level	Responsibility for Plant Losses (TWh)	Responsibility for Network Losses (TWh)	Total Loss Responsibility (TWh)	Sales (TWh)	Gross Generation Requirements (TWh)
High voltage	0.58	0.10	0.68	5.11	5.79
Medium voltage	0.93	0.40	1.33	7.97	9.30
LV – household	1.61	2.99	4.60	11.51	16.12
LV – non-household	0.83	1.54	2.37	5.92	8.29
Total	**3.96**	**5.03**	**8.99**	**30.51**	**39.50**

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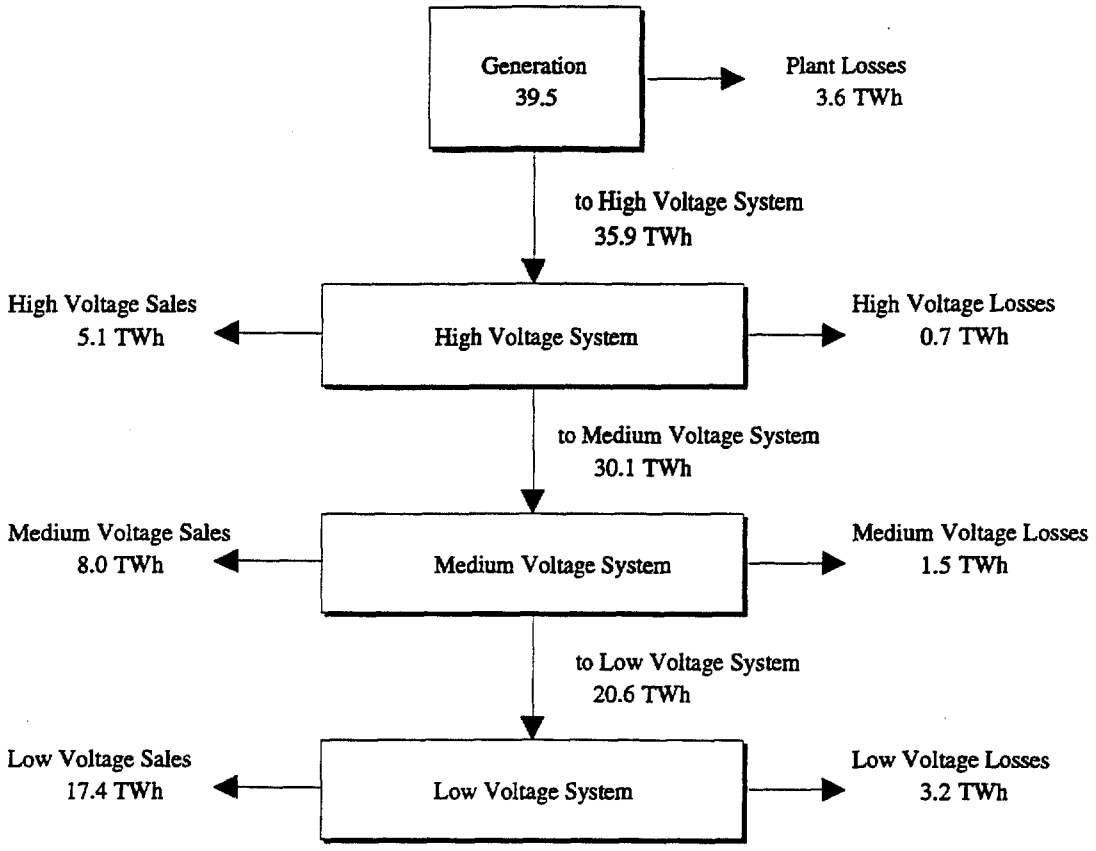

Figure 2-6 Illustration of Electricity Flow – 1995

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Section 3

Review of the Bulgarian Power System

The objective of this section is to analyze NEK's future investment and operating costs that are recoverable through tariffs. This section goes on to describe the expected system operating and cost characteristics for three alternative power supply plans, differentiated on the basis of timing for the shutdown of Units 1 through 4 at Kozloduy. These three scenarios are used throughout this report to illustrate the tariff process.

3.1 THE GENERATION SYSTEM

3.1.1 Operating Characteristics of Bulgarian Power Plants

Electric energy in Bulgaria comes mainly from NEK nuclear, coal-fired, and hydroelectric power plants. Energy is also supplied by local district heating plants, industrial plants, and imports. Table 3-1 at the end of this section summarizes the operating characteristics of the existing nuclear and thermal power plants in the Bulgarian system. Tables 3-2 and 3-3 summarize the operating characteristics of hydroelectric and pumped storage power plants in the Bulgarian system. Table 3-4 summarizes the operating characteristics and required investments for potential generic capacity additions that are added to meet load growth requirements.

3.1.2 Fuel Prices

Table 3-5 compares various fuel price projections for fuels used in nuclear and thermal power plants. Three different fuel price projections made within the last 5 years are compared with NEK's 1995 forecasts used for the tariffs developed in this report. The three alternative forecasts are taken from the following publications:

- *Evaluation of Energy Price Subsidies for Gabrovo, Bulgaria* (Gilbert/Commonwealth, May 1995)
- *Bulgaria Energy Strategy Study* (World Bank, December 1991)
- *Power Complex Rehabilitation Project in Bulgaria* (Bechtel, October 1993)

In general, the NEK 1995 forecasts for the prices of fuels are low compared to the alternative forecasts from the various studies. Gilbert/Commonwealth's forecasts of the prices of domestic and imported coals are significantly higher than the NEK 1995 forecasts. We note this comparison because coal prices are important determinants of revenue requirements and marginal costs. Coal expense is roughly 20 percent of revenue requirements, and an even greater percentage of LRMC, which is heavily weighted by coal on the margin.

3.1.3 Imported Power Costs

The Bulgarian power system is interconnected with power systems of neighboring countries. Capacity or energy deficiencies could be met with long-term, short-term, or emergency imports. At this time, NEK does not have any long-term power purchase contracts. The synchronized

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operation of the interconnected power systems allows exchanges of energy on an emergency basis when one power system, due to unplanned plant outages, has capacity deficiencies.

Imported power is modeled in the IRP Manager Model used for marginal costing and tariff analysis. For system modeling purposes, we estimate that around 600 MW of imports could be supplied during the high demand season from October to April and 300 MW in the low demand season from May to September. The variable component of the import price is set at $70 per MWh, and the fixed component at about $17 per kW-yr.

3.1.4 Operating and Maintenance Costs

Non-fuel production expenses associated with the operation of power plants are called operating and maintenance (O&M) costs. These costs are generally split into two categories: 1) variable O&M costs that are dependent and incurred as a consequence of plant operation, and 2) fixed O&M costs that are invariant with the electrical output of the plant. Calculating both fixed and variable components of O&M cost is important for tariff setting because variable O&M costs and fuel expenses are recovered in energy charges, while fixed O&M is recovered in capacity charges.

We analyzed O&M costs in the NEK dataset against the U.S. experience. For 1994, the O&M cost for nuclear units in Bulgaria was $10 per MWh while average U.S. cost was $15 per MWh. The O&M cost for most of the coal units in Bulgaria was around $10 per MWh while the average U.S. cost was $5 per MWh.

The original NEK generating unit data has O&M costs for each power plant presented as a simple fixed value in $/kW. We judged this an acceptable representation for nuclear and hydro units. However for fossil units it is known that O&M costs include both fixed and variable components. U.S. and European experience shows that about half to two-thirds of the O&M cost for the typical base loaded coal power plant is in the fixed category. Therefore we split the NEK O&M costs between variable and fixed components, with two thirds of the O&M cost put into the fixed category. For new units, we used the U.S. Electric Power Research Institute's Technical Assessment Guide breakdown of fixed and variable costs. Table 3-6 summarizes the O&M costs used in this report.

3.2 GENERATION DEVELOPMENT AND INVESTMENT PLANS

3.2.1 Capacity Development

The power system development plan is a critical determinant of revenue requirements and electricity tariffs. At the present time, several alternative development plans are under consideration. These plans contain varying timing and need assumptions for several power projects that have been identified for the Bulgarian system. The key developments that will impact tariffs within the next 5 years include:

- Rehabilitation of each of the major coal-fired power plants
- Addition of new peaking combustion turbines
- Shutdown of Kozloduy Units 1-4

Debate over nuclear and gas capacity expansion alternatives and financing constraints makes it impossible to select a supply plan that is acceptable to all. It is beyond the scope of this project to examine the many possible resource planning choices and to evaluate the tariff implications of each one. Instead, we have chosen to evaluate three scenarios. The major factor in each of the three plans is the relative timing for shutting down Kozloduy Units 1 through 4. The timing for the shutdowns effects the timing for other resource developments. These three plans are:

- **Plan A (K1,K2:1998; K3,K4:2004).** This scenario assumes Kozloduy 1 and 2 are shut down in 1998 and Kozloduy 3 and 4 in 2004. The resource schedule for this scenario resembles plans that have been acknowledged in discussions between the World Bank and NEK. This scenario is used throughout this report to illustrate tariffs.
- **Plan B (K1:2001; K2:2002).** This scenario assumes a delay in the shutdown of Kozloduy 1 and 2 to 2001 and 2002, respectively. The shutdown of Kozloduy 3 and 4 is beyond the tariff planning horizon in this scenario.
- **Plan C (K1,K2:1997; K3,K4:1998).** This scenario assumes that Kozloduy 1 and 2 are shut down by yearend 1997, and units 3 and 4 are shut down by yearend 1998. This assumption is the preferred alternative from the perspective of the World Bank.

Each of the three alternative scenarios has been developed to meet the long-term reliability requirements of the power system by gradually adding generating resources. It should be noted that there is concern regarding the ability of NEK to finance additional capital projects due to the current poor financial condition of the utility. In this regard, the plans are idealized projections, and tariffs based on these plans are likewise idealized.

3.2.2 Capital Expenditures

Assumed investments required for power plant rehabilitation, new hydro projects, and new thermal projects are shown in Tables 3-8 through 3-10. Table 3-11 shows the year-by-year timing of capital expenditures for each element of the capital program. Cash requirements for capital expenditures average nearly $500 million dollars per year over the period 1996-2000, which is an ambitious program considering the current low levels of tariffs and the difficulty of arranging new borrowing. It is a foregone conclusion that, in the near term, significant elements of this capital program will be deferred.

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3.3 FUTURE GENERATING MIX AND ASSOCIATED PRODUCTION COSTS

Accurate projections of the future resource mix, fuel costs, and other operating assumptions are crucial to tariff analysis because operating costs are a significant portion of revenue requirements and an important determinant of power system marginal costs.

Tables 3-12 and 3-13 show the forecasted base scenario capacity and energy balances for the Bulgarian electrical system for years 1995-2000. These results are from IRP Manager simulations of the electricity production process. There are several significant trends projected for the future mix of fuels used for power generation. With rehabilitation of coal plants and the eventual shutdown of some Kozloduy units, the share of coal in the mix will increase while nuclear will decline. Also, oil and gas use for electric generation will increase, although coal and nuclear will remain the dominant fuels. Use of natural gas for electricity generation is forecast relatively low; however, we note that there is the potential to expand its use.

An important trend is the increasing use of imported coal at the coal-fired power plants. Varna, Bobov Dol, and Rousse are projected to add increasing amounts of imported coal to their fuel mixes, while Maritza East 1,2,3 and Maritza West are expected to continue to burn indigenous lignite. Several factors support the increasing use of imported coal, including its higher quality, cost competitiveness, and availability.

By year 2000, under Plan A assumptions, approximately 50 percent of generation will use coal, 37 percent will use nuclear fuel, 7 percent will use heavy fuel oil or natural gas, and hydroelectric, pumped storage, and imports will generate the remaining 6 percent. For comparison, in 1994 approximately 49 percent of generation used coal, 43 percent used nuclear fuel, about 4 percent used heavy fuel oil or natural gas, and the remaining sources included hydroelectric, pumped storage, and imports. In 1994, over 80 percent of the coal used for power generation was low-quality domestic lignite.

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Table 3-1 Operating Characteristics of Existing Thermal Power Plants

Station	Install. Capacity (MW)	Main fuel	First Year in Service	Maint. Outage (days/yr)	Forced Outage (%)
Kozloduy					
Unit 1	400	Nuclear	1974	120	20
Unit 2	400	Nuclear	1975	120	20
Unit 3	400	Nuclear	1980	90	10
Unit 4	400	Nuclear	1982	90	10
Unit 5	950	Nuclear	1988	75	30/7 (1998 on)
Unit 6	950	Nuclear	1988	75	30/7 (1998 on)
Maritza East 1	180	Lignite	1966-69	30	10
Maritza East 2					
150 MW Units	480	Lignite	1966-69	60/45 (2002)	10
210 MW Units	585	Lignite		60/70 to 2000; 45 from 2001	10
New 210 MW Unit	195	Lignite	1998	45	10
Maritza East 3	780	Lignite	1978-81	55/45 (1999)	10
Maritza 3 Dimitrovgrad	80	Lignite	1971	180	15
Varna					
210 Units 1-3	585	Imported coal	1968-79	45	10/6 post rehab.
210 Units 4-6	585	Imp. coal, NG	1968-79	45	10/6 after rehab.
Bobov Dol	570	Local lignite	1958-63	45	10/6 after rehab.
Rousse	190	Imported Coal	1964-85	30	10
District Heating Plants					
Sofia	150	NG,HFO	1958-85	35	15
Plovdiv	60	HFO	1970-95	20	15
Other	100				15
Industrial Power Plants					
Burgas	120	HFO	1965-71	25	15
Devnia	170	Coal, NG	1965-70	25	15
Himko	50	NG	1966	25	15
Sviloza	70	Coal	1969	25	15
Other	100	HFO		25	15

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Table 3-2 Operating Characteristics of Bulgarian Hydroelectric Power Plants

Stations or Cascades	Installed Capacity (MW)	Average Generation (GWh)	Fixed O&M Cost ($US/kW-yr)
Arda Cascade	274	210	13.2
Batak Cascade	228	358	13.2
Belmeken-Sestrimo Cascade	710	407	13.2
Dospat Vacha Cascade	380	289	13.2
Small Hydro	210	435	13.2

Table 3-3 Operating Characteristics of Bulgarian Pumped-Storage Power Plants

Station	Installed Capacity (MW)	Reservoir Limit (hours)	Round-Trip Efficiency (%)	Fixed O&M Cost ($US/kW-yr)
Chaira 1-4	210	8	75	16.56

Table 3-4a Operating Characteristics of New Capacity Additions

				Heat Rate			
Type	Fuel	Net Cap (MW)	Min Load (MW)	Min Load Fuel (kJ/KWh)	Max Load Fuel (kJ/KWh)	Forced Outage Rate (%)	Planned Outage Rate (Days/Yr)
Coal 300	Lignite	300	210	11,200	11,050	6	45
Coal 100	Lignite	100	70	9,375	8,790	5	30
Combined cycle	Nat. Gas	240	170	7,210	6,000	4	60
Combustion turbine	Nat. Gas	50	10	11,175	11,135	5	30

Table 3-4b Cost Characteristics of New Capacity Additions

	Non-Fuel O&M		Capital	
Type	Fixed ($US/kW-yr)	Variable ($US/ MWh)	Capital Cost Without IDC ($US/kW)	Construction Time (Years)
Coal 300	41	3	1,276	4
Coal 100	41	9	829	4
Combined cycle	5	3	572	2
Combustion turbine	1	8	436	1

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Table 3-5 Comparative Fuel Price Projections

Fuel Type	NEK 1995 $/kcal	Real fuel price esc. 1996 on	NEK 1995 $/GJ	Gilb/Com 1995 $/GJ	Bechtel 1993 $/GJ	Wbank 1991 $/GJ
Nuclear	5.00	0%	1.2		0.5	
Lignite for Maritza East 1,2,3	3.89	1.0%	0.9	1.8	1.1	1.1
Lignite for Maritza West	2.47	0%	0.6		2.1	
Imported brown coal for other plants	7.26	1.2%	1.7	2.7	1.9-2.1	up to 2.5
Heavy fuel oil	13.16	0%	3.1	4.7		
Natural gas	13.24	1%	3.2	3.8	3.3	3 @ brdr

Table 3-6 O&M Costs for Major Thermal Power Plants in Bulgaria – 1995

Units	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Bobov Dol	29	6
Varna	24	6
Russe	41	9
Maritza East	41	3
Maritza 3	77	3
Sofia	24	3
Plovdiv	14	3
Burgas	22	3
Cogeneration	22	3
Devnia (cogen.)	18	3
Devnia (conden.)	7	3
Himko	14	3
Sviloza	6	3
Industrial	42	3
New Combined Cycle	5	4
New CT Plant	1	8

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Table 3-7 Capacity Additions for Plans A, B, and C for the Period 1995-2005

					Plan A K1,K2: 1998; K3,K4:2004		Plan B K1:2001; K2:2002		Plan C K1,K2:1998; K3,K4:1999	
Year	Action	Plant	Unit #	Nominal Unit Capacity (MW)	Increase in Capacity (MW)	Cumul Capacity Increase (MW)	Increase in Capacity (MW)	Cumul Capacity Increase (MW)	Increase in Capacity (MW)	Cumul Capacity Increase (MW)
1996	Commission	Maritza East 2	8	195	195		195		195	
	Commission	Gas Turbine		50	0		100		600	
	Initiate rehabilitation	Varna	1	210	-195	0	-195	100	-195	600
1997	Initiate rehabilitation	Bobov Dol	1	210	-190		-190		-190	
	Complete rehab	Maritza East 3	1	210	15		15		15	
	Initiate rehabilitation	Varna	2	210	-195	-370	-195	-270	-195	230
1998	Initiate rehabilitation	Bobov Dol	2	210	-190		-190		-190	
	Commission	Gas Turbine		300	300		0		0	
	Complete rehab	Kozloduy	5&6	2 x 950	0		0		0	
	Complete rehab	Maritza East 3	2	210	15		15		15	
	Complete rehab	Varna	1	210	210		210		210	
	Initiate rehabilitation	Varna	3	210	-195		-195		-195	
	Retire	**Kozloduy**	**1**	**440**	-400		0		-400	
	Retire	**Kozloduy**	**2**	**440**	-400	-1030	0	-430	-400	-730
1999	Initiate rehabilitation	Bobov Dol	3	210	-190		-190		-190	
	Commission	Gas Turbine		100	0		100		0	
	Retire	**Kozloduy**	**3**	**440**	0		0		-400	
	Retire	**Kozloduy**	**4**	**440**	0		0		-400	
	Complete rehab	Bobov Dol	1	210	210		210		210	
	Complete rehab	Maritza East 3	3	210	15		15		15	
	Complete rehab	Varna	2	210	210	-785	210	-85	210	-1285
2000	Complete rehab	Bobov Dol	2	210	210		210		210	
	Complete rehab	Maritza East 2	5	210	15		15		15	
	Complete rehab	Maritza East 3	4	210	15		15		15	
	Commission	New Coal	-	300	300		0		300	
	Commission	Sofia Coal	-	200	200		0		200	
	Retire	Maritza 1	1-4	50	180		180		180	
	Complete rehab	Varna	3	210	210		210		210	
	Initiate rehabilitation	Varna	4	210	-195	150	-195	350	-195	-350

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Table 3-7 Capacity Additions for Plans A, B, and C for the Period 1995-2005 (Cont'd)

					Plan A K1,K2: 1998; K3,K4:2004		Plan B K1:2001; K2:2002		Plan C K1,K2:1998; K3,K4:1999	
Year	Action	Plant	Unit #	Nominal Unit Capacity (MW)	Increase in Capacity (MW)	Cumul Capacity Increase (MW)	Increase in Capacity (MW)	Cumul Capacity Increase (MW)	Increase in Capacity (MW)	Cumul Capacity Increase (MW)
2001	Complete rehab	Bobov Dol	3	210	210		210		210	
	Complete rehab	Maritza East 2	6	210	15		15		15	
	Retire	**Kozloduy**	**1**	440	0		-400		0	
	Retire	Maritza East 1	1-7	7 x 40	-180		-180		-180	
	Commission	New Coal	-	300	300		0		300	
	Initiate rehabilitation	Varna	5	210	-195	300	-195	-200	-195	-200
2002	Commission	Comb Cycle	-	240	240		240		240	
	Commission	Comb Cycle	-	240	240		240		240	
	Retire	**Kozloduy**	**2**	**440**	0		-400		0	
	Initiate rehabilitation	Maritza East 2	1	150	-120		-120		-120	
	Complete rehab	Maritza East 2	7	210	15		15		15	
	Initiate rehabilitation	Maritza East 2	1	150	0		0		0	
	Commission	Sreden Iskar	-	44	44		44		44	
	Complete rehab	Varna	4	210	210		210		210	
	Initiate rehabilitation	Varna	6	210	-195	734	-195	-166	-195	234
2003	Complete rehab	Maritza East 2	1	150	170		170		170	
	Initiate rehabilitation	Maritza East 2	2	150	-120		-120		-120	
	Complete rehab	Varna	5	210	210	994	210	94	210	494
2004	Commission	Gas Turbine	-	120	120		120		120	
	Retire	**Kozloduy**	**3**	**440**	-400		0		0	
	Retire	**Kozloduy**	**4**	**440**	-400		0		0	
	Complete rehab	Maritza East 2	2	150	170		170		170	
	Initiate rehabilitation	Maritza East 2	3	150	-120		-120		-120	
	Complete rehab	Varna	6	210	210	574	210	474	210	874
2005	Complete rehab	Maritza East 2	3	150	170		170		170	
	Initiate rehabilitation	Maritza East 2	4	150	-120	624	-120	524	-120	924

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Table 3-8 Power Plant Rehabilitation Projects

Project	Investment Cost (1996 $/kW)	Years to Implement
Maritza	64	1
Varna	139	2
Bobov Dol	100	2
Kozloduy 5&6	145	3

Table 3-9 New Hydro Projects

Project	Investment Cost (1995 $/kW)	Years to Implement	Installed Capacity	Operation in Year
Gorna Arda	837	6	156	2002
Sreden Iskar	975	2	44	2002

Table 3-10 New Thermal Projects

Project	Investment Cost (1995 $/kW)	Years to Implement	Installed Capacity	Operation in Year
Maritza East	1,343	5	600	2002
Sofia	870	3	200	2000

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Table 3-11 Forecasted Capital Expenditures

