PN-ACC-216

Coal and Thermal Power Cost Study for Bosnia and Herzegovina

Final Report

Prepared by:

Bechtel Consulting

Under funding from:

USAID

United States 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

August 1997

BECHTEL

Table of Contents

Section		Page
	Executive Summary	
1	**Study Overview and Approach**	**1-1**
	1.1 Introduction	1-1
	1.2 Study Objectives	1-1
	1.3 Other Studies of the BiH Power Sector	1-2
	1.4 Approach	1-2
	1.5 Study Assumptions	1-3
2	**Power Sector Overview**	**2-1**
	2.1 Organization	2-1
	2.2 Fuel Supply	2-1
	2.3 Electricity Demand and Supply	2-3
	2.4 Fuel and Power Pricing Summary	2-4
	2.5 Financial Status of Coal Enterprises	2-7
	2.6 Financial Status of Electricity Enterprises	2-7
	2.6 The Future	2-8
3	**Kakanj Power Station**	**3-1**
	3.1 Overview	3-1
	3.2 Fuel Supply	3-1
	3.3 Discussion of Fuel Supply Constraints	3-4
	3.4 Fuel Cost as a Function of Output	3-5
	3.5 Investment Requirements	3-6
	3.6 Cost of Electricity	3-6
4	**Tuzla Power Station**	**4-1**
	4.1 Overview	4-1
	4.2 Fuel Supply	4-2
	4.3 Discussion of Fuel Supply Constraints	4-4
	4.4 Fuel Cost as a Function of Output	4-5
	4.5 Based on Intrinsic Geological Conditions	4-5
	4.6 Investment Requirements	4-5
	4.7 Cost of Electricity	4-6
5	**Ugljevik Power Station**	**5-1**
	5.1 Overview	5-1
	5.2 Fuel Supply	5-2
	5.3 Discussion of Fuel Supply Constraints	5-2
	5.4 Fuel Cost as a Function of Output	5-3
	5.5 Based on Intrinsic Geological Conditions	5-3

Section		Page
	5.6 Investment Requirements	5-3
	5.7 Cost of Electricity	5-4
6	**Gacko Power Station**	**6-1**
	6.1 Overview	6-1
	6.2 Fuel Supply	6-1
	6.3 Discussion of Fuel Supply Constraints	6-2
	6.4 Fuel Cost as a Function of Output	6-2
	6.5 Based on Intrinsic Geological Conditions	6-2
	6.6 Investment Requirements	6-2
	6.7 Cost of Electricity	6-2
7	**Fuel and Power Cost Summary**	**7-1**
	7.1 Fuel Cost Summary	7-1
	7.2 Historical Cost of Electricity Summary	7-3
	7.3 Future Cost of Electricity Analysis	7-4
	7.3.1 Rehabilitation Options	7-4
	7.3.2 Fuel Cost	7-5
	7.3.3 Comparison With New Plants	7-5
	7.3.4 Incremental Cost Of Electricity	7-5
	7.3.5 Full Cost Of Electricity	7-7
	7.4 Implication For Future Energy Strategy Planning	7-7
	7.4.1 Exports	7-7
	7.4.2 Demand Forecast	7-7
	7.4.3 Consideration of All Generation Options	7-7
	7.4.4 Coordination of Costs with Mine Sector Restructuring Study	7-8
8	**References**	**8-1**
Appendices		
A	**Fuel Cost Model**	**A-1**
	A.1 Model Overview	A-1
	A.1.1 Design Production Level	A-1
	A.1.2 Cost as a Function of Production Level	A-1
	A.2 Demonstration of Model	A-3
	A.2.1 Data and Assumptions	A-3
	A.2.1.1 Overburden Removal	A-4
	A.2.1.2 Reclamation	A-4
	A.2.1.3 Coal Removal	A-4

Section	Page
A.2.1.4 In-Mine Transport	A-5
A.2.1.5 Preparation	A-5
A.2.1.6 Transportation from Mine to Power Plant	A-6
A.2.2 Cost at Design Production	A-6
A.2.2.1 Direct Cost	A-6
A.2.2.2 Capital Requirements	A-6
A.2.2.3 Total Costs	A-6
A.2.3 Cost at Design Production	A-10
A.2.3.1 Direct Cost	A-10
A.2.3.2 Capital Requirements	A-11
A.2.4 Cost of Fuel for the Target 2000 Production Levels	A-12
A.3 Comparison of Results	A-14
B Economic Evaluation Model	**B-1**
B.1 Description of the Model	B-1
B.2 Benefits	B-1
B.2.1 Power System Benefits	B-1
B.2.2 Steam Production Benefits	B-2
B.2.3 Fuel Benefits	B-2
B.2.4 Environmental Benefits	B-2
B.3 Costs	B-2
B.4 Input Assumptions	B-2
B.5 Rehabilitation Investment Requirements	B-3
B.6 Reference and New Thermal Power Plants	B-3
B.7 Emission Reduction Analysis	B-3
B.7.1 Sulfur Emission Reduction	B-4
B.7.2 Nox Emission Reduction	B-4
B.8 Model Input and Output Forms	B-4

Figures and Tables

Figure		Page
ES-1	Coal Cost at Design Production Levels	ES-3
ES-2	Coal and Lignite Cost as a Function of Production Level	ES-3
ES-3	Coal Cost at Current and Target 2000 Production Levels	ES-4
ES-4	Incremental Cost of Electricity	ES-6
ES-5	Full Cost of Electricity	ES-6
1-1	Overall Approach	1-3
2-1	Coal Deposits in BiH	2-1a
2-2	1996 Electricity Consumption	2-3
2-3	1996 Electricity Supply	2-4
2-4	Thermal Power Capacity at the End of 1996	2-4
2-5	Comparative Prices for Standard Customers	2-6
3-1	Coal Reserves by Type of Coal for Middle Bosnia Mines	3-3
3-2	Coal Reserves by Coal Mine for Middle Bosnia Mines	3-4
3-3	Coal production and Design Capacity for Middle Bosnia Mines	3-5
4-1	Coal Reserves in Kreka Coal Mines	4-3
4-2	Coal Reserves for Banovici and Durdevik Coal Mines	4-3
4-3	Target Production Levels in year 2000	4-4
7-1	Comparison of Brown Coal and Lignite Cost at Design Production Levels	7-1
7-2	Production Levels	7-2
7-3	Comparison of Cost as a Function of Production Level	7-2
7-4	Breakdown of Fixed and Variable Costs for 1996	7-3
7-5	Comparison of 1990 and 1996 Reported Costs	7-4
7-6	Incremental Cost of Electricity	7-9
7-7	Full Cost of Electricity	7-9
A-1	Fuel Cost Estimation Approach for Design Production	A-2
A-2	Re-Estimation of Fuel Costs at Other Than Design Production Levels	A-3

Table		
2-1	Key Characteristics of Enterprise Tariff Structures	2-5
2-2	Customer Characteristics Used for Price Comparison	2-4
2-3	Reported 1996 Profit and Loss Statement for Middle Bosnia Mines	2-7
2-4	Reported 1996 Profit and Loss Statement for Electricity Enterprises	2-8
2-5	Hypothetical Effect of Improved Collections in 1996	2-8
3-1	Kakanj Power Plant	3-1
3-2	Investment Requirements at the TPP Kakanj	3-6
4-1a	Tuzla Power Plant - Units 1-3	4-1
4-1b	Tuzla Power Plant - Units 4-6	4-2

Section		Page
4-2	Investment Requirements at the TPP Tuzla	4-6
5-1	Ugljevik Power Plant	5-1
5-2	Investment Requirements at the TPP Ugljevik	5-3
6-1	Gacko Power Plant	6-1
6-2	Investment Requirements at the TPP Gacko	6-2
7-1	Discount Rate Sensitivity Analysis	7-7
A-1	General Mine Characteristics	A-4
A-2	Key Economic Data	A-5
A-3	Direct Cost at Design Production Level	A-7
A-4	Capital Requirements	A-8
A-5	Total Cost at Design Production Level	A-9
A-6	Direct Cost at Current Production Level	A-10
A-7	Total Cost at Current Production Level	A-11
A-8	Direct Costs at "Target 2000" Production Level	A-12
A-9	Total Costs at "Target 2000" Production Level	A-13
A-10	Comparison of Results	A-14

Executive Summary

ES.1 INTRODUCTION

This report documents work conducted by Bechtel Consulting for the governments of the Federation of Bosnia and Herzegovina and the Republika Srpska in support of their energy tariff setting process. The work has been funded by the US Agency for International Development (USAID) under its project for Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics. Tuzla Mining Institute acted as a consultant on this project, providing insight into existing coal mine conditions and future mining plans.

The objectives of this study are to estimate the true economic cost for the thermal electricity generation including the cost of coal production in Bosnia and Herzegovina, and to evaluate the degree to which the existing pricing process ensures that these costs are incorporated into tariffs. The study is being conducted in order to:

- Provide support for the adjustment of the coal and electricity prices to reflect their economic cost of production.
- Provide support for the deregulation of coal price and regulation of electricity prices through a transparent decision-making process protecting the interests of all consumers of electricity, consistent with social stability and environmental protection.

ES.2 OBSERVATIONS AND CONCLUSIONS

The primary conclusions that can be drawn from this analysis are:

- The cost of coal in Bosnia and Herzegovina is high and, while it may be a cost-effective resource for domestic power production, it is not competitive on the world market.
- The regulated coal price in the Federation is inadequate to cover the costs and generate reasonable profit for any of the Federation mines evaluated.
- The incremental investment and operating cost from all rehabilitation projects considered is between 8 and 13 Pf/kWh. It is not likely that long-term arrangements for power exports can be made if power is priced at this level.
- If depreciation and profit on existing assets are considered in addition to incremental cost, the total cost of electricity from proposed rehabilitation projects is from 10 to 16 Pf/kWh.
- Retail tariffs are inadequate for EPBiH and for ERS to support the cost of electricity generated from these rehabilitation projects.
- In the long term, the use of imported natural gas and coal should be given consideration in power resource development strategy and rehabilitation options should be considered on the same basis as new plant options.

ES.3 COAL AND ELECTRICITY PRICING

Bosnia and Herzegovina is divided into two entities - the Federation of Bosnia and Herzegovina (referred to as the Federation) and Republika Srpska (RS). The Ministry of Energy, Mining and

Industry administers the power sector for the Federation. This function is performed by the Ministry of Energy in RS.

All coal and electricity enterprises are state-owned. The Federation is served by Elektroprivreda Bosnia and Herzegovina (EPBiH) and by Elektroprivreda Hrvatske Zajednice Heceg-Bosne (EP Mostar). RS is served by Elektroprivreda Republike Srpske (ERS). EPBiH was also the name of the utility that supplied electricity to all of Bosnia and Herzegovina before the war.

EP Mostar is supplied entirely by hydroelectricity, while EPBiH and ERS are mixed hydro-thermal systems. Each of the latter have two thermal power plants supplied by domestic brown coal and/or lignite. The ERS thermal plants have dedicated mines; power plant and mine operations are integrated. Because of the integrated operation, with no formal transactions between mines and plants, there is no direct economic regulation of coal or lignite prices in the RS. Separate mining enterprises supply EPBiH plants with coal and lignite with prices regulated by the Ministry of Energy, Mining and Industry. The price is currently set at 3.612 DM/GJ. This is lower than the estimated cost of any mine in the Federation except for the Dimnjace mine at Gracanica. The regulated coal price has a purely variable component, with no fixed charges or obligations to purchase.

The Ministry of Energy, Mining and Industry maintains retail electricity pricing jurisdiction in the Federation; however, it appears that in practice, EP Mostar operates under a separate regulatory structure. The Ministry of Energy of RS controls retail electricity pricing in RS.

ES.4 BROWN COAL AND LIGNITE COST

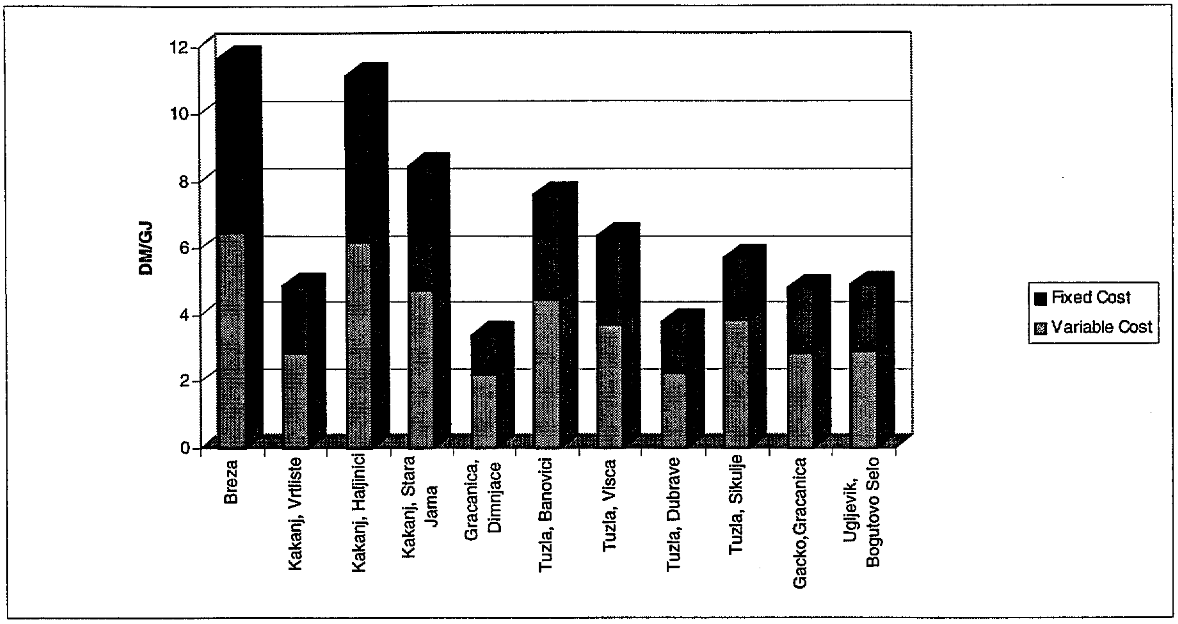
The four thermal power plants are:

- Kakanj Thermal Power Plant - operated by EPBiH and supplied by the Middle Bosnia Mines which include Breza, Kakanj and Gracanica
- Tuzla Thermal Power Plant - operated by EPBiH supplied by the Tuzla Mines
- Gacko Thermal Power Plant - operated by ERS and supplied by a dedicated mine
- Ugljevik Thermal Power Plant - operated by ERS and supplied by a dedicated mine.

Bechtel estimated the cost of delivering coal to these power plants from 19 domestic mines and from the international coal market. The costs were first estimated for design production levels. The results of this analysis is shown in Figure ES-1 for selected mines.

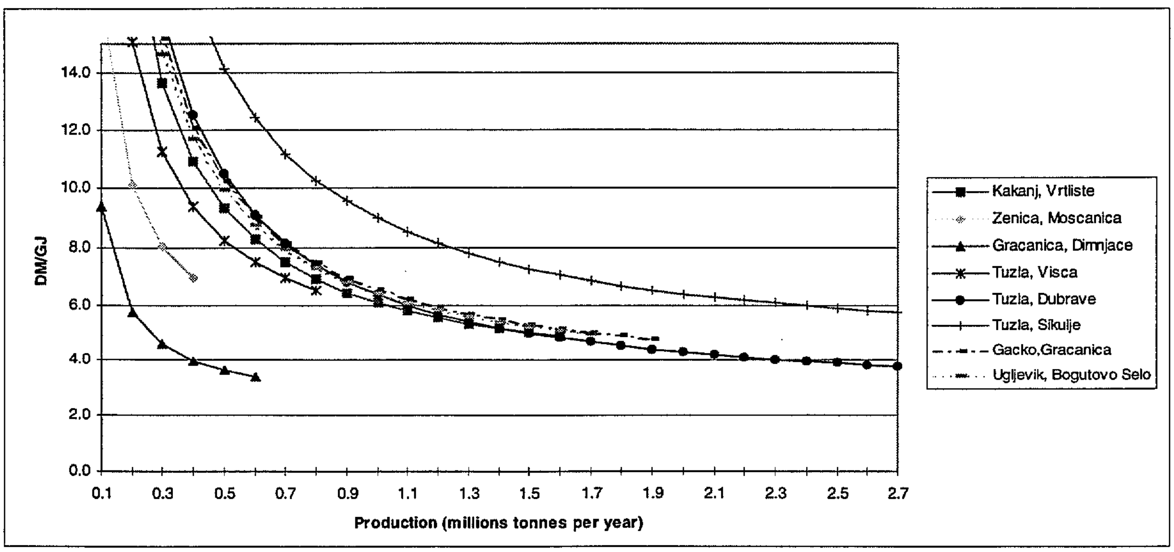
There are eight domestic mines evaluated in which the variable cost was less than this estimated cost of imported coal. These were the surface mine at Kakanj (Vrtliste); the Moscanica mine at Zenica; the Dimnjace mine at Gracanica; the Visca, Dubrave (Kreka), and Sikulje (Kreka) mines at Tuzla; the Gracanica mine at Gacko, and the Bogutovo Selo mine at Ugljevik. When fixed costs are considered, only the Dimnjace and Dubrave mines are competitive with imported coal, at the design production levels.

Figure ES-1 Coal Cost at Design Production Levels



The per unit costs are higher at lower production levels since fixed costs must be allocated to fewer units of production. This is illustrated in Figure ES-2. The 1996 level of production was approximately 30% of the 18 million tonnes per year design capacity. The reduction in output varied significantly among mines. The Dubrave and Sikulje surface mines in Tuzla only operated at about 15% of design capacity while the Bogutovo Selo mine at Ugljevik operated at nearly 70% of design.

Figure ES-2 Coal and Lignite Cost as a Function of Production Level



3

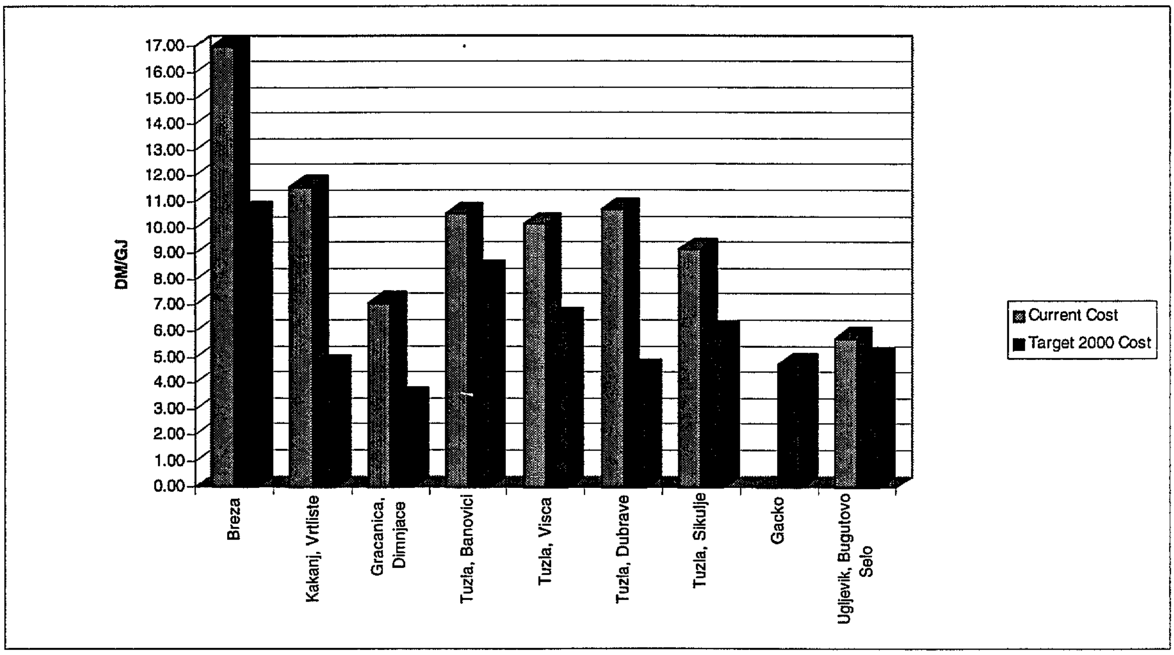
Fixed costs were defined as depreciation and a 12% return on investment to meet profit and income taxes. Sensitivity analysis was also performed for the 8% rate of return. This is an idealized model in which labor is considered to be a totally variable cost. Discussions at the mining enterprises indicate that employment levels have not fallen to a level corresponding to the current low production. Therefore, current costs are actually somewhat higher than estimated with our model.

In the Federation, the price of coal is regulated as a purely variable charge. As has been pointed out, only the Dimnjace mine at Gracanica has overall cost lower than the regulated price at design production levels. No mine evaluated can produce coal profitably at this price at current production levels. The purely variable charge does not adequately reflect the fixed and variable components of the cost of production and places the financial risks of low production on the mining enterprises. Some sort of fixed payments to the mining enterprises, or take-or-pay arrangements, are common ways of sharing this risks with the customer.

With the integration of mining and power operations in RS, the costs and risks of varying production levels are internalized within the enterprise.

A target production level for the year 2000 was defined in order to estimate costs at what will hopefully be more stable conditions. These target levels were not based on a detailed forecast. Mines with high costs were assigned lower values than design levels and lower cost mines were assigned design production levels or higher. The Target 2000 production levels were used in the calculation of cost-of-electricity. The results are shown in Figure ES-3 for key mines supplying existing power plants.

Figure ES-3 Coal Cost at Current and Target 2000 Production Levels



The coal cost used as a basis for the electricity cost calculation was the Target 2000 cost Vrtliste coal for Kakanj, Dubrave lignite for Tuzla Units 1-5, Visca brown coal for Tuzla Unit 6, and the dedicated mines for Gacko and Ugljevik. However, these values will be dependent upon the level of future restructuring of the industry and resource decisions affecting the level of production. Both the Target 2000 production levels and the selection of least-cost mines will be subject to

4

revision in the future based on the results of mine sector restructuring and overall energy strategy studies proposed outside the scope of this study.

In summary, these fuel costs are:

- Kakanj 4.7 DM per GJ
- Tuzla Units 1-5 4.5 DM per GJ
- Tuzla Unit 6 6.5 DM per GJ
- Gacko 4.7 DM per GJ
- Ugljevik 4.9 DM per GJ

ES.5 COST OF THERMALLY GENERATED ELECTRICITY

A number of rehabilitation and new plant options were considered at the pre-conceptual level to determine the cost of electricity generation from thermal sources. The following rehabilitation options are considered:

Option	Total Investment (DM/kW)	FGD Investment (DM/kW)	Life Extension (years)
Tuzla 32 MW units	219	n/a	7
Tuzla 110 MW Unit 3	694	282	10
Tuzla 200 MW Unit 4	485	205	15
Tuzla 200 MW Unit 5	486	205	20
Tuzla 215 MW Unit 6	432	191	20
Kakanj 32 MW Units 1-4	156	n/a	7
Kakanj 110 MW Unit 5	605	291	13
Kakanj 110 MW Unit 6	554	291	21
Kakanj 230 MW Unit 7	388	183	25
Ugljevik 300 MW Unit 1	277	167	23
Gacko 300 MW Unit 1	60	-	27

For comparison purposes, the cost of electricity from three new plant options was considered. Generally speaking, for a rehabilitation option to be justified on an economic basis, its per unit incremental investment and operating costs should be less the cost of electricity from new plant options. New plant options considered in this study are:

Technology	Investment Cost (DM/kW)	Fuel	Fuel Cost (DM/GJ)
Circulating Fluidized Bed	2 640	Local Coal	4.48
Combined-Cycle Plant	1 400	Imported Gas	5.45
Pulverized Coal	2 475	Imported Coal	4.00

It is expected that future energy strategy studies will consider a broader range of new plant and fuel options.

Figure ES-4 shows the incremental cost of electricity from these plants at full capacity and for the Target 2000 fuel costs specified above. The full cost of electricity for rehabilitation projects is equal to the incremental cost plus the impact of depreciation and profit on existing assets. (Note: for new plants, and for fully depreciated plants, incremental and full cost of electricity is equivalent.) The full cost of electricity is shown in Figure ES-5. Economic decisions are based on incremental costs, while the utility financial reporting reflects full production costs.

The following observations can be made:

- The incremental costs of electricity from all rehabilitation options are estimated to be greater than 8 Pf/kWh.
- A new combined cycle power plant using imported natural gas appears to be competitive with rehabilitation projects. It will be important that future energy strategy studies focus on more detailed comparisons of rehabilitation and new plant options.
- The additional costs of depreciation and profits on existing assets are greater for rehabilitation projects involving newer units (e.g., Unit 7 at Kakanj, Ugljevik and Gacko). These costs should not affect economic decisions concerning which units to rehabilitate, nor operating decisions on unit dispatch.
- For rehabilitation options greater than 32 MW in capacity, approximately 1.2 Pf/kWh is associated with the addition of flue-gas desulfurization equipment.