Project	Plant Added into Service US$ Millions						Construction Work in Progress (CWIP) US$ Millions					
	1995	1996	1997	1998	1999	2000	1995	1996	1997	1998	1999	2000
HV network	7	7	7	7	7	8	0	0	0	0	0	0
LV network	34	34	34	34	34	34	0	0	0	0	0	0
MV network	8	8	8	8	9	9	0	0	0	0	0	0
Kozloduy 5&6	23	112	67	7	6	6	0	0	0	0	0	0
Chaira	0	0	40	0	0	0	17	40	0	0	0	0
Belene NPP	0	0	0	0	0	0	672	672	672	672	672	672
Dispatch system	0	0	57	0	0	0	25	57	0	0	0	0
MI Unit 8	0	74	58	0	0	0	74	58	0	0	0	0
Miscellaneous	42	165	129	63	71	72	0	0	0	0	0	0
Bobov Dol	0	0	0	0	21	21	0	0	6	27	27	21
Gorna Arda HPP	0	0	0	0	0	0	0	4	13	42	90	121
Sreden Iskar HPP	0	0	0	0	0	0	0	0	0	0	0	13
Maritza East New	0	0	0	0	0	402	0	24	153	452	727	406
Sofia A	0	0	0	0	0	87	0	5	28	70	87	0
Sofia B	0	0	0	0	0	87	0	5	28	70	87	0
Varna	0	0	0	29	29	29	0	10	39	39	29	10
Other	0	0	0	0	0	0	0	0	0	0	0	82
Total	115	399	400	148	177	755	789	876	939	1371	1720	1325
Change in CWIP		87	63	432	349	-394						
Cash requirements		486	463	580	526	361						

Table 3-12 Capacity Balance in MW for NEK (Plan A) (Operating Installed Capacity) 1994-2000

Station/Year	1994	1995	1996	1997	1998	1999	2000
Kozloduy							
Unit 1	400	400	400	400			
Unit 2	400	400	400	400			
Unit 3	400	400	400	400	400	400	400
Unit 4	400	400	400	400	400	400	400
Unit 5	950	950	950	950	950	950	950
Unit 6	950	950	950	950	950	950	950
Maritza East 1	180	180	180	180	180	180	
Maritza East 2							
150 MW units	480	480	480	480	480	480	480
210 MW units	585	585	585	585	585	585	600
New 210 MW unit			195	195	195	195	195
Maritza East 3	780	780	780	795	810	825	840
Maritza 3 Dimitrovgrad	80	80	80	80	80	80	80
Varna							
210 Units 1-3	585	585	390	195	210	420	630
210 Units 4-6	585	585	585	585	585	585	390
Bobov Dol	570	570	570	380	190	210	420
Rousse	190	190	190	190	190	190	190
Chaira	420	420	420	420	840	840	840
Other thermal and CHP	820	820	820	820	820	820	820
Imports	600	600	600	600	600	600	600
Hydro	1802	1802	1802	1802	1802	1802	1802
New units							
Simple cycle					300	300	300
Sofia Coal 100							200
Lignite 300							300
Total		**11177**	**11177**	**10807**	**10567**	**10812**	**11387**
Peak load		7180	7402	7632	7868	8112	8364

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Table 3-13 Energy Balance in GWh for NEK (Plan A) 1994-2000

Station/Year	1994	1995	1996	1997	1998	1999	2000
Kozloduy							
Unit 1		1882	1882	1882			
Unit 2		1882	1882	1882			
Unit 3		2376	2376	2376	2376	2376	2376
Unit 4		2376	2376	2376	2376	2376	2376
Unit 5		4626	4625	4628	6149	6149	6149
Unit 6		4626	4624	4628	6149	6149	6149
Maritza East 1		1253	1248	1276	1287	1297	
Maritza East 2							
150 MW units		2278	2492	2410	2827	2863	2704
210 MW units		3624	3695	3724	3793	3702	3777
New 210 MW unit			1234	1267	1337	1344	1342
Maritza East 3		4366	4432	4753	5149	5377	5282
Maritza 3 Dimitrovgrad		301	301	301	301	301	301
Varna							
210 Units 1-3		1662	852	646	1076	2025	2470
210 Units 4-6		1655	1607	2056	2369	2446	1055
Bobov Dol		513	791	708	640	988	1732
Rousse		515	486	554	761	703	596
Chaira (gener./ pumping)		126/168	201/268	316/422	419/580	394/540	287/392
Other thermal and CHP		3474	3617	3766	4035	3916	3920
Imports		270	371	793	460	437	311
Hydro		1700	1700	1700	1700	1700	1700
New units							
Simple cycle					326	310	174
Sofia Coal 100							1389
Lignite 300							2166
Unserved energy		158	195	362	333	312	144
Total generation*		**39495**	**40719**	**41982**	**43283**	**44625**	**46008**
Sales		31596	32575	33585	34626	35700	36806

Note: Generation includes power plant own use and transmission and distribution losses.

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Section 4

Review of Existing Tariffs

The objective of this section is to present and evaluate the current pricing of electricity in Bulgaria by reviewing the current regulation of prices, price levels, and pricing structures The marginal costs used in this section for comparisons are taken from Section 5 of this report.

4.1 CURRENT TARIFF SETTING AND REGULATION

Electricity prices are set by the Commission of Pricing (CoP) under the category of "fixed" prices, the most controlled form of pricing regulation in Bulgaria. Other items in this regulatory category are residual fuel oil, natural gas and district heating for households. The formal procedure is that NEK suggests tariffs to the Committee of Energy (CoE). CoE then accepts or rejects NEK's proposal. If proposed tariffs are accepted, they are sent for final approval to the CoP.

Despite the existence of this institutional tariff-setting procedure, in the recent past the overall electric tariff level has been driven by conditions of loans from the World Bank and EBRD. The banks specify minimum tariff levels, and generally tariffs are set in conformance with the minimums. The tariff increase in September 1995 brought average electricity tariffs to $26 per MWh. The agreements with the banks specify increasing the average tariffs to $30 per MWh in March 1996 and $35 per MWh by September 1996. At the time of this report we understand that agreement has been reached to increase tariffs to meet the bank targets.

4.2 CURRENT TARIFF STRUCTURE

The current tariff structure in Bulgaria is appealing because it is simple, and yet it enables essential cost-based differentiation among customers. Current electric tariffs differentiate among customers based on the following factors:

- Households are differentiated from all other customers. Other customers are grouped together as "industrial and public sector" and differentiated by voltage level.
- Peak, daytime, and nighttime time-of-use is recognized in non-household tariffs.
- Summer and winter seasons are differentiated for non-household tariffs.
- Household tariffs are differentiated for two zones, peak and off-peak. Currently household winter and summer tariffs are the same.
- Alternative tariff schedules are provided for non-household customers having 1-, 2- and 3-zone meters.

Table 4-1 shows the non-household tariffs. Electric generation from industries and district heating companies can be sold to NEK at rates shown in Table 4-2.

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Table 4-1 Non-Household Tariffs – September 1995 (leva/kWh)

Service Level	Winter				Summer			
	Peak	Day	Night	Single Zone	Peak	Day	Night	Single Zone
HV	3.55	1.99	0.95	2.86	3.10	1.67	0.81	2.48
MV	3.68	1.99	0.98	2.91	3.19	1.73	0.86	2.57
LV	3.85	2.07	1.02	3.10	3.35	1.81	0.88	2.69

Note: Published tariffs also contain power factor penalties for large users.

Table 4-2 Electricity Buyback Rates for Industry and District Heating Companies – September 1995

Time of Day	leva per kWh	$ per MWh
Peak	1.82	27.2
Day	1.01	15.1
Night	0.44	6.6

4.3 COMPARISON OF TARIFFS WITH LRMC AND COST-OF-SERVICE

The sections below compare electricity pricing in Bulgaria with LRMC and cost-of-service by tariff category and by time-of-day. These comparisons measure the extent to which current pricing meets the cost-based ideal. LRMC and cost-of-service results are taken from scenario estimates of LRMC tariffs and cost-of-service tariffs for Plan A (K1, K2: 1998; K3, K4: 2004) presented in Sections 5 and 6 of this report.

4.3.1 Summary of Comparisons

We make the following general conclusions regarding historic electricity tariffs:

- We estimate the average LRMC of sales is $49 per MWh, and the average cost-of-service is $43 per MWh. Assuming the average tariff will be increased to $35 per MWh in September 1996, tariffs will be low relative to cost-based tariffs.
- Peak pricing has been close to cost-based, while nighttime pricing has been significantly below cost.
- Low voltage tariffs are particularly low relative to LRMC-based tariffs, while medium and high voltage tariffs are closer to cost-based.

Under current tariffs, NEK is experiencing a serious shortfall in revenues, even though current electricity tariffs generate enough revenue to meet the technical definition of financial

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requirements provided under Bulgarian accounting standards. Revenues are inadequate because they do not include:

- An allowance for nuclear plant decommissioning and waste fuel storage
- Sufficient allowance for depreciation, since *book value* has not kept pace with *replacement cost* in Bulgaria's hyper-inflationary economy
- Any direct subsidy of NEK from the state budget, although some subsidy reaches NEK indirectly through state subsidization of domestic coal production

4.3.2 Comparison by Tariff Category

Figure 4-1 compares the weighted average September 1995 tariffs for each tariff category with our scenario estimate of LRMC by tariff category. Sales figures for 1994 are used in weighting the time-of-day (TOD) tariffs to obtain the weighted average by tariff category. Both TOD and single-zone tariffs are shown for non-household customers.

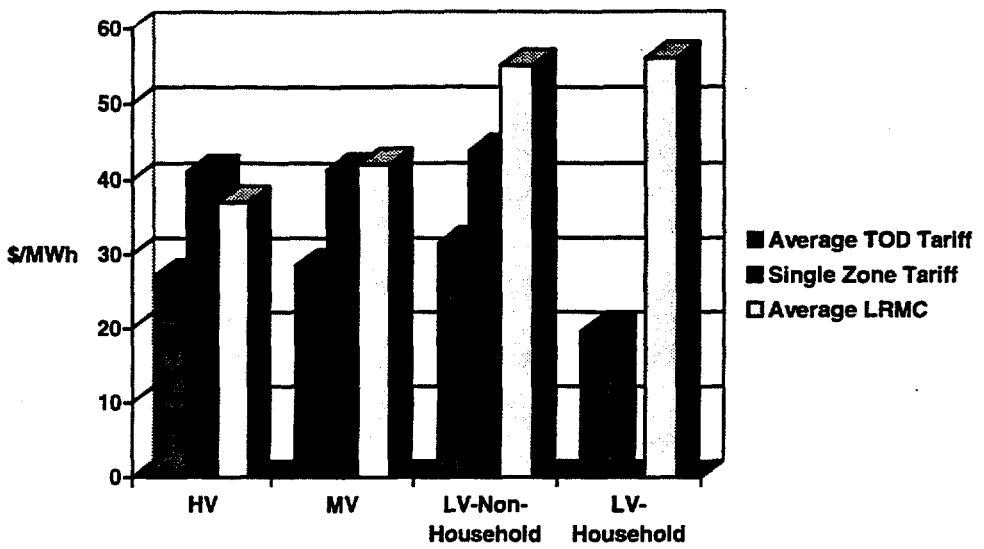

Figure 4-1 Comparison of September 1995 Tariffs with LRMC

Based on the comparisons of September 1995 tariffs to LRMC in Figure 4-1, we make the following observations:

- *High voltage.* The September 1995 time-of-day HV tariffs are about 75 percent of average LRMC. Over 98 percent of all 1994 HV sales were time-of-day. The single-zone HV tariff is slightly more than average LRMC, but is used by very few customers.

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- *Medium voltage.* The September 1995 TOD MV tariff is about 70 percent of average LRMC. As with HV, almost all MV sales are based on TOD pricing. The single-zone tariff appears to be close to average LRMC, but applies to few customers.
- *Low voltage non-household.* The September 1995 TOD LV Non-household tariff is about 60 percent of average LRMC and the single zone tariff is about 80 percent of LRMC. About 53 percent of Low Voltage Non-household sales were under TOD tariffs in 1994 and 47 percent were single zone.
- *Low voltage household.* The September 1995 household tariffs are about 35 percent of average LRMC.

4.3.3 Comparison by Time-of-Day

In Bulgaria, time-of-day (TOD) tariffs are available to all customers. By installing multi-zone metering, Household customers can use daytime and nighttime tariffs, and Non-household customers can use peak, daytime and nighttime tariffs.

This section provides a comparison of TOD tariffs with time-differentiated LRMC. Figures 4-2a, b, and c depict the comparisons for the HV, LV non-household, and LV household categories. The values shown in the figures are weighted averages based on 1994 sales statistics. We make the following observations based on the comparisons in the figures:

- *HV tariff category.* The September 1995 peak period tariff is slightly higher than estimated LRMC, the daytime tariff is about 75 percent of LRMC, and the off-peak tariff is significantly less than LRMC. The HV nighttime tariff is approximately 25 percent of the peak tariff, while nighttime LRMC is approximately 65 percent of peak LRMC. Thus it appears that the HV TOD tariffs exaggerate the difference between economic costs in the peak and nighttime periods.
- *MV tariff category.* The comparisons between TOD tariffs and LRMC for the MV category are similar to the HV, except that the TOD tariffs are lower than LRMC for all time periods. The MV nighttime tariff is approximately 25 percent of the peak tariff, while nighttime LRMC is approximately 60 percent of peak LRMC.
- *LV non-household tariff category.* The tariff is significantly less than LRMC in all time periods; however, exaggerated time-differentiation in tariffs continues to be evident, in comparison to more moderate time-differentiation in LRMC.
- *LV household tariff category.* In September 1995, household electricity tariffs were set at 1.56 leva/kWh ($23 per MWh) for daytime use and 0.83 leva/kWh ($12 per MWh) for nighttime use. These levels are so much less than LRMC in daytime and nighttime periods that analysis of time-differentiation is not useful.

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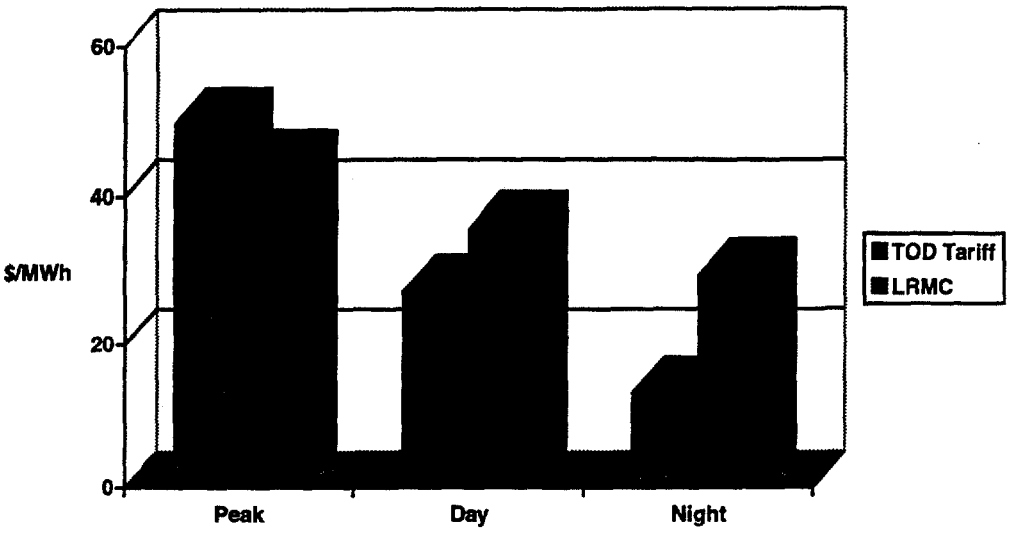

Figure 4-2a HV Tariffs and LRMC by Time of Day

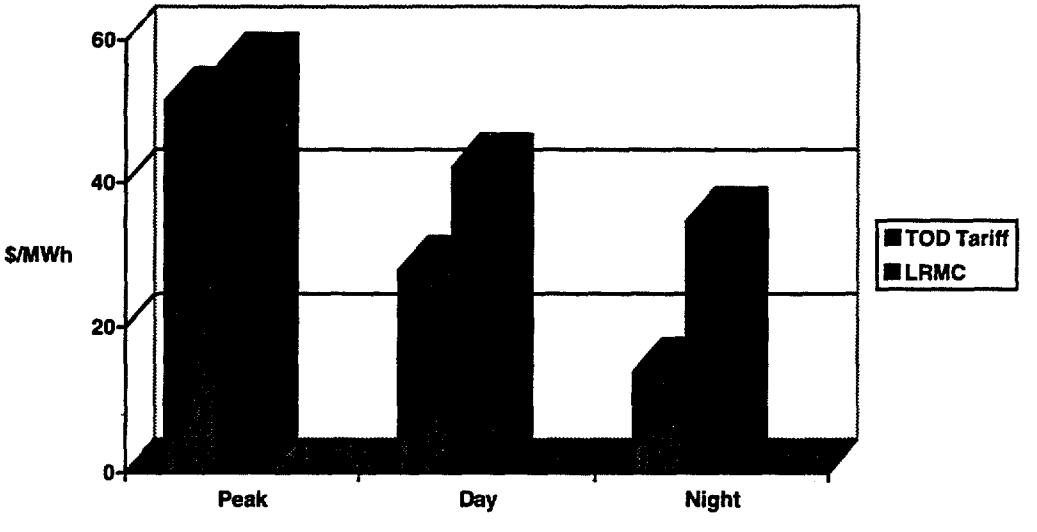

Figure 4-2b LV Non-Household Tariffs and LRMC by Time of Day

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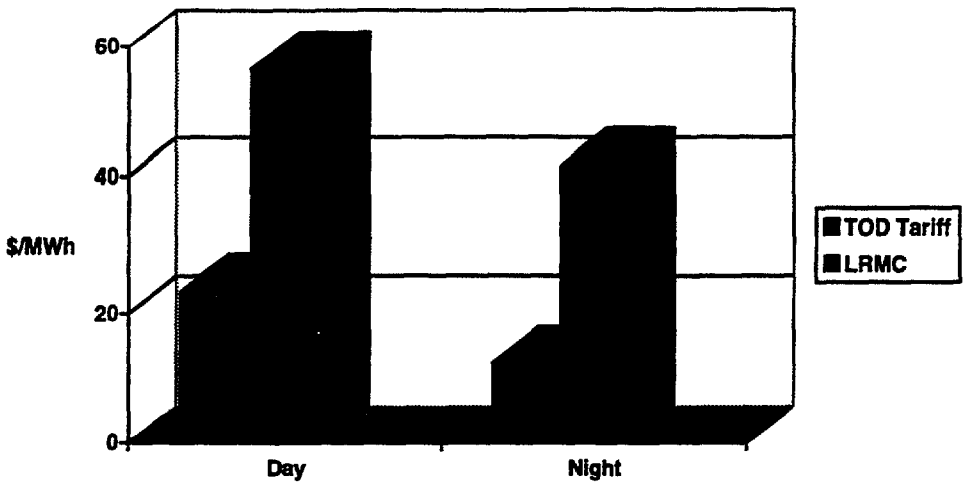

Figure 4-2c LV Household Tariffs and LRMC by Time of Day

4.3.4 Seasonal Tariffs

Seasonal tariffs apply to all non-household customers. These tariffs are higher in the winter than the summer. For example, the HV peak winter tariff is 15 percent higher than the peak summer tariff. The fact that loads are highest in the winter makes this intuitively satisfying. However our analysis indicates that SRMC and marginal capacity cost are actually higher in the summer. Tariffs based on these pricing signals would be higher in the summer than in the winter.

Figure 4-3 illustrates the relationship between winter and summer prices and marginal costs for HV customers. As shown, the existing ratio of winter to summer tariffs for HV is greater than 110 percent for each of the peak, daytime and nighttime periods. The ratio of estimated winter to summer SRMC and LRMC is less than 100 percent. Thus marginal cost analysis would indicate that HV tariffs should be higher in the summer than the winter. This relationship was found for the other tariff categories as well.

How can this counterintuitive result be explained? There are several possibilities all relating to operational difficulties of the generation system during the summer. The system has been designed for greater demand than is now the case and for integrated operation with the former U.S.S.R. The sizing of Kozluduy 5 and 6 at 1,000 MW was done in the 1980s at a time of high projected growth and when the larger U.S.S.R. system could be relied on to supply backup capacity during emergency outages and to absorb excess generation during minimum load periods.

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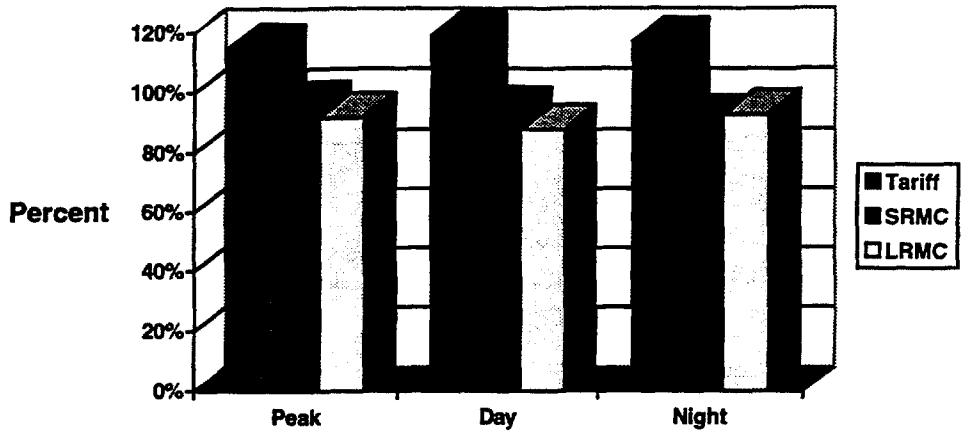

Figure 4-3 Ratio of Winter to Summer Prices and Costs (HV)

The situation today is different from the projections used for planning the power system. The decline in demand since 1989 has resulted in a system in which each of Units 5 and 6 at Kozluduy represent over 14 percent of the Bulgarian peak load. Transmission links exist to the larger system of the former U.S.S.R., but their use has been limited. Combined with the inflexible operation of the coal and lignite-fired capacity, the Bulgarian system is limited in its ability to respond to load changes and unexpected outages. These limitations are particularly severe during the summer when loads are lower and the relative size of the largest generating units to total system output is greatest.

It should be noted that steps are under way to increase the operational flexibility of the Bulgarian electric generation system. The Chaira pumped storage plant is the most notable development. In addition, there are plans for rehabilitating most of the coal and lignite-fired capacity, and system control has been improved to increase their operational flexibility. Even with these improvements, our modeling of the Bulgarian system using IRP Manager indicates that the operational limitations during the summer will result in higher marginal costs than in the winter. However, further investigation is warranted to ensure that the modeling accurately reflects the seasonal operation of the generating units. In particular, we recommend investigating the effect of projected nuclear unit refueling schedules on the results.

4.3.5 Pricing for Power Purchased from Industrial and CHP Plants

September 1995 pricing for generation sold to NEK by industry and district heating companies is compared with SRMC and LRMC generation in Figure 4-4. This comparison illustrates the extent to which prices reflect NEK's incremental cost savings associated with power purchases. NEK's incremental cost savings fall somewhere between SRMC and LRMC, depending on the reliability of the power and the coincidence of power deliveries with the power system's requirements.

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Our comparisons indicate that the "buyback" rate is only as high as SRMC in the peak period. Prices during other periods are significantly lower than even the marginal operating cost of NEK.

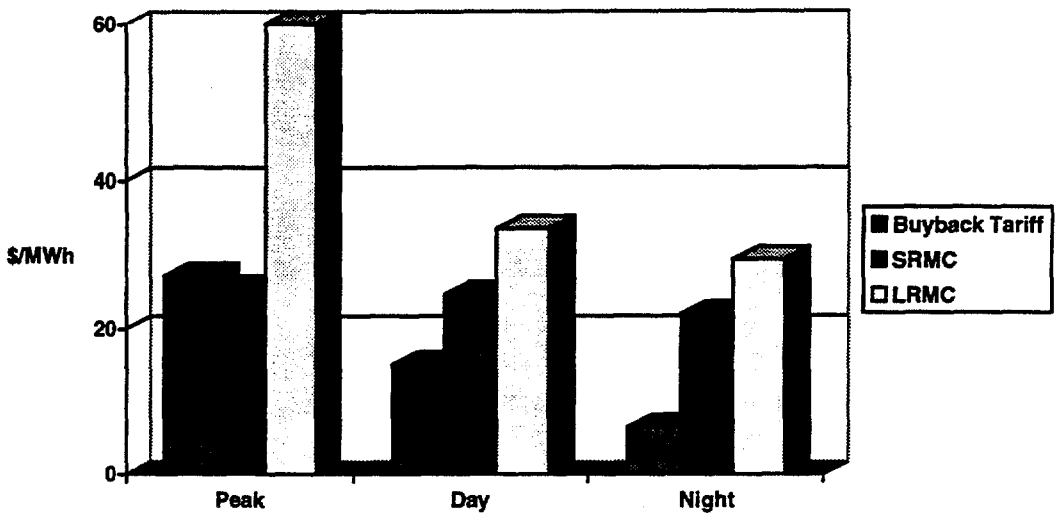

Figure 4-4 Comparison of Pricing for Power Purchased from Industrial and CHP Plants with SRMC and LRMC by Time of Day

The gap between the buyback rate for industries and district heating customers and the estimated generation LRMC will require further study of the following factors:

- The degree to which generation from industrial and district heating companies can be used in peak periods of demand and in emergency situations
- The degree to which this generation can be used to defer capacity expansion by NEK
- Other costs and benefits associated with non-NEK generation
- Influence of avoided cost pricing for development of a competitive market for non-utility generation

The fact that generation from the CHP units is driven by heat demand and may not fully correspond to NEK's requirements may justify a price less than LRMC. However, new Sofia and Sofia East CHPs have been proposed as partial replacement for the Kozluduy Units 1-4. This proposal implies a capacity value and from a purely economic standpoint would justify a buyback price greater than SRMC.

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Section 5

Long-Run Marginal Cost Forecast

The objective of this section is to develop NEK's long-run marginal costs (LRMCs) for supplying electricity to its customers. LRMC is defined as the levelized incremental investment and operating cost of serving an additional kWh of energy demand (or kW of peak). LRMC is used as a guide to structure tariffs to provide economic signals to electricity consumers.

5.1 INTRODUCTION TO LRMC

NEK provides three main services: (1) customer access to the utility system and associated meter reading and billing services, (2) electric energy, and (3) reliable power for meeting peak customer loads. *Marginal customer costs*, *marginal energy costs*, and *marginal demand or capacity costs* represent incremental changes in cost for each respective service. Marginal customer costs are those costs which change as a result of a change in the number of customers. Marginal energy and marginal capacity costs are instantaneous costs related to energy use. The marginal costs for providing utility services are important determinants of tariffs for those services.

The *marginal customer cost* is essentially an access cost and, consequently, it does not vary according to when or how much electricity is used by the customer. The cost is based on the utility's cost to provide all the equipment needed to deliver energy from the network to the customer site, plus the cost of servicing each customer account. Marginal customer costs are relatively low compared to marginal energy and capacity costs, and are not addressed quantitatively in this report.

Marginal energy cost, also known as *short-run marginal cost* (SRMC), is related to kilowatt-hours consumed. For example, one component of marginal energy cost is fuel expense. Marginal energy cost is the change in variable operating costs to meet a change in demand in any given hour.

Marginal capacity costs are those costs which change in relation to changes in kilowatt demand, for example the investment cost for new generating capacity. *Generation* capacity costs reflect the need to provide sufficient generation capacity to meet incremental system loads with an adequate degree of reliability. *Transmission and distribution* capacity costs reflect the need to provide sufficient T&D facilities to supply incremental peak system demand.

Marginal customer, energy and capacity cost estimates by voltage level are used as the building blocks for estimating LRMC for various customer tariff categories. The reason for assessing energy and capacity marginal costs separately is that marginal energy costs provide a guideline to determining variable components of tariffs related to customer energy demand, and marginal capacity costs provide a guideline to determining fixed components related to customer peak demand.

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5.2 MARGINAL COSTING USING PRODUCTION SIMULATION

The operation of the generation system is simulated using the IRP Manager model. This model has been developed by the U.S. company, EPS Solutions, and the software is licensed by NEK and CoE. It is a commonly used model for power system production simulation for tariff analysis. The purpose of production simulation is to project the operation of plants under a given set of assumptions to forecast future outcomes such as fuel use and generation system reliability.

Key factors that affect the model-based forecasting of marginal costs include:

- Technical characteristics of the generating units including capacity, reliability, maintenance requirements, and the need to provide heat as well as electric power
- Cost characteristics of generating units, including operation and maintenance (O&M) cost and fuel efficiency
- Fuel prices
- Peak demand
- Daily and seasonal shape of loads
- Import/export power agreements

5.2.1 Marginal Energy Costing

Marginal energy cost is a function of the marginal generating units that would respond to increased electric consumption. A unit is considered "on the margin" or "marginal" if its output responds to small changes in demand. Marginal energy cost is based on the cost of operating the marginal generating resource to meet an incremental change in electricity demand.

Figure 5-1 illustrates how IRP Manager identifies the marginal generating resource. The figure shows a monthly load curve for the system and the method of meeting the load with various generating sources. In this example, electric generation from nuclear, coal, industrial and combined heat and power (CHP) units covers the baseload portion of the electric demand curve. Hydro, pumped-storage units and gas- and oil-fired units cover the daily peaks and valleys. Imports are the most expensive source of power and are used only in event of insufficient Bulgarian generating resources. In the figure gas- and oil-fired generation is marginal off-peak, and storage hydro and imports are marginal the rest of the day.

The marginal energy cost for the system is given by the incremental cost of operating the marginal units weighted by the percent of time that each unit operates on the margin. Our projections indicate that in the future gas-, oil-, and coal-fired units, as well as imports, will operate on the margin. The marginal energy cost will thus be affected by prices for gas, oil, coal, and imported energy.

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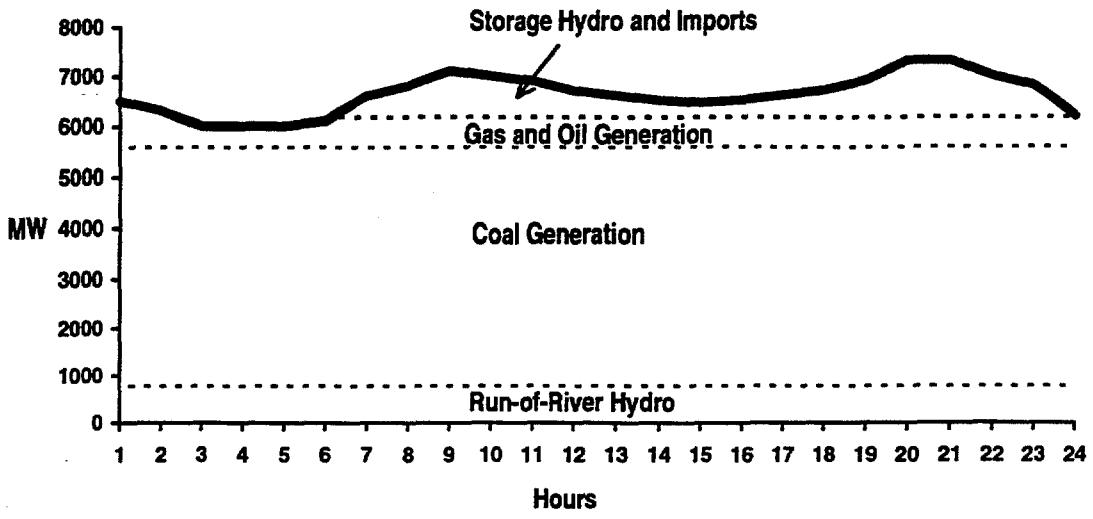

Figure 5-1 Illustration of Marginal Energy Cost

In contrast to marginal energy cost, the *average generating cost* is based on the average operating costs of all units that contribute to meeting load, including the nuclear, thermal, and hydro units; the CHP and industrial unit costs allocated to electricity generation; the price and amount of imports; and the operating costs of the condensing units.

5.2.2 Marginal Capacity Costing

Marginal capacity cost is a function of the reliability of the generation system. Production simulation calculates measures of generation reliability such as loss-of-load probability (LOLP) and expected unserved energy (EUE). LOLP is the probability that generating resources will be insufficient to meet the demand. EUE is a probabilistic measure of the amount of energy that the generation system is unable to supply over a given period of time due to inevitable resource outages. Higher system LOLP or EUE indicates a greater value to the system for incremental capacity.

Marginal capacity cost is the capital cost of resource additions to meet the reliability requirements associated with incremental demand. We consider both LOLP and EUE in the reliability analysis; however, the primary reliability criterion that we use to determine when capacity additions are required is 5 percent annual LOLP.

The reliability of the generation system varies by time of day and by season because of changing load demand, and the variations in the generating resources available to serve load. The contribution of a particular time period to EUE provides the basis for allocating marginal capacity cost to time periods.

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5.3 GENERATION SYSTEM LRMC

Two methods of calculating generation system LRMC are used in this report to illustrate alternative methods and to demonstrate the sensitivity of results to methodological approach. These methods are referred to as the *Incremental Plant Method* and the *Revenue Requirements Method.* The analyses are conducted in constant 1996 U.S. currency for the period 1996-2005. We assume an *incremental* opportunity cost of capital of 10 percent per year. In the sections below we discuss the marginal costing methodologies and results for the Bulgarian power system for the three scenario resource plans developed in Section 3.

5.3.1 Incremental Plant Method

Overview

The Incremental Plant Method is applied in the following way:

- Marginal energy cost is estimated by the IRP Manager model within the generation system simulation.
- Marginal capacity cost is estimated based on the investment cost of the gas turbine proxy, incurred at the time the incremental plant is added to meet system capacity requirements. The technical and operating characteristics for the gas turbine are shown in Table 5-1.
- Levelized marginal capacity cost is calculated per unit of peak demand increase over the study time horizon.
- Marginal energy and capacity costs are combined for total generation system LRMC.

Table 5-1 Technical and Economic Characteristics of Gas Turbines

	Simple Cycle Gas Turbine	Combined Cycle
Capital cost without IDC	436 $/kW	572 $/kW
Capacity	50 MW	240 MW
Construction time	1 year	2 years
Investment schedule		
First year	100%	50%
Second year	0%	50%
Fixed O&M cost	1 $/kW-yr	5 $/kW-yr
Real escalation for O&M	1%	1%

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Marginal Capacity Cost Methodology

The *incremental plant* is defined as the first unit in the development plan that can either be deferred in case of a decrease in demand or accelerated in case of an increase in demand. We use the IRP Manager model to identify the incremental plant. The methodology involves removing all discretionary capacity additions from the initial model run, and then testing capacity additions for cost-effectiveness to determine when capacity additions are first needed to ensure adequate system reliability.

To calculate marginal capacity cost, the investment cost of a gas-fired combustion turbine-generator is used. The combustion turbine has the lowest investment cost of any generating resource, although its operating cost is relatively high. The low investment cost of the turbine-generator makes it an appropriate proxy for the marginal cost of "pure" generation capacity.

The calculation of marginal capacity cost is performed in two steps. The first step removes all discretionary resource additions from the plan. The second step calculates the first year when new peaking units are needed in the system. The calculation uses the IRP Manager Iterative Cost Effectiveness Methodology (ICEM). ICEM performs a cost-effectiveness analysis and determines the year and total capacity of new unit additions.

Generally there are two options to determine the year when new capacity is needed in the system. One way is to build the system expansion plan to meet some target level of system reliability (e.g., loss-of-load probability (LOLP) or reserve margin). However, economic theory suggests that reliability should be treated as a variable to be optimized, and both price and capacity levels should be optimized simultaneously. The optimal price is then the marginal cost price, while the optimal reliability level is achieved when the marginal cost of capacity additions equals the expected value of economic cost savings to consumers due to electricity supply shortages avoided by those capacity increments. For this second approach we use $70 per MWh as an approximation of the consumer costs for system unreliability.

Results

Table 5-2 presents the calculation of the generation LRMC using the Incremental Plant Method for Plan A (K1, K2: 1998; K3, K4: 2004).

SRMC shown in the table is a direct output of the IRP Manager Model. We used the IRP Manager Model to calculate marginal costs for each of the three scenario resource plans. The results are summarized in Table 5-3. We find that SRMC is highest for Plan C (K1, K2: 1998; K3, K4: 1999) because the earlier retirement of Kozloduy units causes generating units with higher variable costs to be more frequently on the margin, and there is also more unserved energy on the margin. However there is little variation in SRMC among the scenarios, which is attributed to the predominance on the margin of coal-fired units with similar operating costs, regardless of scenario. Marginal capacity costs are also similar among the scenarios, because the year-by-year system unserved energy is similar for all scenarios.

Table 5-2 Generation LRMC – Incremental Plant Method Plan A (K1, K2: 1998; K3, K4: 2004)

Item	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Label
Investment cost, $/kW		493		0	0	0	0	0	0	0	A
First year present value, $/kW			542								B=A*1.1
Capital recovery, $/kW-year			59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	C=Pmt(B)
Fixed O&M, $/kW-year			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	D
Annualized fixed cost, $/kW-year			60.7	60.7	60.7	60.7	60.7	60.7	60.7	60.8	E=C+D
Incremental energy, MWh	5694	5694	5694	5694	5694	5694	5694	5694	5694	5694	F=1 MW * 8.76 hours *.65
SRMC from IRP Manager, $/MWh	20.9	24.5	26.5	27.5	24.3	21.5	25.3	24.9	26.5	26.8	G
Marginal capacity cost, $/MWh			10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	H=E/F
Total LRMC, $/MWh	20.9	24.5	37.1	38.2	35.0	32.1	36.0	35.6	37.1	37.4	I=G+H
Levelized LRMC for a load increment/decrement @ 65% load factor											
Variable	24.6 $/Mwh = Level SRMC (line G), 1996-2005										
Fixed per MWh	9.3 $/Mwh = Level marginal capacity cost (line H), 1996-2005										
Fixed per kW-yr	52.7 $/kW-yr = Level marginal capacity cost (line E), 1996-2005										
Total	33.9 $/Mwh = LRMC (line I), 1996-2005										

Table 5-3 Generation LRMC Summary for Alternative Methods

Component of Cost	Plan A (K1,2: 1998; K3,4: 2004)	Plan B (K1:2001; K2: 2002)	Plan C (K1,2: 1998; K3,4: 1999)
Incremental Plant Method			
Marginal Energy Cost, $/MWh	25	24	27
Marg. Cap. Cost, $/MWh (65% load factor)	9	10	10
Total, $/MWh	34	34	37
Revenue Requirements Method			
Variable, $/MWh	24	27	29
Fixed, $/MWh (65% load factor)	3	15	23
Total, $/MWh	27	42	52

5.3.2 Revenue Requirements Method

Overview

As a verification of the results obtained using the Incremental Plant Method, we also use the Revenue Requirements Method. Like the Incremental Plant Method, the Revenue Requirements Method makes use of the IRP Manager Model and the ICEM optimization routine within the model. Essentially the Revenue Requirements Method determines LRMC as the avoided cost of incremental resource additions that would serve a hypothetical load increment. The procedure for the Revenue Requirements Method is:

- Develop optimized generation plan for a given electricity demand forecast. Potential resource additions for the optimal plan are chosen from a menu of generic alternatives. For simplicity, we make two potential supply-side additions available to ICEM, the simple-cycle combustion turbine and the combined-cycle combustion turbine. Technical and operating characteristics for these technologies are shown in Table 5-1.
- Develop optimized generation plan for a given electricity demand forecast with a small increase/decrease in demand. Based on some preliminary testing, we adopted the approach of increasing demand by 250 MW in all hours of the year. Three main considerations affect the choice of demand increment, namely, that the increment should:
  - Be small enough to be considered marginal
  - Be large enough to smooth "lumpiness" impacts on system operations
  - Suit the size of the resource expansion alternatives

  In the interest of time, we adopted a load increment approach, however, a technically superior approach involves averaging results from incremental and decremental trials. Another technical enhancement to our approach would involve multiple IRP Manager runs with load increments/decrements in time-of-day periods, rather than in all hours.
- Calculate the revenue requirements for each optimized plan (investment and operating costs).
- Separate revenue requirements into energy- and capacity-related costs.
- Calculate the difference in revenue requirements between the base case and the load increment case to yield the levelized cost per unit of demand increase for energy-related, capacity-related, and total costs.

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Results

LRMC for the three scenarios is summarized in Table 5-3. In general, these results are less satisfying than the results for the Incremental Plant Method, also shown in Table 5-3. The following summarizes our experience using the Revenue Requirements Method:

- **Plan A (K1, K2: 1998;K3, K4: 2004).** Table 5-4 illustrates the calculation of LRMC for the Revenue Requirements Method for Plan A. Two new 50 MW simple cycle combustion turbines are added in 1996 to the initial resource base (see Table 3-7). We note that this result is theoretically unsatisfying because 100 MW of additions seem insufficient to meet the 250 MW load increment. This result illustrates the need to establish optimal load/resource balance as the starting point for the Revenue Requirements Method. It should be noted that such complexities are a common pitfall of marginal costing. The Revenue Requirements Method requires judgment and relatively high time commitment.

- **Plan B (K1: 2001;K2: 2002).** One 240 MW combined cycle and two 50 MW simple cycle units are added in 1996 to meet an incremental demand of 250 MW. This appears to be the most reasonable of the three scenarios.

Table 5-4 Generation LRMC – Revenue Requirements Method for Plan A

Item	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Label
Load increment											
Incremental energy, GWh	2,258	2,328	2,400	2,474	2,551	2,583	2,614	2,646	2,679	2,712	A
Incremental peak load, MW	258	266	274	282	291	295	298	302	306	310	B
Incremental costs from IRP Manager											
Incremental fuel cost, $thousand	34,570	40,850	44,490	44,990	49,820	47,760	50,100	51,570	53,430	55,500	C
Inc. variable O&M cost, $thousand	9,850	10,610	11,950	12,700	14,070	13,430	14,400	14,820	15,030	15,280	D
Inc. fixed O&M cost, $thousand	84	85	86	87	87	88	89	90	91	92	E
Capital recovery for additions	5,280	5,280	5,280	5,280	5,280	5,280	5,280	5,280	5,280	5,280	F
Total variable cost	44,420	51,460	56,440	57,690	63,890	61,190	64,500	66,390	68,460	70,780	G=C+D
Total fixed cost	5,364	5,365	5,366	5,367	5,367	5,368	5,369	5,370	5,371	5,372	H=E+F
Levelized marginal cost for a load increment/decrement in all hours of the year											
Energy	23.5	$/Mwh	= Level variable cost (line G) / level incremental energy (line A)								
Capacity	3.3	$/Mwh	= Level fixed cost (line H) / level inc. energy (line A) / 0.65 load factor								
	18.9	$/kW-yr	= Level fixed cost (line E) / level inc. peak load (line b)								
Total	26.9	$/Mwh	= Level LRMC								

- **Plan C (K1, K2: 1998; K3, K4: 1999).** One combined cycle unit and two simple cycle units are added in 1996, and another combined cycle unit is added in 1997. This is probably too much incremental capacity to meet the incremental demand and reserve requirements. As a result, the LRMC estimate is considered to be too high. We suspect that the initial Plan C resource plan is "underbuilt" relative to the optimal.

5.3.3 LRMC Summary for the Two Methods

Summary of Results

We make the following observations with reference to Table 5-3 comparing results for the two approaches:

- In general we find the results for the Incremental Plant Approach satisfactory. The Revenue Requirements Method is more difficult to implement and we are less satisfied with its results.
- There is not much variation in the case-by-case comparisons for the Incremental Plant Approach because in all cases the system is close to load/resource balance. As expected, marginal energy and capacity costs are highest for the case with the earliest shut down of Kozloduy. Earlier shutdown increases marginal capacity costs by accelerating the timing for capacity additions. Earlier shutdown also increases marginal energy costs, because low variable cost nuclear is replaced by higher variable cost thermal generation in the dispatch order.
- In general, LRMC for the Revenue Requirements Method should exceed LRMC for the Incremental Plant Method, due to the addition of a sizable load *increment*. The Table 5-3 comparison of results for Plan B illustrates this relationship.
- Note that the Incremental Plant Method allocates more of LRMC as energy-related, and less as capacity-related, in comparison to the fixed and variable components from the Revenue Requirements Method. The Incremental Plant Method attempts a separate, direct estimate of the marginal energy and capacity costs. In the Revenue Requirements Method, the variable and fixed components of LRMC are based on the cost structure of the incremental additions, which does not necessarily resemble the cost structure of *system* marginal costs. This introduces an added complexity for allocating marginal costs to capacity and energy, because the split between fixed and variable costs must be adjusted consistent with system marginal costs.
- In summary, the Incremental Plant Method provides a reliable measure of LRMC and a direct allocation between energy- and capacity-related costs. Therefore, the generation LRMC used in other sections of this report is based on the results obtained using the Incremental Plant Method.

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5.4 LRMC OF T&D

Ideally, a forecast of LRMC for T&D would be based on projected demand growth-related investments for T&D, plus O&M. For the transmission system, such investment costs would include expenditures for generation interconnections and line and substation projects to serve load growth. For the distribution system, such investment costs would primarily include expenditures for distribution substations.

Estimating such T&D investment costs is a relatively complex planning exercise that is outside the scope of this report. Any increased precision that would come with a more detailed estimate is only of marginal value for the illustrative purposes that this study aims to achieve. While a forecast of T&D LRMC based on planned investments is beyond the scope of the current report, we recommend work in this area to improve LRMC estimates. A possible starting point for a Bulgarian estimate of T&D LRMC is NEK's 5-year investment plan/budget.