6

Figure ES-4 Incremental Cost of Electricity Comparison

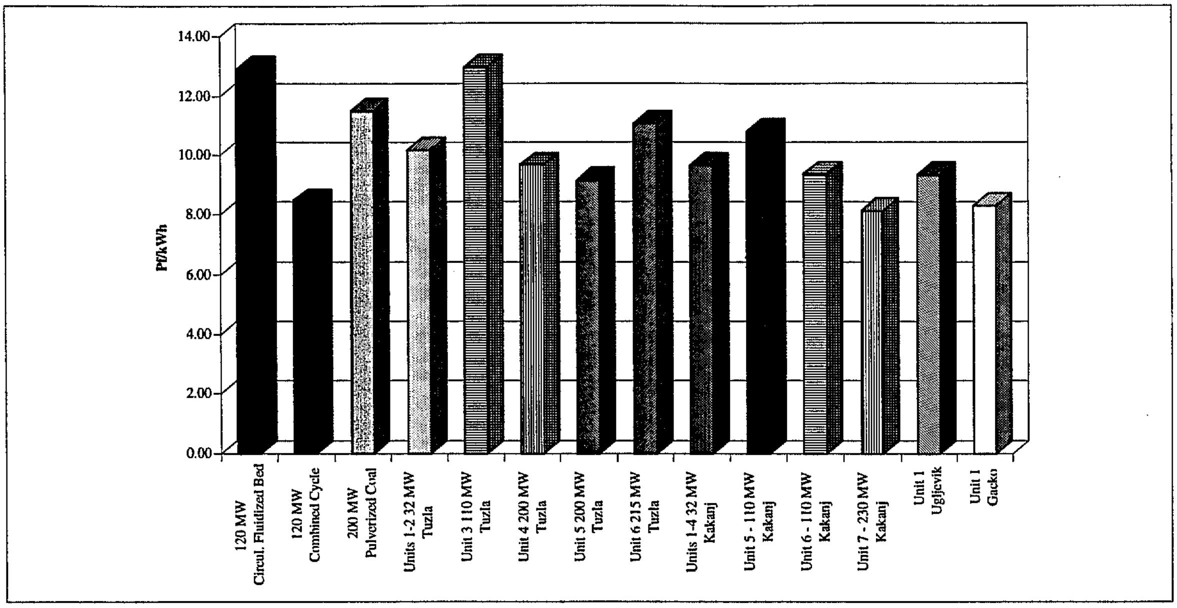
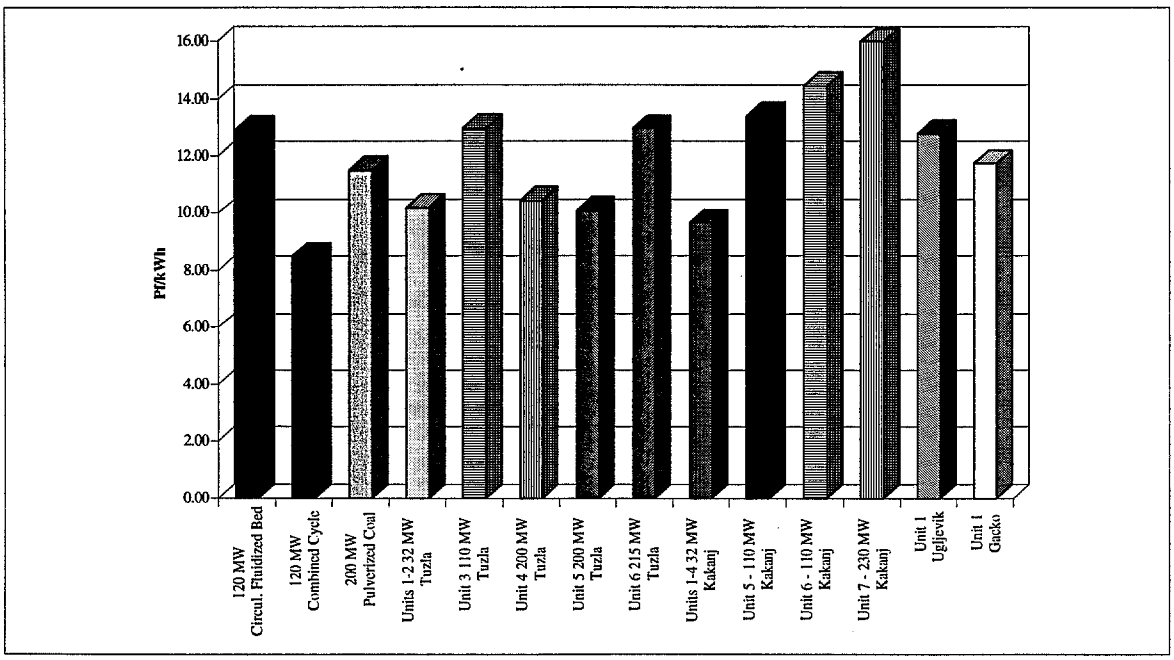


Figure ES-5 Full Cost of Electricity Comparison



Section 1 Study Overview and Approach

1.1 INTRODUCTION

This report documents work conducted by Bechtel Consulting for the governments of the Federation of Bosnia and Herzegovina (Federation) and the Republika Srpska (RS) in support of their energy tariff setting process. The work has been funded by the US Agency for International Development (USAID) under its project for Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics. Tuzla Mining Institute acted as a consultant on this project, providing insight into existing conditions and future mining plans.

The Bechtel team traveled to Bosnia and Herzegovina in April 1997 to conduct the major data gathering effort for this report. We would like to thank the many managers and staff of organizations that contributed to this report. These include Ministry of Energy, Mining and Industry (Federation), Ministry of Energy (RS), Elektroprivreda Bosnia and Herzegovina (EPBiH), Elektroprivreda Hrvatske Zajednice Heceg-Bosne (EP Mostar), Elektroprivreda of the Republic of Srpska (ERS), Middle Bosnia Mines and Tuzla Mines.

1.2 STUDY OBJECTIVES

The objectives of this study are to estimate the true economic cost of thermal electricity generation including the cost of coal production in Bosnia and Herzegovina and to evaluate the degree to which the existing pricing process ensures that these costs are incorporated into tariffs. The study is being conducted in order to:

- Provide support for the adjustment of the coal and electricity prices to reflect their economic cost of production.
- Provide support for the deregulation of coal price and regulation of electricity prices through a transparent decision making process protecting the interests of all consumers of electricity, consistent with social stability and environmental protection.

This effort is ~~the first step in planned~~ to support to the tariff setting process in Bosnia and Herzegovina. Tasks that are foreseen subsequent to this study are:

- Facilitate the creation of a temporary inter-ministerial Tariff Setting Committee which would include ministries concerned with energy, economic and finance matters, with the authority to set electricity tariffs and settle payment disputes between the national company and coal enterprises, until such a permanent public utility regulatory authority is established and the price of coal is decontrolled and set by market forces.
- Provide the services of tariff specialists who can advise the Tariff Setting Committee on: cost allocation methods, transfer pricing, tariff setting, contractual methods between electricity companies and coal suppliers and their customers. Advise would also be provided for developing a schedule for adjusting electricity tariffs and freeing coal prices to bring both in line with their production costs, giving due consideration to social stability in the country.
- Monitor electricity and coal mine companies' receipts to identify the effect of increased revenues to these entities.
- Draft legislation to create an independent regulatory body to replace the Tariff Setting Committee.

1.3 OTHER STUDIES OF THE BOSNIAN POWER SECTOR

This is one of a series of studies being carried out by donors and coordinated by the Energy Task Force. This series of studies began with an Austrian-funded examination of the potential for investment in thermal power plant equipment and a USAID-funded strategy paper for increasing private sector participation in the sector. The Bechtel team met with Verbundplan/ Drauconsulting and Price Waterhouse, the contractors conducting these studies, and has utilized intermediate results where appropriate. These studies are to be finalized during the early summer of this year.

The EBRD is sponsoring a long-term strategy analysis of the Bosnia and Herzegovina energy sector and comprehensive power tariff study. Bechtel consulted with EBRD and the firms selected to conduct this work, Sociedad General de Industriale (SGI) and Fichtner, respectively, to ensure that the results of our analysis could be incorporated in these broader and more comprehensive studies.

The IMC and the European Union are developing plans for subsector restructuring studies in coal mines and power respectively.

1.4 APPROACH

Figure 1-1 summarizes the approach used in the study.

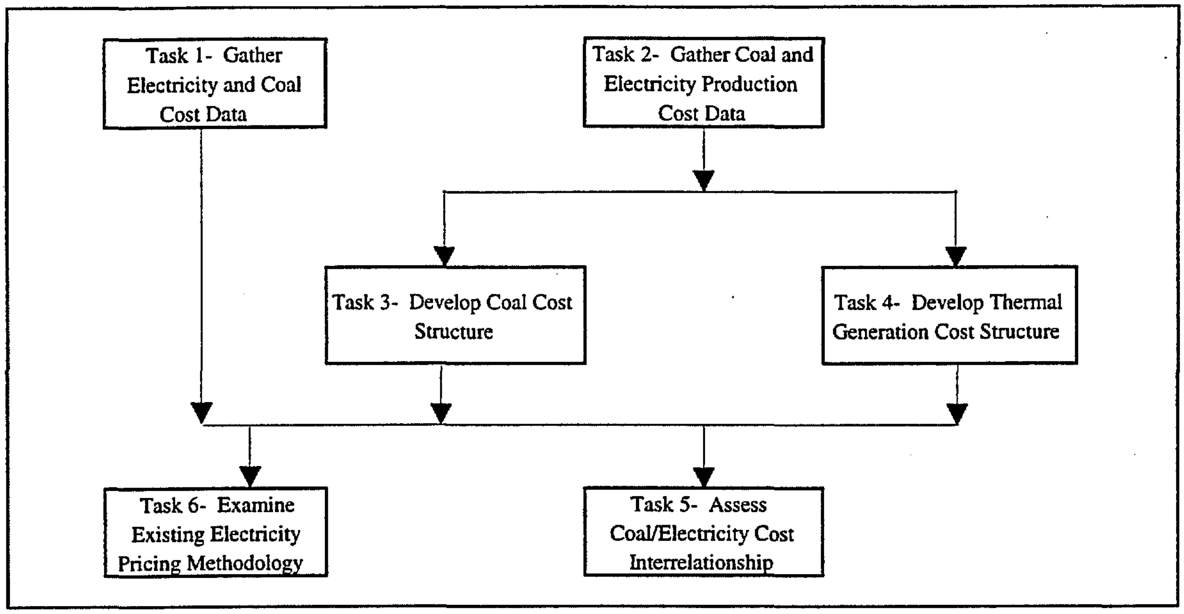
Current pricing of coal and electricity is relatively simple, both from a methodological and institutional point of view. A summary of the review of pricing, along with its impact on enterprise finances, is found in Section 2.

Sections 3 through 6 provides summaries of the coal/lignite and electricity cost structures according to power plant and associated mines.

Fuel costs were estimated at design production levels to obtain fixed and variable cost components for each of 19 mines in Bosnia and Herzegovina. Costs for overburden removal, reclamation, coal removal, in-mine transport, preparation and transport to power stations were estimated. Capital requirements were estimated and operating margins were based on an opportunity cost of capital of 12%. Costs were then developed for current production levels and those considered reasonable for the year 2000. The cost of electricity was based on the production rate for the year 2000. Generally, these rates were comparable to design capacity. Appendix A provides a detailed description of the fuel cost model.

Electricity production costs are calculated based on coal production levels estimated to be reached by the year 2000 and investment requirements of power plant rehabilitation. Rehabilitation costs are considered with flue-gas desulfurization for 100 MW units and larger. As points of reference, the cost of electricity from three new plant options were also considered. The new plant options were a circulating fluidized bed unit burning local lignite, a pulverized coal unit burning imported coal and a combined cycle natural gas unit. Appendix B provides a detailed description of the electricity investment and production cost model.

Figure 1-1 Overall Approach



1.5 STUDY ASSUMPTIONS

Key assumptions were:

- Opportunity cost of capital - 12%, with the sensitivity analysis performed for 8%
- Reference year for costs - 1997
- Fixed costs estimated for production from mines at design values will be same at different production levels.
- For surface mines, the ratio of overburden removal to coal removal will be constant with production level.
- All coal or lignite fired power plants greater than 32 MW will need flue-gas desulfurization equipment (FGD). Thus, the rehabilitation of existing power plants will require investments in FGD equipment.
- Power plants will utilize the least expensive coal supply within the coal basin.
- Power plant rehabilitation projects will enable power plants to produce up to their pre-war production and capacity levels.
- Increased power plant availability will translate directly into increased electricity production (i.e., their output will not be limited by demand).

Section 2 Power Sector Overview

The following section describes the organization, fuel supply, plans and physical characteristics of the power sector of Bosnia and Herzegovina.

2.1 ORGANIZATION

Prior to 1992, Bosnia and Herzegovina was a republic of the Yugoslav Federation, and its power system was an integral part of the Yugoslav national system. Interchanges between the state-owned power enterprises serving the former Yugoslav republics was supported by a 400 kV backbone system and was accompanied by full membership in the Western European grid (UCPTE). This arrangement was changed by independence in 1992 and then by war in the country. Under the Dayton Peace Accords (November, 1995), the country of Bosnia and Herzegovina has been divided into two entities the Federation of Bosnia and Herzegovina (referred to as the Federation) and Republika Srpska (RS). The Ministry of Energy, Mining and Industry administers the power sector for the Federation. This function is performed by the Ministry of Energy in RS.

The Federation is served by Elektroprivreda Bosnia and Herzegovina (EPBiH) and by Elektroprivreda Hrvastske Zajednice Heceg-Bosne (EP Mostar). RS is served by Elektroprivreda Republika Srpska (ERS). EPBiH was also the name of the utility that supplied electricity to all of Bosnia and Herzegovina before the war.

2.2 FUEL SUPPLY

Figure 2-1 presents data on coal deposits in BiH, and the locations of thermal power plants.

The Federation has two major coal mining areas serving the power plants. One is located near the city of Tuzla and the other one is centered near the city of Kakanj. The Republika Srpska has two mine-mouth coal mines located at Gacko and Ugljevik.

Coal production in the Tuzla region is concentrated in three major coal mines: Kreka (lignite), and Banovici and Durdevik (brown coal). Together they are organized as the single company Coal Mines Tuzla hadquatered in Tuzla. The coal mines are the biggest producers of lignite and brown coal in the Federation (around 63% of total production).

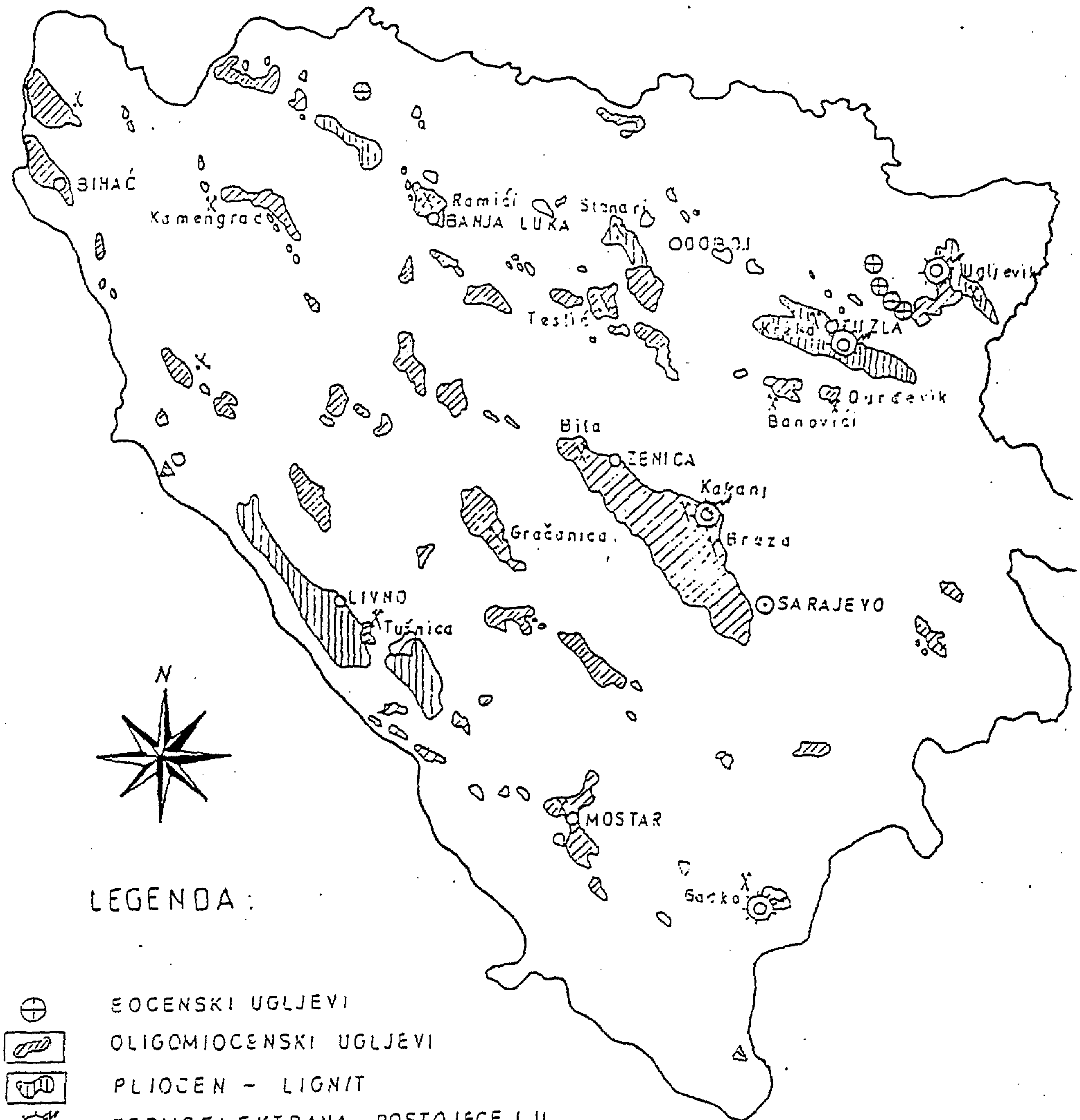
Until 1992 annual production was approximately 9.5 million tonnes, of which 5.5 million tonnes of lignite in Kreka and 3.5-4 million tonnes of brown coal in mines Banovici and Durdevik. Production increase followed the consumption needs and out of total production, TPP Tuzla received 53.7%, industries 20.3%, and others approximately 26%. Post war production is at 2.8 million tonnes or approximately 30% of pre-war production, of which 80% was sold to the power plant.

In the 1986-1990 period average coal production (in tonnes) in the Tuzla region by coal mine was:

Coal Mine	Production (t/year)	% of total	Surface Prod. (t/year)	% for the mine	Underground Prod. (t/year)	% for the mine
Kreka - lignitè	5 468 495	60.3	2 937 248	53.7	2 593 750	47.3
Banovici	2 217 087	24.4	1 916 000	86.0	300 436	14.0
Durdevik	1 384 527	15.3	1 176 583	85.0	207 944	15.0
Total	*9 070 109*	*100*	*6 029 811*	*64.0*	*3 102 120*	*36.0*

Table 2-1 Coal Deposits in BiH

PROSTORNI RAZMJEŠTAJ REZERVI UGLJA BOSNE I HERCEGOVINE



LEGENDA:

- EOCENSKI UGLJEVI
- OLIGOMIOCENSKI UGLJEVI
- PLIOCEN - LIGNIT
- TERMOELEKTRANA POSTOJECE I U
- POSTOJEĆA PROIZVODNJA
- LIKVIDIRANA PROIZVODNJA

In the same period coal was sold to the following customers (in tonnes):

Coal Mine	TPP Tuzla	%	Industry	%	Other	%	Total
Kreka - lignite	3 171 212	58.0	743 000	13.6	1 553 000	28.4	5 468 495
Banovici	837 547	37.3	816 188	36.8	563 334	25.5	2 217 087
Durdevik	868 542	62.7	281 344	20.3	224 640	17.0	1 384 527
Total	*4 887 301*	*53.7*	*1 840 532*	*20.3*	*2 340 970*	*26.0*	*9 070 109*

The coal production in the Kakanj region is concentrated in four major coal mines: Gracanica (lignite), (Kakanj brown and lignite coal), and Breza and Zenica (brown coal) organized as the single mining company Middle Bosnia Mines hadquatered in Kakanj. Middle Bosnia Mines company is the second largest producer of lignite and brown coal in the federation.

Until 1992 annual production was approximately 4.3 million tonnes. The Kakanj coal mine produced 2.5 million tonnes, around 0.5 million tonnes were produced in Breza, around 1.2 million tonnes in Zenica, and around 0.5 million tonnes in Gracanica. The yearly production in the late 1980s was stable, and out of the total production TPP Kakanj received an average of 2.3 million tonnes. Industries and other local customers received 1.3 million tonnes. Delivery to customers outside BiH was 0.6 million tonnes the bulk of which being provided by the Gracanica coal mine. Post war production is at 0.7 million tonnes or approximately 16% of pre war production, of which 80% was sold to the TPP Kakanj.

In the 1986-1990 period the average coal production (in tonnes) for the Middle Bosnia Mines was:

Coal Mine	Production (t/year)	% of total	Surface Prod. (t/year)	Underground Prod. (t/year)
Kakanj	1 928 820	52.4	915 240	1 013 580
Breza	566 732	14.8	174 984	391 748
Zenica	1 206 893	32.8	367 734	839 159
Total	*3 702 445*	*100*	*1 457 958*	*2 243 487*

In this same period the Gracanica mine produced an average of 592 770 tonnes of which 497 220 tonnes was sold to industrial and other customers and 94 550 tonnes were exported outside BiH.

In the same period coal was sold to the TPP Kakanj, and industrial and other customers in the following amounts (in tonnes):

Coal Mine	TPP Kakanj	% of total	Ind. and Others	% of total
Kakanj	1 718 143	89.0	210 777	11.0
Breza	448 606	78.5	118 126	21.7
Zenica	178 170	14.8	1 028 723	85.2
Total	*2 325 819*	*63.0*	*1 357 626*	*37.0*

13

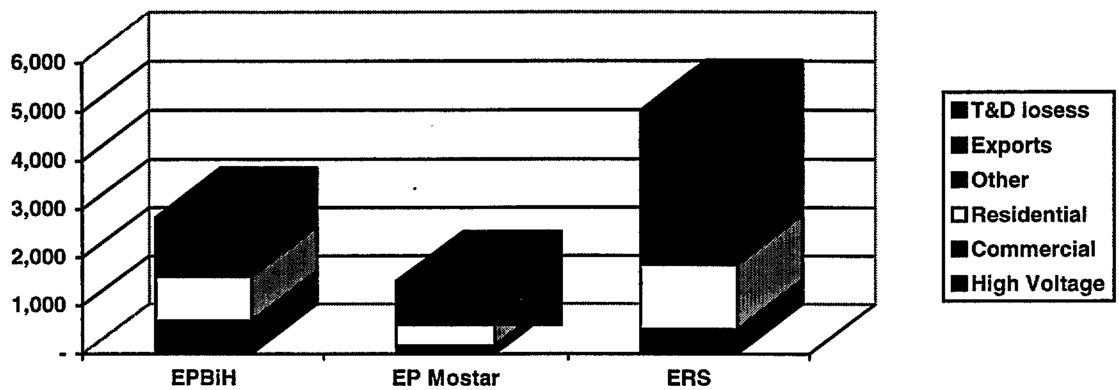
The two coal mines in Republika Srpska are at Ugljevik and Gacko, serving the power plant needs. Coal production for the period 1987-1996 was in the following amounts (in 1000 tonnes):

Mine/Year	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Ugljevik	1543	1978	1772	1836	1588	820	194	81	131	1168
Gacko	2056	1666	1418	2383	1703	460	400	245	102	-

2.3 ELECTRICITY DEMAND AND SUPPLY

Figure 2-2 compares the 1996 customer base of the three entities. Excluding exports, consumption numbers for EPBiH and ERS were comparable in 1996 and consumption for EP Mostar was approximately 40% of either of the two larger enterprises. However, exports by ERS were much higher than either of the two Federation enterprises, resulting in much higher production requirements in the RS than in the Federation.

Figure 2-2 1996 Electricity Consumption (GWh)



Both EPBiH and ERS have mixed hydro-thermal generating capacity. EP Mostar is exclusively hydro. This is illustrated in Figure 2-3.

Approximately 60% of the original thermal generating equipment in the Federation is greater than 20 years old and 20% is greater than the nominal design life of 30 years. All generating equipment has suffered from lack of maintenance. The resulting decline in the capacity of thermal generating plants of EPBiH and ERS is summarized in Figure 2-4. The single unit of the Gacko plant went out of service in June, 1996. Bechtel was informed by the plant personnel that the plant returned to service in May, 1997.

14

Figure 2-3 1996 Electricity Supply (GWh)

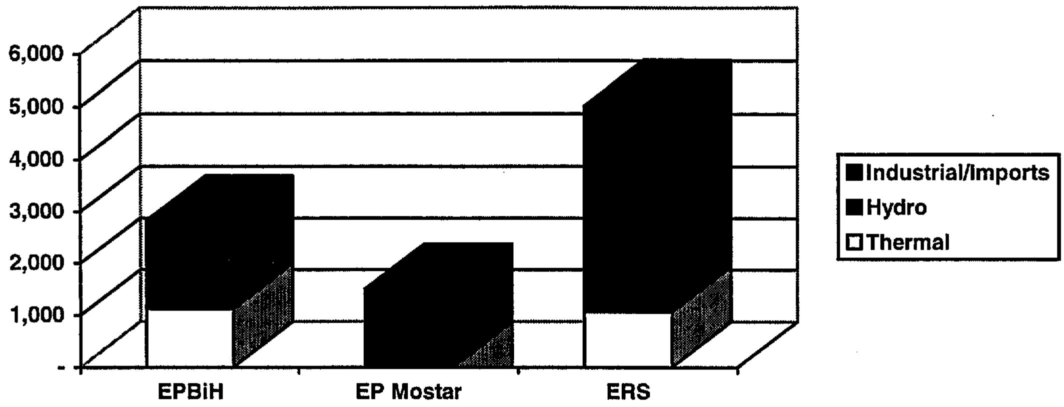
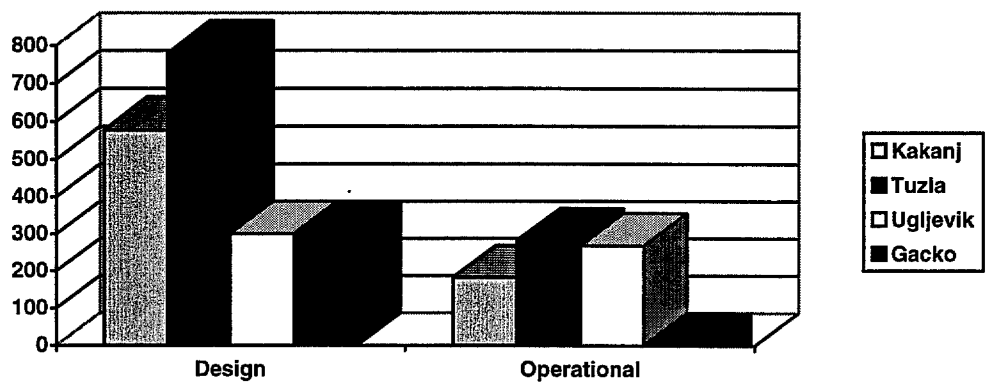


Figure 2-4 Thermal Power Capacity at the End of 1996 (MW)



The two EPBiH thermal plants, Kakanj and Tuzla, are supplied by a number of lignite and brown coal mines near the plants. As mentioned earlier, these mines have been consolidated into two enterprises. Middle Bosnia Mines supplies the Kakanj plant and Tuzla Mines supplies the Tuzla plant. The RS power plants are each located near dedicated mines.

2.4 FUEL AND POWER PRICING SUMMARY

The following discussion is based on interviews with the mining and utility enterprises and from Reference 2-5. The price regulation is different for each of the electric power enterprises. However, there is no independent regulation of any electricity or mining enterprise.

The Ministry of Energy, Mining and Industry maintains jurisdiction in the Federation; however, it appears that in practice, EP Mostar operates under a separate regulatory structure. The Ministry sets prices of lignite and brown coal in the Federation and approves transport charges. The current price is set in terms of heat content at 3.612 DM/GJ. As will be discussed in more detail in later sections, this price is well below the cost of production at most of the mines in the Federation.

15

The Ministry has final approval authority over retail electricity tariffs for EPBiH. These tariffs are first proposed by EPBiH and approved by their Board of Directors, which is chaired by a Deputy Minister.

EP Mostar proposes retail tariffs for electricity. These are approved by the various Croatian municipalities. It is not clear how pricing disputes between the enterprise and the municipalities, or between municipalities, would be mediated.

The Ministry of Energy of the RS has final approval authority for retail electricity tariffs for the ERS. Since dedicated mining operations are integrated into the ERS, there is no separate price regulation of lignite and brown coal. However, the cost of coal production is reported in the financial statements.

The tariff structure varies among enterprises. Table 2-1 summarizes their key characteristics.

Table 2-1 Key Characteristics of Enterprise Tariff Structures

	Seasonal Pricing	Time-of-Day Pricing	Demand Charges	Differentiation by Voltage Level of Service	Power Factor Penalties	Inverted Block Structure	Evidence of Cross-Subsidation
EPBiH	non-residential	non-residential	non-residential	yes	none	residential	yes
EP Mostar	all categories	non-residential	non-residential	yes	none	none	yes
ERS	none	non-residential	non-residential	yes	high voltage	none	yes

All structures incorporate the differentiation of prices based on the voltage level of service and time-of-day pricing and demand charges for non-residential customers. The average residential price in 1996 was below the overall average price for all electric power enterprises even though this customer category represents the highest cost of delivery. This suggests the use of cross-subsidies.

The average 1996 price for EPBiH was reported as 8.7 Pf/kWh. The average 1996 price for EP Mostar was 25% higher than this and for ERS was 40% lower. Some key cost factors and their potential for explaining the price differences follow:

- The higher level of residential sales of EP Mostar compared to EPBiH (71% versus 53% in 1996) results in higher costs. This should be largely offset by the lower generating costs of EP Mostar with all of its generation coming from hydro-electric sources.
- ERS also has a higher percent of sales to residential customers than EPBiH, the cost of which should be largely offset by a higher percentage of hydro-electric sources and their associated lower costs.
- ERS has much higher exports than EPBiH or EP Mostar. Profits from these sales may be an explanation of the lower prices available to ERS domestic customers in 1996. However, we do not have adequate data on export transactions to verify this hypothesis.

Comparisons of average prices can be misleading because of differences in the customer mix. To eliminate this, we have compared prices for customers with standard characteristics as shown in Table 2-2. Residential Customer #1 is intended to represent a residential customer not using electric heating, while Residential Customer #2 represents the one who does.

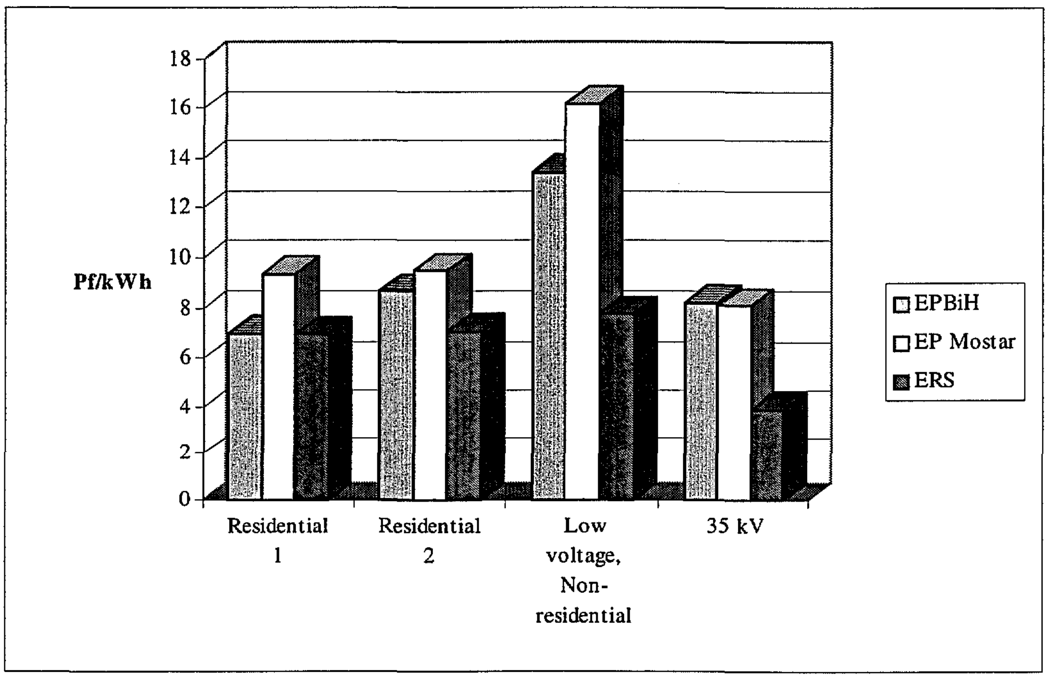
16

Table 2-2 Customer Characteristics Used for Price Comparison

	Consumption (kWh/month)			Monthly Peak (kW)	
	Winter	Summer	% Consumption in Peak Period	Winter	Summer
Residential Customer #1	300	300	na	na	na
Residential Customer #2	600	300	na	na	na
Low voltage, Non-Residential	800	600	60%	2.5	1.5
35 kV Customer	100 000	100 000	40%	150	150

Figure 2-5 shows the comparative prices for the three enterprises based on current tariffs (effective May 1996 for EPBiH, June 1995 for EP Mostar and January 1997 for ERS). For Residential Customer #1 (no electric heating), the average electricity price for EPBiH and ERS are comparable with the price for EP Mostar being higher. For Residential Customer #2 (electric heating, the average price for EPBiH comes closer to EP Mostar. The relatively high price for EPBiH and EP Mostar non-residential low voltage customers compared with residential prices suggests a cross-subsidy. The relatively low prices of ERS compared to the other electricity enterprises is evidenced across customer categories.

Figure 2-5 Comparative Prices for Standard Customers



This comparison does not address the question of whether the tariff levels reflect cost of production. The next section addresses this issue and the associated financial performance of coal and electricity enterprises.

2.5 FINANCIAL STATUS OF COAL ENTERPRISES

The only separate coal enterprises in the Federation are Middle Bosnia Mines and Tuzla Mines. They receive 3.612 DM/GJ of coal produced as discussed above. The 1996 profit and loss statement for Middle Bosnia Mines is shown in Table 2-3. It shows a loss almost equal to the revenues received for the sales of coal. The price set by the Ministry is clearly not intended to meet the reported cost of production. We have not reviewed Tuzla Mining financial information, but have been informed that financial losses were experienced in 1996 as well.

Table 2-3 Reported 1996 Profit and Loss Statement for Middle Bosnia Mines

Revenues (millions (DM)	
Coal Sales	35.8
Kakanj Power Plant	*23.6*
Others	*12.2*
Other	3.4
Total	39.1
Expenses (millions DM)	
Material, Energy, Spare Parts	13.9
Amortization	18.3
Salaries and Other Labor Costs	21.7
Services	10.1
Other	5.3
Total	69.3
Operating Margin	(30.1)

2.6 FINANCIAL STATUS OF ELECTRICITY ENTERPRISES

Table 2-4 provides a comparison of the 1996 profit and loss statement for the three electricity enterprises. (As noted above, EP Mostar has no coal-fired generation and therefore purchases no coal. There is no purchase of coal for ERS because coal and electricity operations are integrated.) The level of collections was low, less the 70%, for all three enterprises. Only EP Mostar realized a profit.

Low collections are a serious problem, but cannot fully explain the poor financial performance of EPBiH and ERS. Table 2-5 shows the effect that improving collections to the 98% level would have had on the 1996 financial results. EPBiH and ERS would have remained unprofitable. EP Mostar would have risen to a commercially acceptable level of profitability if collections had been adequate if its reported costs fully reflect its cost of operation.

We know from visits of the EPBiH and ERS thermal plants that inadequate maintenance in being conducted by these enterprises because of lack of funds. We have also been told that this lack of maintenance extends to transmission and distribution equipment as well. Therefore, reported costs understate their true cost of operations. Furthermore, as discussed above, EPBiH coal costs understate the reported costs by the mines. We have also been informed that the EP Mostar system also suffers from lack of maintenance so that their costs may be understated as well.

Therefore, even if collections were to rise to commercially acceptable levels, current electricity tariffs would be inadequate to cover costs for EPBiH and ERS.

Table 2-4 Reported 1996 Profit and Loss Statements for Electricity Enterprises

	EPBiH	EP Mostar	ERS	Label	Description
Retail Sales and Exports (GWh)	2197	1197	4325	A	
Average Collections (Pf/kWh)	6.9	5.5	3.6	B	E/A
Collection Ratio	61.9%	69.0%	64.3%	C	
Average Price (Pf/kWh)	11.2	8.0	5.6	D	B/C
Revenues (million DM)					
Income from Sales of Electricity	152	66	157	E	
Other Operating Income	45	8	6	F	
Total Revenues	194	74	163	G	E+F
Expenses (million DM)					
Coal	75	-	-	H	
Amortization	122	32	179	I	
Wages and Salaries	40	17	9	J	
Other	65	12	70	K	
Total Costs	302	61	259	L	H+I+J+K
Operating Margin	(105)	13	(96)	M	G - L

Source: Reference 2-1 for EPBiH and Reference 2-5 for EP Mostar and ERS

Table 2-5 Hypothetical Effect of Improved Collections in 1996

	EPBiH	EP Mostar	ERS	Label	Description
Retail Sales and Exports (GWh)	2197	1197	4325	AA	
Average Collections (Pf/kWh)	6.9	7.8	5.5	BB	EE/AA
Collection Ratio	98%	98%	98%	CC	
Average Price (Pf/kWh)	7.1	8.0	5.6	DD	BB/DD
Revenues (million DM)					
Income from Sales of Electricity	234	94	239	EE	E * CC/C
Income from Secondary Activities	45	8	6	FF	
Total Revenues	279	101	245	GG	EE+FF
Expenses (million DM)	302	61	259	LL	
Operating Margin	(23)	40	(14)	MM	GG - LL

2.7 THE FUTURE

The discussion in this section so far was focused on the current situation. Some of the difficulties in the power sector will improve as the economy is revitalized and customers are better able to pay. Without fundamental changes in resource use, incremental increases in electricity demand will be met by

19

increased generation from thermal plants using domestic lignite and brown coal. This will require investments in rehabilitation of EPBiH and ERS thermal plants. EP Mostar has plans for a new thermal plant to meet load growth and provide backup to hydro power plants in dry seasons.

Additional investments in the power sector and associated coal mining will have to meet stricter commercial criteria.than has been true for the emergency aid received to meet minimum levels of service during and immediately after the war. Investors and lenders will want to be assured that the investments have been selected in an economically rigorous way, that tariffs will cover those costs, and that the electricity enterprises will be managed on a commercial basis.

Future decisions will have to be made considering all options, including further exploitation of hydro resources, power purchases, uses of alternative fuels such as natural gas and investments in conservation. A comprehensive tariff analysis will have to be conducted to assure that future tariffs cover the costs of generation, transmission, and distribution. The following sections provide a basis for assessing the true economic cost of existing thermal generation, for prioritizing future investments, and for developing tariffs that reflect long-run marginal costs.

20

Section 3 Kakanj Power Station

3.1 OVERVIEW

Thermal power plant (TPP) Kakanj is located in the central region of Bosnia near the town of Kakanj. The plant is the oldest power plant in BiH, and was developed in five phases. The first phase was completed in 1956, with the last unit finished in 1988. The plant has a total of seven units with the installed capacity of 584 MW. The power plant also supplies heat to the city of Kakanj from the 32 MW and 110 MW units.

TPP Kakanj uses coal from the Middle Bosnia Mines. The first six units use a mixture of lignite and brown coal, while the seventh unit is designed to use only higher calorific brown coal.

Technical characteristics and recent generation levels for all units are provided in Table 3-1.

Table 3-1 Kakanj Power Plant

	Units 1-4	Units 5-6	Unit 7
Construction Year	1956 and 1960	1969, 1977	1988
Installed Capacity (MW)	32	110	230
Net Capacity (MW)	25	92	208
Average Net Capacity in 1990 (MW)	23,23,23,21	78, 92	208
Minimum Net Capacity (MW)	16	60,55	140
Heat Rate (kJ/kWh at the max. output)	13 680	11 600, 11 600	9 174
Heat rate (kJ/kWh average for 1990)	15650,unit 4 -16400	13 350, 13 850	11 700
Heat Rate (kJ/kWh at the min. output)	19260	14 400, 15 200	12 540
Operating Hours	234 880, 234 880, 210 540, 200 035	140 295, 102 413	24 500
Remaining Life In Years (design)	0	6, 15	26
Working Condition	Operating	Operating	Conserved
Fuel	Local Coal	Local Coal	Local Coal
Fuel Calorific Value (kJ/kg - average)	11 720	11 720	12 979
Fuel Calorific Value (kJ/kg - range)	9 800 - 16 750	9 800 - 16 750	10 046 - 16 744
Method of Burning	Pulverized Coal	Pulverized Coal	Pulverized Coal
Net Production (GWh)			
in 1990	156, 162, 124, 141	418, 517	1 288
in 1995	40, 26, 41, 52	67, -	-
in 1996	94, 38, 53, 2	275, 21	-

The initial value of assets was 1 756 million DM of which 744 million DM is already accumulated depreciation. Current asset value is thus 1 011 million of which 17 million is calculated depreciation for 1997.

3.2 FUEL SUPPLY

The Kakanj power station was designed to receive coal from the Middle Bosnia coal mines. These mines are Breza, Kakanj, Zenica and, Gracanica. The management of the Middle Bosnia coal mines reported an average cost of the operations for 1996 of DM 99.52/t[1] of coal. After cleaning, this coal has an

[1] MIDDLE BOSNIA MINES - ANNUAL REPORT FOR 1996. - Shortened version, Kakanj, March 1997.

2\

average heating value of approximately 16 000 kJ/kg which translates into a fuel cost of 6.22 DM/GJ. This cost does not represent "normal" conditions due to war damage and production interruptions. Fuel costs should be lower as will be discussed below.

The Breza operations comprise underground mining of a 5 m thick seam of brown coal using long wall mining with shield support and a 2 m shearer cutting head. The production is presently approximately 110 thousand tonnes per year (tpy) with a design capacity of 330 thousand tpy. The reserves are estimated at 25 million tonnes of a coal with a heating value of between 12 500 to 17 700 kJ/kg. A coal wash plant using heavy medium methods can improve the quality to 21 000 kJ/kg. The cost of production has been reported for 1996 as 108.55 DM/t[1]. The Tuzla Mining Institute estimated a cost of 150.64 DM/t[10] for the output of 300 thousand tpy. Considering the thick seam and state-of-the-art mining method, the capacity could possibly be increased under normalized staffing and production conditions with adequate maintenance and safety to 420 thousand tpy[2].

The Kakanj brown coal operation comprises a surface mine Vrtliste, and the underground mines Haljinici and Stara Jama. The best reported production was in 1990 with Vrtliste reporting 1 million tpy and Haljinici reporting 780 thousand and Stara Jama 237 thousand tpy[3]. The production from the underground mines was reduced in 1996 to 121 tpy[1] at costs estimated at 168 DM/t[2] for Haljinici and 234 DM/t for Stara Jama[2]. The quality of the underground mined coal seems lower than the Breza coal with the calorific value between 12 500 and 15 000 kJ/kg before washing. The coal quality could be improved above 15 000 kJ/kg by adding a coal washing plant. The cost of the coal could be reduced by productivity improvements and higher production rates. However, it is doubtful that the geological and coal access constraints will allow the production of a competitive power station fuel from these underground mines. This is reflected in the estimate for the expected future production.

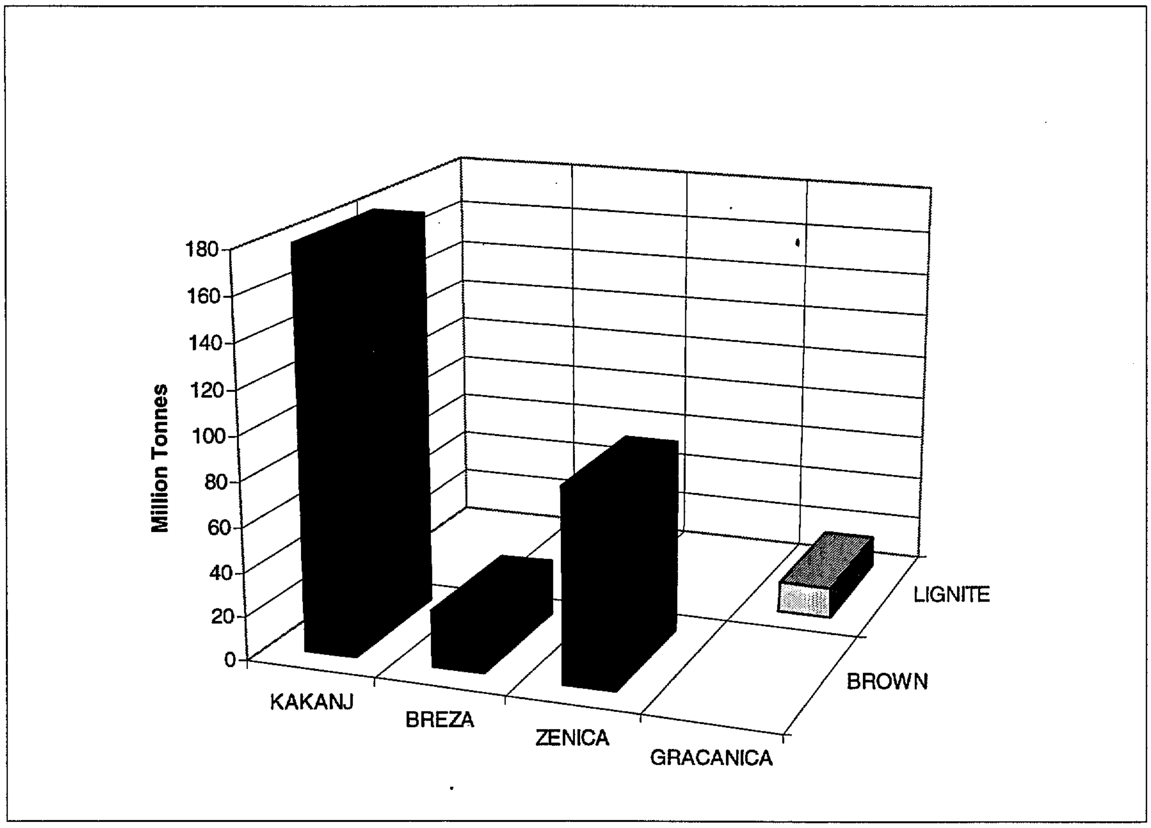
The Vrtliste operation is designed for a capacity of 1 to 1.2 million tpy[1] to supply the bulk of the fuel for the Kakanj power station. Production in 1996 was approximately 300 thousand tonnes which represented 74 percent of the fuel for the Kakanj power station. The mine has reserves of 60 million tonnes at a heating value of 12 400 kJ/kg. A coal cost of 33.45 DM/t[2] was reported for the Vrtliste operation. The model estimated cost of mining of 58.5 DM/t for an annual production of 1.8 million tonnes of raw coal. This seems feasible, even though in the future, the cost could increase due to an increase in the overburden to coal ratio of over 5.75. The mining method of shovel and truck for both, overburden and coal removal, assisted by blasting, is labor intensive, but probably the best choice for the conditions. Reclamation of mined out areas has not yet started. In the model we assessed an additional 9.9 DM/t of coal for this operation. In mine coal transport, and transport to the power station adds another 1.1 DM/t. A planned washplant could improve quality of the coal to match the specifications of the boilers at the Kakanj power station. The fuel quality could possibly be improved to 15,000 kJ/kg for approximately 4.7 DM/t of the final product. The total delivered cost of 1.5 million tpy of washed coal would be approximately 58.5 DM/t. Adding the operating margin this translates into a fuel cost of 4.66 DM/GJ. A washing plant would also reduce the present requirement to purchase higher heating value and higher cost coal from underground mines to satisfy the power station fuel quality specifications.

---

[2] Draft: USAID Kakanj Project Background Review - 20 September 1996
[3] Yearly reports by DIREKCIJA SREDNJA BOSNA - February 20, 1997

22

Figure 3-1 Coal Reserves by Type of Coal for Middle Bosnia Mines



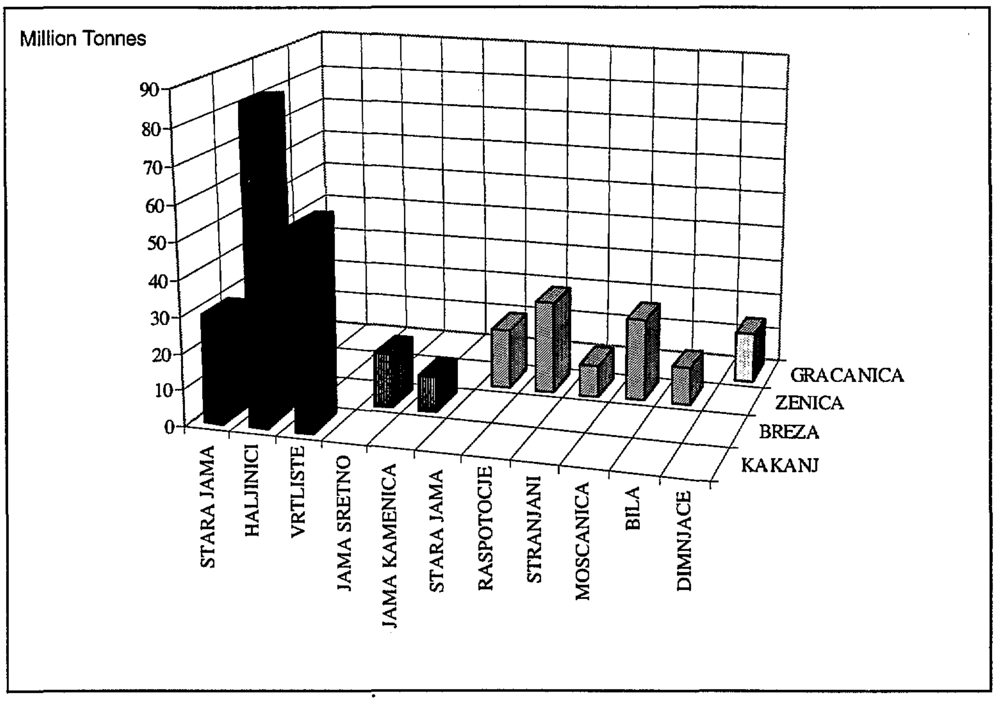
The Zenica coal mines comprise of two brown coal surface mines and four underground mines. These mines produce a higher quality product of up to 20 000 kJ/kg at capacity of up to 1 million tpy[3]. Present production in 1996 was reported as 65 thousand tonnes from underground and 52 thousand tonnes from surface mine operations[1], for a total of just 110 thousand tonnes. The cost of production is very high for these operations with a 1996 combined cost of 209 DM/tonne[1]. Very little of this coal has been used for power station fuel in the past, and under normal conditions little coal will probably be needed in the future. The cost of the coal is too high for power station fuel. This coal can be used as home heating and industrial boiler fuel, but it will probably have to compete with natural gas in this market.

The Gracanica coal mine is a surface mine which produced less than 100 thousand tpy in 1996[1] of which approximately 23 thousand tpy were used at the Kakanj power station. As reported by the mine management[4], the 14 m coal seam and 30 m overburden are mined by the shovel and truck method. The mine is designed for a capacity of 600 thousand tpy and mining cost could be 22.8 DM/t, including 2 DM/t for mine reclamation work. A classification plant could remove large rock from the coal to improve the quality from 11 000 kJ/kg to 12 500 kJ/kg for an estimated cost of 2.3 DM/t of cleaned coal. The cleaned 550 thousand tpy of coal must be transported by truck over 100 km distance to the Kakanj power station which adds 15 DM/t. The cost of the coal delivered at the power plant is then 37. 8 DM/t

[4] Personal conversation with Mr. Kadunic Redzo, Coal Mine Gracanica, on April 23, 1997

or 3.38 DM/GJ. This is a comparatively excellent cost of fuel for the Kakanj power station. However, the reported coal reserves of the Dimnjace mine of under 25 million tonnes are low.