We are unaware of any previous estimates of LRMC for the Bulgarian transmission and distribution systems. The *Study on High Voltage Transmission Network* (Fichner, January 1994) estimated transmission investments required in support of expanding the generation system, and this information can be used to estimate marginal costs for the high voltage (HV) system of 110 kV and up. We have no Bulgarian data that could be used to estimate the marginal costs for the medium voltage (MV) network between 6 and 110 kV, or for the low voltage (LV) network below 6 kV. The LRMC used in this study for the Bulgarian MV and LV networks is based on international comparisons.

Table 5-5 shows estimates of T&D LRMC for Belarus and two U.S. utilities. LRMC for the Bulgarian HV network, based on the Fichner "Option 2" investment plan, is also shown in the table. Note that the voltage class aggregations shown in the table differ from the Bulgarian categorizations of HV, MV, and LV; thus, any extrapolation of these marginal costs to the Bulgarian system is indirect. The table can be used to gain an order-of-magnitude comparison of LRMC components for networks.

Table 5-6 presents the marginal costs of T&D used in this study. The HV network LRMC used in this study is based on the Fichner investment cost projections for the "Option 2" case which is in turn based on a hypothetical generation expansion plan that resembles the scenario plans presented in this report, but is not wholly consistent with them. Table 5-7 shows Fichner's assumptions for transmission system expansion projects and associated costs, and illustrates the derivation of HV LRMC based on the Fichner estimated costs of expansion.

The estimates used in this study for MV and LV are based loosely on the Bechtel study for Belarus. We have reduced the Belarus estimates slightly based on the judgment that the distribution system in Bulgaria can accommodate significant demand growth without the requirement for investments due to the historic decrease in demand relative to levels once served by the system.

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Table 5-5 International Comparison of Estimates of LRMC for T&D ($US 1996 per kW-year)

Voltage	Fichner Study for Bulgaria	Bechtel Study for Belarus	Southern California Edison (USA)	Missouri Public Service (USA)
Extra high voltage (EHV) (>200 kV)	7	2	–	–
EHV plus high voltage (HV) (>30 kV)	–	7	36	23
EHV plus HV plus medium (MV) (>1 kV)	–	13	–	–
EHV plus trans. plus distr. (T&D total)	–	45	95	51

Table 5-6 Assumptions for LRMC for Bulgarian T&D ($US 1996)

Voltage	LRMC $/kW-yr
High voltage (>110 kV)	7
Medium voltage (6-110 kV)	8
Low voltage (<6 kV)	25
Total	40

Table 5-7 Derivation of HV LRMC from Fichner Study ($US 1996)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Project										
Vidin S/S	3.1	3.9	.8							
Dobrich S/S			1.9	7.7	7.7	1.9				
TPP Jambol - A		2.8	9.8	9.8	2.8	2.8				
TPP Jambol - B								1.5	6.0	6.0
TPP Burgas - A							3.0	10.4	10.4	3.0
NPP Belene							7.9	27.8	27.8	7.9
HV investments, $million	3.1	6.7	12.5	17.5	10.5	4.7	10.9	39.7	44.2	16.9
Peak demand growth, MW	220	240	230	240	250	110	110	110	110	110
Level annual invest, $million	12.7									
Demand growth, MW, '96-'05	1730									
Estimated LRMC, $/kW-yr	7									

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5.5 LRMC LOSS ADJUSTMENT BY VOLTAGE LEVEL

Power loss is power that is produced by the power plants and delivered to the transmission system, but not delivered to customers because it is dissipated in the process of transmission along the T&D network. Each voltage level serves sales at that voltage level and is a conduit for sales at lower voltage levels. Therefore, the peak experienced by the system at a given voltage level is affected by the load characteristics at that voltage and lower.

For example, the MV system serves MV sales and distributes electricity to the LV system. Therefore, the peak experienced at this level reflects both medium and low voltage demand, but not high voltage demand. Marginal energy and capacity costs vary by the voltage level at which customers take service because higher power losses occur for service at lower voltage levels. Losses by voltage level are described further in Section 3.

5.6 LRMC BY VOLTAGE LEVEL

Table 5-8 illustrates a simplified estimate of average annual LRMC for electric *sales by voltage level* consistent with Plan A (K1, K2: 1998; K3, K4: 2004) marginal costs. This illustration accounts for the effects of losses by voltage level, and for the LRMC of network facilities attributed to each voltage level.

Table 5-8 LRMC by Voltage Level

Point of Sale	Loss Fctr	SRMC $/MWh	Capacity Contribution to LRMC ($/kW-yr)					Avg. Load Fctr (%)	Cap. Cost $/MWh	Total LRMC $/MWh
			Gen	HV	MV	LV	Total			
Gross generation	1.00	24.6								
Net generation	1.10	27.0	52.7				52.7	63	9.5	36.6
High voltage	1.12	27.6	53.8	7.0			60.8	73	9.5	37.1
Medium voltage	1.18	29.0	56.6	7.4	8.0		72.0	65	12.6	41.7
Low voltage household	1.40	34.4	67.1	8.7	9.5	25.0	110.4	58	21.7	56.2
Low voltage non-household	1.40	34.4	67.1	8.7	9.5	25.0	110.4	60	21.0	55.4

LRMC at voltage level i is derived according to the following equations:

$$LRMC_i = SRMC_i + MCC_i$$

where

$SRMC_i$, short run marginal cost at voltage level i, is the change in operating costs, OC, for a change in demand D. The formula is:

$$SRMC_i = dOC/dD_i$$

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Demand D is related to sales S by the following formula:

$$D_i = S_i / LOSS_i$$

where

$LOSS_i$, the cumulative losses at voltage i, is given by:

$$LOSS_i = (1-L_{Gen}) * (1-L_{HV}) * ... * (1-L_i)$$

By substitution:

$$SRMC_i = dOC / dS_i / LOSS_i$$

$$= SRMC_{GG} / LOSS_i \text{, where GG = gross generation level}$$

Similarly, $MCC_i = MCC_{NG} / LOSS_i$, where NG = net generation level

MCC_i in units of \$/kW-year is converted to \$/MWh by the following conversion:

MCC_i in \$/MWh = MCC_i in \$/kW-year / $LF_{Customer}$, where $LF_{Customer}$, the customer "load factor," is the ratio of the customer's peak demand to average demand

Substituting, we arrive at the equation used to calculate LRMC by voltage level:

$$LRMC_i = (SRMC_{GG} + MCC_{NG} / LF_{Customer}) / LOSS_i$$

5.7 LRMC BY TIME PERIOD

It is important to recognize seasonal and time-of-day differences in marginal costs in the tariff-setting process. The seasonal and time-of-day variations in marginal costs provide a rationale for time-varying tariffs.

5.7.1 Marginal Energy Cost by Time Period

Marginal energy cost, or SRMC, by time period is found by averaging hourly marginal energy costs. This process is internal to the IRP Manager Model which allows user-specified time-of-use periods. Table 5-9 shows marginal energy cost by season and by time-of-day. Seasonal SRMC is projected to be higher in the summer and lower in the winter, with the winter SRMC about 10 percent lower than in the summer. Seasonal differences in SRMC are counterintuitive, as usually higher loads would result in higher SRMC. In this case, higher SRMC in summer is a result of maintenance scheduling of nuclear and coal units and decreased capacity of some units, all happening in the summer season.

Time-of-day differences in SRMC average about 10-15 percent between the daytime and the nighttime. This is a relatively small level of variation for an electric system with significant residential and commercial loads. The difference in SRMC on a time-of-day basis can be

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explained by the system's relatively flat daily load curve and relatively small differences in operating costs among the generating units that contribute the most to marginal energy cost.

5.7.2 Marginal Capacity Cost by Time Period

We assign demand-related marginal costs to time periods according to the contribution of that time period to expected system unserved energy (EUE). Table 5-9 shows the projected contribution to generation system EUE by season and time-of-day for NEK for 1996.

The winter season, which includes the annual peak consumption month of January, contributes about 46 percent to the annual EUE. The summer season contributes around 54 percent to the annual EUE. We find that the seasonal breakdown of marginal capacity cost is consistent for all years of the study period. This seasonal distribution of contribution to EUE is a function of many factors, and two important factors are electric consumption level and generation maintenance scheduling. The highest consumption is in the winter, and generally this situation results in more unserved energy in the winter. Therefore, our findings seem counter-intuitive. However, it appears that our results reflect real operational difficulties during summer months due to nuclear refueling scheduling and minimum load operating restrictions for a large portion of the installed generation.

Daily peak periods (1,560 hours per year) account for 41 percent of the EUE. The daytime non-peak period (3,967 hours per year) is responsible for 38 percent of the EUE. As would be expected, nighttime and non-peak weekend hours (3,233 hours per year), contribute less to EUE at 22 percent.

Table 5-9 Time-of-Day Variation in SRMC and EUE for 1995 for Plan A

	Marginal Energy Cost, Level $/MWh	EUE, % of Annual Total	Hours in Period
Winter			
Peak	25	19	780
Daytime	24	16	2002
Nighttime	21	11	1586
Summer			
Peak	26	22	780
Daytime	25.5	22	1965
Nighttime	23	10	1647
Total		100	8760

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Section 6

Financial Requirements and Cost of Electric Service

This section presents a process for evaluating *cost-of-service* for the Bulgarian electric sector. Cost-of-service is the utility financial requirements for meeting customer electric service requirements. Cost-of-service is an *average* cost, as distinguished from the *marginal* cost of electric service. Tariffs usually are set at levels that allow the utility to collect its cost-of-service without generating either financial surplus or deficit. Section 7 of this report will discuss reconciling marginal cost pricing principles and cost-of-service for final tariff design.

We develop an idealized example showing the cost-of-service for NEK assuming relatively strong financial performance. This financial outlook does not necessarily resemble the past financial performance of NEK, which has been operating at a loss. Our financial outlook includes allowance for utility asset depreciation much closer to the likely replacement cost, and we include an expense item for nuclear plant decommissioning and waste fuel storage. We have not attempted to model the possibility of reduced subsidization of the domestic lignite purchased for generating electricity. We present a preliminary estimate of the NEK financial requirements to meet the full economic cost of the utility. It comes as no surprise that current revenues for NEK are inadequate relative to the estimated revenue requirements.

6.1 FINANCIAL OBJECTIVES

An essential requirement of a tariff is that it produce adequate revenues to meet the financial requirements to operate, replace, and expand the power system. These requirements include out-of-pocket operating expenses, an adequate allowance for depreciation to provide funds for replacing the system as the economic life of equipment comes to an end, and a reasonable return on investment.

We have assumed the following key idealized objectives for NEK financial planning:

- Cash flow from electric sales will provide for all operating expenses
- New plant investments will be financed with up to 50 percent long-term debt, and the rest from customer revenues
- There will be no direct external subsidization of NEK finances
- There will be negligible customer default on bill payments

6.2 COST-OF-SERVICE FORECAST APPROACH

6.2.1 Revenue Requirements

The starting point for determining revenue requirements is the utility's set of financial statements. Developing the forecasted financial requirements includes the following steps:

- *Financial Modeling.* The IRP Manager Model is run to simulate the future demand, supply, finance, and tariffs for the electric utility. This allows a *forward-looking*

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approach to cost-of-service. Although the forward-looking approach is not universally used in the utility industry, it is becoming the standard as the industry adopts financial practices used in other commercial enterprises. The model is used to forecast the balance sheet, income statement, and sources and uses of funds.

- *Revenue Reconciliation.* Alternative financial scenarios are evaluated to ensure that the utility will have adequate revenues to meet operating costs and finance replacement and expansion programs.
- *Financial Analysis.* Financial analysis attempts to optimize the financial plan, ensuring adequate cash flow and balancing debt financing with internal funding. Financial ratios are calculated to evaluate key targets, including cash to debt service, the cash generation ratio, and the ratio of internal funds to construction expenditures.

6.2.2 Cost Allocation

Once the utility's revenue requirements are identified, each cost component is allocated to customer classes based on *causality*. Energy-related costs are allocated largely in proportion to the amount of energy consumed by each class. Capacity-related costs are allocated based on class contribution to peak period system demand. Customer-related costs are assigned on the basis of number of customers and maximum demand, after first making direct assignments of those costs which are identified with specific customers or classes.

6.3 REVENUE REQUIREMENTS ASSUMPTIONS

The scenario financial outlook developed in this report is based on the IRP Manager dataset of October 1995 provided by NEK. Several variables within the IRP Manager dataset have been changed to meet the financial objectives assumed for our analysis. Key revenue requirements assumptions are discussed in the sections below.

6.3.1 External Versus Internal Funding

Under the traditional utility model, operating expenses are passed through to the customer, and the capital program is financed from a combination of internal and external funds. A key variable driving the cost-of-service is the relative amounts of external financing, in the form of debt, versus internal financing, in the form of increased allowance for depreciation and return on assets. Currently, nearly all of NEK's capitalization is in the form of owner's equity. Increasing the use of debt financing for capital requirements would lower customer revenue requirements during the period of debt buildup.

In market economies, a common utility capitalization structure is 50 percent debt, 50 percent equity. In comparison, NEK, at less than 10 percent debt, clearly has not reached its "debt capacity," and a significant portion of future capital requirements can be financed by debt before NEK's capitalization approaches even 20 percent. However, since NEK is a government-owned

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utility, increased debt in the utility sector must be considered within the larger context of ongoing initiatives to control public-sector debt obligations to foreign banks.

Assuming that it is desirable to increase the proportion of debt in NEK's capitalization, NEK borrowing may be limited by requirements of lenders regarding the proportion of internal to external funding for capital projects. For example, the $93 million World Bank loan for the Chaira Project and network improvements stipulates a contribution of $33 million from internal funds to make up the balance of the total project cost of $126 million. Tariff increases are a condition of the World Bank loan to ensure the availability of the required internal funds.

In the example developed in this section, we assume that Bulgarian debt policy and international lending institutions will allow up to 50 percent debt financing of new capital requirements. The rest is financed internally by increasing depreciation and return on assets.

6.3.2 Treatment of Depreciation

Depreciation is an accounting mechanism intended to reflect the loss in value of tangible assets. In the context of utility finance, depreciation expense is the mechanism by which the utility recovers from customers the funds previously provided for the construction or acquisition of utility plant. These recovered funds are available to replace utility plant as it ages.

In a hyper-inflationary economy such as Bulgaria's, the depreciation reserve quickly loses its purchasing power and in time the depreciation fund is inadequate for the capital requirements of the utility. To ensure adequate depreciation expense, asset revaluation is advisable in a hyper-inflationary economy. In Bulgaria, the last asset revaluation was conducted in 1992. Inflation subsequent to the 1992 asset revaluation has decreased the purchasing power of the Bulgarian leva by several times. Therefore, accounting depreciation based on the 1992 asset revaluation is currently inadequate for financing utility capital programs.

Our financial analysis treats depreciation as a variable that is optimized to ensure adequate revenue requirements to meet the utility's financial requirements. The amount of depreciation is determined using a trial and error approach of evaluating financial outcomes assuming different overall levels of depreciation. This process of increasing depreciation implies a de facto asset revaluation. A "sanity check" is used to ensure that the implied asset value is not overstated relative to asset value determined in the 1992 revaluation.

6.3.3 Environmental Costs

Costs of Nuclear Decommissioning and Disposal of Spent Nuclear Fuel. At the time of this report we do not have access to reliable cost estimates for the decommissioning of Kozloduy. However, comparison of international estimates of decommissioning costs indicate that such costs will be an important component of NEK's financial requirements. Table 6-1 presents the estimated costs of future decommissioning for the Bohunice V-1 Nuclear Power Plant in Slovakia, which is similar in design to Kozloduy, the Dukovany Nuclear Power Plant in the

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Czech Republic, and the Diablo Canyon Nuclear Power Plant in California. For these examples, the estimated cost of decommissioning ranges from about $300 to $400 per kW of installed capacity. Also shown in the table are the costs for Kozloduy used in our financial analysis.

Table 6-1 Examples of Cost of Nuclear Decommissioning

Plant	Location	No. Units and MW per Unit	Type, Vintage	Estimated Cost of Decom. ($ Million)	Decom. Cost $ per kW Installed Capacity	Est. Cost of Waste Storage ($ Million)	Current Annual Contribution to Decom. & Waste ($ Million)
Bohunice V-1	Slovakia	2-440 MW units	Russian VVER 440/230	$285	$323	–	–
Dukovany	Czech Republic	4-440 MW units	VVER 440/213	$700	$400	$1,800	$36
Diablo Canyon	California	2-1080 MW units	Press. Water, 1985	$839	$388	$343	$65
Kozloduy*	Bulgaria	4-440 MW 2-1000 MW	VVER-440/230 VVER-1000	$1,095	$291	$100	–

* Estimates for Kozloduy decommissioning are based on 75% of Diablo Canyon costs. Estimates for Kozloduy waste storage are loosely based on NEK's estimate (April 1996). We make no judgment regarding the accuracy of these estimates, which are presented here for illustrative purposes only.

A key financial issue is the timing of the funding period for decommissioning. U.S. regulations define the funding period extending from the date of commercial operation ending on the estimated date that commercial operations cease. Under this mechanism, the future costs for decommissioning activities are incurred by today's electricity customers. The fund itself is invested in stocks and bonds, and the compounded earnings potential of the fund is factored into the determination of how much to collect from today's customers. Figure 6-1 shows the timing for building and depleting the decommissioning fund for the Diablo Canyon Nuclear Power Plant in California. The fund is currently building in level annual amounts over the 31-year estimated life of the facility, and the fund will be depleted over a 19-year decommissioning period.

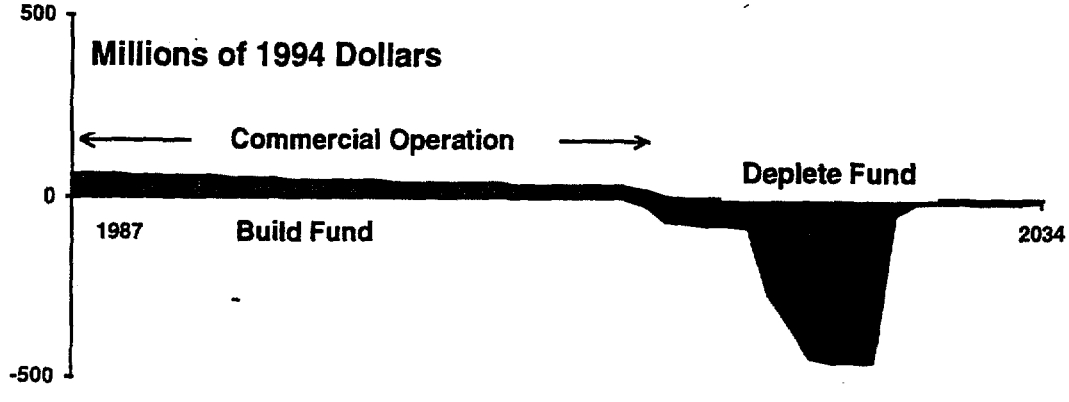

Figure 6-1 PG&E Decommissioning Fund

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Funding for nuclear waste and spent fuel storage and disposal is conceptually similar to decommissioning funding. In some countries utilities pay a spent fuel storage surcharge to the federal government over the life of the nuclear power plant on the basis of the energy generated at the plant. In exchange, the government develops the disposal site and ultimately takes possession of the waste stored in temporary facilities.

In Bulgaria, there are no existing funds for Kozloduy decommissioning and spent fuel disposal. Unless such funds are built up prior to decommissioning the units, some or all of the costs will have to be financed after the units are shut down. This raises the question of whether it is fair to require future generations to subsidize today's electricity consumption.

Table 6-2 presents an order-of-magnitude estimate of the required timing and dollar contributions for funding decommissioning and spent fuel storage for Kozloduy Units 1 through 6. It should be emphasized that the timing for the end of commercial operations of each unit is unresolved, and the required detailed cost estimates are not available to us at the time of this report. Decommissioning timing and amounts are based on Diablo Canyon costs reduced by 25 percent. Spent fuel storage cost, which has been estimated by NEK to cost $63 million (Sofia, April 1996), is somewhat increased to $100 million in our analysis. We assume that it will not be possible to build the fund prior to the start of decommissioning for Units 1 through 4; however, we have assumed full funding for these four units by 2010. The fund for Units 5 and 6 is built up more gradually over the period 1996 to 2030 in our scenario analysis.

Based on the aforementioned assumptions, our analysis indicates that $72 million is the approximate required annual contribution to the fund. This amounts to a customer cost of $2/MWh of sales. Key uncertainties in this analysis include decommissioning and spent fuel costs, cost escalation, earnings on temporary investment of funds, and fund contribution period. Sensitivity studies on these variables indicate fund requirements in the range of $40 to $120 million per year.

Other Environmental Costs. The foremost of NEK's environmental liabilities is the Kozloduy nuclear plant which is currently far below Western safety standards. Also, NEK generates a large amount of SO_2 from the power plants at the Maritza East Complex which use high sulfur local lignite as fuel.

Our scenario analysis does not reflect these environmental liabilities; however, it should be noted that they impose real social and consumer cost impacts. In addition to the negative human health and ecological impacts, environmental liabilities depress the market value of NEK, lowering its prospects for borrowing and privatization. An outside investor might face pressure to bring the Bulgarian plants into compliance with EC standards, which would be very expensive. Our financial analysis does not consider environmental contingencies such as costs associated with retrofitting environmental controls on existing plants and establishing environmental catastrophe funds.