Figure 3-2 Coal Reserves by Coal Mine for Middle Bosnia Mines



3.3 DISCUSSION OF FUEL SUPPLY CONSTRAINTS

Figure 3-2 indicates sufficient reserves of coal. The reserves include only proven reserves. While Units 1 through 6 of the Kakanj power station require a design fuel of between 9 800 to 16 750 kJ/kg with a guaranteed value of 11 720 kJ/kg. The 230 MW boiler for Unit 7 requires fuel of a calorific value between 10 046 and 16 744 kJ/kg with a guarantee value of 12 979 kJ/kg[5]. Historical data[5] indicate that the medium annual fuel quality, mainly fuel from Kakanj and Breza coal mines, deteriorated over time from 13 000 kJ/kg in 1979 to below 11 000 kJ/kg by 1994 with an increase to 12 000 kJ/kg in 1995. The increase was probably due to an increased supply from Breza coal mine and higher quality of coal from Zenica mines. Discussions with plant operators[6] indicated large temporary swings in fuel quality due to inadequate or out of order homogenization equipment. Under normal conditions the quality of the coal from the Vrtliste surface mine and Breza underground mine should be individually controlled by washing and then mixing before combustion. The deterioration of the fuel quality is caused by dilutions with rock indicated by an increase in the ash content of the coal to over 45% for the Kakanj coal. The Breza coal shows a historical improvement in the ash content to 20% in 1995 from over 40% in 1984 due to the addition of a wash plant. The Vrtliste coal should also be passed through a simple washing operation to remove the rock dilutions. An improved (higher heating value and lower quality variations) fuel would improve the boiler operation considerably. The wet bottom boilers will react favorably to an improved fuel quality due to higher flame temperatures. NOx emissions may increase as could fouling in the upper

[5] Executive Summary: Long Term Rehabilitation Study TPP Kakanj, Verbundplan/Drauconsulting

24

boiler passages due to the higher temperatures. The removal of the rock would also reduce the maintenance requirements on the hammer mills as well as reduce the disposal costs for flyash and slag.

3.4 FUEL COSTS AS A FUNCTION OF OUTPUT

The 1996 average coal production cost of 6.22 DM/GJ for the Middle Bosnia Mines could not compete with a potential imported fuel alternative for Kakanj. Fuel cost can and must be lowered. This can be done by improving the productivity in the mining operations by normalizing the employment rate and improving the availability of mining equipment. In addition, production increases from lower cost mines must replace the fuel which presently needs to be acquired from smaller and high cost underground mines.

Figure 3-3. Coal Production and Design Capacity for the Middle Bosnia Mines

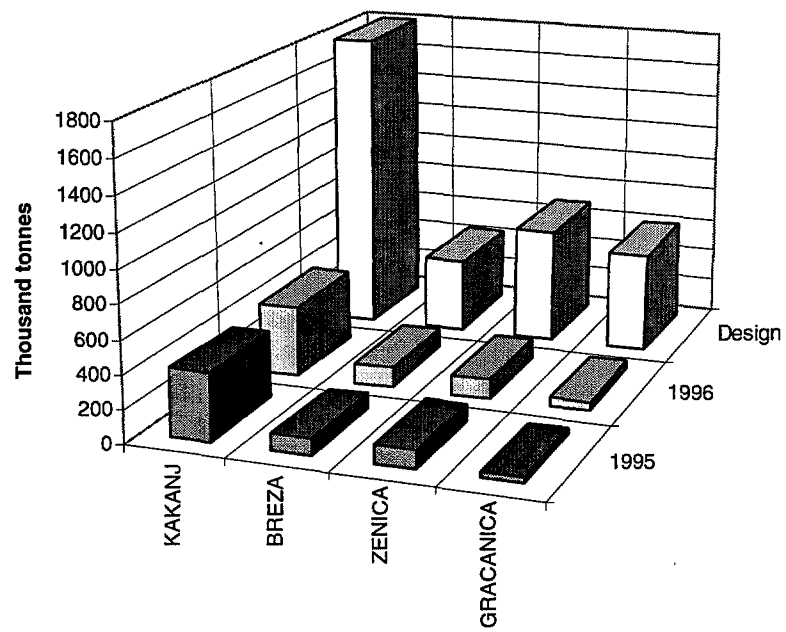


Figure 3-3 illustrates the present and potential design production of the Middle Bosnia Mines. An increase of production should lower the cost, if combined with an increase in productivity of the work force, and an increase of availability of the mining equipment up to their design rate. An increase of coal production beyond that point will require the acquisition of additional equipment, and more personnel to operate the equipment which will result in higher cost. Coal production limits and cost increases can also be result of an excessive overburden removal requirement. Changes in the geological and topographical conditions as mining progresses will influence this requirement. A coal seam thickness increase, and overburden thickness decrease can improve production and lower costs while the thinning of the coal seam and an increase of the overburden has the opposite effect. Conditions may get worse with encountering of layers of rock which must be drilled and blasted, or the splitting of the coal seam to expose a parting of non-coal material. In underground operations, the production limits for a long wall operation are reached when, either the maximum capacity of a face operation is reached, or when the mine reaches the maximum capacity of the coal transportation system. Production increases may require development of new entries and purchase of more production equipment, such as hydraulic support shields, coal shearer and coal transport system, with the result of an immediate and relatively high incremental production cost increase.

The Vrtliste surface mine and the Breza underground mine are both candidates to improve productivity and lower cost by increasing production. At other coal mines, such as Zenica, production is too low, when combined with the high production costs and the distance from the Kakanj power station, to be of lasting interest for the fuel supply of Kakanj power station.

3.5 INVESTMENT REQUIREMENTS

Major work being prepared in TPP Kakanj for 1997 includes:

- Second phase of rehabilitation work on 110 MW units (Units 5 and 6) in order to bring units to the satisfactory level of availability/reliability and satisfy the basic environmental requirements
- Further conservation and testing of 230 MW unit (Unit 7)
- Rehabilitation of 32 MW units.

Rehabilitation investment estimates, investments in FGD equipment and estimates on the continued operation of units are presented in Table 3-2.

Table 3-2 Investment Requirements at the TPP Kakanj

Unit Name	Capacity (MW)	Total Rehab. Inves. (million DM)	FGD Investment (million DM)	Continue to Operate for Next
Units 1-4	4x32	20	-	7 years
Unit 5	110	66.5	32	13 years
Unit 6	110	61	32	21 years
Unit 7	230	84.6	42	25 years

3.6 COST OF ELECTRICITY

Since the power plant is operated as a single enterprise, no unit cost allocation methods are currently applied. Consequently, the cost of electric energy production is calculated by the utility on the power plant basis. The analysis reported the production cost for three years 1990, 1995 and 1996. Year 1990 is a representative year for pre-war conditions with a stable foreign currency exchange rate. In calculating the cost of electricity, 3.612 DM/GJ was used as the utility cost of fuel. The cost of producing hot water and steam was also taken into account.

	1990	1995	1996
Reported Production Cost	10.8 Pf/kWh	12.3 Pf/kWh	11.2 Pf/kWh

We also used the calculated coal production cost to develop the electricity production cost for 1996. Future cost of electricity analysis and project comparison for all power plants is described in Section 7.

26

Section 4 Tuzla Power Station

4.1 OVERVIEW

Thermal power plant (TPP) Tuzla is located west of the town of Tuzla in the center of the coal basin Kreka-Banovici, containing largest mining operation in BiH. The plant consists of six units. The first two 32 MW units were installed in 1963 and 1964. A 110 MW unit was added in 1967. Two 200 MW units were commissioned in 1971 and 1974 and finally, a 215 MW unit was put into service in 1978. The plant also delivers steam for the nearby industries from 32 MW and 100 MW units, and supplies hot water for the city of Tuzla from 100 MW and 200 MW units.

The supply of cooling water comes from the accumulation in lake Modrac through a 12 mile long pipeline. The power plant is connected to electric grid through 220 kV and 110 kV switchyards and to the 400 kV network by the nearby switchyard at Ljubace.

TPP Tuzla uses local coal from the Tuzla Mines. The first five units use a mixture of lignite and brown coal (approximately 70/30 ratio) while the sixth unit is designed to use only brown coal.

Technical characteristics and the recent electricity generation are provided in Tables 4-1a and 4-1b.

Table 4-1a Tuzla Power Plant - Units 1-3

	Unit 1	Unit 2	Unit 3
Construction Year	1963	1964	1966
Installed Capacity (MW)	32	32	110
Net Capacity (MW)	28	28	91
Average Net Capacity in 1990 (MW)	23	23	73
Minimum Net Capacity (MW)	15	15	35
Heat Rate (kJ/kWh at the max. output)	11 354	11 453	11 147
Heat rate (kJ/kWh average for 1990)	14 984	16 520	13 751
Heat Rate (kJ/kWh at the min. output)	17 088	18 708	15 316
Operating Hours	211 500	192 000	203 500
Remaining Life In Years (design)	0	0	0
Working Condition	Operating	Operating	Operating
Fuel	Local Coal	Local Coal	Local Coal
Fuel Calorific Value (kJ/kg - range)	8 512 - 17 053	8 512 - 17 053	10 491
Method of Burning	Pulverized Coal	Pulverized Coal	Pulverized Coal
Net Production (GWh)			
in 1990	121	104	419
in 1995	34	121	227
in 1996	104	44	450

27

Table 4-1b. Tuzla Power Plant - Units 4-6

	Unit 4	Unit 5	Unit 6
Construction Year	1971	1974	1978
Installed Capacity (MW)	200	200	215
Net Capacity (MW)	182	182	198
Average Net Capacity in 1990 (MW)	166	167	170
Minimum Net Capacity (MW)	125	125	115
Heat Rate (kJ/kWh at the max. output)	10 272	10 272	10 232
Heat rate (kJ/kWh average for 1990)	11 916	12 974	11 730
Heat Rate (kJ/kWh at the min. output)	12 372	13 177	12 676
Operating Hours	130 000	120 000	95 000
Remaining Life In Years (design)	9	12	16
Working Condition	Conserved	Operating	Conserved
Fuel	Local Coal	Local Coal	Local Coal
Fuel Calorific Value (kJ/kg - range)	9 937	9 937	15 443
Method of Burning	Pulverized Coal	Pulverized Coal	Pulverized Coal
Net Production (GWh)			
in 1990	953	1 119	1 118
in 1995	-	-	-
in 1996	-	129	-

The initial powre plant asset value was 1 264 million DM, of which 977 million DM is already accumulated depreciation. Current asset value is thus 287 million of which 17 million is calculated depreciation for 1997.

4.2 FUEL SUPPLY

The mines in the Tuzla area produce lignite at the Kreka coal mine and brown coal at the coal mines Banovici and Durdevik. All coal mines use surface and underground mining methods. Coal reserves are indicated in Figure 4-1 for Kreka, and in Figure 4-2 for Banovici and Durdevik coal mines.

The average yearly coal production Figure 4-3 indicates that a total of 6 million tonnes was mined by surface mines and 3 million tonnes came from underground operations for a total of 9 million tonnes per year which was supplied to the Tuzla power station. The quality of the coal ranges from 8 600 kJ/kg for the lignite to over 15 000 kJ/kg for the brown coal. The coal is crushed to minus 80 mm at the mines and transported by rail to the power station. Lignite and brown coal are stored separately in open piles. The lignite piles are equipped with stacker reclaimers.

28

Figure 4-1 Coal Reserves in Kreka Coal Mines

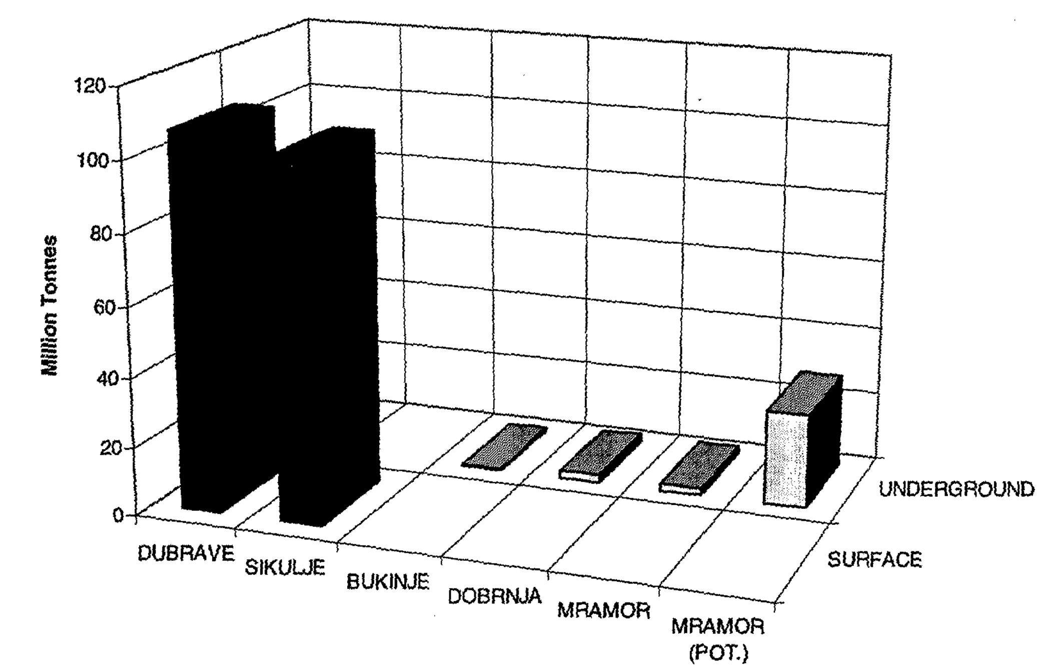
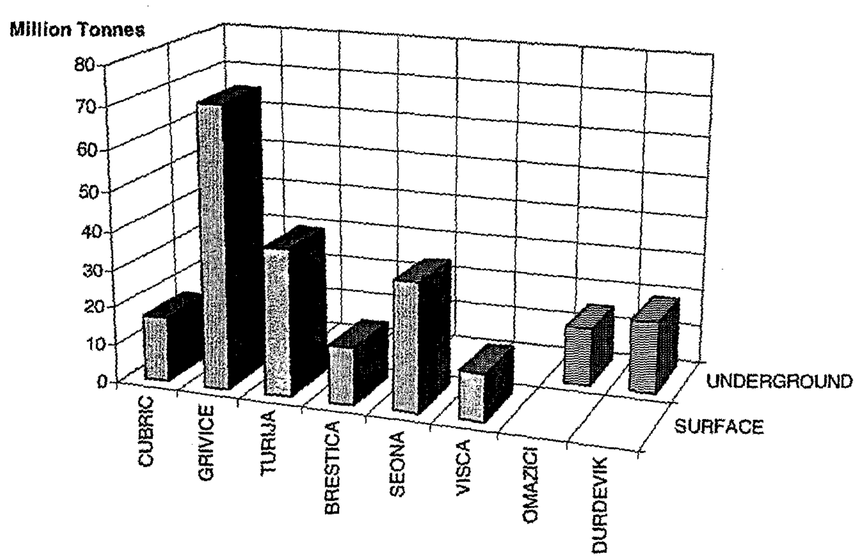
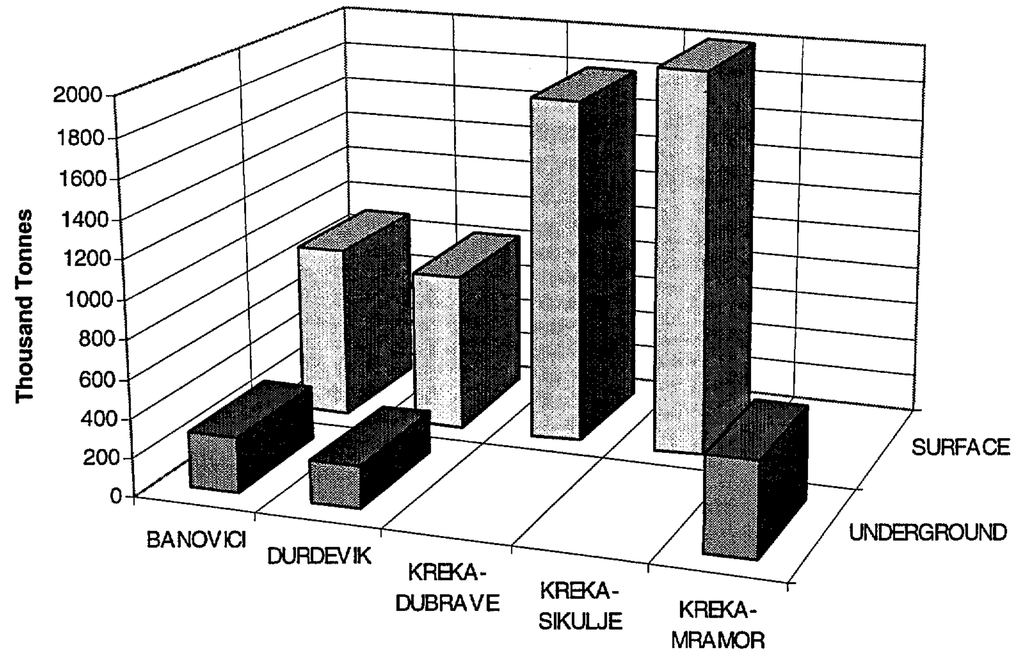


Figure 4-2 Coal Reserves for Banovici and Durdevik Coal Mines



29

Figure 4-3 Target Production Levels in Year 2000



4.3 DISCUSSION OF FUEL SUPPLY CONSTRAINTS

For the targeted production capacities Bechtel estimated the cost of fuel delivered to the power station to be between 4.48 DM/t and 18.32 DM/t.

The surface mines have lower delivered cost of coal, but exceeding the potential cost of imported coal. The lowest cost has been estimated for the Dubrave lignite mine with 4.48 DM/GJ. The mine has sufficient reserves and production potential to satisfy the demand for the Tuzla power station. The Dubrave lignite has a heating value of approximately 9 500 kJ/kg. The boilers that are designed for higher heating value coal may have to be derated to accommodate the lower quality coal. In view of the expected near term lower power demand compared to available generation capacity from the Tuzla power station, derating of the boiler(s) may be more economical than the continued burning of higher quality, but costly fuel from other mines in the area.

Almost every underground mine shows a cost of fuel of over 10 DM/GJ. The quality of this coal is comparatively higher than the lignite. However, the quality is not high enough to compete as an export fuel, or as fuel for other power stations in the Federation or the Republic of Srpska. The use of the fuel for domestic (home heating) and industrial use is feasible to the extend where there is sufficient demand. In the future the brown coal will also have to compete with other more convenient and lower cost fuels such as natural gas and even fuel oil.

30

4.4 FUEL COSTS AS A FUNCTION OF OUTPUT

The analysis provided for the Kakanj power plant fuel supply is also applicable for the Tuzla power plant. Generally, an increase in production will reduce the specific cost of the coal in case the equipment has sufficient reserve capacity, and the increase is combined with an overall productivity improvement of the operation. Bechtel estimates indicate a reduced coal production requirement to satisfy power generation in the future. This reduction will bring most mines below their design capacity. The model also indicates a potential fuel cost of 4.48 DM/t under design conditions for the Dubrave coal mine. This suggests the way to reduce the fuel cost is to increase the production, and improve the calorific value at lower cost mines, and replace higher cost fuel from other sources.

4.5 BASED ON INTRINSIC GEOLOGIC CONDITIONS

The Tuzla area lignite and brown coal reserves are deposited in a synclinal formation. Even though the seams are relatively thick between 4 and 25 meters they are dipping towards the center of the syncline and the overburden to coal ratio increases fast over time and has the average of over 9. Only Dubrave has a ratio of below 4 which is reflected in the lower fuel cost.

4.6 INVESTMENT REQUIREMENTS

Major work planned for 1997 includes:

- Second stage of the rehabilitation work on 100 MW unit to bring the unit to the acceptable level of availability/reliability and to meet principal environmental requirements.
- Prepare and restart one 200 MW unit (Unit 4) to ensure adequate supply of power in 1997 and to serve as a backup source of hot water for Tuzla
- Further conservation and testing of the 215 MW unit (Unit 6).
- Rehabilitation of common systems and equipment.
- Rehabilitation work on the 32 MW units.

Rehabilitation investment estimates, investments in FGD equipment and estimates on the continued operation of units are presented in Table 4-2.

Table 4-2 Investment Requirements at the TPP Tuzla

Unit Name	Capacity (MW)	Total Rehab. Inves. (million DM)	FGD Investment (million DM)	Continue to Operate for Next
Units 1-2	2x32	14	-	7 years
Unit 3	110	76.3	31	10 years
Unit 4	200	97	41	15 years
Unit 5	200	97.2	41	20 years
Unit 6	215	92.9	41	20 years

4.7 COST OF ELECTRICITY

Since the power plant is operated as a single enterprise no per unit cost allocation methods are currently applied. Consequently, the cost of electric energy production was calculated on the power plant basis. The analysis done by Elektroprivreda BiH developed full production cost for three years 1990, 1995 and

31

1996. 1990 is a representative year for a pre-war condition with a stable foreign currency exchange rate. In calculating the cost of electricity 3.612 DM/GJ was used as the utility cost of fuel. The cost of producing hot water and steam was also taken into account.

	1990	1995	1996
Reported Production Cost	8.85 Pf/kWh	10.3 Pf/kWh	10.7 Pf/kWh

Bechtel also used the estimated coal production cost to develop the electricity production cost for 1996. Future cost of electricity analysis and project comparison for all power plants is described in Section 7.

Section 5 Ugljevik Power Station

5.1 OVERVIEW

The Ugljevik coal mine and thermal power plant (TPP) are located in the north-eastern part of BiH approximately 18 km from the city of Bijeljina, and 45 km from the city of Tuzla. The plant is designed as a mine-mouth facility and the coal is transported through the system of conveyors to the power plant. Since the coal is used only for the power plant, the coal mine was developed and operated as part of the electric utility.

The mine and TPP Ugljevik have been built on the Ugljevik coal basin, which has a total reserve of approximately 462 million tonnes. The original technical project of TPP Ugljevik, with two 300 MW units was made on the basis of available coal reserves. The construction of the coal mine and power plant started in November 1977 and the first unit was completed in May 1985. The plant operated until April 1992 when it had to be shut down due to the outbreak of war in BiH, and was restarted again in November 1995. In 1984 construction also started on the second unit and part of the equipment was delivered and is stored at the site. The first unit operates without a flue gas desulphurisation (FGD) plant that was planned to be included with the second unit.

Technical characteristics and the recent electricity generation are provided in Table 5-1.

Table 5-1 Ugljevik Power Plant

	Unit 1
Construction Year	1985
Installed Capacity (MW)	300
Net Capacity (MW)	271
Average Net Capacity in 1990 (MW)	260
Heat Rate (kJ/kWh at the max. output)	11 032
Heat rate (kJ/kWh average for 1990)	12 000
Operating Hours	50 000
Remaining Life In Years (design)	23
Working Condition	Operating
Fuel	Local Coal
Fuel Calorific Value (kJ/kg - range)	10 467
Method of Burning	Pulverized Coal
Production (GWh)	
in 1990	1 665
in 1995	101
in 1996	831

Currently, the power plant operates at a reduced net capacity of 187 MW because of the transmission constraint and the availability of coal. The current heat rate, at the reduced capacity, based on the 1996 electricity and coal production numbers is estimated between 13 000 - 14 000 kJ/kWh.

Between 1986 and 1991, the plant operated for a full year under normal conditions and produced an average of 1 500 GWh a year with an average coal production of 1 752 million tonnes. This translates into an average approximate production of 1.17 kg of coal for each kWh produced during this period.

The initial value of assets (TPP and the coal mine) was 652 million DM. Depreciation in 1996 was 52 million DM and the calculated depreciation for 1997 is 60 million DM.

5.2 FUEL SUPPLY

The Ugljevik power station receives its fuel from the Bogutovo Selo[7] brown coal mine. The mine mouth power station is connected with the mine by a belt conveyor system. Additionally, coal can be transported by truck. The coal is crushed to below 80 mm before transportation. The Bogutovo Selo mine has proven reserves of 38.7 million tonnes which provide sufficient fuel for the first 300 MW block of the power station. Fuel for the projected second block of 300 MW will be supplied by the Ugljevik-East mine, which will mine a continuation of the coal seams exploited at the Bogutovo Selo mine. The project to develop the Ugljevik-East mine and to complete the second 300 MW block at the power station has been interrupted.

The coal has an average heating value of 10 500 kJ/kg. The design capacity of the Bogutovo Selo mine is 1 750 thousand tpy. The mine produced 1 222 thousand tonnes in 1996.

5.3 DISCUSSION OF FUEL SUPPLY CONSTRAINTS

The Bogutovo Selo mine has only one customer, the power station. While this arrangement has the benefit of a long term supply contract, the mining operation depends completely on the operation of the power station. As explained later, negative aspects of such arrangement are experienced at the Gacko power station.

The mine produces brown coal from a 27 m thick coal seam with 180 m of overburden. The overburden to coal ratio is 6.5 [7]. Overburden is removed by shovel and truck in up to 10 lifts. The material is trucked to a disposal area several miles outside the pit area. The Ugljevik-East mine has been planned to use short truck haulage for the overburden to a crushing station at each lift level. After crushing the overburden, it would be transported by an over-land belt conveyor system to a disposal site which can reach a distance of 9 km.

A visit to the Bogutovo Selo pit indicated burning of spoil banks at the mined-out pit areas. Such burns are an environmental hazard and should be controlled. An immediate back fill and reclamation of the mine-out areas following coal removal should be implemented to avoid excessive exposure of residual coal to the environment and its self ignition. The overburden requires some drilling and blasting, and seems rather soft. Such overburden characteristics could allow the use of bucket wheel excavators and cross-pit disposal of the spoil by belt conveyors and spreaders. Such operations are also widely used in the German brown coal mines. This method of mining increases productivity and lowers the operating cost. Such operation may also reduce the vulnerability of the operation to wet season, which presently hinder or even completely stop the mining operation. The power station is equipped with a 200 000 tonne storage area to compensate for such production disruption. However, this could become an overdesigned facility and an unnecessary inventory expense, if the mining operation could be equipped for year-round operation. Excessively prolonged storage of coal at the power station can also cause self

[7] Letter to Bechtel Consulting of April 29, 1997 by J.M.D.P. "Elektroprivreda" Republic of Srpska, Dependent National Enterprise "Mine and Thermal Power Plant"-Ugljevik with Complete Responsibility

ignition of the coal in the stock pile. The storage facility should mainly be used to mix the coal and homogenize the fuel quality. The brown coal has 25% ash, 30 % moisture and contains 4 % sulfur. Eight (8) fan mills are used to pulverize and dry the coal before combustion in the boiler. The life of the fans is approximately 2000 hours signaling high wear characteristics of the fuel.

5.4 FUEL COSTS AS A FUNCTION OF OUTPUT

The Ugljevik power station does not buy the coal from the mine. Fuel costs were determined using Elektroprivreda RS data[7] and information[8], which includes answers to Bechtel's questions. The present production level of 1 222 thousand tpy results in the coal cost of over 47.6 DM/t and the fuel cost of over 5.7 DM/GJ. An adjusted cost for a design production of 1 750 thousand tpy can be estimated as approximately 40 DM/t.

Table VIII of the "Ugljevik Mine and Thermal Power Plant" [8] description presents projections for Ugljevik-East to produce 1 750 thousand tpy for a coal cost of approximately 42.9 DM/t based on average annual mine expenses. This fuel cost translates also into approximately 4.9 DM/GJ. The reported projected cost for Ugljevik-East also includes a "profit" reflecting some social items. These items add up to 25 percent of the total cost, and increase the cost of coal to over 5 DM/GJ.

5.5 BASED ON INTRINSIC GEOLOGIC CONDITIONS

The cost of coal is highly depend on the overburden removal requirement which represents 50 percent of the total cost for the Bogutovo Selo mine. This is the reason why an overburden to coal ratio of over 5 is mostly considered uneconomical for a surface mining operation. On a positive note is that the Bogutovo Selo mine overburden seems to contain very little hard rock. The overburden can be freely dug by excavation equipment without drilling and blasting. Such conditions may allow the use of high capacity equipment such as bucket wheel excavators and cross-pit conveyors to reduce the overburden removal cost. The present system of shovel and truck operation is very labor intensive, consumes costly fuel, and is unreliable during wet seasons. The planned system for Ugljevik-East, namely combining trucks, crushing equipment and belt conveyors, is an improvement over present long distance truck haul conditions, but seems still more costly and weather sensitive than the earlier suggested cross pit conveying system. The coal mines do not have plans for reclamation to dispose of the spoil in an environmentally acceptable manner, and to restore the mined-out areas to their original contours. Such plans must also include the control of the self ignition of discarded coal which is a present problem in the pit of the Bogutovo Selo mine. The cost model assessed an additional 7 DM/t of coal for the reclamation work.

5.6 INVESTMENT REQUIREMENTS

Major work planned at the power plant in 1997 includes:

- Major maintenance and overhaul of the unit

Rehabilitation investment estimate, investment in FGD equipment and an estimate of the continued operation of the unit are presented in Table 5-2.

[8] Ugljevik II Mine & Thermal Power Plant, Power Utility of the Republic of Srpska

Table 5-2 Investment Requirements at the TPP Ugljevik

Unit Name	Capacity (MW)	Total Rehab. Inves. (million DM)	FGD Investment (million DM)	Continue to Operate for Next
Unit 1	300	83	50	23 years

5.7 COST OF ELECTRICITY

Reported cost of power production for year 1990 was at 9.12 Pf/kWh of which approximately 50% was for coal mine and power plant amortization. In 1996 plant and the coal mine operated at the reduced capacity. This operating regime together with the lack of full maintenance during the last couple of years resulted in the increased heat rate. Reduced output also resulted in proportionally higher per unit fixed cost and amortization. For 1996 the reported cost of production was 10.4 Pf/kWh.

Bechtel used the estimated coal production cost to develop the electricity production cost for 1996. Future cost of electricity analysis and project comparison for all power plants is described in Section 7.

Section 6 Gacko Power Station

6.1 OVERVIEW

The Gacko coal mine and thermal power plant (TPP) are located in the south-eastern part of BiH near the town of Gacko. The power complex is designed as a mine-mouth facility and coal is transported through the system of conveyors to the power plant. Since coal is produced exclusively for the power plant, the coal mine was developed and operated as part of the electric utility.

The mine and power plant have been built on the Gacko coal basin, which has a total reserve of approximately 400 million tonnes. The construction of the coal mine and power plant started in 1974 and the 300 MW unit was completed in February 1983. The plant was not adequately designed for the calorific value, and the quality of coal, and had to be operated at reduced capacity. During 1989, the boiler was reconstructed and adjusted to the actual quality of the coal. Throughout the war, due to the further technical difficulties and unavailability of spare parts, the plant operated only sporadically.

Technical characteristics and the recent power generation are provided in Table 6-1.

Table 6-1 Gacko Power Plant

	Unit 1
Construction Year	1983
Installed Capacity (MW)	300
Net Capacity (MW)	240
Average Net Capacity in 1990 (MW)	213
Heat Rate (kJ/kWh at the max. output)	11 200
Heat rate (kJ/kWh average for 1990)	11 200
Operating Hours	50 000
Remaining Life In Years (design)	20
Working Condition	Operating
Fuel	Local Coal
Fuel Calorific Value (kJ/kg - range)	7 200
Method of Burning	Pulverized Coal
Production (GWh)	
in 1990	1 384
in 1995	2
in 1996	-

Between 1984 and 1991, the plant operated under normal conditions and on the average produced 1 157 GWh of electricity using an average of 1 774 million tonnes of coal. This usage translates into an average production of 1.53 kg of coal for each kWh produced during this period.

6.2 FUEL SUPPLY

As TPP Ugljevik has a mine mouth operation, so has the TPP Gacko. The mine is closely coupled with the 300 MW power station by a belt conveyors system which transports the coal from an in-pit crusher to the open storage at the power station. This pile was on fire during the visit in April 1997 indicating the sensitivity of the coal to spontaneous combustion. The power station did not operate for some time and the exposed quantity of coal is significant.

6.3 DISCUSSION OF FUEL SUPPLY CONSTRAINTS

A major constraint is the tendency for the coal to self ignite. This can be avoided by minimizing the storage of the coal as well as compact that coal which must be stored to separate mine and power plant operations. It was observed that the coal seam contains a parting of sandy material which can not be separated before mining. It was also observed that the coal contains a very high amount of limestone. This characteristic would be welcome for fluidized bed boiler operations but not for pulverized coal fired units. The highly alkaline ash after combustion will be soft and sticky causing buildup of ash on the boiler tubes and in the fly ash ducts.

6.4 FUEL COSTS AS A FUNCTION OF OUTPUT

The operation of the mine is tied to the operation of the power station and similar conclusions can be drawn here as were reported for Ugljevik.

6.5 BASED ON INTRINSIC GEOLOGIC CONDITIONS

It seems that the overburden is soft and easily removed. No blasting is required. The seam has a shallow dip which promises the similar overburden to coal ratios for an extended time. The topography is flat.

Sulfur content in the coal is up to 0.9%, and the ash analysis had shown that the CaO content is between 70-80%. High CaO content is the result of the coal burning process that reduces the SO2 emission to the environmentally acceptable level. Consequently, flue-gas desulfurization equipment is not planned for the power plant.

6.6 INVESTMENT REQUIREMENTS

The unit had just finished major repair and started operation in May. Rehabilitation work planned in the near future includes:

- reconstruction of the ash storage and rehabilitation of the ESP system.

Rehabilitation investment estimate, investment in FGD equipment, and an estimate of the continued operation of the unit are presented in Table 6-2.

Table 6-2 Investment Requirements at the TPP Gacko

Unit Name	Capacity (MW)	Total Rehab. Inves. (million DM)	FGD Investment (million DM)	Continue to Operate for Next
Unit 1	300	18	-	27 years

6.7 COST OF ELECTRICITY

Since the plant did not operate under normal conditions for a long period of time during 1996 and 1997, the current cost of production is unavailable. However, we used available numbers to estimate the cost of production under normal conditions.

Reported cost of power production, by the plant management, for the year 1990 was 8.91 Pf/kWh. Out of this amount approximately 30% was for the power plant amortization. The lack of full maintenance during the last couple of years also resulted in the increased heat rate.

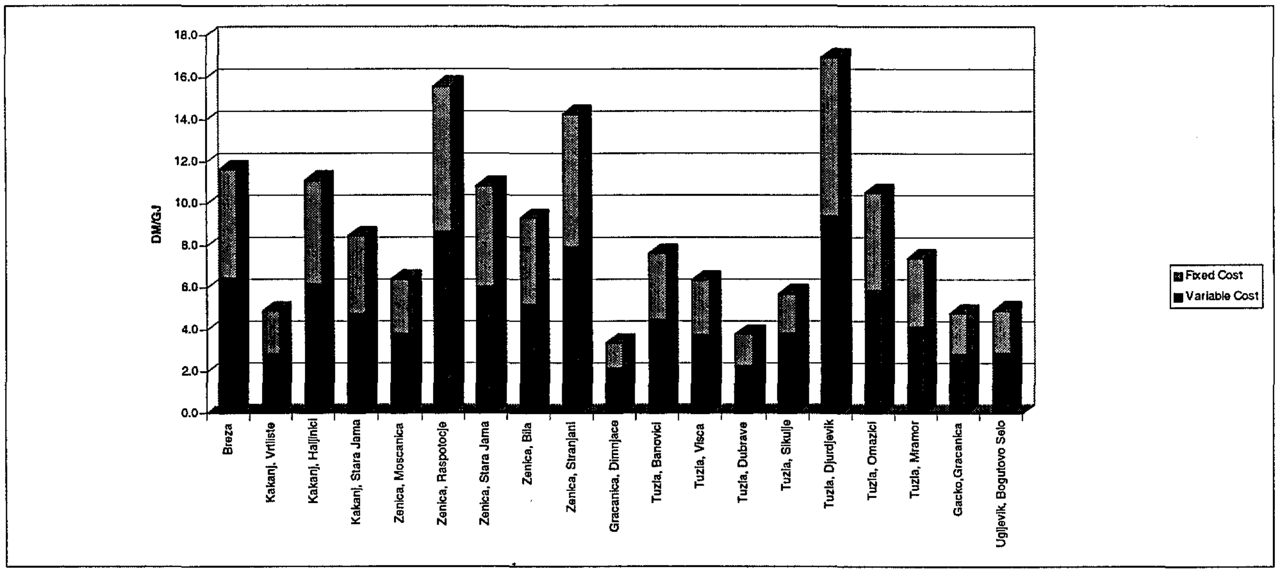
Future cost of electricity analysis and project comparison for all power plants is further described in Section 7.

Section 7 Fuel and Power Cost Summary

7.1. FUEL COST SUMMARY

The cost of fuel from most domestic mines was calculated using a model described in Appendix A. This section provides a summary of results. Figure 7-1 shows fixed and variable costs at design production levels. Fixed costs have been defined as depreciation and operating margin (taxes and profit) and all other costs have been taken to be variable.

Figure 7-1 Comparison of Brown Coal and Lignite Cost at Design Production Levels



Only one mine is able to deliver fuel to power plants at a cost less than the regulated price of 3.612 DM/GJ based on design production levels, and that is the Dimnjace coal mine at Gracanica. The Dubrave (Kreka) coal mine at Tuzla has estimated costs which are only slightly higher at its design output.

The cost of delivering imported coal to domestic power plant is estimated at 4 DM/GJ. The two mines identified are also the only ones that are clearly competitive with imported coal. They presently represent approximately 18% of the design production capacity for all of Bosnia and Herzegovina.

An additional six mines have variable costs which are 4 DM/GJ or less. These are:

- the surface mine at Kakanj (Vrtliste)
- the Moscanica mine in Zenica
- the Visca and Sikulje (Kreka) mines at Tuzla
- the Gracanica mine at Gacko
- the Bogutovo Selo mine at Ugljevik

These mines represent an additional 50% of the design production capacity of Bosnia and Herzegovina. Together, the eight mines noted are the primary sources of fuel for thermal power plants. Even the variable costs of the remainder of mines are higher than the cost of imported coal.

The production in 1996 was at a fraction of design levels as shown in Figure 7-2. Reduced production has increased per unit cost of coal for all coal mines.

Figure 7-2 Production Levels

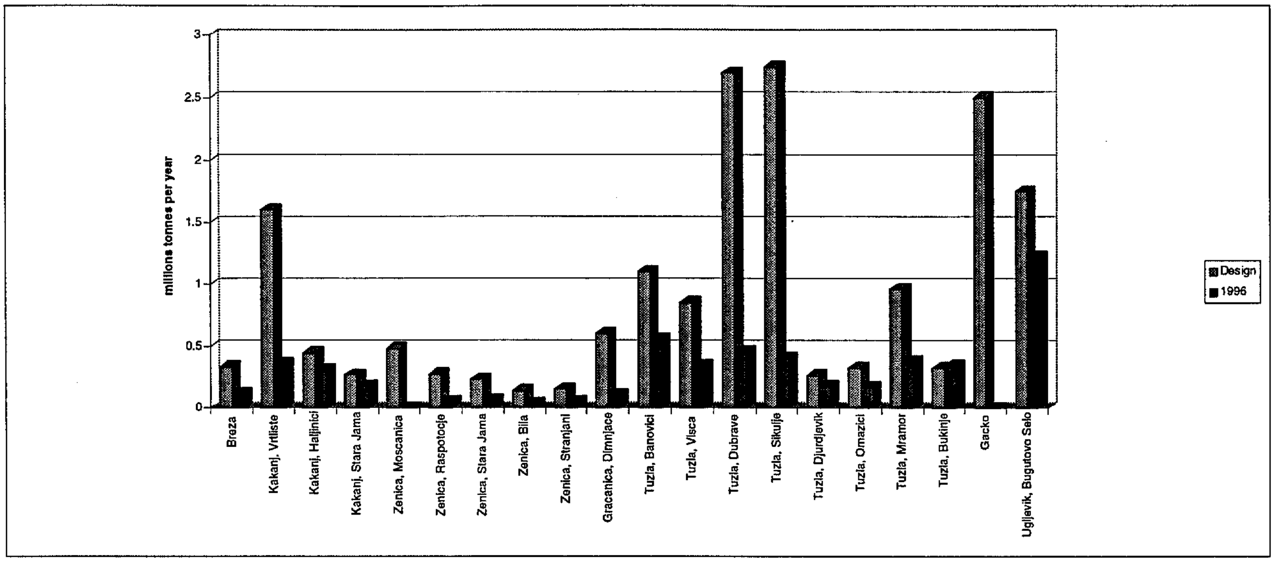
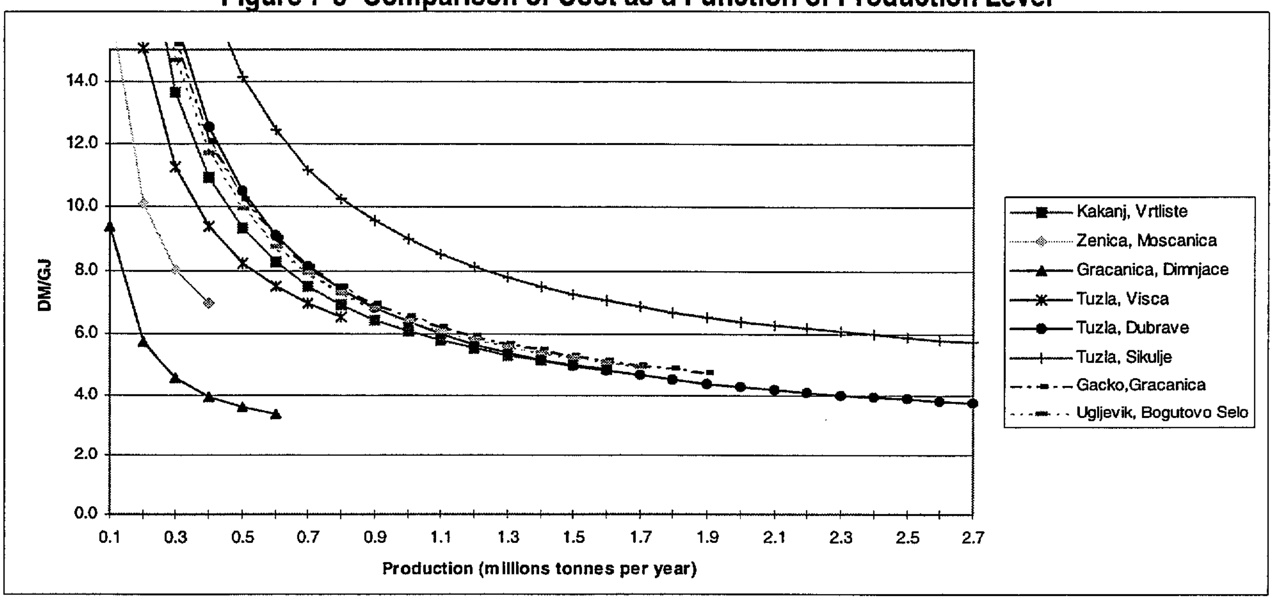


Figure 7-3 shows the estimated cost for fuel from selected mines as a function of production level. This figure is based on the fixed and variable cost relationship shown in Figure 7-1.

Figure 7-3 Comparison of Cost as a Function of Production Level

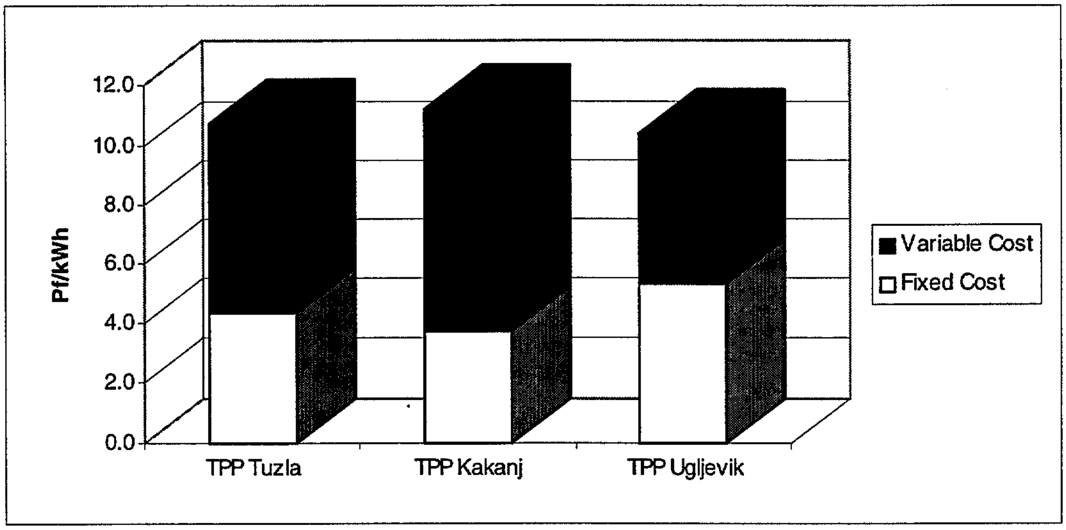


41

7.2. HISTORICAL COST OF ELECTRICITY SUMMARY

The cost of electricity is a sum of fixed and variable cost components. Fixed operating costs are essentially independent of the actual generation, or number of hours of operation, and are generally expressed in DM/kW-year. The major components of fixed cost is depreciation and return on investment (i.e. profit). Since EPBiH and ERS has operated at a loss, depreciation is the only component of historical fixed costs. Variable costs are costs directly proportional to the amount of kilowatts produced. Variable costs are generally expressed in DM/MWh or Pf/kWh. Figure 7-4 shows the breakdown of fixed and variable costs for thermal plants in 1996 based on reported values. (Note: TPP Gacko did not operate during 1996.)

Figure 7-4. Breakdown of Fixed and Variable Costs for 1996

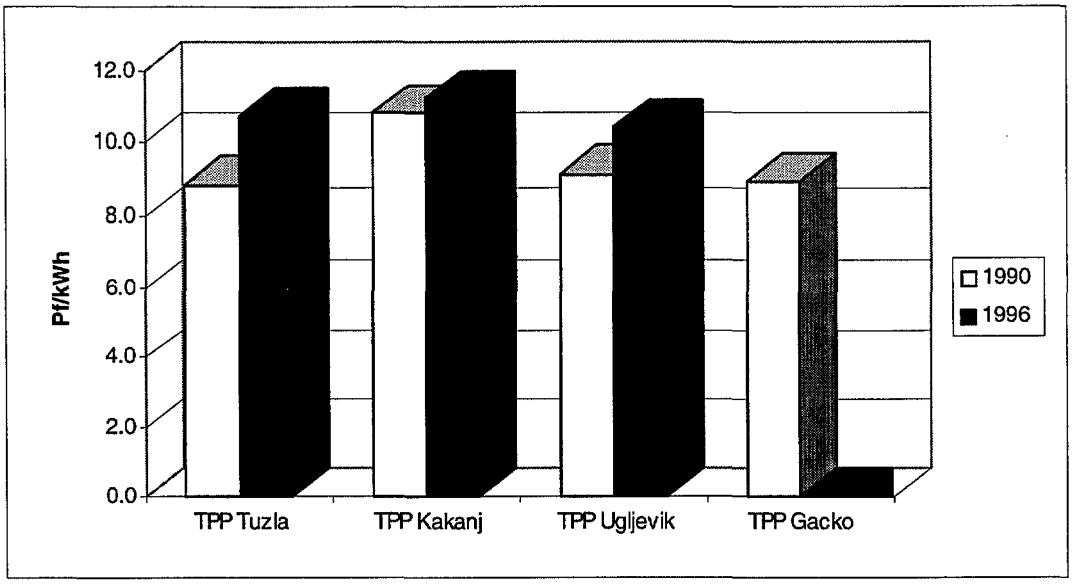


Because of fixed cost, lower levels of production result in higher per unit costs of electricity. Figure 7-5 shows 1990 and 1996 reported costs. The higher costs of electricity in 1996 are due to the drop in productions levels.

The reported cost do not necessarily reflect the true economic cost. For example, opportunity cost of capital is a true economic cost. However, if a utility operates at a loss, reported costs do not reflect profit. Reported costs reflect the regulated price of fuel which may, or may not, be a reflection of true economic cost of coal.

It is important to note that the historical costs are presented only to indicate past and current cost levels. Future incremental and full costs of electricity are developed based on the rehabilitation costs, on technical characteristics of each unit, on the remaining asset value, and on the calculated fuel supply cost described in chapter 7.1 and Appendix A.

Figure 7-5. Comparison of 1990 and 1996 Reported Costs



7.3. FUTURE COST OF ELECTRICITY ANALYSIS

The power production from all coal-fired units was calculated using a model and the input data described in Appendix B. This section provides a summary of results.

As stated in the coal production summary, it is not projected that the current very high coal production cost will continue in the future. When evaluating the future cost of electricity, the long-term projection for coal cost were used, assuming that the mining sector is optimized to the power plant production levels. We also estimated the rationalization of the coal mining sector, so that the future coal supplies will come from the least expensive source at each location. Finally, we made a comparison of the cost of electricity from existing power plants, with the necessary rehabilitation investment, with the cost of electricity from new power projects using local and imported fuel.

7.3.1. Rehabilitation Options

A number of rehabilitation options were considered at the pre-conceptual level to determine the cost of electricity generation from thermal power plants. These are summarized below.

Option	Total Investment (DM/kW)	FGD Investment (DM/kW)	Life Extension (years)	Capacity Factor After Rehab.	Heat Rate After Rehab. (kJ/kWh)
Tuzla 32 MW units	219	-	7	65	15 575
Tuzla 110 MW Unit 3	694	282	10	78	11 700
Tuzla 200 MW Unit 4	485	205	15	78	11 900
Tuzla 200 MW Unit 5	486	205	20	78	11 900
Tuzla 215 MW Unit 6	432	191	20	78	11 700
Kakanj 32 MW Units 1-4	156	-	7	65	15 575
Kakanj 110 MW Unit 5	605	291	13	75	12 400
Kakanj 110 MW Unit 6	554	291	21	78	12 000
Kakanj 230 MW Unit 7	388	183	25	82	11 000
Ugljevik 300 MW Unit 1	277	167	23	80	12 000
Gacko 300 MW Unit 1	60	-	27	80	11 200

7.3.2. *Fuel Cost*

Mines were selected for each power plant and cost of coal from these mines were based on the Target 2000 level of production. The mines were selected on the basis of least cost with adequate production supply capacity. The selected mines and associated costs are summarized below.

Plant	Mine Assumed to Supply	Target 2000 Production Level (basis for cost of electricity analysis)	Estimated Cost of Production
		(thousand tonne/year)	(DM/GJ)
Kakanj 1-7	Vrtliste	1800	4.66
Tuzla 1-6	Dubrave	1800	4.48
Tuzla 7	Visca	820	6.47
Gacko 1	Gracanica	2000	4.72
Ugljevik 1	Bogutovo Selo	1750	4.92

44

7.3.3. Comparison With New Plants

For comparison purposes, the cost of electricity from three new plant options was considered. Generally speaking, for a rehabilitation option to be justified on an economic basis, its per unit incremental investment and operating costs should be less than the cost of electricity from new plant options. New plant options considered in this study are shown below.