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Table 6-2 Funding Assumptions for Kozloduy Decommissioning and Spent Fuel Facilities in Millions of 1996 Constant Dollars

Line No.	Year	Cost Esc Factor	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Spent Fuel Facility	O&M	Total Cost	Annual Contrib to Fund	Fund Earnings @4%	EOY Fund Balance
1	1995	1.00												0
2	1996	1.00							2		2	72	0	70
3	1997	1.02							3		3	72	3	142
4	1998	1.04							5		5	72	6	214
5	1999	1.06							11		11	72	9	284
6	2000	1.08							54		54	72	11	313
7	2001	1.10	3						22	1	26	72	13	372
8	2002	1.13	7	4					6	1	17	72	15	441
9	2003	1.15	8	4					6	1	19	72	18	512
10	2004	1.17	8	4						1	13	72	20	591
11	2005	1.20	8	4	3					1	17	72	24	670
12	2006	1.22	8	5	8	4				1	25	72	27	744
13	2007	1.24	35	8	8	5				1	57	72	30	788
14	2008	1.27	36	33	8	5				1	83	72	32	809
15	2009	1.29	35	35	9	5				1	85	72	32	829
16	2010	1.32	14	53	9	5				1	81	72	33	852
17	2011	1.35	12	56	38	9				1	116	23	34	793
18	2012	1.37	1	6	39	36				1	82	23	32	765
19	2013	1.40	1	1	38	38				1	79	23	31	740
20	2014	1.43	1	1	15	57				1	75	23	30	717
21	2015	1.46	1	1	13	61				1	77	23	29	692
22	2016	1.49	1	1	1	6				1	11	23	28	732
23	2017	1.52	1	1	1	1				2	5	23	29	779
24	2018	1.55	1	1	1	1	11	11		2	27	23	31	806
25	2019	1.58	1	1	1	1	13	13		2	31	23	32	830
26	2020	1.61	1	0	1	1	14	14		2	31	23	33	855
27	2021	1.64			1	1	14	14		2	31	23	34	881
28	2022	1.67			1	1	14	14		2	32	23	35	907
29	2023	1.71			1	1	25	25		2	53	23	36	913
30	2024	1.74			1	0	102	102		2	208	23	37	765
31	2025	1.78					110	110		2	221	23	31	597
32	2026	1.81					164	164		2	330	23	24	314
33	2027	1.85					175	175		2	351	23	13	-2
34	2028	1.88					17	17		2	37	23	0	-16
35	2029	1.92					2	2		2	6	23	-1	0
36	2030	1.96					2	2		2	7	23	0	16
37	2031	2.00					2	2		2	7	2	1	11
38	2032	2.04					2	2		2	7	2	0	6
39	2033	2.08					2	2		2	7	2	0	1
40	2034	2.12					3	3		2	7	2	0	-4

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6.4 REVENUE REQUIREMENTS RESULTS

6.4.1 Balance Sheet

Table 6-3 shows the forecasted balance sheet of NEK for our scenario analysis. The value of NEK's fixed assets are shown at $3.5 billion in 1996, with $0.9 billion of accumulated depreciation Our asset value has been set higher than book value to increase the depreciation allowance and return on equity, so that NEK's cash flow can support its required capital program. As shown in Table 6-4, our asset value is roughly two times higher than the numbers in the 1994 Arthur Andersen audit of NEK showing assets net of depreciation of $1.4 billion, after conversion of 1994 leva to 1996 dollars. Asset value as shown in the Arthur Andersen audit is known to be low because it is based on the 1992 asset revaluation in leva, and since that time inflation has decreased the value of the leva by several times.

Table 6-3 Forecast Balance Sheet – Plan A (Millions of 1996 Dollars)

Assets	1996	1997	1998	1999	2000
Gross plant in service	3518	3918	4066	4243	4998
+CWIP	876	939	1371	1720	1325
Total utility plant	**4394**	**4857**	**5437**	**5963**	**6324**
-Accumulated depreciation and amortization	911	1098	1299	1509	1748
Net utility plant	**3482**	**3759**	**4138**	**4454**	**4576**
+Other assets	478	458	442	404	382
Total assets	**3675**	**3947**	**4326**	**4620**	**4736**
Liabilities					
Common stock	3104	3104	3104	3104	3104
+Retained earnings	259	400	526	636	752
Total common equity	**3362**	**3504**	**3630**	**3740**	**3856**
Long-term debt	269	426	679	858	853
Total capital	**3631**	**3930**	**4309**	**4598**	**4708**
+Other liabilities	330	286	272	260	250
Total liabilities	**3675**	**3947**	**4326**	**4620**	**4736**

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Table 6-4 Comparison of Financial Assumptions with Arthur Andersen Audit (All Currencies in Billions)

Balance Sheet Item	AA 1994 Audit (leva) A	Convert 1994 leva to 1994 $ B	AA Audit ($) C	Convert 1994 leva to 1996 $ D	Table 6-3 1996 $ E	Revalue Factor F
Plant in service	80.5	53	1.5	1.6	3.5	
Less accumulated depreciation	12.9	53	0.2	0.2	0.9	
Plant in service net depreciation	6.6	53	1.3	1.4	2.6	2

C = A/B
D = C x 1.06
F = E/D

An important point of comparison for the asset value used in our scenario is the asset value determined at the time of the 1992 asset revaluation. According to the World Bank staff appraisal for the 1992 loan, 1992 asset value was about $2.7 billion. Adjusting for inflation to 1996 dollars, we estimate today's asset value may be roughly 3 billion 1996 dollars. It appears that the $2.6 billion net asset value in our balance sheet is roughly in conformance with actual replacement value.

Balance Sheet Uncertainties. The capital program is a major uncertainty depending on future electric consumption, the timing for retiring Kozloduy units, the timing for rehabilitating existing plant and the choice of new generating technologies to meet anticipated resource requirements. The investment program in our IRP Manager database totals $2.4 billion over the period 1996-2000, an average of nearly $500 million per year. For comparison, the paper "Strategy for the Development of the Energy Sector of the Republic of Bulgaria" (Sofia, October 1995) estimates the capital program will require $2 billion over this same period.

The balance sheet is sensitive to initialization assumptions for NEK's existing liabilities in government loans and delinquent payments to fuel suppliers. Our scenario assumes NEK has no debt to the government, only commercial debt to Bulgarian and external banks. Under this scenario, any existing debt to the Bulgarian government is converted to owner's equity.

6.4.2 Income Statement

Table 6-5 shows our forecast income statement for 1996-2000. Overall annual base revenue requirements associated with the Plan A scenario range from $1.4 billion in 1996 to $1.6 billion in 2000. Net income is roughly $150 million per year, after operating expenses and taxes.

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Table 6-5 Forecast Income Statement – Plan A (Millions of 1996 Dollars)

	1996	1997	1998	1999	2000
Base revenues	1358	1451	1478	1516	1587
+Other revenues	59	59	60	60	60
Total operating revenues	**1417**	**1510**	**1538**	**1576**	**1648**
-Fuel expenses	406	419	447	474	499
-Purchased power expenses	38	67	96	95	48
-Operation/maintenance expenses	443	440	412	430	471
-Network expense	12	12	12	12	12
-Nuclear decommissioning	72	72	72	72	72
-Deferred fuel expense	0	0	0	0	0
-Depreciation expense	163	187	201	210	239
Total operating expenses	**1134**	**1198**	**1239**	**1293**	**1341**
-Income taxes	142	155	137	125	139
Total operating expenses and taxes	**1276**	**1353**	**1377**	**1419**	**1480**
Income before interest expenses	142	157	161	158	168
-Interest on long-term debt	9	16	35	47	53
Income after interest expenses	**133**	**142**	**126**	**110**	**115**

The income statement presented in the table shows an idealized financial result for NEK assuming tariffs are raised to cost-of-service levels. Under this scenario NEK is a profitable enterprise. In reality the range of possible financial results for NEK over the next several years is quite large, from significant losses to moderate profits. The important factors determining the company's profitability include:

- Level of electricity tariffs
- Required replacement and expansion programs
- Sales of electricity
- Inflation and the extent to which it raises costs
- Fuel costs
- Taxes
- Borrowing
- Value of the leva
- Availability of power plants

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- Power imports and exports
- Environmental requirements

We evaluated the sensitivity of base case revenue requirements to the amount of external debt funding for NEK's capital program. Assuming no debt funding for new capital programs, the average cost-of-service for the period 1996-2000 would increase by over 10 percent relative to the case with up to 50 percent debt financing. This sensitivity illustrates the point that the utility can lower tariffs during the period that it increases the proportion of debt in its capitalization structure. Most utilities maintain a fixed capitalization structure that strikes a balance between the relative costs and risks of debt and equity.

6.4.3 Sources and Uses Statement

Table 6-6 shows sources and uses of funds over the period 1996-2000 for our scenario forecast of NEK finances. The financing sources for NEK's investment program include 55 percent from the company's own cash generation from operations, and the remaining 45 percent from new loans. One hundred percent of net income is reinvested in the utility capital program and there is no dividend to the federal government. NEK's external debt increases significantly over the 5-year period. By year 2000, NEK's accumulated debt, as shown in the balance sheet, is assumed to approach $1 billion. Assuming continuing government ownership of NEK, this would represent a significant fraction of the national balance of debt.

Table 6-6 Sources and Uses Statement (Millions of 1996 Dollars)

	1996	1997	1998	1999	2000
Funds provided by operations					
Income before capital service	142	157	161	158	168
Depreciation and amortization	163	187	201	210	239
Total	**305**	**344**	**361**	**368**	**407**
Interest	-9	-16	-35	-47	-53
Funds from operations	**297**	**328**	**326**	**320**	**354**
Net capital requirements					
Plant, subsidiary, investments	-486	-463	-580	-526	-361
Investment in working capital	14	-23	1	27	11
Debt and preferred stock retirements	-6	-119	-40	-70	-95
Total	**-479**	**-605**	**-619**	**-569**	**-445**
External financing required	-182	-277	-292	-249	-90

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6.4.4 Financial indicators

Key indicators for the Plan A financial outlook for the period 1995-2000 are summarized in Table 6-7.

Table 6-7 Key Financial Indicators

	1996	1997	1998	1999	2000	Target
Capitalization						
Long term debt to total capital* (%)	7	11	16	19	18	
Owner's equity to total capital* (%)	93	89	84	81	82	
New debt to new investment (%)	37	60	50	47	25	50 max
Cash flow						
Interest coverage including AFUDC	32	20	9	6	6	
Cash to debt service	19.9	2.6	4.8	3.1	2.8	1.25 min
Cash generation ratio	0.86	0.56	0.61	0.55	0.71	0.6 min
Earnings to current interest	32	20	9	6	6	
Return on rate base* (%)	5.0	5.0	5.0	5.0	5.0	5.0

* Reflects increased asset value.

Cash flow ratios measure the strength of the utility's financial condition to support construction programs to maintain a reliable power system. An adequate supply of cash is considered a key financial objective for NEK because NEK must show lending institutions how their loans will be paid back. One measure of cash flow is the *cash generation ratio*, the ratio of after-tax cash generation (operating revenues – operating expenses excluding depreciation – taxes – principal payments) to total annual investment and debt service requirements. If the cash generation ratio is high enough, the utility is in a strong position to carry out construction programs to maintain a reliable power system. We have used a target cash generation ratio of 0.6 as a key determinant of the appropriate level of revenues requirements for NEK.

Based on the financial ratios, we make the following conclusions regarding NEK's financial outlook under the Plan A scenario:

- The capitalization ratios indicate increasing use of debt financing. Increasing the debt has the impact of deferring the tariff impacts of the costs associated with facilities under construction. Cash financing, on the other hand, has the impact of making electric consumers pay in advance for plant that will be placed in service to meet future electric requirements.
- The return on net assets ratio of 5 percent is relatively low, consistent with a public enterprise. We note that in the global capital market, investors typically require a higher return than what is assumed in our scenario.

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- The adequate cash generation ratio indicates that the utility operates free of financial deficits and is in strong position to finance capital additions.

6.5 COST ALLOCATION TO CUSTOMER CLASS

6.5.1 Cost-of-Service Methodology

Once the total revenue requirement for the utility is determined, that amount is allocated among the various customer classes in a cost-of-service study, and then converted into tariffs. A cost-of-service study requires two key elements: 1) each utility account must be assigned to utility services on the basis of causality, for example fuel costs are considered energy production-related costs; and 2) consumption of each utility service by each customer class must be evaluated to relate utility costs to consumption.

In the past, Bulgarian pricing of electric services has not required detailed cost-of-service accounting, and there is no existing allocation of historic costs to electric services. This lack of information limits the possible scope of cost-of-service studies. If cost-of-service is to play a role in future Bulgarian tariff setting, it would be advisable for NEK to implement a company-wide integrated billing and accounting system to track historic costs, and a related system for forecasting future cost-of-service.

Table 6-8 shows the cost allocation used in our scenario analysis. The cost allocation framework is used in the cost-of-service calculation to allocate overall revenue requirements to customer class based on relative use of energy services. The IRP Manager model is used to calculate cost-of-service by customer class. For illustrative purposes we have used only two cost categories, energy- and capacity-related costs. These costs are typically much larger than the other categories including customer costs, reactive power costs, etc.

6.5.2 Cost-of-Service Results

Table 6-9 summarizes the results of the simplified cost-of-service study by customer class, and compares the results with LRMC. In summary, for the Plan A scenario the cost-of-service for electric sales is forecast to average $43 per MWh of sales, in levelized 1995 dollars over the period 1995-2000. The comparable LRMC for the Bulgarian system is about $49 per MWh of sales. LRMC and cost-of-service are quite close, and this relationship is characteristic of a utility facing the need to expand and replace its existing system.

Cost-of-service is highest for the household class. Factors contributing to this relationship include higher network losses and lower load factor than for the other classes. The proportion of capacity-related to energy-related cost-of-service for the household class is higher than for the other classes. This is explained by considering the relatively low load factor for the class in

Table 6-8 Cost Allocation Assumptions

Cost Element	Functional Category	Allocation Method	Periods Included	Customers Included
Power plant assets	GEN_CAP	100% Peak	Peak	All
Fuel	FUEL	100% Energy	All	All
Power plant variable O&M	GEN_V_OM	100% Energy	All	All
Power plant fixed O&M	GEN_F_OM	100% Peak	Peak	All
HV capacity	HI_CAP	100% Peak*	Peak	All
HV O&M expense	HI_OM	100% Energy	All	All
MV capacity	MD_CAP	100% Peak *	Peak	MV, LV
MV O&M expense	MD_OM	100% Energy	All	MV, LV
LV capacity	LO_CAP	100% Peak *	Peak	LV
LV O&M expense	LO_OM	100% Energy	All	LV
Administration	ADMIN	20% Peak 50% Energy 20% Energy 10% Energy	Peak Peak Daytime Nighttime	All

* Non-coincident peak.

Table 6-9 Comparison of Cost-of-Service and LRMC for NEK Dollars per MWh of Sales Level over 1996-2000 (1996 Dollars)

	Cost-of-Service			LRMC		
Customer Class	Variable	Fixed	Total	Marginal Energy Cost	Marginal Capacity Cost	Total LRMC
HV	16	18	34	28	10	37
MV	17	21	38	29	13	42
LV-HH	20	30	50	34	29	56
LV-NHH	18	29	46	34	21	55
Average	25	18	43			49

comparison to the other classes. With a low load factor, capacity-related costs are spread over lower sales per megawatt of peak demand, and thus the capacity-related cost-of-service per megawatthour of sales is higher for households than for the other classes.

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One key aspect of cost-of-service is that in general fixed costs are a higher percentage of total cost than for LRMC because existing assets are accounted as sunk costs in the cost-of-service study. In this regard, the relative allocations of costs to variable and fixed components in the cost-of-service study are irrelevant for designing the split between fixed and variable components of economically efficient tariffs.

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Section 7

Tariff Design

The objective of this section is to illustrate fundamental aspects of tariff design and LRMC-based transfer pricing for non-utility generation. This section also evaluates an indexation formula for updating tariffs. The tariff design developed in this section reflects the LRMC by voltage level, the balancing of LRMC and financial requirements, and the protection of low income groups.

7.1 RELATIONSHIPS BETWEEN LRMC, FINANCIAL REQUIREMENTS, AND TARIFFS

Tariffs based on strict LRMC may produce more or less revenue than needed to meet financial requirements. It has been suggested by some economists that this need not cause a problem for a government-owned utility since surpluses and deficits can be adjusted by taxation and subsidization, respectively. From a strict economic point of view this solution is considered the most efficient. However, it has serious shortcomings:

- The scarcity of public funds makes strict LRMC-based revenues unacceptable if they produce less than financial requirements.
- If strict LRMC-based revenues produce surpluses over financial requirements, consumer resistance generally prevents their use even if the surpluses are recycled back to consumers by way of public coffers.
- The goals of increased efficiency and competition in the power sector go hand-in-hand with financial autonomy, which requires that financial requirements be met.

Figure 7-1 compares LRMC, financial requirements and current tariffs for HV, MV, and LV consumers. We make the following observations based on these comparisons:

- Current tariffs are set too low to fully recover NEK's required financial outlays. This situation inhibits the utility from making essential operating and capital expenditures, and indicates Bulgaria's need to transition to cost-based electric tariffs.
- Comparing LRMC with financial requirements, strict LRMC-based tariffs in Bulgaria would produce revenues in excess of financial requirements. However, there is the potential for cost-of-service to eventually exceed LRMC if unanticipated costs arise or if the current decapitalization of NEK continues.
- Class-by-class comparison of financial requirements with LRMC shows that LRMC and cost-of-service are fairly close for the household class. Cost-of-service is less than LRMC for the high voltage, medium voltage, and low voltage non-household classes.

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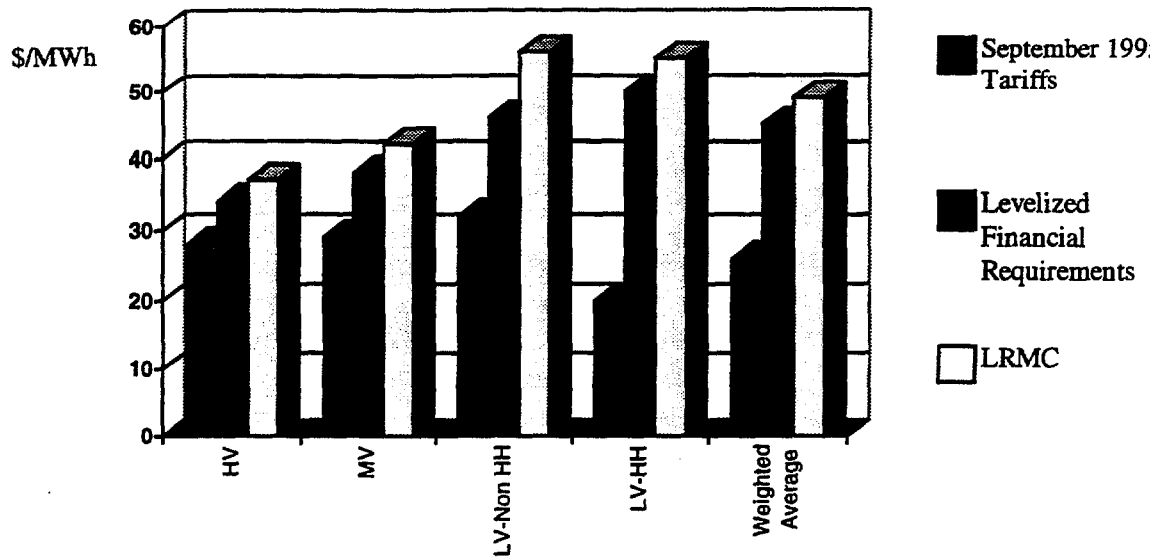

Figure 7-1 Comparison of September 1995 Electricity Tariffs, Financial Requirements, and LRMC

7.2 TARIFF DESIGN ALTERNATIVES

The use of marginal costs in allocating cost responsibilities to customer classes, and in formulating tariff schedules to recover these costs, is in accord with fundamental microeconomic theory: when the price the buyer is paying equals the marginal cost of supply, productive efficiency is maximized and a commensurate increase in total welfare is realized. Under a strict LRMC-based tariff design process, the individual cost-of-service for each customer class is not used. However, even if the LRMC-based tariff design process is to be used, cost-of-service for each customer class is an important point of comparison for evaluating LRMC-based tariffs. For example, cost-of-service can be used to set an upper bound on the LRMC-based tariff for a particular customer class, if the goal is to minimize the tariff but still recover utility costs to serve the customer.

From a practical standpoint, we envision electricity tariffs based on a hybrid of cost-of-service and LRMC. Based on the forecasted relationships between LRMC, financial requirements, and current tariffs, the potential exists to raise tariffs to cost-of-service without exceeding LRMC. This suggests that there is the potential to implement any of several alternative tariff designs that recover the overall revenue requirement and, to a greater or lesser degree, meet the objectives of LRMC pricing. One obvious alternative is to raise each of the four tariffs to recover the cost-of-service for that customer class. Two additional alternatives are described below.

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7.2.1 Equal Percentage of Marginal Cost (EPMC) Tariff Design

Table 7-1 illustrates a revenue allocation alternative known as *equal percentage of marginal cost* (EPMC). EPMC is used to allocate revenue requirements to each customer class based on its relative LRMC in comparison to the other classes. This method retains the relative structure of LRMC for tariffs to various customer classes. Each tariff is LRMC scaled by a common factor equal to the ratio of cost-of-service to LRMC. EPMC is a hybrid of LRMC and cost-of-service that has been adopted at many utilities.

Table 7-1 EPMC Tariff Allocation

Item	High Voltage	Medium	Low Voltage Household	Low Voltage Non-Household	Total
Level demand, GWH	5531	8575	12595	6276	32977
LRMC	34	42	56	55	49
LRMC-based revenues	205	357	707	348	1617
Overall % of marginal cost	13%	22%	44%	22%	100%
Cost-of-service revenue requirements	189	326	626	291	1432
EPMC adjustment					-186
Adjusted revenue requirements	182	315	626	308	1432
EPMC average tariff, $/MWh	33	37	50	49	43

Table 7-2 compares the EPMC results with September 1995 tariffs and with other tariff design alternatives. The EPMC allocation produces average tariffs equal to financial requirements of $43 per MWh of sales.

7.2.2 LRMC-Based Tariffs Except for Non-Household Customer Class

One means of protecting the household tariff is to raise the other tariffs to LRMC. Thus each of the other tariffs would exceed cost-of-service. The additional revenue collected from LRMC tariffs for the non-household classes is used to offset undercollection of cost-of-service from the household class. This alternative is compared with current tariffs and other cost-based tariff design alternatives in Table 7-2.

7.2.3 Capacity and Energy Components of Tariffs

Revenue requirements are allocated to energy costs in $/MWH, capacity costs in $/kW-month, and customer costs in $/month. Including all three cost components in tariffs allows a greater degree of *unbundling* of the services provided by the utility, and thereby provides more accurate pricing signals. For the illustrative purposes of this report, we ignore the relatively small customer cost component.

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Table 7-2 Alternative Tariff Designs
Level 1996 $/MWh over the Period 1995-2000

Customer Class	September 1995 Tariff	Cost of Service Tariff	EPMC Tariff	LRMC (Except HHold)	LRMC Tariff
HV	28	34	33	37	37
MV	29	38	37	42	42
LV HH	20	50	50	41	56
LV NHH	32	46	49	55	55
Weighted Average	26	43	43	43	49

The capacity component of tariffs can be assessed as either a demand charge on the basis of the consumer's contribution to the system's peak load, or as an energy charge allocated among the billing periods. The latter method is typically applied for consumers without demand meters, which is the case for all customer classes in Bulgaria, and in the situation of a utility with marginal capacity cost not concentrated in a particular billing period, which is also the case for Bulgaria. IRP Manager modeling of the Bulgarian power sector indicates that increased consumption in any billing period increases system capacity requirements. Therefore for the illustrative purposes of this study we have allocated NEK's anticipated capacity-related financial requirements to time periods as a $/MWH component of tariffs.

In general, fixed costs are a higher percentage of total cost for cost-of-service than for LRMC because in the cost-of-service analysis the financial costs associated with the existing asset base are counted as sunk costs. In this regard, the relative allocations of costs to variable and fixed components in the cost-of-service study are irrelevant for designing the split between fixed and variable components of economically efficient tariffs. We recommend that the split between capacity- and energy-related components of tariffs should be proportional to LRMC for capacity and energy. Conceptually, this is analogous to the EPMC tariff approach discussed earlier.

7.2.4 LRMC-Based Seasonal Allocation

In general, seasonal tariffs are set proportional to seasonal LRMC, consistent with the economic efficiency rationale for EPMC tariffs. The seasonal allocations of capacity- and energy-related components of tariffs are based on the following logic:

- The capacity-related component of tariffs is allocated to time period based on proportionate system unserved energy during that time period. Unserved energy measures system reliability, and therefore it is reasonable to allocate marginal capacity cost across hours or time periods according to the relative system unserved energy in each hour or time period. In general, unserved energy is concentrated in peak load periods, and therefore the capacity-related component is highest for sales during the peak period.

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- The variable energy-related component of tariffs is allocated to time periods proportionate to seasonal marginal energy cost. Marginal energy costs are a function of system operations and can vary significantly by time period.

Alternatively, seasonal tariffs can be designed to encourage consumer behavior that lowers the total social cost of energy services. For example, consider winter heating with electricity, which for some consumers is an uneconomic use stimulated by artificially low electric tariffs in the winter. By raising the winter tariff approaching winter LRMC, some customers will be induced to pursue lower cost alternatives to electric heating by switching to other fuels such as oil.

7.2.5 Regional Tariff Differentiation

Cost of service varies by region due to area specific power system constraints. This introduces the possibility of tariff differentiation by region. The economist would argue that efficient pricing requires regional tariff differentiation; however, this ignores important political and social concerns. Currently NEK provides the same tariffs throughout Bulgaria.

7.3 PRICING FOR NON-UTILITY GENERATION

The market-based model for non-utility generation uses marginal cost-based pricing for the buyback tariff for generation from existing industrial and combined heat and power producers. In general the pricing is based on generation-level marginal costs with appropriate adjustment based on the voltage level of interconnection. Prices for *new* generation are based on competitive bidding by producers in a solicitation process. Key considerations for pricing for individual independent power providers include location, service voltage, reliability of the generating resource, delivery guarantee, and term of contract. The fundamentals of pricing for power purchases are reviewed in Section 5.

7.4 BLOCK PRICING STRUCTURE

A *block pricing structure* provides a means of maintaining marginal cost pricing for marginal consumption even if the consumer's overall bill varies from strict LRMC for electric service. A two block pricing structure attempts to price consumption in the second (marginal) block at LRMC. The first block is priced such that total revenues for the customer class meet the utility's revenue objectives for that class. The attractiveness of this structure is that it provides the proper economic signals for marginal electricity usage, provides a flexible mechanism for adjusting revenue to financial requirements, and mimics the underlying cost structure of the power system.

The most obvious application of the block tariff structure is pricing for poor households. The block tariff is designed to provide realistic pricing signals for marginal usage, and to lower household electricity bills for some consumers, while bringing revenues from the category as a whole closer to the cost-of-service. *Lifeline tariffs* provide an extreme low-cost block for subsistence household use of electricity. A difficulty with this structure is that it does not protect the poor household with high subsistence use of electricity for space heating. Another form is a

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special low price electric tariff that is offered to poor consumers who qualify on the basis of income or some other measure of wealth.

Other systems that can be used include vouchers, use of the existing social assistance systems, cash payments on behalf of at-risk groups, and cross subsidization by other electric consumers. A key consideration for the appropriate mechanism is distortion of consumer choices of fuel for their energy requirements.

7.5 TARIFF TRANSITIONING

7.5.1 Transitional Pricing

Comparison of current tariffs with cost-based tariff alternatives shows that there is a need to transition to higher tariffs. Ideally, tariffs would be increased immediately to cover the cost-of-service. One way to manage the transition would be for the government to provide subsidies direct to poor consumers. The combination of direct subsidy and cost-based electricity tariff would remove the current incentive for uneconomic uses of electricity.

Continuing to delay cost-based tariff-setting eventually will force deferral of facility replacement projects. The average cost-of-service may eventually exceed LRMC when, by necessity, the utility accelerates deferred replacement programs. In a market economy, pricing above marginal cost is inefficient and unstable. Eventually, customers attempt to bypass the utility system by relocating or by installing autoproduction and conservation. Customers also attempt to access the market for competitive power supplies. The utility has weak incentives for socially desirable demand-side management and conservation, because any reduction in demand further exacerbates the gap between LRMC and average cost-of-service. Eventually corporate earnings suffer. These considerations suggest that it is important for NEK to transition to cost-based tariffs *as soon as possible*.

Figure 7-2 illustrates the relationships among average cost-of-service, marginal cost, and tariff transitioning in Bulgaria.

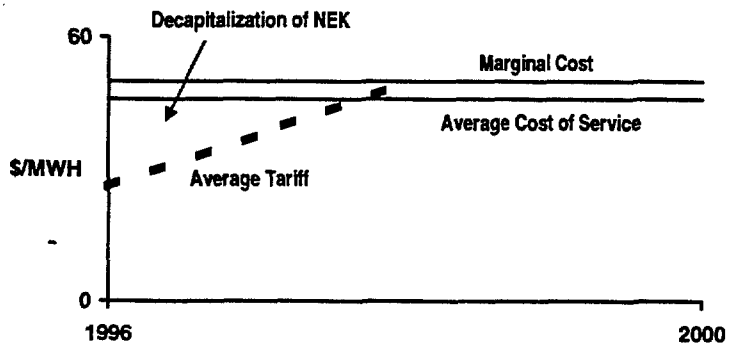

Figure 7-2 Bulgaria Tariff Transitioning

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7.5.2 Tariff Indexation

Tariffs developed on the basis of forecasted system expansion, operations, and fuel prices are subject to significant forecast risk (for example, the risk that future fuel prices will vary from the forecast). One means of avoiding forecast risk for tariff-setting is to use indexation or alternatively, cost adjustment proceedings. In this way tariffs can be made responsive to changes in underlying costs. Indexation is easier to administer and eliminates often contentious and inefficient cost adjustment proceedings. Cost adjustment proceedings are a more direct approach that is not subject to the accuracy tradeoffs inherent in modeling complex and dynamic cost structures in a simple indexation formula.

The analysis below reviews a tariff indexation formula that has been developed by CoE and NEK and proposed for use in Bulgaria. It provides a means to adjust for the effects of inflation, currency exchange, and fuel price swings.

Structure of Formula

The indexes in the tariff indexation formula relate current inflation, exchange rates, and fuel prices to the prior time period. The formula provides an automatic mechanism to raise/lower electricity prices in response to the trends represented in the underlying indexes. The structure of the formula is as follows:

$$P_i = P_{i-1} \times (0.2\, I_{\text{Exchange Rate}} + 0.4\, I_{\text{Bulgarian Inflation}} + 0.2\, I_{\text{Imported Nuclear and Coal}} + 0.2\, I_{\text{Local Coal}})$$

where:

P_i	=	Average electricity price to consumers in period i
$I_{\text{Exchange Rate}}$	=	Index of the Bulgarian currency relative to an international currency benchmark, which we assume is U.S. dollars
$I_{\text{Bulgarian Inflation}}$	=	Index of Bulgarian currency inflation
$I_{\text{Imported Nuclear and Coal}}$	=	Index of the price of imported nuclear and coal fuels
$I_{\text{Local Coal}}$	=	Index of the price of Bulgarian coals

The formula contains assumptions about the underlying cost structure of future electricity revenue requirements. The equation is based on the following empirical assumptions:

- Sixty percent of the cost structure is assumed to change relative to measures of price escalation and inflation. In theory, these measures apply to fixed costs associated with capital expenditures and fixed operating expenses. One third of these costs is assumed to escalate with the international exchange rate, and two-thirds with Bulgarian inflation. The underlying assumption is that the equipment, materials, labor, depreciation and taxes associated with fixed costs are distributed one third for international goods and services, and two-thirds for Bulgarian goods and services.
- The remaining 40 percent of the cost structure escalates with prices for imported and domestic fuels. Half of the fuel expense is assumed to escalate with imported

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nuclear and coal, and half with domestic coal. The underlying assumption is that the fuel mix is half imported nuclear and coal, and half domestic coal.

Analysis of Formula

Table 7-3 presents an analysis of the tariff indexation formula based on the underlying structure of cost-of-service. Cost-of-service is broken out by fixed and variable components, such as existing generation assets and fuel expense. Each cost-of-service element is assumed to escalate according to one or more of the four indexes. The choice of escalation index for each cost-of-service element corresponds to the choices in the indexation formula, which we have not attempted to verify. Basically our analysis is used to check the coefficients used in the indexation formula. Our analysis roughly verifies that the coefficients proposed in the indexation formula accurately reflect the underlying structure of cost-of-service. We note that any change to the underlying cost structure, such as shutting down Kozloduy, will impact the accuracy of the formula.

Table 7-3 Tariff Indexation Analysis – 1996

Cost Category	Variable or Fixed Cost	Cost-of-Service Amount $ Million	% of Total Cost	Imported Coal & Nuclear %	Domestic Coal %	Bulgar Inflation %	Exchange Rate %
Fuel	Variable	448	0.33	0.5	0.5		
Generation (depr., taxes, decomm.)	Fixed	276	0.20			0.67	0.33
Generation fixed O&M	Fixed	390	0.28			0.67	0.33
Generation variable O&M	Variable	76	0.06			1	
Network fixed (O&M, depr., taxes)	Fixed	169	0.12			0.67	0.33
Network variable O&M	Variable	12	0.01			1	
Total or Weighted Average		1371	1	**0.16**	**0.16**	**0.47**	**0.20**
Current coefficients				0.2	0.2	0.4	0.2

Table 7-4 shows how well the current formula performs for the Plan A cost-of-service analysis. Annual average cost-of-service is compared with the average tariff that would result based on an initial price and the escalation indexes used in the cost-of-service analysis. This analysis shows that as long as the initial tariff is based on cost-of-service (Case 1 in Table 7-4), the formula reasonably tracks the cost-of-service in subsequent years. Case 2 shows the performance of the indexation formula using the proposed September 1996 average tariff as the initial tariff. This example shows that if the initial tariff is not based on cost-of-service, the formula does not converge on cost-based tariffs in subsequent years.

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Table 7-4 Tariff Index Performance for Plan A – Cost-of-Service Analysis

Year	Avg Cost of Srvc	Cost of Srvc % Incrs	% Sales Grwth	Nucl Fuel % Incrs	Dmstc Coal % Incrs	Import Coal % Incrs	Bulgar Inflate %	Exch Rate %	% Price Adjust per Formula	Indxd Tariff Case 1	Indxd Tariff Case 2
1996	**43.1**									**43.1**	**35.0**
1997	**44.5**	6.8	3.4	0.0	1.0	1.2	0.0	0.0	0.3	**43.2**	**35.1**
1998	**43.8**	1.9	3.4	0.0	1.0	1.2	0.0	0.0	0.3	**43.3**	**35.2**
1999	**43.5**	2.6	3.4	0.0	1.0	1.2	0.0	0.0	0.3	**43.5**	**35.3**
2000	**44.1**	4.7	3.4	0.0	1.0	1.2	0.0	0.0	0.3	**43.6**	**35.4**

The current average tariff in Bulgaria is below cost-of-service, therefore unless the indexation grows the tariff at a faster rate than the underlying cost structure for the utility, tariffs will never reach the cost-based ideal. It is clear that the tariff indexation formula does not provide for growing tariffs at a faster rate than underlying cost-of-service. One approach to building in a faster rate of growth would be to increase the coefficients such that the sum of the coefficients exceeds 1.

Indexing Average Price Versus Total Revenues

In our analysis of the indexation formula we assume that it applies to the *average price*. Since revenues equal average price times sales, sales growth will increase the revenues under the formula mechanism. If sales double, the utility's revenues based on the pricing formula will double. Alternatively, if the formula is applied to *total revenues*, sales growth will have no impact on revenues. This is appropriate if all cost-of-service elements are fixed costs, but we know that at least in the case of operating expenses this is not true.

An alternative to the two extremes is to use two formulas, one to cover operating and maintenance expenses and one for revenue associated with capital costs. San Diego Gas & Electric in California has established such formulas. The O&M expense formula includes separate labor and non-labor expense escalation indexes, as well as explicit adjustments for customer growth and utility productivity improvements. The formula assumes that productivity offsets customer growth at a rate of 1.5 percent per year. Capital-related expenses for generation, transmission and distribution plant are estimated based on the relationship between customer growth and plant additions. This relationship is derived from regression analysis, and thereby accounts for the recent historic experience that a significant portion of demand growth can be served from existing resources.

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Section 1

Introduction

1.1 BACKGROUND AND OBJECTIVES

This is the Final Report on District Heating Tariffs, prepared under the auspices of the Bulgaria Energy Tariff Implementation Project. This work has been performed under funding from the U.S. Agency for International Development (USAID) under its project for Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics. Bechtel is prime contractor for this project and Arthur Andersen is a subcontractor.

The primary objectives of the district heating analysis presented in this report were to:

- Investigate the existing cost and pricing of district heating
- Estimate the level and structure of tariffs based on long-run marginal cost (LRMC)
- Estimate financial requirements of the Sofia District Heating Company
- Make recommendations on tariffs taking into consideration: LRMC; financial requirements of Sofia District Heating; impact on energy-intensive industries; and protection of economically disadvantaged groups

The analysis was performed with the cooperation of the Committee of Energy (CoE), the Commission of Pricing (CoP), the Ministry of Finance, and the various district heating companies, including Sofia District Heating.

The tasks of this analysis are:

- Task 1 – Evaluate district heating demand
- Task 2 – Evaluate the existing Sofia District Heating supply system
- Task 3 – Analyze economic cost structure of district heating supply
- Task 4 – Evaluate existing district heating tariffs
- Task 5 – Formulate pricing strategy based on LRMC
- Task 6 – Conduct financial analysis of Sofia District Heating Company
- Task 7 – Adjust LRMC tariffs to reflect financial analysis and protection of the poor
- Task 8 – Develop district heating tariff structure and implementation plan

1.2 GUIDELINES FOR TARIFF DESIGN DEVELOPMENT

The objectives of tariff design are identified below:

- Objective 1 – provide clear economic signals to customers on the long-run costs of district heating supply
- Objective 2 – provide adequate funds to operate the Sofia District Heating and provide a reasonable return on investment

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- Objective 3 – address social equity and economic development issues such as protection of economically disadvantaged groups and consideration of economic competitiveness

The first objective generally calls for LRMC-based pricing as developed in Section 4. However, metering and control limitations in most Central European district heating systems constrain both the ability of Sofia District Heating to provide clear signals to individual customers and their ability to respond. Objective 2 ensures that the power system can meet its financial obligations. The current financial condition of Sofia District Heating and most other Bulgarian district heating companies providing residential district heating gives high priority to this objective. Objective 3 requires that some method be devised to ensure heat supply to poor families.

1.3 GUIDE TO THE TARIFF STUDY REPORT

The Study Report is organized so as to answer the following questions:

▪ What are the basic demand and resource characteristics of district heating in Bulgaria (Tasks 1 and 2)?	Section 2
▪ What are the reported costs of district heating compared to the existing prices (Task 3)?	Section 3
▪ What is the LRMC of the various components of district heating supply (Task 5)?	Section 4
▪ How must tariffs based on LRMC be modified to meet other tariff-setting goals (Tasks 7 and 8)?	Section 5

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Section 2

District Heating Supply and Demand

The objective of this section is to review overall district heating supply and demand situation in Bulgaria focusing on the Sofia region.

2.1 OVERALL SUPPLY/DEMAND STRUCTURE

Bulgaria has well-developed district heating systems in most major cities and towns. These systems provide steam and hot water to industry and hot water to households for heating and general use. Some sources estimate that 58 percent of the 1990 heat consumption of industry was provided by centralized district heating systems. These systems provided 22 percent of the household and public sector's requirements (Reference 1). The share of the population using district heating was 16 percent in 1990 and earlier statistics from 1985 indicate the share of floor space heated by district heating only 11 percent (Reference 2). However, district heating customers use more heat per capita and per square meter of floor space than average. The city of Sofia, served by the Sofia District Heating Company accounts for nearly half of the district heat production of the country.

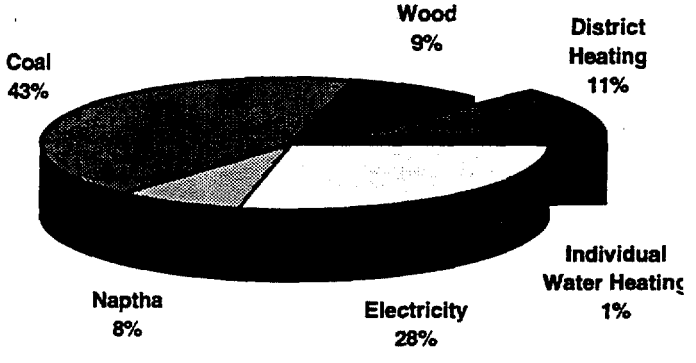

Figure 2-1 Heating Mode by Floor Area – 1985

Coal and electric heating are the dominant types of heating in Bulgaria as shown in Figure 2-1. (Reference 2). Electricity is the fastest growing heating mode. Pricing of electricity and district heating is such that they result in a roughly equivalent cost to the consumer. However, district heating prices cover less than half of costs and direct subsidies are required from the government. As discussed in the Electricity Tariff Report, the price of electricity to household customers does not cover true costs either, cross-subsidies with other electricity users has prevented the need for direct subsidies of electricity. Natural gas is not currently available for residential heating, but extension of the gas system to household consumers is under consideration for a number of communities. Pricing of gas to residential users is undetermined at this time.

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District heat is supplied from a variety of combined heat and power (CHP) and heat-only plants with a combined heating capacity of about 8 GWt. The principle owners/operators of district heating are:

- the National Electric Company (NEK) – produces heat at the Kozluduy Nuclear Plant and the Maritza East I Plant
- several district heating companies – operate twelve major CHP plants which are primarily heat producers and eight major heat-only plants
- industry – supply steam for their own use with some sold to near-by industries, meeting most of industry steam demand.

2.2 THE SOFIA DISTRICT HEATING COMPANY

The Sofia District Heating Company is municipally owned. However, CoE maintains tight control through approval authority for operation and maintenance. The Committee for Prices sets prices for district heat from these companies. The Sofia system is served by two plants having a combination of CHP and heat-only equipment and two heat-only boiler plants. The characteristics of these facilities is shown in Table 2-1.

Table 2-1 Characteristics of Sofia District Heating Plants

Plant Name	Capacity (MW)		CHP Capacity		Age		Fuel
	Electric	Heat	(MWt)	(%)	Electric	Heat	
Sofia	125	1,162	465	40.0	37	15-20	Fuel oil
Sofia East	186	1,453	523	36.0	31	15-20	Gas
Zemliane	—	622	—	—	29	15-20	Fuel oil
Liulin	—	622	—	—	4	8-20	Gas

Approximately 200 MWt of the heat capacity is for steam with the remainder for hot water.

The transmission system is made up of 960 km of hot water lines, 60 km of steam lines, and 5,656 direct and 7,575 indirect substations. The indirect substations are connected to the primary loop of the district heating system and customers are served by a secondary loop by means of a heat exchanger. Less than half of the household customers are served by indirect substations. The heat exchanger and secondary loop are consumer owned. The remainder of consumers are served by direct substations in which hot water from the primary loop flows directly into the building space heating elements and domestic hot water is taken directly from the primary loop supply. Industrial trunk pipelines are owned by industrial consumers. The 1994 sales statistics are summarized in Table 2-2.

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Table 2-2 Sofia District Heating Production and Sales Statistics – 1994

Item	Gcal
Heat Generation	6,709,187
Transmission Losses	1,277,467
Sales	5,431,720
Steam	323,153
Hot water	5,108,567

There has been virtually no metering at substations so that transmission losses are only calculated. The calculated losses of 19 percent are approximately double what should be expected. There is no metering of individual customers so that there is no measure of distribution losses. Sofia District Heating supplies heat to substations, owning and operating generation, transmission, and substation facilities. Ownership and operation of distribution facilities is unclear at this time.

The steam sales shown in Table 2-2 represent sales to industry. Hot water sales were made to Households and two categories of Public Sector customers – Budget and Nonbudget. The share of each customer category is shown in Figure 2-2.

In 1993-95, a feasibility study was conducted for a number of options for the Sofia system (Reference 3). Existing equipment was inspected, projections of future demand made, investment options were evaluated, and investment plans developed. Equipment condition of generating units was found to be poor, primarily as a result of inadequate funding for maintenance and operation outside equipment specifications. The transmission and distribution system was found to be unreliable due to its low quality piping, inappropriately selected insulation material, high leakage from "gasket type" compensators and at substations, and low thermal efficiency.

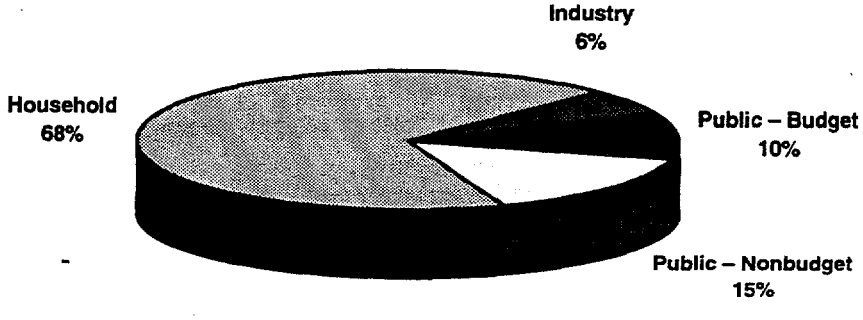

Figure 2-2 Share of Sales by Customer Category – 1994

The conclusions of that study were to rehabilitate existing generating units for safety, environmental impact, and immediate reliability, while deferring investments in generation for increasing efficiency and replacement. Lack of capital, current and projected overcapacity were cited as major reasons for this conclusion. The projected supply/demand balance used in Reference 3 is shown in Table 2-3.

Expected growth in demand from Household and Public Sector customers is projected to be more than offset by demand reductions resulting from conservation and reduction in transmission losses. The result is that there is no immediate need for capacity additions, although investment will be required for rehabilitation of generation and the transmission system and environmental improvements

The energy planning data provided by CoE and NEK indicate the installation of CHP capacity at Sofia and Sofia East early in the next century with a electric generation capacity of 240 MW each. This size is larger than any of the options considered in the Reference 3 feasibility study. This plants may well be needed in the context of the overall energy system. In particular, the need to replace decommissioned capacity at the Kozluduy Nuclear Plant will require additional electricity capacity as discussed in the Electricity Tariff Report. However, the need for these units is not driven by the requirements of the Sofia district heating system.