Technology	Investment (DM/kW)	Fuel	Fuel Cost (DM/GJ)	Capacity Factor (%)	Heat Rate (kJ/kWh)
Circulating Fluidized Bed	2640	Local Coal	4.48	87	10 000
Combined-Cycle Plant	1400	Imported Gas	5.45	90	8 500
Pulverized Coal	2475	Imported Coal	4	88	10 100

The local coal cost use was based on the projected cost of production at Vrtliste. The cost of gas was based on imports from Russia, and imported coal reflects bituminous coal imported on the world market. The price of imported gas from Russia throughout Europe is directly negotiated with the Russian exporter on a case by case basis. Recent experience with gas contracts shows that a reasonable assumption is to use the price of 3.3 $/GJ or 5.45 DM/GJ.

The imported coal cost was estimated considering delivery of coal to a potential port at Ploce on the Adriatic coast with subsequent rail transport to, for example, Kakanj. World coal prices have been very stable and coal could probably be landed for approximately 70 DM per tonne. Rail transportation from Ploce to Kakanj is estimated to cost approximately 0.15 DM per tonne per km or 30 DM per tonne (200 km). Imported coal should have a heating value of 25 000 kJ/kg. The delivered fuel cost would cost 4.00 DM per GJ. Another coal import route would be over the Danube/Sava river route, starting at Constanca on the Black Sea to Bosanski Samac. The transport would be by river and by railroad. This route would be more complex and costly since it has an additional river transportation segment, passes through different countries and requires two coal transfers.

7.3.4. Incremental Cost Of Electricity

Figure 7-6 presents the incremental cost of electricity analysis for the coal cost based on the Target 2000 production level. Results show that none of the rehabilitation projects provide an inexpensive alternative. Incremental costs, or in case of new projects corresponding full electricity costs, are above 8 Pf/kWh.

Incremental costs of electricity for rehabilitation projects do not include depreciation costs for the existing equipment. When calculating future costs, comparing the cost with the new power plant, or when making decisions about the future investments, the value of the existing equipment should not play any role. Loans on the existing assets will have to be paid in the same amount disregards of how the unit or power plant will operate in the future. Consequently, decision on future investments should be exclusively based on the analysis and comparison of the future cost of electricity.

Sensitivity analysis was performed for the lower 8% opportunity cost of capital. Results are presented in Table 7-1. As expected, under this assumption there is an overall reduction in costs. New power projects

45

have the biggest reduction, thus increasing their competitiveness with the rehabilitation projects. The resulting cost reduction is mostly attributed to the decrease in the capital investments cost.

Table 7-1 Discount Rate Sensitivity Analysis

Option	Incremental Production Costs - 12 % Discount Rate (Pf/kWh)	Incremental Production Costs - 8 % Discount Rate (Pf/kWh)
Circulating Fluidized Bed	12.91	10.70
Combined-Cycle Plant	8.48	7.50
Pulverized Coal	11.49	9.44
Tuzla 32 MW units	10.19	9.90
Tuzla 110 MW Unit 3	12.97	11.50
Tuzla 200 MW Unit 4	9.67	8.91
Tuzla 200 MW Unit 5	9.15	8.47
Tuzla 215 MW Unit 6	11.07	10.51
Kakanj 32 MW Units 1-4	9.74	9.50
Kakanj 110 MW Unit 5	10.78	9.90
Kakanj 110 MW Unit 6	9.36	8.60
Kakanj 230 MW Unit 7	8.14	7.64
Ugljevik 300 MW Unit 1	9.34	8.60
Gacko 300 MW Unit 1	8.32	7.70

7.3.5. Full Cost Of Electricity

The incremental costs of electricity do not reflect depreciation and opportunity cost of capital associated with existing assets. The effect of existing asset costs were added to the incremental costs to obtain the full cost of electricity. The full cost of electricity can be compared with historical, or accounting, costs. Again, full cost should not be used for making economic or operational decisions.

The full cost of electricity is calculated from the incremental cost by adding a portion of the fixed cost associated with the original and subsequent investments in the power plant, reflected in the power plant asset value. Based on the asset value and the expected life of the unit, a calculation was made to determine fixed cost needed for depreciation, and the return on the investment. In our case return on the investment rate is based on the assumed opportunity cost of capital.

For TPP Ugljevik and TPP Gacko an estimate of current assets value was made based on the initial asset value, and the remaining life of each unit. For TPP Tuzla and TPP Kakanj the current asset value is known for each plant, but not at the unit level. An allocation was made based on capacity of each unit and the remaining years of accounting life.

The results are presented in Figure 7-7 and show a substantial increase in cost of electricity for most of the newer existing units. For units operating beyond their accounting life there was no increase in costs, as the units are assumed to be fully depreciated over time.

7.4. IMPLICATION FOR FUTURE ENERGY STRATEGY PLANNING

7.4.1. Exports

The incremental cost of electricity, even for the most attractive rehabilitation projects, is above 8 Pf/kWh. When looking at exports of electric energy, surplus of production capacity should always be considered for power sale to the interconnected utilities. If exports are priced above the variable cost of electricity, they potentially reduce part of the charges domestic customers have to pay to cover for the power plant fixed costs. However, long term power project development arrangements designed only for exporting power should be based on the full cost of electricity. Also, when there is an opportunity, power could be imported if the cost is lower that the variable cost of electricity. However, these arrangements fall into the short term arrangements of all interconnected utilities.

7.4.2. Demand Forecast

Before the war, electricity generation and consumption in BiH was at comparatively high levels. Demand forecast for electricity should analyize developements for two major customer groups: households and industry. Industry sector in BiH was dominated by the electricity intensive industries. If the electricity is priced to cover the full cost of production, transmission and distribution, part of industry sector will not be able to continue economical operation. Similar effect is thrue for the households, where electricity price increases are followed by the decreases and rationalization of the electricity consumption.

7.4.3. Consideration of All Generation Options

When considering the thermal power plant rehabilitation options, each utility should compare the economics of thermal generation with the economics of other generation, or demand-side management, options. As an example, preliminary analysis from local experts indicates that a number of the remaining hydro sites could be developed to produce energy at the cost close, or below, 9 Pf/kWh.

7.4.4. Coordination of Costs with Mine Sector Restructuring Study

As presented in this report, mining costs are very dependent on the coal production levels. Coal production in BiH is driven by the power production needs, so mining sector restructuring study should be closely coordinated with the power sector development study. Once the demand projections, and the future power generation requirements are better assessed, production and the quality of coal could be optimized. When assessing the cost of production for the Target 2000 production level, we anticipated this optimized scenario.

Figure 7-6 Incremental Cost of Electricity

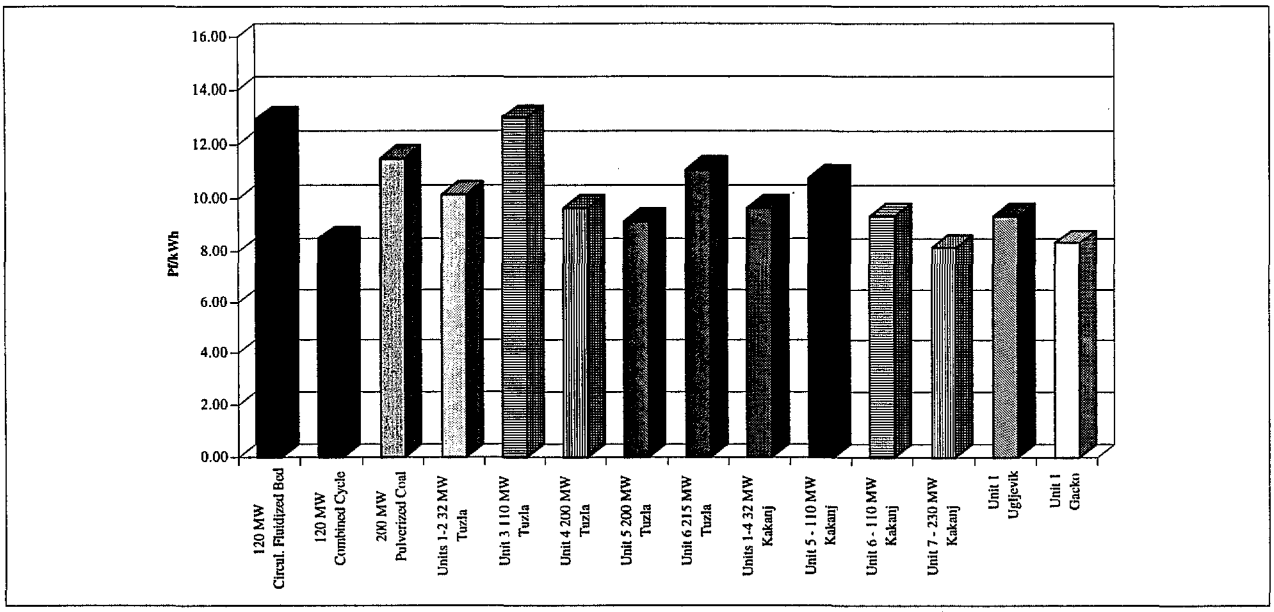
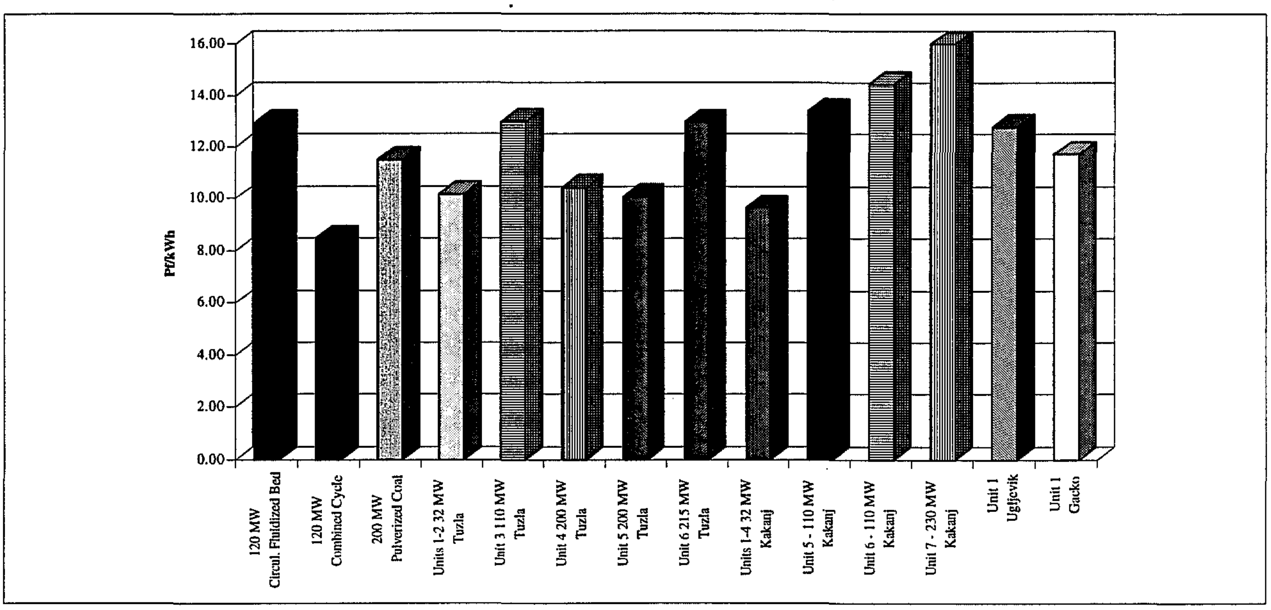


Figure 7-7 Full Cost of Electricity



Section 8 References

1. Elektroprivreda BiH, "1996 Annual Report"
2. BiH Ministry of Energy, Mining and Industry, "Rehabilitation, Reconstruction and Erection Program of Power Sector of Federation of Bosnia and Herzegovina in 1997".
3. Elektroprivreda RS, "1996 Annual Report"
4. Ugljevik II Mine and Thermal Power Plant
5. Middle Bosnia Mines, "1996 Financial Results"
6. Price Waterhouse, "Electric Power Sector Strategic Alternatives", August 1997
7. PMAG : "1997 Middle Bosnia Mines Funding Priorities"
8. PMAG : "1997 Tuzla Mines Funding Priorities"
9. Tuzla Mining Institute, "Projection of Coal Supply Options for TPP Tuzla", May 1997
10. Tuzla Mining Institute, "Projection of Coal Supply Options for TPP Kakanj", May 1997

49

Appendix A
Fuel Cost Model

Appendix A Fuel Cost Model

This appendix provides a description of the model used to estimate fuel cost for the Coal and Thermal Power Plant study. The appendix includes the following items:

- Model overview
- Demonstration of model using data obtained for study
- Comparison of model results with those obtained by Tuzla Mining Institute
- Estimation of the cost of imported coal

The model is a spreadsheet based tool (Excel 5), and is provided with the report for further use, revisions, and analyses.

A.1 MODEL OVERVIEW

Bechtel prepared a model to estimate the cost of fuel from domestic mines to the thermal power stations in the Federation and the Republic of Srpska. The cost structure of the industry was developed for design production levels, then applied to different levels of production.

A.1.1 Design Production Level

Six direct cost areas were considered- overburden removal (for surface mines only); mine reclamation (for surface mines only); coal or lignite removal; in-mine transport; preparation; and transportation from mine to power plant.

The associated average capital investment associated with the direct cost for the design production level was estimated and the required operating margin was calculated. The operating margin is the economic return on investment. It is equal to the opportunity cost of capital times the average capital investment. An opportunity cost of capital of 12% was assumed. From a financial standpoint the operating margin is used to pay interest on loans, taxes, and contribute to profits. This procedure is shown in Figure A-1.

As shown, transportation costs were considered to be outside the responsibility of the organizations considered. Therefore, the direct costs used included an allowance for the operating margin for the separate transportation enterprise.

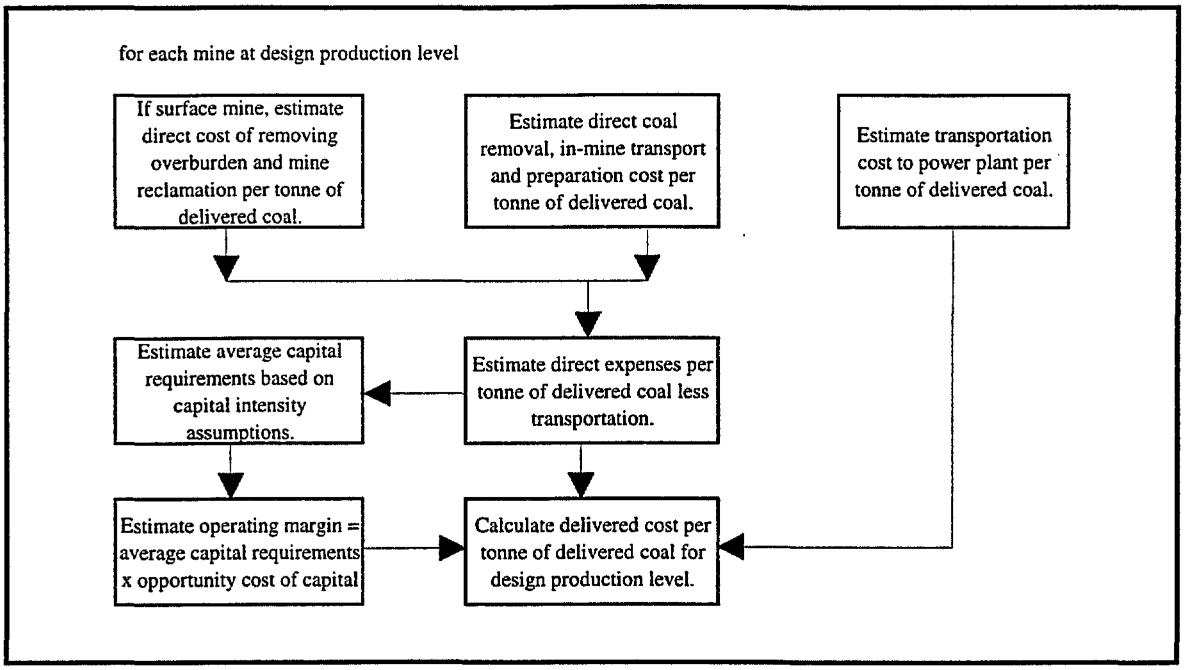
This delivered coal cost estimate based on design production levels was used as a basis for calculated cost at other production levels as will be discussed in the next section.

A.1.2 Cost as a Function of Production Level

Current production levels are currently much lower than design levels and future production requirements may well not correspond to original mine designs. Therefore, it is important for the model to reflect costs at other than design production levels. Costs at different production levels were calculated based on two key assumptions- the average capital investment would not change and, in the case of surface mines, the ratio of overburden removal to coal removal would defined by the overburden ratio.

51

Figure A-1 Fuel Cost Estimation Approach for Design Production

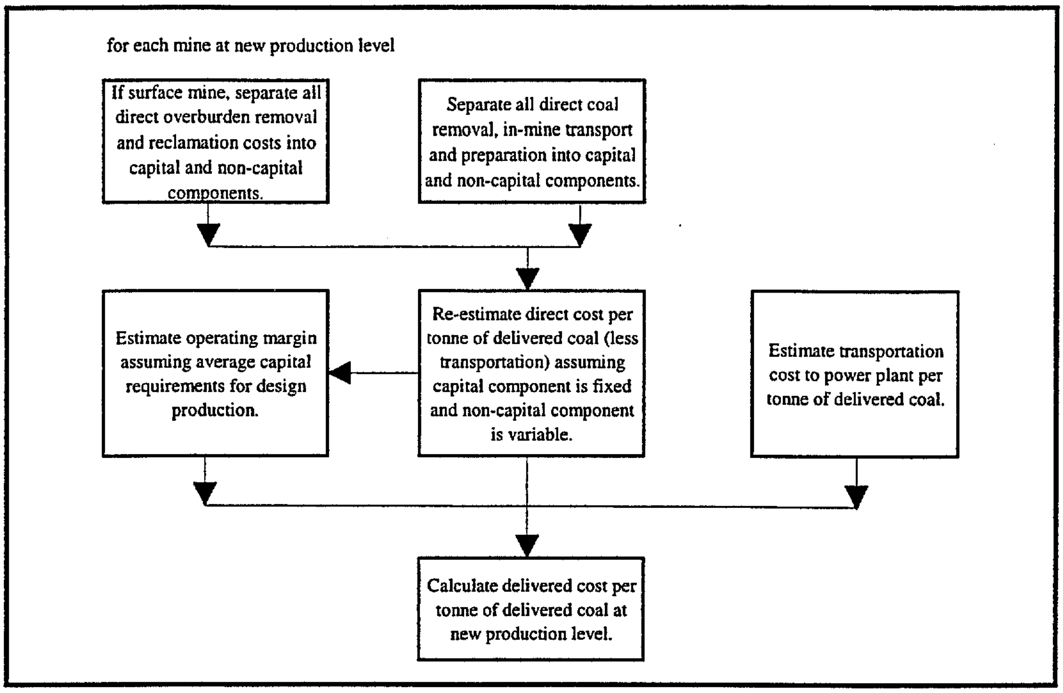


These assumptions are key because radical changes in production can be met by different strategies. For example, sustained low production would likely result in lower capital investment over the long term because equipment would not be replaced. Likewise, changes in production can be met by varying the ratio of overburden to coal removal for periods of time (e.g., during the war overburden removal was suspended altogether at Kakanj).

Two production levels other than design are defined. The current level (1996 level) is characterized by low production with the burden of capital investment based on design production levels. An addition production level, referred to as Target 2000, was used to define a future production level (at year 2000). This future level was selected to respond to our belief that future coal demand will differ from current demand, and from the demand for which existing mines were designed. However, it was selected without a detailed forecast and without consideration of mining sector rationalization, both of which are outside the scope of this study.

Figure A-2 shows the procedure used in calculating fuel costs at the different production levels.

Figure A-2 Re-Estimation of Fuel Costs at Other Than Design Production Levels



A.2 DEMONSTRATION OF MODEL

A.2.1 Data and Assumptions

Bechtel assessed the available information and developed delivered coal cost for most active coal mines. The Bechtel team also visited the power stations, four surface mines and one underground mine. The impressions and discussions at the scene with mining personnel enhanced the fuel cost assessment effort. Data was obtained the Middle Bosnia Mines, Tuzla Mines, ERS, Tuzla Mining Institute, and various studies sponsored by donor nations. Bechtel distributed questions about the coal mining operations to the mining companies, ERS, and the Tuzla Mining Institute.

In addition, Tuzla Mining Institute developed detailed information on each mine in the Federation. This information included a projection of costs, including profit and taxes, for a specific mine plan and forecast production level for each mine. The Bechtel model utilized some of the basic information supplied in the Tuzla Mining Institute projection, as will be identified in this appendix. However, the approach was somewhat different and represents an independent cost estimate. Bechtel and Tuzla Mining Institute results are compared for key fuel sources.

General mine data that was not used directly in cost calculations is display in Table A-1. Key data used in calculations is shown in Table A-2. The column labels in Table A-2 are used to describe calculations in later tables.

Table A-1 General Mine Characteristics

Mine Group / Mine	Reserves (millions tonnes)	Power Plant Supplied	Mine Type	# of Seams	Thickness (m)	Overburden Thickness (m)	Mining Method
Breza							
Sretno	25	Kakanj	underground	1	5	na	long wall
Kamanica		Kakanj	underground	1	5.5	na	na
Kakanj							
Vrtliste	60	Kakanj	surface	1	4 - 20	70 - 80	drill, blast, shovel & truck
Haljinici	na	Kakanj	underground	na	6 - 8	na	long wall
Stara Jama	na	Kakanj	underground	na	6 - 8	na	long wall/room & pillar
Zenica							
Moscanica	na	Kakanj	surface	2	5.6 - 9	na	shovel & truck
Podbrezje	na	Kakanj	surface	na	na	na	na
Raspotocje	38	Kakanj	underground	5	3 - 8	na	long wall
Stara Jama	22	Kakanj	underground	7	3 - 14	na	long wall/room & pillar
Bila	22	Kakanj	underground	2	6 - 8	na	room & pillar
Stranjani	na	Kakanj	underground	5	3 - 14	na	room & pillar
Gracanica							
Dimnjace	14	Kakanj	surface	na	14	30	shovel & truck
Tuzla							
Banovici	140	Tuzla	surface	1	18	80 - 150	drill, blast, shovel & truck
Visca	12	Tuzla	surface	1	4 - 25	60 - 240	drill, blast, shovel & truck
Dubrave	107	Tuzla	surface	3	20/20/12	30/25/2015	bucketwheel
Sikulje	102	Tuzla	surface	2	7/8	80/25	dragline/bucketwheel
Djurdjevik	19	Tuzla	underground	1	25	na	long wall/room & pillar
Omazici	15	Tuzla	underground	1	18	na	room & pillar
Mramor	27	Tuzla	underground	4	11	na	long wall/room & pillar
Bukinje	1	Tuzla	underground	4	10	na	room & pillar
Gacko	25	Gacko	surface	3	17	50	shovel/conveyor
Ugljevik							
Bogutovo Selo	38	Ugljevik	surface	1	27	180	truck & shovel

A.2.1.1 Overburden Removal

Bechtel used a cost for overburden removal of between 4 DM per cubic meter and 6 DM per cubic meter for the surface mine operation, depending on the estimated difficulty to dig the overburden.

A.2.1.2 Reclamation

A reclamation cost of 1.1 DM per cubic meter of overburden was added for all surface mines.

A.2.1.3 Coal Removal

Coal removal cost after exposure of the coal seam was estimated uniformly as 4 DM per tonne mined for all surface mining operations.

For underground operations Bechtel used the projected cost by the Tuzla Mining Institute[1] as cost to remove the coal from the face under design conditions. Present and expected cost were calculated based on available production data.