Table 2-3 Projected Hot Water Supply and Demand – Sofia System (MWt)

Item	1994	1995	1996	1997	1998	1999	2000
Historical peak demand	1,598	1,598	1,598	1,598	1,598	1,598	1,598
Adjustment for design ambient -15 degrees C	266	266	266	266	266	266	266
Cumulative new household customers	18	36	53	71	89	105	122
Cumulative new public sector customers	13	25	39	52	65	80	95
Effect of conservation	(9)	(24)	(45)	(76)	(118)	(174)	(232)
Transmission losses	442	446	420	391	362	331	313
Gross peak demand	2,327	2,346	2,331	2,303	2,261	2,206	2,162
Capacity	3,359	3,359	3,359	3,359	3,359	3,359	3,359

The adjustment for -15 degrees C is a reliability requirement ensuring adequate spare capacity.

Table 2-4 shows the projected hot water energy demand by customer category. This was developed using the Reference 3 projection for total hot water energy demand and allocating among customer categories according to 1994 statistics.

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Table 2-4 Projected Hot Water Energy Demand by Customer Category (Tcal)

Customer	1994	1995	1996	1997	1998	1999	2000
Households	3,711	3,730	3,811	3,869	3,902	3,899	3,857
Public Sector	—	—	—	—	—	—	—
Budget	561	570	590	607	619	630	633
Nonbudget	837	851	881	906	924	940	945
Industry	—	—	—	—	—	—	—
Total Sales	5,109	5,152	5,282	5,382	5,446	5,469	5,435
Network losses	1,081	1,090	1,026	957	885	809	767
Generation	6,190	6,242	6,308	6,339	6,330	6,278	6,201

The demand for steam on the Sofia system is much smaller than for hot water. The projected supply/demand balance for steam on the Sofia system from Reference 3 is shown in Table 2-5. It is not clear what the reduction in public sector demand is, although it appears to represent a shifting of some heating customers from steam to hot water. The reductions in steam demand represented by this shift, conservation and reduction in transmission losses more than off-sets projected increases in industrial demand. Table 2-6 translates the capacity projection to steam energy demand by customer category assuming all steam sales are to industry.

Table 2-5 Projected Steam Supply and Demand – Sofia System (MWt)

Item	1994	1995	1996	1997	1998	1999	2000
Historical peak demand	236	236	236	236	236	236	236
Adjustment for design ambient -15 degrees C	39	39	39	39	39	39	39
Cumulative new industrial customers	—	—	—	—	—	6	14
Cumulative reduction in public sector demand	(6)	(17)	(28)	(33)	(33)	(31)	(28)
Effect of conservation	(0)	(1)	(2)	(4)	(6)	(7)	(9)
Transmission losses	80	77	65	59	55	53	52
Gross peak demand	349	334	310	297	291	296	303
Capacity	500	500	500	500	500	500	500

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Table 2-6 Projected Steam Demand by Customer Category (Tcal)

Customer	1994	1995	1996	1997	1998	1999	2000
Households	—	—	—	—	—	—	—
Public Sector	—	—	—	—	—	—	—
Budget	—	—	—	—	—	—	—
Nonbudget	—	—	—	—	—	—	—
Industry	323	309	295	286	283	292	303
Total Sales	323	309	295	286	283	292	303
Network losses	196	188	159	145	135	130	126
Generation	323	309	295	286	283	292	303

2.3 REFERENCES

1. World Bank, Bulgaria Energy Strategy Study, December 1991

2. Danish Energy Group, Study on Identification of Guideline Projects for the Sustainable Development of the District Heating Sector of Bulgaria, February 1993

3. Gilbert/Commonwealth International, Inc., Bulgarian District Heating System Feasibility Study, February 1995

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Section 3

Review of District Heating Tariff Structure, Pricing, and Regulation

The objective of this section is to present and evaluate the current pricing of district heating in Bulgaria, including the structure (i.e., the pricing relationship between customer categories), the level of pricing, and the regulation of prices.

3.1 REGULATION OF DISTRICT HEATING

As discussed in the previous section, the following three types of entities provide district heating: the National Electric Company, industry, and district heating companies. The final type of entity provides all of the non-industrial district heating. Prior to 1992, the district heating companies were under the CoE. There are now independent legal entities. The law allows for a variety of ownership possibilities including state ownership, limited liability companies, and joint stock companies. At present, the only municipally owned company is Sofia District Heating.

CoE has regulatory authority over the general strategy of the companies and approves budgets for operations and maintenance. In general, the companies are unprofitable because of low prices to non-industrial customers. The small Trjavna system which primarily supplies industry is in fact profitable. As a result, direct subsidies are required under the direction of CoE and the actual independence of these companies is limited. Direct subsidies have continued to Sofia District Heating after municipal ownership.

Prices for Households and Public Sector – Budget (made up of entities funded by the government budget) are set by the Commission of Pricing (CoP) under the category of "fixed" prices, the heaviest form of price regulation. Electricity, residual fuel oil and gas prices are also in this category. Beginning in July 1994, prices for Public Sector – Nonbudget (primarily private offices) went to a less regulated price category called "supervised" prices. Bread and milk are in this category. Steam prices to industry are not regulated.

3.2 DISTRICT HEATING TARIFFS

While district heating remains heavily subsidized, progress has been made in increasing prices over the past 5 years. Figure 3-1 shows this increase for the Households and Public Sector – Budget, the customer categories receiving heavy price regulation. Although, there was a nominal price increase in March 1995, prices for these categories have remained unchanged in real terms since April 1994.

The current tariffs (September 1995) for Households and Public Sector – Budget are as follows: Option 1- 610 leva / Gcal and 1.6 leva / m^3 of heating space per month; and Option 2- 810 leva / Gcal (12.1 $/Gcal at 67 leva/$). This compares with a LRMC for district heating from the substation estimated at 1,880 leva/Gcal (28.1 $/Gcal). Thus, current tariffs cover slightly more than 40 percent of cost. The losses experienced by Sofia District Heating in 1994 reflect this situation.

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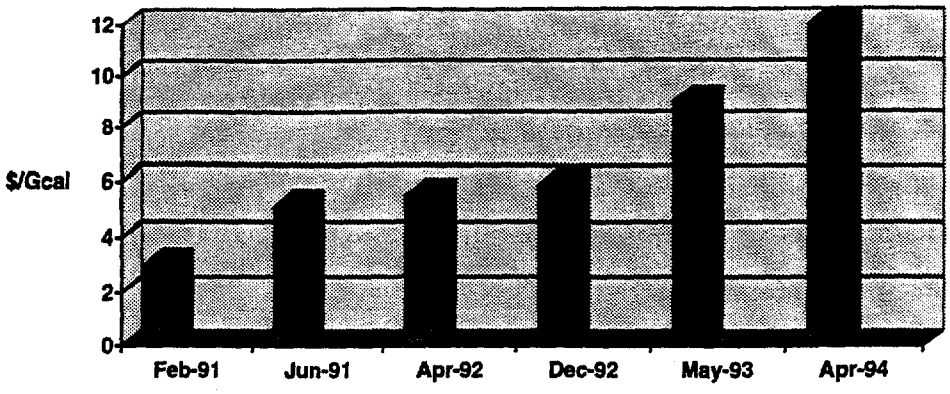

Figure 3-1 Evolution of Household District Heating Prices – 1995

The average revenue collected in 1994 by tariff category is shown in Figure 3-2 compared with the estimate long-run marginal cost (LRMC) for that category as calculated in Section 4.

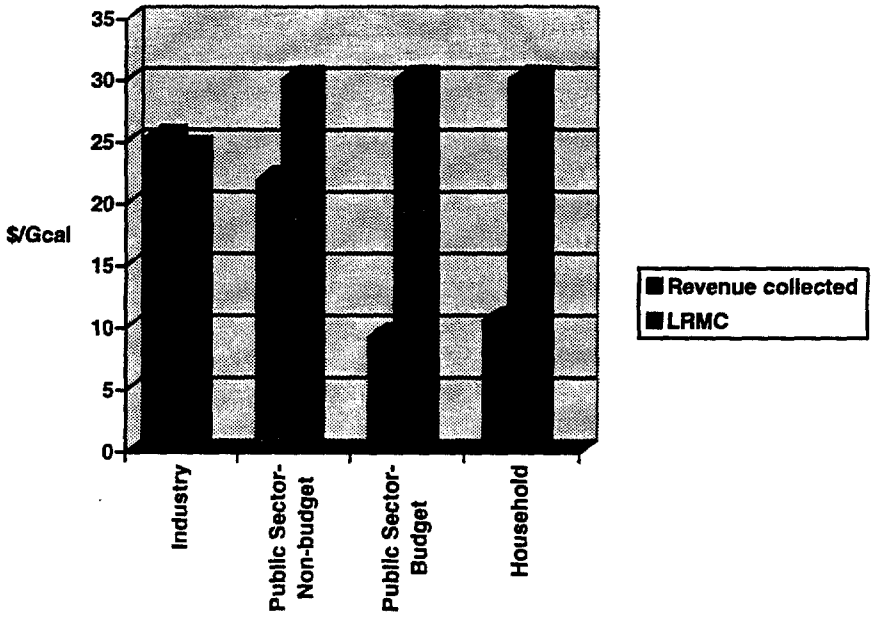

Figure 3-2 Revenue by Customer Category – 1994

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3.3 METERING, BILLING, AND CONTROL

In the past, district heating has been unmetered. Plant production was measured, losses were calculated and costs were allocated to customers on the basis of the floor area of their flats. There was no metering or control for individual flats. Temperature could only be controlled by the customer through the opening of windows. Heat distribution follows the radial design with radiators connected in series throughout flats so that future metering and control of individual flats will be very complicated and costly.

The situation is largely the same today. However, under Phase I of a program administered by CoE, 2,500 substations now have meters. All substations are targeted to have meters by the end of 1997. In the interim, customers served by metered substations pay on the basis of actual delivered energy to the substation. Interviews with district heating managers have indicated that this is resulting in a 10 to 25 percent reduction in price to these customers. As part of this program, rehabilitation of the network is being funded to reduce system losses.

From the point of view of actual district heating service, the customer is the substation. Distribution from the substation is owned by building owners and compensation for distribution investment is a component of rent. However, the district heating companies bill individual residential flats, commercial users, and government offices.

Residential users pay in cash up to 100,000 leva; firms use bank transfers. For Sofia District Heating, there are 14 designated collection points in Sofia. Because of the physical constraints of the systems, individuals cannot be denied service if they do not pay. It would be physically possible to disconnect substations or individual buildings, but doing so would not be acceptable to paying customers. In any case, it is difficult to use denial of heating service given the importance of heat to survival. Individuals can be taken to court if they do not pay, but interviews with managers indicate that this course is not effective. Existing laws do not allow for liens on property. Two effective points of control are: 1) individuals have to clear debts to obtain a passport, and 2) tax authorities often demand receipts for heat expense to support tax returns. However, these approaches have limited applicability.

By far the biggest nonpayment offenders are government organizations (Budget category).

Under Phase II of the above-mentioned program, some flats will be equipped with thermostats and controls. However, this will have no effect in the near term. Any district heating tariff and billing procedure reforms will have to reflect existing metering and control constraints.

3.4 IMPACT OF COMBINED HEAT AND POWER OPERATION

District heating companies can sell electricity generated by CHP plants to NEK. The buyback rates currently in effect are shown in Table 3-1.

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Table 3-1 Buyback Rates for Electricity Generated by District Heating Companies

Time of Day	leva/kWh$_t$	\$/MWh$_t$
Peak	1.82	27.2
Day	1.01	15.1
Night	0.44	6.6

In the near term, the effect of this is that the district heating companies lose money for every kWh sold because the buyback rates do not cover fuel costs except in peak periods. In the long term, future CHP projects, such as those envisioned at Sofia and Sofia East and part of the overall energy plan of Bulgaria, cannot be justified.

To illustrate, the reported fuel requirements for producing electricity by Sofia District Heating in 1994 was 7,874 kJ/kWh. At 3.13 \$/GJ for gas, the fuel cost was 24.6 \$/MWh. Thus, the buyback rate is inadequate to cover fuel costs even in the peak period. The actual reported revenue from electricity sales was 720 leva/Gcal (19.2 \$/Gcal at 37.5 leva/\$ in 1994) indicating that some significant sales were made outside the peak period.

This situation exacerbates the already financially strained condition of the district heating companies. Either the buyback rate is fair and the generation of electricity by CHP units should be discouraged or the rate is too low, reflecting less than the value of CHP electricity generation to NEK.

These buyback rate are less than the Short Run Marginal Cost for the electricity system calculated in the Electricity Tariff Report in all periods except the peak and significantly less than the LRMC for generation. The fact that generation from the CHP units is driven by heat demand and may not fully correspond to NEK needs may justify a price less than LRMC. However, new Sofia and Sofia East CHPs have been proposed as partial replacement for the Kozluduy Unit 1-4. This proposal implies a capacity value. In any case, we see no justification for buyback rates less than SRMC.

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Section 4

Long-Run Marginal Cost Estimate

The objective of this section is to present a pricing strategy for district heating based on strict long-run marginal cost (LRMC), with no consideration of financial, social, or political factors that could affect the tariff structure. The per unit LRMC is defined as the levelized incremental investment and operating cost of serving an additional kWh of energy demand (or kW of peak) for an indefinite period of time. One component of LRMC is short-run marginal cost (SRMC). This is defined as those parts of LRMC that vary immediately with demand. The remainder of LRMC varies with demand in the long term, but the variation is delayed by fixed cost components of the system.

4.1 OVERALL APPROACH AND ASSUMPTIONS

The overall approach to district heating LRMC estimation was to estimate LRMC of each component of the system (i.e., generation and transmission from the generating plants to substations, and distribution of heat from substations to individual customers). The concept of "opportunity cost of capital" was used in the calculations. This is defined as the value of an incremental amount of capital. Economies with more severe capital constraints have higher opportunity costs of capital. A value of 10 percent was used in the calculations.

Natural gas firing was assumed with the 1 percent real price escalation. The result fuel price forecast is shown in Table 4-1. Taxes were not considered.

Table 4-1 Natural Gas Price Forecast for District Heating

Item	1995	1996	1997	1998	1999	2000
$/Gcal	13.24	13.37	13.50	13.64	13.77	13.91
$/GJ	3.16	3.19	3.23	3.26	3.29	3.32

4.2 GENERATION LRMC

A theoretically ideal way of estimating generation LRMC is to develop a least-cost investment plans for a reference forecast of demand and an incremental increase in demand, estimate fixed and variable costs for both, and estimate LRMC based on the differential fixed and variable costs between the two plans. This approach is based on an assumption of current economically efficient operation. Price subsidies, and investment, maintenance, and operating cost constraints have distorted the operation of district heating in Bulgaria and limit the practical application of this approach.

An alternative is termed the Incremental Plant Approach. The Incremental Plant Method was applied in the following way:

- Energy-related (i.e., variable) costs were estimated based on short-run marginal cost (SRMC). For purposes of this estimate only fuel costs were assumed to contribute to SRMC. Some part of non-fuel operating and maintenance costs is often included in this value as well; however, for purposes of the calculations in this section all non-fuel costs were considered to be capacity-related.

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- Capacity-related costs (i.e., fixed) costs were estimated based on the investment and non-fuel operating and maintenance costs of the incremental plant. A planning reserve margin of 20 percent was used.
- Levelized capacity-related costs were calculated per unit of peak demand increase and per unit of energy demand increase.
- Energy- and capacity-related costs per unit of energy demand increase were combined for a total generation system LRMC.

The incremental plants were assumed to be a standalone hot water heater for the hot water system and a standalone steam boiler for the steam system. The assumed characteristics of these plants are summarized in Table 4-2.

Table 4-2 Characteristics of Incremental Plants

Item	Water Heater	Steam Boiler
Thermal Capacity (MWt)	20	30
Capital Cost ($ million)	0.75	1.55
Construction Time (years)	1	1
Economic Life (years)	25	25
Overall Efficiency	85%	85%
O&M ($000/year)	22.5	46.5

The resulting LRMC calculation is shown in Table 4-3.

Table 4-3 Generation LRMC Calculation[1]

Item	Water Heater	Steam Boiler	Label	Explanation
Capacity-Related Costs ($/kWt)				
Investment	4.13	5.69	A	Per unit capital cost/ PMT(10%,25,1)
O&M	1.13	1.55	B	Annual O&M/ Capacity
Planning Reserve	1.05	1.45	C	(A+B)*20%
Total	6.31	8.69	D	A+B+C
Expressed in Terms of Energy Production ($/Gcal)				
Levelized Fuel Cost	13.53	13.53	E	from Table 4-1
Levelized SRMC	15.92	15.92	F	E/.85%
Capacity-Related Costs (assuming 25% capacity factor)	3.41	2.48	G	D/(8.76*25%)
Total LRMC	19.33	18.40	H	E+F+G

1. Based on the assumption that generation capacity additions are required immediately with an incremental demand increase.

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The SRMC varies over time by time-of-day and season, depending on the fuel price and the characteristics of the facilities providing incremental demand. The data necessary to make the calculation of SRMC by time-of-day is not readily available. There is currently no seasonal pricing for natural gas so that there should not be significant seasonality to district heating SRMC. Table 4-4 shows the projected average SRMC as a function of time based on the projection of natural gas cost.

Table 4-4 SRMC as a Function of Projected Natural Gas Price

Item	1995	1996	1997	1998	1999	2000
Natural Gas Price ($/Gcal)	13.24	13.37	13.50	13.64	13.77	13.91
SRMC ($/Gcal)	15.58	15.73	15.88	16.05	16.20	16.36

If capacity is not required immediately, the contribution of capacity-related costs is diminished. In Table 4-3, it is assumed that new capacity is needed immediately. The existing overcapacity in the generation system of Sofia District Heating suggests that this is not the case. Table 4-5 shows the effect of a delayed need for new generation capacity on LRMC.

Table 4-5 Capacity-Related Costs as a Function of Need for New Capacity ($/kWt/year)

Year Capacity Needed	Water Heater	Steam Boiler	Explanation
1995	6.31	8.69	A
1996	5.73	7.90	A/(1.1)
1997	5.21	7.18	$A/(1.1)^2$
1998	4.74	6.53	$A/(1.1)^3$
1999	4.31	5.94	$A/(1.1)^4$
2000	3.92	5.40	$A/(1.1)^5$

Because of existing overcapacity in the Sofia District Heating generation system, we estimated that the year 2000 would be the year in which new investment would be required.

4.3 TRANSMISSION

Transmission costs are generally considered to be fixed (i.e., capacity-related) since the design of these facilities is primarily determined be peak demand (kWt). Generally, the Average Incremental Cost (AIC) Method is used to estimate transmission LRMC. The formula for this calculation is as follows:

$$AIC = \left[\sum_{1}^{T}(I_i + OM_i - OM_{i-1})/(1+occ)^i\right]\left[\sum_{L+1}^{T+L}(D_i - D_{i-1})/(1+occ)^i\right]$$

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where

AIC = average incremental cost (proxy for LRMC)

T = planning period (years)

L = time delay between investment and commissioning of facilities (years)

I_i = annual investment in year i

OM_i = fixed O&M in year i

D_i = demand in year i

occ = opportunity cost of capital

Data required to make this calculation was not readily available. Therefore, an estimate was made based on an estimate of replacement cost:

- Existing transmission assets were revalued according to replacement value.
- The revaluation was discounted to reflect the average number of years until replacement. Because of the need for immediate rehabilitation of the transmission system, immediate need for replacement was assumed.
- The theoretical design peak for the size generation system was estimated. (The system is overcapacity so that the design peak is much higher than the actual 1994 peak of 2890 MWt.)
- The replacement value as a function of peak load was estimated.

The application of this procedure is shown in Table 4-6.

Table 4-6 Transmission LRMC Calculation[1]

Item	Physical units	per unit cost	Total Cost (millions $)	Label	Explanation
Lines	1027.1 km	121.3 $/meter (Ref. 1)	249	A	
Substations	4420 substations	41.7 $/kWt (Ref. 2)	184	B	
Total			433	C	A+B
Generating capacity	4420 MW_t			D	
Theoretical design peak	3683 MW_t			E	D/(1.2)
Per unit investment	117.63 $/$kW_t$ of peak			F	C*1000/E
LRMC ($/$kW_t$/year of peak)					
Investment	12.03 $/$kW_t$/year			G	F * PMT(10%,40,1)
Fixed O&M	1.18 $/$kW_t$/year			H	F * 1%
Total LRMC	13.21			I	G + H

1. Based on the assumption that transmission capacity additions are required immediately with an incremental demand increase.

As with generation LRMC, this value is discounted if capacity is not immediately needed as a result of a demand increase. Because of the immediate investment required in the transmission system to reduce losses, no discounting was applied.

4.4 DISTRIBUTION

The AIC Method, described in the previous section, can be applied to the distribution system. The data to apply the method was not readily available so a method utilizing replacement cost was applied. This is illustrated in Table 4-7.

As with generation LRMC, the estimated value is discounted if capacity is not immediately needed as a result of a demand increase. Because most new customers would require extensions of the distribution system, no discounting was applied.

Table 4-7 Distribution LRMC Calculation[1]

Description	Value	Label	Explanation
Reference distribution cost (1982 $)[2]	1335	A	
based on heating density (kWh/m^2)	200	B	
peak (MW$_t$)	200	C	
Adjusted to 1995 $	1960	D	A* (1.03)^{13}
Expressed as a function of non-simultaneous demand ($/MW$_t$)	9.80	E	D / C
Sofia heating density (kWh$_t$/m^2)	263	F	1994 Statistics
Adjusted to Bulgarian heating density ($/MW$_t$)	7.46	G	E * B / F
Sofia diversity factor	85%	H	
Expressed in terms of simultaneous demand ($/MW$_t$)	8.78	I	G / H
LRMC ($/kW$_t$/year of peak)			
Investment	0.93	J	I * PMT(10%,30,1)
Fixed O&M	0.09	K	I * 1%
Total LRMC	1.02	L	J + K

1. Based on the assumption that distribution capacity additions are required immediately with an incremental demand increase.
2. Swedish example in Reference 3.

4.5 PRICING

The LRMC pricing structure is summarized in Tables 4-8- and 4-9. The losses assumed for the calculation correspond to the projected 2000 loss rate as discussed in Section 2.

Table 4-8 LRMC Pricing – Hot Water

Point of Sale	Loss Factor[1]	Energy Contri-bution[2] ($/Gcal)	Capacity Generation	Contribution to LRMC ($/kW-yr)			Average Load Factor	Average Capacity Contri-bution ($/Gcal)	Average Total LRMC	
				Primary	Secondary	Total			($/Gcal)	(lev/Gcal)
Generation	1.00	15.9	3.9			3.9	25%	2.1	18.0	1206
Substation level	1.17	18.6	4.6	13.2		17.8	25%	9.4	28.1	1880
Household	1.23	19.6	4.8	13.9	1.0	19.7	25%	10.5	30.1	2016
Public Sector	1.23	19.6	4.8	13.9	1.0	19.7	25%	10.5	30.1	2016

1. Loss factors are based on hot water system loss for 2000 (14.5 percent for the primary loop and 5 percent for secondary loop).
2. Energy contribution is based on the projected levelized cost of natural gas through 2000 adjusted by production efficiency.

Table 4-9 LRMC Pricing – Steam

Point of Sale	Loss Factor[1]	Energy Contri-bution[2] ($/Gcal)	Capacity Generation	Contribution to LRMC ($/kW-yr)			Average Load Factor	Average Capacity Contri-bution ($/Gcal)	Average Total LRMC	
				Primary	Secondary	Total			($/Gcal)	(lev/Gcal)
Generation	1.00	15.9	8.7			8.7	60%	1.9	17.8	1196
Substation level	1.20	19.2	10.5	13.2		23.7	60%	5.2	24.4	1636
Industry	1.20	19.2	10.5	13.2	0.0	23.7	60%	5.2	24.4	1636

1. Loss factors are based on steam system loss goals for 2000 (17 percent for the primary loop)with Industry served directly from primary loop.
2. Energy contribution is based on the projected levelized cost of natural gas through 2000 adjusted by production efficiency.

4.6 COMPARISON WITH EXISTING TARIFFS

The existing tariff is based on customer ownership of facilities downstream of the substation. Therefore, the tariff is at the substation level. However, economic comparisons of alternative heating costs should include the cost of these facilities.

The tariff can take the form:

Revenue = A x Energy + B x Maximum Heating Demand

Table 4-10 shows the LRMC for hot water expressed in comparable terms to existing tariffs.

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Table 4-10 LRMC-Based Tariff

Description		Calculation
Energy component (A)	=	18.6 $/Gcal
	=	1248 leva/Gcal at 67 leva/$
Capacity component of LRMC	=	17.8 $/kW$_t$/year
1995 System peak	=	2,346,173 kW$_t$
Estimated heat load (m^3)	=	83,842,223 m^3 (based on area from Reference 3 and 2.5 meter ceilings)
Demand component (B)	=	0.055 $/m^3 of heating space
	=	3.7 leva/m^3 at 67 leva/$

4.7 REFERENCES

1. Bechtel Corporation, Reconstruction of the Trnava Municipal and Industrial District Heating Plant, December 1995

2. Gilbert/Commonwealth International, Inc., Bulgarian District Heating System Feasibility Study, February 1995

3. International Energy Agency, District Heating and Combined Heat and Power Systems – A Technology Review, 1993

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Section 5

Implementation Issues

The objective of this section is to investigate the financial impact associated with this proposed price increase, approaches to assuring that economically disadvantaged groups receive heat, treatment of non-payers, and proposed changes in price regulation.

5.1 FINANCIAL IMPACT

The LRMC tariff as estimated would have covered the financial costs of Sofia District Heating as reported in 1994. This is illustrated in Table 5-1. Revenues based on steam system LRMC are estimated to be slightly lower than what was actually collected in 1994; however, revenues from hot water sales are estimated to be more than twice as large under LRMC pricing. Under such pricing no subsidies would have been required, Sofia District Heating would have contributed income taxes to the government and would have earned a profit which could be applied to its investment requirements.

Table 5-1 Hypothetical Impact of LRMC Tariff on 1994 Income Statement

Item	As Reported (1995 $000)	With Proposed Tariff Increase and Full Payment ($000)
Revenue		
Hot water	64,073	143,375
Steam	8,321	7,892
Electricity	12,580	12,580
Other	5,083	5,083
Total Revenue	90,057	168,930
Expenses		
Fuel	122,107	122,107
Depreciation	10,778	10,778
Other	26,504	26,504
Total Expenses	159,389	159,389
Operating Income	(69,331)	9,541
Interest	114	114
Income Taxes	—	3,959
Subsidies	28,571	0
Net Income	(40,875)	5,468

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Four cases were considered as follows:

- Case A – Revenue requirements estimate was made based on extrapolation of 1994 financial data and investment plan from Reference 5-1. No adjustments were made to the value of existing assets or to electricity buyback rates.
- Case B – Same as Case A except that net asset values were adjusted to replacement cost.
- Case C – Same as Case B except that electricity buyback rates were increased to electric system marginal cost.
- Case D – Same as Case C except an allowance was made for nonpayment by some customers amounting to 10 percent of operating cost.

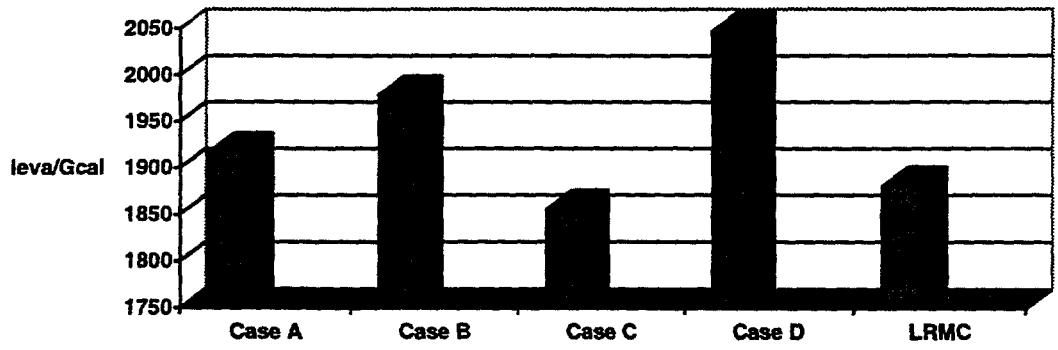

Figure 5-1 Summary of Revenue Requirements Analysis for Hot Water Supply

The Case A revenue requirement estimate was slightly higher than hot water LRMC. However, the tariff based on this estimate was found to be insufficient to support the proposed investment plan. Asset values were adjusted to reflect replacement cost in Case B and this was found to support the proposed investment plan. However, the resulting tariff would be substantially higher than LRMC (i.e., more than 5 percent). Higher buyback rates for electricity would reduce the revenue requirements for hot water supply and there is reason to believe that higher buyback rates are economically justified. In Case C the future buyback rates are set at the LRMC of generation on the electricity system. The result was to reduce the projected revenue requirements to slightly less than the hot water LRMC.

Cases A through C are based on the assumption that there is full payment from all customers. If some customers do not pay and are allowed to receive service then the cost has to be borne by the remaining customers. Case D was based on an assumption of nonpayment amounting to 10 percent of operating cost. Discussions with district heating managers indicate that nonpayment is currently higher than this. The resulting revenue requirements for paying customers would be almost 10 percent greater than LRMC.

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Based on this analysis, one can conclude that future tariffs to Household and to Public Sector – Budget based on LRMC would be adequate to meet the financial requirements of Sofia District Heating only if the buyback rate for electricity can be increased to the electric generation system LRMC and non-payment by district heating customers can be severely reduced. Otherwise, it will be impossible to support investment requirements without subsidies even with LRMC pricing.

5.2 COMPETITION WITH OTHER HEAT SOURCES

As market forces increasingly affect energy pricing, competition between fuels and heat supply systems will become increasingly important. Figure 5-2 shows relative heating costs from a variety of sources in Bulgaria. Natural gas is not currently used for household heating and a range of potential heating costs is presented based on a price of natural gas delivered to the household of between $150 per thousand cubic meters and $260 per thousand cubic meters. This range represents potential variations in future pricing policy for gas to households and distribution costs between communities. The full economic cost of district heating and electricity is based on LRMC to households, including distribution. Electricity LRMC is addressed in detail in the Electricity Tariff Report. Oil heating costs are based on a delivered cost of fuel oil to households of 6 $/GJ and represent full economic cost.

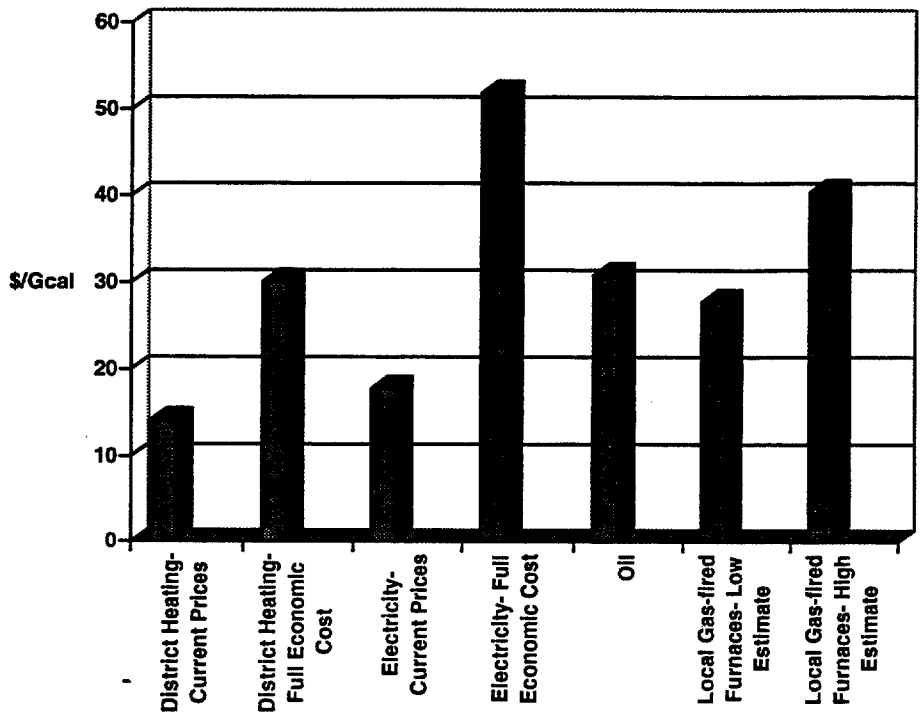

Figure 5-2 Relative Heating Costs from Various Sources

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The following observations can be made based on these estimated heating costs:

- District heating and electric heating are the least expensive modes of heating under current pricing. This is due to direct subsidies in the case of district heating and cross-subsidies in the case of electricity. The deregulation of oil prices has made oil heating uncompetitive.
- Current price distortions are the greatest for electricity. Current pricing makes it the heating source of choice for anyone without access to a district heating system. It is by far the most expensive source when full economic costs are considered.
- When full economic costs are considered, oil is competitive with other forms of heating.
- Natural gas will be competitive with other forms of heating for communities with the lowest distribution costs.

The distortions in electricity pricing have already resulted in a massive shift away from oil heating (i.e., from approximately 1,200 thousand tonnes per year in 1985 to a negligible amount in 1995). Its replacement with electric heating represents a large economic cost to the country. The lesson is that while it is important to increase district heating prices, it is important that this be done in conjunction with electricity price reform. Otherwise, district heating consumers will incorrectly perceive that electric heating is less expensive than heat from their district heating systems.

Under pricing based on full economic costs, district heating will remain competitive with other forms of heating. However, if Sofia District Heating is to maintain its current customer base it will be important to reduce costs and gradually offer customers greater control over usage.

5.3 IMPACT ON ECONOMICALLY DISADVANTAGED GROUPS

Figure 5-3 shows the relationship between the percentage of income spent for energy and the level of income for 1993. For comparison, the percentage of income spent for spirits and tobacco is also shown and the percentage of income that would have been spent if energy tariffs were at market rates (i.e., about 300 percent higher than the 1993 level).

Generally, energy for household use should make up no more than approximately 10 to 15 percent of a household budget. As shown in Figure 5-3, this criterion was met for all income groups in 1993. However, if tariffs had been 300 percent higher, as proposed for district heating and household electricity tariffs, those with annual incomes of less than 12,000 leva would have spent well above 15 percent. Those with incomes between 12,000 and 20,000 leva would have spent only slightly above 15 percent.

Those earning less than 12,000 leva represented 17.6 percent of the population. This is the segment of the population to which protection from tariff increases should be provided. The situation for those in the 12,000 to 20,000 leva income bracket, adjusted for inflation, should be monitored, but the assistance programs should be initially directed at those with lower incomes.

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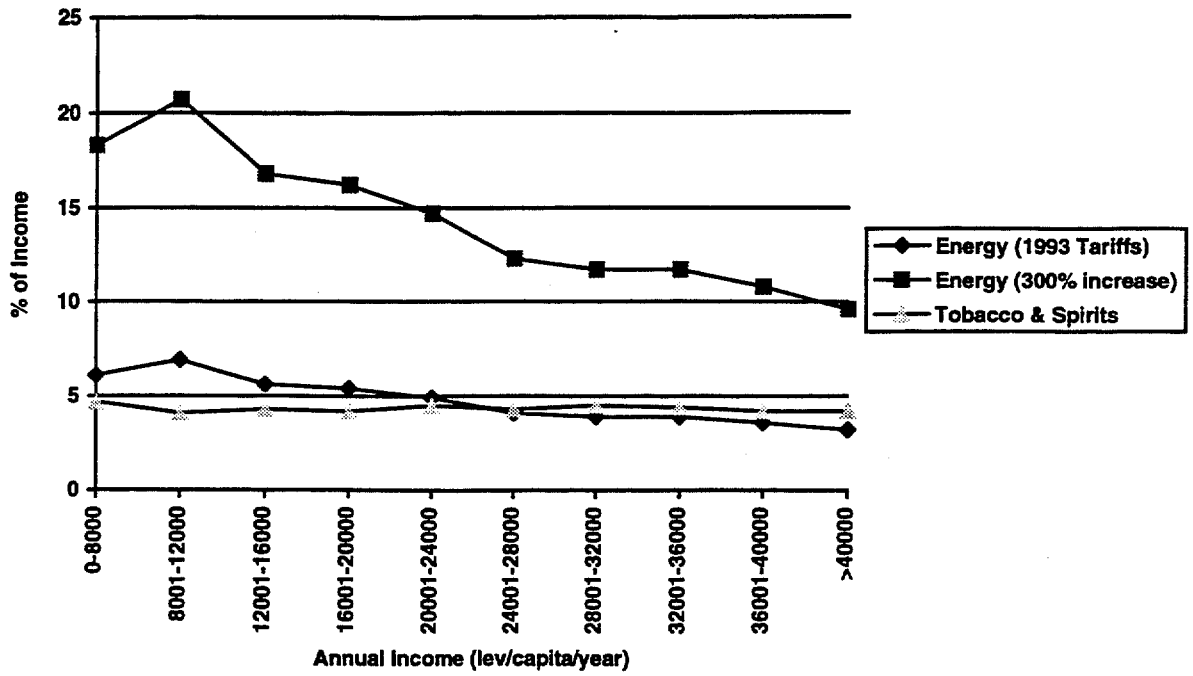

Figure 5-3 Contribution of Energy to Household Budget as a Function of Income – 1993

There are several ways that relief can be provided, with varying degrees of effectiveness in protecting low-income customers. The current method of providing direct subsidies to the district heating companies reduces tariffs for all customers and provides the largest subsidy to those who heat the most, usually those with higher incomes. Cross-subsidies between customer classes are not an option because the price to other customer classes (i.e., Industrial and Public Sector – Nonbudget) is no longer heavily regulated. Cross-subsidies within the Household customer class would result in tariffs greater than LRMC and would most likely result in district heating becoming more expensive to paying customers than oil heating. This leaves some form of direct assistance to the poor.

5.4 PROPOSED PRICE REGULATION

Price regulation for district heating should have the following characteristics:

- Regional or municipal administration to allow for geographic differences in fuel prices and district heating system cost.
- Oversight at the national level to coordinate district heating tariffs with electricity price reform.
- A formula for automatic adjustment to reflect inflation and fuel price changes.

The formula should provide incentives for efficient operation. The formula could either be based on LRMC or be based on cost-of-service or a hybrid of the two. All pricing approaches will be

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limited by metering. The following discussion is based on the assumption that all substations will be metered. Calculated usage will have to substitute for unmetered substations.

5.4.1 LRMC Pricing Formula

For metered substations, the tariff would take the form:

$$R_{ij} = A_i x E_{ij} + B_i x D_j$$

where

R_{ij} = payment in month *i* for substation *j*

A_i = coefficient based on SRMC for month *i*

E_i = usage in month i for substation *j*

B_i = demand charge in month i (leva/cubic meter of heating space connected to substation) based on capacity component of LRMC

D_j = heating space connected to substation *j*

The energy coefficient, A_i, should be adjusted to reflect changes in fuel costs as shown by the following formula:

$$A_i = A_o x F_i / F_o$$

where

F_i = per unit fuel cost in month *i*

F_o = per unit fuel cost in month in base month *o*

The demand charge, B_i, should be adjusted to reflect general inflation as shown by the following formula:

$$B_i = B_o x CPI_o / CPI_i$$

where

CPI_i = Consumer price index in month *i*

CPI_o = Consumer price index in base month *o*

The demand coefficient, B, is based on the capacity component of LRMC and expressed as a function of cubic meters of heating space. Therefore the initial coefficient, B_o, is calculated as follows:

$$B_o = LRMC_c x P_o / H_o$$

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where

$LRMC_c$	= the capacity component of LRMC including generation and transmission divided by 12 ($/kW$_t$/month)
P_o	= projected peak in first year (kW$_t$)
H_o	= connected heating space in first year (m^3)

It is expected that the coefficients A and B will vary among district heating systems reflected cost differences.

The energy coefficient, A_i, should be revised periodically (e.g., 5 years) to reflect changes in system losses. In between revisions, the utility will have an incentive to reduce losses in order to reduce costs and maximize profits. The period between revisions should be long enough to allow the utility to recover investments in loss reduction.

The demand coefficient, B, should be revised on a periodic basis to reflect structural changes in cost and the performance of the utility in providing service.

5.4.2 Rate-of-Return Alternative

Pricing based on a "fair" rate-of-return on an historical value of assets is the most common regulated energy utility pricing in the U.S. This approach results in coefficients for energy and demand (A and B). The difference with the LRMC approach is primarily with the treatment of the demand coefficient. Under this approach,

$$B_i = \left(FOM_k + D_k + NFA_k xR\right) / 12 / H_i$$

where

FOM_k	= projected annual fixed operating and maintenance costs for year *k*
D_k	= projected annual depreciation for year *k*
NFA_k	= net fixed assets for year *k*
R	= fair rate of return

The primary problem with rate-of-return price regulation is that energy companies are rewarded for capital investment, but not necessarily for increasing operating efficiencies. There is a trend to move away from rate-of-return price regulation where competition is technically feasible (e.g., electricity generation) and in situations in which the approach has resulted in prices which deviate significantly from LRMC.

The approach depends upon a reliable valuation of assets. In the U.S., most energy utilities are privately owned so that their value is subject to market forces. In addition, low inflation allows historical accounting value to be meaningful in most cases. Neither of these conditions is true in

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Bulgaria. As a result, while analytical approaches can be used to estimate asset value, these estimates are not subject to the discipline of the market. Furthermore, constant revision is required for net fixed assets and depreciation to reflect inflation.

In the U.S., value of R is usually a weighted average of cost of capital of the enterprise. It is then applied to historical asset values (i.e., historical value of fixed assets minus historical accumulated depreciation). A portion of R is "real" return and the remainder is intended to adjust the return for inflation. The following formula expresses this relationship:

$$R = (1+\text{real return}) \times (1+\text{general inflation rate})$$

If net asset values are periodically corrected for inflation, as will be the case in Bulgaria, only the "real" portion of R should be applied to the corrected net asset values. "Real" rate-of-return is usually in the range of 2 to 5 percent.

5.5 TRANSITION PRICING

Sofia District Heating tariffs to Households and Public Sector – Budget should rise from the current 810 leva/Gcal (12.1 $/Gcal) to approximately 1,880 leva/Gcal (28.1 $/Gcal) delivered to substations to fully reflect economic cost. How quickly should this change be made? The factors which support a quick transition are:

- Continued low district heating tariffs cannot support investment in the district heating systems.
- Direct subsidies are straining the budget.
- Customers have little incentive to conserve.

On the other hand, the disadvantages of a rapid change to higher tariffs are:

- A rapid change could damage economically vulnerable groups unless accompanied by some form of assistance.
- The change could actually contribute to overall price distortions if not accompanied by electricity price reform.
- It could appear unjust because of the low degree of control that customers have over their usage.

In the electricity section of this report, transitional pricing is proposed resulting in household electricity tariffs being in line with cost by 2000. Table 5-2 shows the effect of a similar transition pricing plan for Sofia District Heating. A linear increase in tariffs in real terms until LRMC is reached in 2000 is shown. The shortfall shown represents required subsidies from the government to meet revenue requirements. Even with LRMC pricing, there is some shortfall due to an assumption that the nonpayment problem will continue. In this analysis, nonpayment was estimated at 10 percent of operating expenses.

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The advantages of this pricing plan are that it is consistent with proposed electricity tariff increases and is accompanied by investments in metering. The primary disadvantage is that it calls for continuing, although declining, subsidies from the government.

Table 5-2 Effect of Transition Pricing on Finances

Item	1995	1996	1997	1998	1999	2000	Label	Explanation
Total Revenue Requirements ($000)	**150,229**	**163,924**	**163,081**	**164,428**	**165,124**	**166,053**	A	
Adjust for Public Sector – Nonbudget								
Public Sector – Nonbudget LRMC ($/Gcal)	28.1	28.1	28.1	28.1	28.1	28.1	B	
Demand (Tcal)	851	881	906	924	940	945	C	
Total Adjustment	-23,891	-24,718	-25,418	-25,936	-26,372	-26,520	D	-(B*C)
Revenue Requirements for Household and Public Sector – Budget ($000)	**126,338**	**139,206**	**137,663**	**138,492**	**138,752**	**139,533**	E	A+D
Proposed Tariff ($/Gcal)	12.1	15.3	18.5	21.7	24.9	28.1	F	
Demand (Tcal)	4,300,278	4,401,574	4,476,182	4,521,418	4,528,991	4,489,808	G	
Revenues based on proposed tariff ($000)	**51,988**	**67,277**	**82,720**	**98,002**	**112,638**	**126,009**	H	F*G
Shortfall ($000)	**74,349**	**71,929**	**54,943**	**40,490**	**26,114**	**13,524**	I	E-H

5.6 REFERENCES

1. Gilbert/Commonwealth International, Inc., Bulgarian District Heating System Feasibility Study, February 1995

2. Republic of Bulgaria, Statistical Yearbook, 1994

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