[1] Mining Institute Tuzla: "Middle Bosnia Mines" Kakanj, TE "Kakanj" in Kakanj, and "Coal Mines Tuzla" TE Tuzla in Tuzla, Tuzla, May 1997

Table A-2 Key Economic Data

Mine Group *Mine*	Capacity (thousand tonnes mined /year)	*Design*	*Current*	*Target- 2000*	Overburden Removal Cost (DM/m^3)	Average Overburden Ratio	Reclamation Cost (DM/1000 m^3 of overburden)	Coal Removal Cost (DM/tonne mined)	In-Mine Transport (DM/tonne mined)	Mined Quality (GJ/tonne)	Delivered Quality (GJ/tonne)	Preparation Cost (DM/tonnedelivered)	Preparation Cost (DM per GJ/tonne Quality Improvement)	Transportation Distance (km)	Transportation Cost (DM/tonne delivered/km)
Label		A1	B1	C1	D1	E1	F1	G1	H1	I1	J1	K1	L1	M	N1
Breza		330	111	420	na	na	na	150.6	6.29	17.7	21	2	0.6	30	0.15
Kakanj															
Vrtliste		1600	355	1800	6.0	5.57	1.1	4	4.2	12.4	15	2	0.3	7	0.15
Haljinici		444	307	300	na	na	na	105.2	0	12.6	15	2	0.2	30	0.15
Stara Jama		265	170	250	na	na	na	91.61	7	15.1	15.7	2	0.2	10	0.15
Zenica															
Moscanica		480	-	390	5.0	9.53	1.1	4	4	13.5	13.5	2	0.2	35	0.15
Raspotocje		270	50	200	na	na	na	235.3	7	20.1	20.7	2	0.2	35	0.15
Stara Jama		230	60	210	na	na	na	158.2	7	19.9	20.7	2	0.2	35	0.15
Bila		140	30	100	na	na	na	105.3	7	16	16.8	2	0.2	35	0.15
Stranjani		150	50	125	na	na	na	177.1	7	16.9	17.7	2	0.2	35	0.15
Gracanica															
Dimnjace		600	100	600	5.0	1.66	1.1	4	4.2	11	12.5	2	0.2	100	0.15
Tuzla															
Banovici		1100	550	900	6.0	9.95	1.1	4	6	14	15	2	0.2	35	0.15
Visca		850	340	820	6.0	9.5	1.1	4	4	15	15	2	0.3	20	0.15
Dubrave		2700	455	1800	4.5	3.62	1.1	4	4	10	9.72	2	0.3	5	0.15
Sikulje		2750	400	2000	5.0	5.75	1.1	4	4	9	8.63	2	0.3	20	0.15
Djurdjevik		260	170	220	na	na	na	179	7	14	19.6	2	0.3	20	0.15
Omazici		325	165	285	na	na	na	114	7	15	16.7	2	0.2	35	0.15
Mramor		960	380	485	na	na	na	61	7	12	12.1	2	0.2	12	0.15
Gacko															
Gracanica		1,900	1,500	2,000	4.8	3.2	1.1	4	4	7	7.2	2	0.2	2	0.15
Ugljevik															
Bogutovo Selo		1,750	1,222	1,750	4.0	6.54	1.1	4	4	11	10.5	2	0.2	2	0.15

A.2.1.4 In-Mine Transport

A cost of 4.20 DM per tonne mined was added for in-mine transportation for all surface mines. A cost of 7 DM per tonne was added for most underground in-mine transportation to arrive at a design, present and expected coal cost at the mine fence expressed in DM per tonne.

A.2.1.5 Preparation

Bechtel added the cost for coal preparation by assessing the existing or planned operations, and estimating the preparation cost per tonne of clean coal. Where data was not available, quality improvements were estimated. A charge of 2 DM per tonne of delivered coal was charged for crushing at all mines.

For those mines where coal preparation involves improvement in coal quality, an additional charge from 0.2 DM per GJ/tonne to 0.6 DM per GJ/tonne of heat content improvement from mined to delivered coal (i.e., .0002-.0006 DM per kJ/kg improvement) was added.

A.2.1.6 Transportation from Mine to Power Plant

The transportation distances were estimated to bring the coal to the power stations. The cost of coal transportation was estimated at 0.15 DM per tonne and km.

A.2.2 Cost at Design Production

A.2.2.1 Direct Costs

Based on these assumptions, the direct costs for overburden removal, reclamation, coal removal, in-mine transport, preparation and mine-to-plant transport was calculated for production at design levels, as shown in Table A-3. Two lines are added to describe the calculation. The Label line labels the columns and the Description line provide the formulas for the calculations. The formulas for overburden removal and reclamation cost are based on an assumption of 0.97 cubic meters of overburden removed per tonne of coal.

A.2.2.2 Capital Requirements

Capital requirements were based on the estimated direct costs, and assumptions on the capital intensity of each of the cost components. This is shown in Table A-4. The formulas reflect the fact that production levels in Table A-2 are expressed in terms of mined coal, and costs in Table A-3 are expressed in terms of delivered coal.

A.2.2.3 Total Costs

The required operating margin was calculated based on a 12% opportunity cost of capital times the average net fixed assets over the operation of the mine. For purposes of this simplified calculation, average net fixed assets were taken to be one half of capital requirements estimated in Table A-4. In Table A-5 the operating margin is expressed in terms of DM per tonne of delivered coal, and added to the direct costs to obtain to total revenue required to cover the full cost of delivered coal. The full cost of delivered coal is also expressed in terms of the heat content (DM/GJ).

56

Table A-3 Direct Costs at Design Production Level

	Overburden Removal	Reclamation	Coal Removal	In-Mine Transport	Preparation	Transport to Power Plant	Total Direct Cost
Mine Group *Mine*	(DM/tonne coal delivered)						
Label	A2	B2	C2	D2	E2	F2	G2
Description	0.97*D1*E1*J1/I1	0.97*E1*F1/1000*J1/I1	G1*J1/I1	H1*J1/I1	K1+(J1-I1)*L1	M1*N1	SUM(A2:F2)
Breza	0.0	0.0	178.7	7.5	4.0	4.5	194.7
Kakanj							
Vrtliste	39.2	7.2	4.8	5.1	2.8	1.1	60.2
Haljinici	0.0	0.0	125.4	0.0	2.5	4.5	132.4
Stara Jama	0.0	0.0	94.8	7.2	2.1	1.5	105.6
Zenica							
Moscanica	46.3	10.2	4.0	4.2	2.0	5.3	71.9
Raspotocje	0.0	0.0	242.3	7.2	2.1	5.3	256.9
Stara Jama	0.0	0.0	164.3	7.3	2.2	5.3	179.0
Bila	0.0	0.0	110.8	7.4	2.2	5.3	125.6
Stranjani	0.0	0.0	185.9	7.3	2.2	5.3	200.7
Gracanica							
Dimnjace	9.2	2.0	4.5	4.8	2.3	15.0	37.8
Tuzla							
Banovici	64.1	11.7	4.4	7.0	2.3	5.3	94.7
Visca	55.3	10.1	4.0	4.2	2.0	3.0	78.7
Dubrave	15.8	3.9	4.0	4.2	2.0	0.8	30.6
Sikulje	27.9	6.1	4.0	4.2	2.0	3.0	47.3
Djurdjevik	0.0	0.0	248.0	9.7	3.6	3.0	264.3
Omazici	0.0	0.0	125.7	7.7	2.3	5.3	141.0
Mramor	0.0	0.0	61.1	7.0	2.0	1.8	71.9
Gacko							
Gracanica	14.9	3.4	4.0	4.2	2.0	0.3	28.8
Ugljevik							
Bogutovo Selo	25.4	7.0	4.0	4.2	2.0	0.3	42.9

81

Table A-4 Capital Requirements

	Overburden Removal			Reclamation			Coal Removal			In-Mine Transport			Preparation			
Mine Group *Mine*	Design Investment (DM)	Capital Contribution to Total	Life (years)	Design Investment (DM)	Capital Contribution to Total	Life (years)	Design Investment (DM)	Capital Contribution to Total	Life (years)	Design Investment (DM)	Capital Contribution to Total	Life (years)	Design Investment (DM)	Capital Contribution to Total	Life (years)	Total Design Investment (DM)
Label	A3	B3	C3	D3	E3	F3	G3	H3	I3	J3	K3	L3	M3	N3	O3	P3
Description	A2*B3*C3*A1*I1/J1			B2*E3*F3*A1*I1/J1			C2*H3*I3*A1*I1/J1			D2*K3*L3*A1*I1/J1			E2*M3*N3*A1*I1/J1			A3+D3+G3+J3+M3
Breza	0	0%	15	0	0%	5	223700	30%	15	3114	30%	5	4982	30%	15	231795
Kakanj																
Vrtliste	233616	30%	15	7138	15%	5	28800	30%	15	5040	15%	5	11031	20%	15	285625
Haljinici	0	0%	15	0	0%	5	210250	30%	15	0	30%	5	4162	30%	15	214412
Stara Jama	0	0%	15	0	0%	5	109245	30%	15	2783	30%	5	2426	30%	15	114453
Zenica																
Moscanica	99926	30%	15	3664	15%	5	8640	30%	15	1512	15%	5	2880	20%	15	116622
Raspotocje	0	0%	15	0	0%	5	285841	30%	15	2835	30%	5	2502	30%	15	291178
Stara Jama	0	0%	15	0	0%	5	163768	30%	15	2415	30%	5	2146	30%	15	168329
Bila	0	0%	15	0	0%	5	66358	30%	15	1470	30%	5	1297	30%	15	69125
Stranjani	0	0%	15	0	0%	5	119516	30%	15	1575	30%	5	1394	30%	15	122485
Gracanica																
Dimnjace	21757	30%	15	798	15%	5	10800	30%	15	1890	15%	5	3643	20%	15	38888
Tuzla																
Banovici	286908	30%	15	8767	15%	5	19800	30%	15	5189	15%	5	6826	20%	15	327490
Visca	211675	30%	15	6468	15%	5	15300	30%	15	2678	15%	5	5100	20%	15	241220
Dubrave	192159	30%	15	7829	15%	5	48600	30%	15	8505	15%	5	16200	20%	15	273292
Sikulje	0	0%	15	0	0%	5	49500	30%	15	17325	30%	5	24750	30%	15	91575
Djurdjevik	0	0%	15	0	0%	5	209547	30%	15	2730	30%	5	3073	30%	15	215350
Omazici	0	0%	15	0	0%	5	166433	30%	15	3413	30%	5	3067	30%	15	172912
Mramor	0	0%	15	0	0%	5	263909	30%	15	10080	30%	5	8640	30%	15	282629
Gacko																
Gracanica	127503	30%	15	4870	15%	5	34200	30%	15	5985	15%	5	11400	20%	15	183958
Ugljevik																
Bogutovo Selo	200010	30%	15	9167	15%	5	31500	30%	15	5513	15%	5	10500	20%	15	256689

58

Table A-5 Total Costs at Design Production Level

Mine Group	Mine	Average Net Fixed Assets (1000 DM)	Total Expense (DM/tonne of coal delivered/year)	Operating Margin	Total Revenue Required for Delivered Coal	(DM/GJ)
	Label	A4	B4	C4	D4	E4
	Description	P3	G2	.12*A4/ (A1*I1/J1)	B4+C4	D4/J1
Breza		115898	194.7	50.0	244.7	*11.65*
Kakanj						
	Vrtliste	142812	60.2	13.0	73.1	*4.88*
	Haljinici	107206	132.4	34.5	167.0	*11.13*
	Stara Jama	57227	105.6	26.8	132.4	*8.46*
Zenica						
	Moscanica	58311	71.9	14.6	86.5	*6.43*
	Raspotocje	145589	256.9	66.6	323.6	*15.61*
	Stara Jama	84164	179.0	45.6	224.6	*10.87*
	Bila	34563	125.6	31.2	156.8	*9.31*
	Stranjani	61242	200.7	51.4	252.1	*14.25*
Gracanica						
	Dimnjace	19444	37.8	4.4	42.2	*3.38*
Tuzla						
	Banovici	163745	94.7	19.7	114.5	*7.61*
	Visca	120610	78.7	17.0	95.7	*6.38*
	Dubrave	136646	30.6	6.1	36.7	*3.78*
	Sikulje	45788	47.3	2.0	49.3	*5.71*
	Djurdjevik	107675	264.3	68.8	333.1	*16.96*
	Omazici	86456	141.0	35.3	176.3	*10.55*
	Mramor	141314	71.9	17.7	89.6	*7.41*
Gacko						
	Gracanica	91979	28.8	5.8	34.6	*4.81*
Ugljevik						
	Bogutovo Selo	128345	42.9	8.8	51.7	*4.92*

59

A.2.3 Cost of Fuel at Current Production Levels

The cost of fuel at current production levels are calculated based on the assumption the average capital investment and the ratio of overburden to coal removal remains the same as for the design production level case.

A.2.3.1 Direct Costs

The re-estimation of direct costs for current production levels is shown in Table A-6. The formula for each cost area the non-capital component of direct costs are variable and the capital component as fixed. The annual capital component is taken to be the average capital requirements, as calculated in Table A-3 divided by the average life of capital investment.

Table A-6 Direct Costs at Current Production Level

Mine Group *Mine*	Overburden Removal	Reclamation	Coal Removal	In-Mine Transport	Preparation	Transport to Power Plant	Total Direct Cost
	(DM/tonne coal delivered)						
Label	A5	B5	C5	D5	E5	F5	G5
Description	(1-B3)*A2 +A3/C3/ (B1*I1/J1)	(1-E3)*B2 +D3/F3// (B1*I1/J1)	(1-H3)*C2 +G3/I3// (B1*I1/J1)	(1-K3)*D2 +J3/L3// (B1*I1/J1)	(1-N3)*E2 +M3/O3// (B1*I1/J1)	M1*N1	SUM(A5:F5)
Breza	0.0	0.0	284.5	11.9	6.3	4.5	307.2
Kakanj							
Vrtliste	80.5	11.0	9.9	7.8	4.7	1.1	115.0
Haljinici	0.0	0.0	142.2	0.0	2.8	4.5	149.6
Stara Jama	0.0	0.0	110.6	8.5	2.5	1.5	123.1
Zenica							
Moscanica	na	na	na	na	na	na	na
Raspotocje	0.0	0.0	562.2	16.7	4.9	5.3	589.1
Stara Jama	0.0	0.0	304.0	13.4	4.0	5.3	326.7
Bila	0.0	0.0	232.7	15.5	4.6	5.3	258.0
Stranjani	0.0	0.0	297.4	11.8	3.5	5.3	317.9
Gracanica							
Dimnjace	20.9	3.3	10.4	7.8	4.3	15.0	61.7
Tuzla							
Banovici	83.3	13.5	5.7	8.0	2.7	5.3	118.5
Visca	80.2	12.4	5.8	5.1	2.6	3.0	109.2
Dubrave	39.2	6.7	9.9	7.3	4.0	0.8	67.9
Sikulje	27.9	6.1	11.1	11.6	5.5	3.0	65.2
Djurdjevik	0.0	0.0	287.4	11.2	4.2	3.0	305.8
Omazici	0.0	0.0	162.3	10.0	3.0	5.3	180.5
Mramor	0.0	0.0	89.1	10.2	2.9	1.8	104.0
Gacko							
Gracanica	na	na	na	na	na	na	na
Ugljevik							
Bogutovo Selo	28.7	7.4	4.5	4.5	2.2	0.3	47.6

60

A.2.3.2 Total Costs

The total costs at current production levels are calculated in the same way as for design production levels. Average capital requirements, and therefore operating margin, are taken to be the same as for the design production levels. However, the operating margin per tonne of coal delivered is higher due to lower production. This is added to the total direct costs calculated in Table A-7 to obtain the total revenue required for delivered coal. This is also expressed in terms of heat content of delivered coal.

Table A-7 Total Costs at Current Production Level

Mine Group / *Mine*	Average Capital Required (1000 DM)	Total Expense (DM/tonne of coal delivered/year)	Operating Margin	Total Revenue Required for Delivered Coal	*(DM/GJ)*
Label	A6	B6	C6	D6	E6
Description	P3	G5	.12*A6/(B1 *I1/J1)	B6+C6	D6/J1
Breza	115898	307.2	148.7	455.9	*21.71*
Kakanj					
Vrtliste	142812	115.0	58.4	173.4	*11.56*
Haljinici	107206	149.6	50.0	199.5	*13.30*
Stara Jama	57227	123.1	41.8	164.8	*10.53*
Zenica					
Moscanica	58311	na	na	na	*na*
Raspotocje	145589	589.1	359.9	949.0	*45.78*
Stara Jama	84164	326.7	174.8	501.5	*24.27*
Bila	34563	258.0	145.5	403.4	*23.97*
Stranjani	61242	317.9	154.3	472.3	*26.69*
Gracanica					
Dimnjace	19444	61.7	26.5	88.2	*7.06*
Tuzla					
Banovici	163745	118.5	39.5	158.0	*10.51*
Visca	120610	109.2	42.6	151.8	*10.12*
Dubrave	136646	67.9	36.0	103.9	*10.69*
Sikulje	45788	65.2	13.7	79.0	*9.15*
Djurdjevik	107675	305.8	105.2	411.0	*20.93*
Omazici	86456	180.5	69.5	250.0	*14.96*
Mramor	141314	104.0	44.6	148.6	*12.29*
Gacko					
Gracanica	91979	na	na	na	*na*
Ugljevik					
Bogutovo Selo	128345	47.6	12.6	60.2	*5.73*

61

A.2.4 Cost of Fuel for the Target 2000 Production Levels

Direct and total cost calculation for the Target 2000 production level are shown in Tables A-8 and A-9, respectively.

Table A-8 Direct Costs at "Target 2000" Production Level

	Overburden Removal	Reclamation	Coal Removal	In-Mine Transport	Preparation	Transport to Power Plant	Total Direct Cost
Mine Group *Mine*	(DM/tonne coal delivered)						
Label	A7	B7	C7	D7	E7	F7	G7
Description	(1-B3)*A2 +A3/C3/ (C1*I1/J1)	(1-E3)*B2 +D3/F3/ (C1*I1/J1)	(1-H3)*C2 +G3/I3/ (C1*I1/J1)	(1-K3)*D2 +J3/L3/ (C1*I1/J1)	(1-N3)*E2 +M3/O3/ (C1*I1/J1)	M1*N1	SUM(A7:F7)
Breza	0.0	0.0	167.2	7.0	3.7	4.5	182.4
Kakanj							
Vrtliste	37.9	7.1	4.7	5.0	2.7	1.1	58.5
Haljinici	0.0	0.0	143.5	0.0	2.8	4.5	150.8
Stara Jama	0.0	0.0	96.5	7.4	2.1	1.5	107.5
Zenica							
Moscanica	49.5	10.5	4.3	4.3	2.1	5.3	76.0
Raspotocje	0.0	0.0	267.8	8.0	2.3	5.3	283.3
Stara Jama	0.0	0.0	169.0	7.5	2.2	5.3	183.9
Bila	0.0	0.0	124.1	8.2	2.4	5.3	140.0
Stranjani	0.0	0.0	197.1	7.8	2.3	5.3	212.4
Gracanica							
Dimnjace	9.2	2.0	4.5	4.8	2.3	15.0	37.8
Tuzla							
Banovici	68.3	12.1	4.7	7.2	2.4	5.3	100.0
Visca	55.9	10.2	4.0	4.2	2.0	3.0	79.4
Dubrave	18.2	4.2	4.6	4.5	2.2	0.8	34.4
Sikulje	27.9	6.1	4.5	4.7	2.2	3.0	48.4
Djurdjevik	0.0	0.0	261.5	10.2	3.8	3.0	278.6
Omazici	0.0	0.0	131.0	8.1	2.4	5.3	146.7
Mramor	0.0	0.0	79.0	9.1	2.6	1.8	92.5
Gacko							
Gracanica	14.7	3.4	3.9	4.2	2.0	0.3	28.5
Ugljevik							
Bogutovo Selo	25.4	7.0	4.0	4.2	2.0	0.3	42.9

62

Table A-9 Total Costs at "Target 2000" Production Level

Mine Group / Mine	Average Capital Required (1000 DM)	Total Expense (DM/tonne of coal delivered/year)	Operating Margin	Total Revenue Required for Delivered Coal	(DM/GJ)
Label	A8	B8	C8	D8	E8
Description	P3	G7	.12*A8/ (C1*I1/J1)	B8+C8	D8/J1
Breza	115898	182.4	39.3	221.7	*10.56*
Kakanj					
Vrtliste	142812	58.5	11.5	70.0	*4.66*
Haljinici	107206	150.8	51.1	202.0	*13.46*
Stara Jama	57227	107.5	28.4	135.9	*8.68*
Zenica					
Moscanica	58311	76.0	17.9	93.9	*6.98*
Raspotocje	145589	283.3	90.0	373.3	*18.01*
Stara Jama	84164	183.9	49.9	233.9	*11.32*
Bila	34563	140.0	43.6	183.7	*10.91*
Stranjani	61242	212.4	61.7	274.1	*15.49*
Gracanica					
Dimnjace	19444	37.8	4.4	42.2	*3.38*
Tuzla					
Banovici	163745	100.0	24.1	124.1	*8.26*
Visca	120610	79.4	17.7	97.1	*6.47*
Dubrave	136646	34.4	9.1	43.5	*4.48*
Sikulje	45788	48.4	2.7	51.1	*5.93*
Djurdjevik	107675	278.6	81.3	359.9	*18.32*
Omazici	86456	146.7	40.2	186.9	*11.19*
Mramor	141314	92.5	35.0	127.4	*10.54*
Gacko					
Gracanica	91979	28.5	5.5	34.0	*4.72*
Ugljevik					
Bogutovo Selo	128345	42.9	8.8	51.7	*4.92*

63

A.3 COMPARISON OF RESULTS

As discussed previously, the Tuzla Mining Institute developed projections of the cost of production from each mine in the Federation. These projections were based on optimal coal mining plans and utilized a financial approach that calculated profit at 8.5% after-tax return on investment and taxes at 36% of profit. This compares to a 12% opportunity cost of capital used in the Bechtel estimate, that is intended to cover profit and taxes.

The results are compared for four mines (two from Middle Bosnia Mines and two from Tuzla Mines) in Table A-10. The results are very close for both Middle Bosnia Mines. The results are less close for the two Tuzla mines.

Table A-10 Comparison of Results

	Bechtel Estimate	Tuzla Mining Institute Estimate
	(DM/GJ)	
Breza	10.56	10.74
Kakanj		
Vrtliste	4.66	4.93
Tuzla		
Dubrave	4.48	5.99
Sikulje	5.93	5.17

64

Appendix B
Economic Evaluation Model

65

Appendix B Economic Evaluation Model

B.1 DESCRIPTION OF THE MODEL

This section presents an energy-economic analysis model that provides a preliminary estimate of project cost and benefits, and serves for prioritization and screening of rehabilitation and new power projects. The model is a spreadsheet based tool (Excel 5), and is provided with the report for further use, revisions, and analyses.

The objective of the model is to calculate the present worth of benefits and costs associated with the rehabilitation or new project and to compare it with the cost of building a reference power plant. This comparison provides an estimate of the cost of the additional electric energy coming out of rehabilitation projects. This additional or incremental cost and cost/benefit analysis serves to prioritize the rehabilitation project, and to compare the cost of electricity from rehabilitation. projects with the cost of electricity from new power plants.

The following are the benefits considered in the model:

- Increased electric generation capacity
- Increased availability of the plant
- Increased heat generation
- Reduced fuel use due to increased energy efficiency
- Reduced O&M cost
- Substitution of fuels
- Reduced environment impact

The following costs are considered:

- Capital costs
- Fuel cost
- Operations and maintenance cost

The net present value of each item is the ratio of the lifetime stream of benefits or costs calculated for each option based on the year of implementation. As the result, the model calculates the cost/benefit ratio, economic rate of return and the levelized incremental cost of energy of the specific rehabilitation or new power project.

The following discussion presents a more detailed description of benefits and costs and the approach for calculating the economic value of the project.

B.2 BENEFITS

B.2.1 Power System Benefits

The power system benefits include:

- Increased electric generation capacity (MW)
- Increased electric generation due to technical improvements in equipment (increased availability and reduced heat rate)

66

- Reduced operating and maintenance cost due to new equipment and other technical improvements

In general, the result of rehabilitation project is normally a combination of power plant operating improvements resulting in the electrical output increase, improved availability of the power plant, reduced cost of operating the plant, increases in heat supply, all resulting in the increased electrical capacity and generation.

The value that we assign to the additional electrical capacity and generation depends of the marginal cost for capacity and energy. In the analysis we used the cost and operating characteristics of a gas-fired combined cycle power plant to calculate the marginal costs. Our understanding is that the existing gas pipeline has enough capacity for an additional 100 MW gas-fired power plant, so that gas-fired power plant is the real alternative to rehabilitation or new power projects using coal.

B.2.2 Steam Production Benefits

The incremental steam benefits are based on the cost of purchasing and operating a gas-fired boiler operating at 89% efficiency with a 5% allowance for capital and operating and maintenance (O&M) cost.

B.2.3 Fuel Benefits

Fuel benefits come from reduced fuel use due to increased energy efficiency.

B.2.4 Environmental Benefits

New plant options all use coal and will be required to meet environmental regulations. As a result the differences in the environmental emission characteristics were used a factor in selection. On the other hand, the equipment upgrade and environmental control options can have a significant impact on emissions and the economic value of this impact could be a basis for selection of one option over another. In fact, the selection of environmental control technologies is entirely dependent upon some value being placed on emission reduction. Environmental benefits were calculated based on projected emission reductions of individual options and a range of perceived values for this reduction.

B.3 COSTS

Costs considered in the analysis are:

- Capital
- Fuel
- Operations and maintenance (O&M)

Capital and O&M values were based on recent engineering estimates. Fuel costs were based on heat rate estimates, estimates of costs of domestic coal, and projections of world market fuel prices for imported fuels.

B.4 INPUT ASSUMPTIONS

This is a list of major assumptions used throughout the analysis. Detailed examples for rehabilitation cost analysis are presented in section B-8.

61

For the analysis we used a 12% for the opportunity cost of capital (8% for the sensitivity analysis), and 1997 as a reference year when calculating future costs of electricity.

Major technical assumption is that thermal power plants, if rehabilitated, will have to install the FGD equipment. Sulfur emission from existing power plants is too high for them to operate without the desulphurisation equipment for prolonged period of time. The environmental regulation for the country would have to address this issue in more details. FGD equipment was not included with 32 MW units. These units are soon scheduled for retirement. They will supply power only until larger units are brought on line, and continue to serve as the system reserve. Otherwise economics of the continued operation of 32 MW units would look dramatically different, with the cost of electricity exceeding costs from larger units.

Other assumption is that the increased availability of units will directly transfer into increased production of that unit and into increased capacity value. While this assumption is true for the present stage of BiH power system that is trying to keep up with the load increase, in the long run this assumption will have to be verified with a more detailed production costing model.

B.5 REHABILITATION INVESTMENT REQUIREMENTS

For Tuzla and Kakanj power plants rehabilitation requirements and environmental protection investments are obtained from the Verbundpaln/Drauconsulting study. For the power plants in Ugljevik and Gacko cost inputs of the ERS staff and the Bechtel estimates are used.

B.6 REFERENCE AND NEW THERMAL POWER PLANTS

The reference value for electric capacity and energy value are based on a gas-fired combined cycle plant. The justification for using this plant is twofold. First, this option is a realistic alternative to the rehabilitation options and presents a benchmark for comparison for any thermal option. Second, the gas-fired combined cycle has a well-defined cost and operating characteristics using fuel traded in Europe assuring a market-based cost comparison. Of course, detailed planning study would also consider impact of factors such as a security of supply, fuel price volatility and the place of unit in the existing power system. However, the selection of another plant type as point of reference would not change the prioritization of projects, or the cost of electricity analysis.

For the cost comparison we also presented a cost structure for two new thermal power projects, one using local and the other one using imported coal. New projects are designed to utilize atmospheric fluidized bed technology. Input data for new power projects are based on the EPRI-TAG (Electric Power Research Institute - Technical Assesment Guide). Detailed technical and operating characteristics for the reference and new power plants are presented in section B-8.

B.7 EMISSION REDUCTION ANALYSIS

Traditional analysis of power supply options has focused on the out-of-pocket costs of power production, such as capital investment, fuel cost and operation and maintenance expenses. Environmental impacts have generally been external to economic analysis and, for this reason, are often referred to as "externalities". The limitation of this approach is that either environmental benefits/costs are not considered at all, or that they are only considered indirectly through the use of design criteria to meet a defined set of regulations. There is no mechanism to allocate limited capital resources to projects which provide the most, including environmental, benefits. In our cost analysis we introduce different approach where a cost value is defined for SOx and NOx emissions. This approach for evaluating power supply

68

options with differing emission characteristics is increasingly used in the United States, with the established market for emission trading.

On point of reference, for a high end of emission impact price was used by the State of California in evaluating impacts of power supply options on out-of-state emission levels in regulatory proceedings. This level is approximately 1700 $/tone for SOx emission and 450 $/tone for NOx emission.

We selected values that are 10% of those used for evaluations in California, for the first assessment the environmental cost will have on economic criteria and on ranking the rehabilitation projects.

B.7.1 Sulfur Emission Reduction

The capital requirement for SOx control technology for existing and new power plants is substantial. Sulfur content in the lignite and brown coal throughout BiH, according to the EU regulations, would require use of FGD equipment for SOx emission reduction. The consequence is that the substantial portion of future rehabilitation or upgrade investment could be spent only for this purpose, lowering the economics for continuos operation of older power plants. In our analysis we calculated emission reduction values based on the sulfur content in coal, and assumption of the 90% sulfur removal with the FGD equipment. The value of SOx reduction is set at the value of 170 $/tone or 280 DM/tone.

B.7.2 NOx Emission Reduction

The estimate is that new/upgraded equipment and combustion modifications will improve the boiler burning characteristics and reduce the NOx emissions by 10%. The value of NOx reduction is set at the 10% value used in California at 45 $/tone or 74.3 DM/tone.

B.8 MODEL INPUT AND OUTPUT FORMS

Following is a detailed list of input assumptions and output results and the preliminary analysis for BiH power system expansion and rehabilitation options.

ECONOMIC AND REFERENCE PLANT INPUTS

Opportunity Cost of Capital	12%		
Base year	1997		
Reference Plant (Gas Fired Combined Cycle)			
Installed cost	1650	DM/kW	(including AFUDC)
Operating Life	30	Years	
Var. Operating Cost (excl. f	5.8	DM/MWh	
Fixed Operating Cost	6.6	DM/kW-yr	
Heat Rate	8500	kJ/kWh	

Fuel Num.	Fuel Cost DM/GJ	Fuel
1	4.00	Imported Coal
2	5.45	Natural Gas
3	4.66	Kakanj (Vrtliste)
4	4.48	Tuzla (lignite)
5	6.50	Tuzla (Visca)
6	4.92	Ugljevik
7	4.72	Gacko

Capacity Value	211.4	DM/kW-yr
Energy Value	52.1	DM/MWh
Emission Reduction Value		
SO_2	280.5	DM/tonne
NO_x	74.3	DM/tonne
Value of Heat Production	6.42	DM/GJ
Assumed efficiency of thermal generation	0.89	
Factor for translating availability increases to equivalent capacity	0.60	

Note: **INPUTS MARKED IN RED**

REHABILITATION OPTION SCREENING ANALYSIS - New Plant Option

Power Plant	Fuel:
Circul. Fluidized Bed	**Tuzla (lignite)**
120 MW	

INVESTMENT COST ASSOCIATED WITH NEW PLANT

Spec. Investment	2640	DM/kW
Import Component	158,400,000	DM
Domestic Component	158,400,000	DM

Capital cash flow (%)

year	1	2	3	4
Import Component	12%	35%	35%	18%
Domestic Component	12%	35%	35%	18%

PERFORMANCE CHARACTERISTICS OF NEW PLANT

	After Proposed Changes	Units
Installed Capacity	120	MW
Net Electric Capacity	109.2	MW
Number of Similar Units	1	
Heat Rate	10000	kJ/kWh
Availability	87.0%	
Remaining Life	35	years
Thermal Generation	0	GJ/yr
Fuel Type	4	
Fuel Cost	4.48	DM/GJ
Variable O&M Cost	9.6	DM/MWh
Fixed O&M Cost	56.3	DM/kW-yr
Hours of Operation: (per year)	6351	hours
Generation	693,529	MWh
Fuel Use	6,935,292	GJ/yr

Emission Rates		Replaced Unit		
	SO2	0.70	0.07	kg/GJ
	NOx	0.82	0.66	kg/GJ
Annual Emissions				
	SO2		489	tonnes
	NOx		4563	tonnes

Annual Emission Reduction (if replacing existing unit)

SO2	4889	tonnes
NOx	5703	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant
Circul. Fluidized Bed

Fuel:
Tuzla (lignite)

COST	Net Present Value (thousands DM)
Capital	373,707
Fuel	254,014
O&M	104,493
Total Costs	732,214
BENEFITS	
Increase in Capacity	188,764
Availability Improvement	0
Increased Electric Generation	295,163
Increased Heat Production	0
Alternative Fuel Cost	0
Alternative O&M Cost	0
Total Non-Environmental Benefits	483,927
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO_2	11,211
NOx	3,462
Total Benefits	498,600

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.66	0.68
Economic Rate of Return	2.2%	2.9%
Levelized Cost of Electricity	12.91 Pf/kWh	

72

REHABILITATION OPTION SCREENING ANALYSIS - New Plant Option

Power Plant	Fuel:
Combined Cycle	**Natural Gas**
120 MW	

INVESTMENT COST ASSOCIATED WITH NEW PLANT

Spec. Investment	1403	DM/kW
Import Component	84,150,000	DM
Domestic Component	84,150,000	DM

Capital cash flow (%)

year	1	2	3	4
Import Component	30%	35%	35%	
Domestic Component	30%	35%	35%	

PERFORMANCE CHARACTERISTICS OF NEW PLANT

	After Proposed Changes	Units
Installed Capacity	120	MW
Net Electric Capacity	112	MW
Number of Similar Units	1	
Heat Rate	8500	kJ/kWh
Availability	90.0%	
Remaining Life	30	years
Thermal Generation	0	GJ/yr
Fuel Type	2	
Fuel Cost	5.45	DM/GJ
Variable O&M Cost	5.8	DM/MWh
Fixed O&M Cost	6.6	DM/kW-yr
Hours of Operation: (per year)	6570	hours
Generation	735,840	MWh
Fuel Use	6,254,640	GJ/yr

Emission Rates		Replaced Unit		
	SO_2	0.70	0.03	kg/GJ
	NOx	0.82	0.17	kg/GJ
Annual Emissions				
	SO_2		176	tonnes
	NOx		1054	tonnes

Annual Emission Reduction (if replacing existing unit)

SO_2	4409	tonnes
NOx	5144	tonnes

13

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant	Fuel:
Combined Cycle	**Natural Gas**

COST	Net Present Value (thousands DM)
Capital	188,213
Fuel	274,331
O&M	40,185
Total Costs	502,729
BENEFITS	
Increase in Capacity	190,754
Availability Improvement	0
Increased Electric Generation	308,562
Increased Heat Production	0
Alternative Fuel Cost	0
Alternative O&M Cost	0
Total Non-Environmental Benefits	499,316
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	9,962
NOx	3,076
Total Benefits	512,354

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.99	1.02
Economic Rate of Return	11.8%	12.7%
Levelized Cost of Electricity	8.48 Pf/kWh	

REHABILITATION OPTION SCREENING ANALYSIS - New Plant Option

Power Plant	Fuel:
Pulverized Coal	**Imported Coal**
200 MW	

INVESTMENT COST ASSOCIATED WITH NEW PLANT

Spec. Investment	2475	DM/kW
Import Component	247,500,000	DM
Domestic Component	247,500,000	DM

Capital cash flow (%)

year	1	2	3	4
Import Component	12%	35%	35%	18%
Domestic Component	12%	35%	35%	18%

PERFORMANCE CHARACTERISTICS OF NEW PLANT

		After Proposed Changes	Units
Installed Capacity		200	MW
Net Electric Capacity		182	MW
Number of Similar Units		1	
Heat Rate		10093	kJ/kWh
Availability		88.0%	
Remaining Life		35	years
Thermal Generation		0	GJ/yr
Fuel Type		1	
Fuel Cost		4.00	DM/GJ
Variable O&M Cost		5.1	DM/MWh
Fixed O&M Cost		53.5	DM/kW-yr
Hours of Operation: (per year)		6424	hours
Generation		1,169,168	MWh
Fuel Use		11,800,237	GJ/yr

Emission Rates	Replaced Unit		
SO2	0.70	0.03	kg/GJ
NOx	0.82	0.09	kg/GJ
Annual Emissions			
SO2		354	tonnes
NOx		1062	tonnes

Annual Emission Reduction (if replacing existing unit)

SO2	8318	tonnes
NOx	9704	tonnes

15

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant	Fuel:
Pulverized Coal	**Imported Coal**

COST	Net Present Value (thousands DM)
Capital	583,918
Fuel	385,892
O&M	128,437
Total Costs	1,098,246
BENEFITS	
Increase in Capacity	314,606
Availability Improvement	0
Increased Electric Generation	497,594
Increased Heat Production	0
Alternative Fuel Cost	0
Alternative O&M Cost	0
Total Non-Environmental Benefits	812,200
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	19,075
NOx	5,891
Total Benefits	837,165

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.74	0.76
Economic Rate of Return	5.2%	5.8%
Levelized Cost of Electricity	11.49 Pf/kWh	

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant: **Tuzla**
Units 1-2 32 MW

Existing Fuel: **Tuzla (lignite)**
Proposed Fuel: **Tuzla (lignite)**

CURRENT ASSET VALUE 0.00 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	14,000,000	DM
Domestic Component		DM

Capital cash flow (%)

year	1	2	3	4
Import Component	100%			
Domestic Component	100%			

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		24	24	MW
Number of Similar Units		2	2	
Heat Rate		16517	15575	kJ/kWh
Availability		45.0%	65.0%	
Remaining Life		3	7	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		4	4	
Fuel Cost		4.48	4.48	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		60	56.3	DM/kW-yr
Hours of Operation: (per year)		3285	4745	hours
Generation		157,680	227,760	MWh
Fuel Use		2,604,401	3,547,362	GJ/yr
Emission Rates				
	SO2	8.7	8.7	kg/GJ
	NOx	0.38	0.31	kg/GJ
Annual Emissions				
	SO2	22,658	30,862	tonnes
	NOx	990	1,100	tonnes
Annual Emissions prorated to same generation				
	SO2	22,658	21,366	tonnes
	NOx	990	761	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:	Proposed Fuel:
Tuzla	**Tuzla (lignite)**
Units 1-2 32 MW	

COST	Net Present Value (thousands DM)
Capital	14,000
Fuel	72,528
O&M	16,037
Total Costs	102,565
BENEFITS	
Increase in Capacity	21,941
Availability Improvement	5,558
Increased Electric Generation	34,395
Increased Heat Production	0
Alternative Fuel Cost	28,024
Alternative O&M Cost	7,246
Total Non-Environmental Benefits	97,165
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	5,300
NOx	82
Total Benefits	102,547

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.95	1.00
Economic Rate of Return	2.2%	12.0%
Incremental Levelized Cost of Electr	10.19 Pf/kWh	
Full Levelized Cost of Electricity	10.19 Pf/kWh	

18

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Tuzla	**Tuzla (lignite)**
Unit 3 110 MW	Proposed Fuel:
	Tuzla (lignite)

CURRENT ASSET VALUE 0.00 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES-FOR ALL UNITS

Import Component	60,000,000	DM
Domestic Component	16,290,000	DM

Note: 31 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		91	91	MW
Number of Similar Units		1	1	
Heat Rate		12300	11700	kJ/kWh
Availability		70.0%	78.0%	
Remaining Life		5	10	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		4	4	
Fuel Cost		4.48	4.48	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		60	56.3	DM/kW-yr
Hours of Operation: (per year)		5110	5694	hours
Generation		465,010	518,154	MWh
Fuel Use		5,719,623	6,062,402	GJ/yr
Emission Rates				
	SO2	0.70	0.07	kg/GJ
	NOx	0.82	0.74	kg/GJ
Annual Emissions				
	SO2	4,032	427	tonnes
	NOx	4,704	4,487	tonnes
Annual Emissions prorated to same generation				
	SO2	4,032	384	tonnes
	NOx	4,704	4,027	tonnes

19

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:
Tuzla
Unit 3 110 MW

Proposed Fuel:
Tuzla (lignite)

COST	Net Present Value (thousands DM)
Capital	80,867
Fuel	153,458
O&M	56,743
Total Costs	291,068
BENEFITS	
Increase in Capacity	39,356
Availability Improvement	5,218
Increased Electric Generation	65,146
Increased Heat Production	0
Alternative Fuel Cost	92,368
Alternative O&M Cost	36,445
Total Non-Environmental Benefits	238,534
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	3,729
NOx	292
Total Benefits	242,554

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.82	0.83
Economic Rate of Return	-3.9%	-2.8%
Incremental Levelized Cost of Electr	12.97 Pf/kWh	
Full Levelized Cost of Electricity	12.97 Pf/kWh	

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Tuzla	**Tuzla (lignite)**
Unit 4 200 MW	Proposed Fuel:
	Tuzla (lignite)

CURRENT ASSET VALUE 55.19 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES-FOR ALL UNITS

Import Component	80,000,000	DM
Domestic Component	17,070,000	DM

Note: 41 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		182	182	MW
Number of Similar Units		1	1	
Heat Rate		12500	11900	kJ/kWh
Availability		72.0%	78.0%	
Remaining Life		5	15	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		4	4	
Fuel Cost		4.48	4.48	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		60	56.3	DM/kW-yr
Hours of Operation: (per year)		5256	5694	hours
Generation		956,592	1,036,308	MWh
Fuel Use		11,957,400	12,332,065	GJ/yr
Emission Rates				
	SO2	0.70	0.07	kg/GJ
	NOx	0.82	0.74	kg/GJ
Annual Emissions				
	SO2	8,429	869	tonnes
	NOx	9,833	9,127	tonnes
Annual Emissions prorated to same generation				
	SO2	8,429	802	tonnes
	NOx	9,833	8,425	tonnes

9(

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:	Proposed Fuel:
Tuzla	**Tuzla (lignite)**
Unit 4 200 MW	

COST	Net Present Value (thousands DM)
Capital	102,894
Fuel	376,284
O&M	136,797
Total Costs	615,976
BENEFITS	
Increase in Capacity	123,375
Availability Improvement	9,435
Increased Electric Generation	187,920
Increased Heat Production	0
Alternative Fuel Cost	193,105
Alternative O&M Cost	73,847
Total Non-Environmental Benefits	587,682
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	7,774
NOx	550
Total Benefits	596,006

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.95	0.97
Economic Rate of Return	7.8%	9.0%
Incremental Levelized Cost of Electr	9.67 Pf/kWh	
Full Levelized Cost of Electricity	10.45 Pf/kWh	

82

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Tuzla	**Tuzla (lignite)**
Unit 5 200 MW	Proposed Fuel:
	Tuzla (lignite)

CURRENT ASSET VALUE 73.59 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	80,000,000	DM
Domestic Component	17,237,000	DM

Note: 41 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		182	182	MW
Number of Similar Units		1	1	
Heat Rate		12900	11900	kJ/kWh
Availability		72.0%	78.0%	
Remaining Life		5	20	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		4	4	
Fuel Cost		4.48	4.48	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		60	56.3	DM/kW-yr
Hours of Operation: (per year)		5256	5694	hours
Generation		956,592	1,036,308	MWh
Fuel Use		12,340,037	12,332,065	GJ/yr
Emission Rates				
	SO_2	0.70	0.07	kg/GJ
	NO_x	0.82	0.74	kg/GJ
Annual Emissions				
	SO_2	8,698	869	tonnes
	NO_x	10,148	9,127	tonnes
Annual Emissions prorated to same generation				
	SO_2	8,698	802	tonnes
	NO_x	10,148	8,425	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:	Proposed Fuel:
Tuzla	**Tuzla (lignite)**
Unit 5 200 MW	

COST	Net Present Value (thousands DM)
Capital	103,071
Fuel	412,669
O&M	150,025
Total Costs	665,765
BENEFITS	
Increase in Capacity	148,718
Availability Improvement	10,348
Increased Electric Generation	223,449
Increased Heat Production	0
Alternative Fuel Cost	199,284
Alternative O&M Cost	73,847
Total Non-Environmental Benefits	655,646
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO_2	8,046
NOx	635
Total Benefits	664,327

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.98	1.00
Economic Rate of Return	10.8%	11.8%
Incremental Levelized Cost of Electr	9.15 Pf/kWh	
Full Levelized Cost of Electricity	10.10 Pf/kWh	

84

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Tuzla	**Tuzla (Visca)**
Unit 6 215 MW	Proposed Fuel:
	Tuzla (Visca)

CURRENT ASSET VALUE 158.22 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES-FOR ALL UNITS

Import Component	70,000,000	DM
Domestic Component	22,900,000	DM

Note: 41 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		198	198	MW
Number of Similar Units		1	1	
Heat Rate		12500	11700	kJ/kWh
Availability		72.0%	78.0%	
Remaining Life		5	20	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		5	5	
Fuel Cost		6.50	6.50	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		60	56.3	DM/kW-yr
Hours of Operation: (per year)		5256	5694	hours
Generation		1,040,688	1,127,412	MWh
Fuel Use		13,008,600	13,190,720	GJ/yr
Emission Rates				
	SO2	1.48	0.15	kg/GJ
	NOx	0.88	0.79	kg/GJ
Annual Emissions				
	SO2	19,316	1,959	tonnes
	NOx	11,414	10,417	tonnes
Annual Emissions prorated to same generation				
	SO2	19,316	1,808	tonnes
	NOx	11,414	9,615	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:
Tuzla
Unit 6 215 MW

Proposed Fuel:
Tuzla (Visca)

COST	-Net Present Value (thousands DM)
Capital	98,474
Fuel	640,428
O&M	163,214
Total Costs	902,116
BENEFITS	
Increase in Capacity	161,792
Availability Improvement	11,257
Increased Electric Generation	243,093
Increased Heat Production	0
Alternative Fuel Cost	304,805
Alternative O&M Cost	80,339
Total Non-Environmental Benefits	801,287
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	17,844
NOx	679
Total Benefits	819,810

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.89	0.91
Economic Rate of Return	#NUM!	#NUM!
Incremental Levelized Cost of Electr	11.07 Pf/kWh	
Full Levelized Cost of Electricity	12.95 Pf/kWh	

86

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Kakanj	**Kakanj (Vrtliste)**
Units 1-4 32 MW	Proposed Fuel:
	Kakanj (Vrtliste)

CURRENT ASSET VALUE 0.00 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	10,000,000	DM
Domestic Component	10,000,000	DM

Capital cash flow (%)

year	1	2	3	4
Import Component	100%			
Domestic Component	100%			

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		24	24	MW
Number of Similar Units		4	4	
Heat Rate		16517	15575	kJ/kWh
Availability		45.0%	65.0%	
Remaining Life		3	7	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		3	3	
Fuel Cost		4.66	4.66	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		60	56.3	DM/kW-yr
Hours of Operation: (per year)		3285	4745	hours
Generation		315,360	455,520	MWh
Fuel Use		5,208,801	7,094,724	GJ/yr
Emission Rates				
	SO2	8.7	8.7	kg/GJ
	NOx	0.38	0.31	kg/GJ
Annual Emissions				
	SO2	45,317	61,724	tonnes
	NOx	1,979	2,199	tonnes
Annual Emissions prorated to same generation				
	SO2	45,317	42,732	tonnes
	NOx	1,979	1,523	tonnes

91

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:
Kakanj
Units 1-4 32 MW

Proposed Fuel:
Kakanj (Vrtliste)

COST	Net Present Value (thousands DM)
Capital	20,000
Fuel	150,884
O&M	25,912
Total Costs	196,796
BENEFITS	
Increase in Capacity	43,883
Availability Improvement	11,116
Increased Electric Generation	68,791
Increased Heat Production	0
Alternative Fuel Cost	58,300
Alternative O&M Cost	11,033
Total Non-Environmental Benefits	193,122
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	10,599
NOx	165
Total Benefits	203,887

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.98	1.04
Economic Rate of Return	7.9%	21.1%
Incremental Levelized Cost of Electr	9.65 Pf/kWh	
Full Levelized Cost of Electricity	9.65 Pf/kWh	

88

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:
Kakanj
Unit 5 - 110 MW

Existing Fuel:
Kakanj (Vrtliste)
Proposed Fuel:
Kakanj (Vrtliste)

CURRENT ASSET VALUE 80.49 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	50,000,000	DM
Domestic Component	16,528,000	DM

Note: 32 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		88	88	MW
Number of Similar Units		1	1	
Heat Rate		13350	12400	kJ/kWh
Availability		55.0%	75.0%	
Remaining Life		5	13	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		3	3	
Fuel Cost		4.66	4.66	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		50	45.0	DM/kW-yr
Hours of Operation: (per year)		4015	5475	hours
Generation		353,320	481,800	MWh
Fuel Use		4,716,822	5,974,320	GJ/yr
Emission Rates				
	SO2	1.54	0.15	kg/GJ
	NOx	0.68	0.61	kg/GJ
Annual Emissions				
	SO2	7,244	918	tonnes
	NOx	3,220	3,670	tonnes
Annual Emissions prorated to same generation				
	SO2	7,244	673	tonnes
	NOx	3,220	2,692	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:
Kakanj
Unit 5 - 110 MW

Proposed Fuel:
Kakanj (Vrtliste)

COST	Net Present Value (thousands DM)
Capital	70,520
Fuel	178,834
O&M	54,838
Total Costs	304,192
BENEFITS	
Increase in Capacity	52,447
Availability Improvement	14,342
Increased Electric Generation	94,808
Increased Heat Production	0
Alternative Fuel Cost	79,234
Alternative O&M Cost	28,597
Total Non-Environmental Benefits	269,430
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	6,826
NOx	333
Total Benefits	276,589

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.89	0.91
Economic Rate of Return	2.7%	4.4%
Incremental Levelized Cost of Electr	10.78 Pf/kWh	
Full Levelized Cost of Electricity	13.38 Pf/kWh	

90

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Kakanj	**Kakanj (Vrtliste)**
Unit 6 - 110 MW	Proposed Fuel:
	Kakanj (Vrtliste)

CURRENT ASSET VALUE 201.22 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	50,000,000	DM
Domestic Component	10,958,000	DM

Note: 32 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		92	92	MW
Number of Similar Units		1	1	
Heat Rate		13850	12000	kJ/kWh
Availability		70.0%	78.0%	
Remaining Life		5	21	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		3	3	
Fuel Cost		4.66	4.66	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		50	45.0	DM/kW-yr
Hours of Operation: (per year)		5110	5694	hours
Generation		470,120	523,848	MWh
Fuel Use		6,511,162	6,286,176	GJ/yr
Emission Rates				
	SO2	1.54	0.15	kg/GJ
	NOx	0.68	0.61	kg/GJ
Annual Emissions				
	SO2	10,000	965	tonnes
	NOx	4,444	3,862	tonnes
Annual Emissions prorated to same generation				
	SO2	10,000	866	tonnes
	NOx	4,444	3,466	tonnes

91

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:
Kakanj
Unit 6 - 110 MW

Proposed Fuel:
Kakanj (Vrtliste)

COST	Net Present Value (thousands DM)
Capital	64,615
Fuel	221,518
O&M	68,939
Total Costs	355,073
BENEFITS	
Increase in Capacity	76,977
Availability Improvement	7,061
Increased Electric Generation	117,997
Increased Heat Production	0
Alternative Fuel Cost	109,376
Alternative O&M Cost	33,529
Total Non-Environmental Benefits	344,939
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	9,325
NOx	357
Total Benefits	354,622

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.97	1.00
Economic Rate of Return	9.8%	11.9%
Incremental Levelized Cost of Electr	9.36 Pf/kWh	
Full Levelized Cost of Electricity	14.44 Pf/kWh	

92

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:	Existing Fuel:
Kakanj	**Kakanj (Vrtliste)**
Unit 7 - 230 MW	Proposed Fuel:
	Kakanj (Vrtliste)

CURRENT ASSET VALUE 729.29 mil. DM

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	64,621,000	DM
Domestic Component	24,621,050	DM

Note: 42 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		198	198	MW
Number of Similar Units		1	1	
Heat Rate		11700	11000	kJ/kWh
Availability		72.0%	82.0%	
Remaining Life		5	25	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		3	3	
Fuel Cost		4.66	4.66	DM/GJ
Variable O&M Cost		10	9.5	DM/MWh
Fixed O&M Cost		50	45.0	DM/kW-yr
Hours of Operation: (per year)		5256	5986	hours
Generation		1,040,688	1,185,228	MWh
Fuel Use		12,176,050	13,037,508	GJ/yr
Emission Rates				
	SO2	1.54	0.15	kg/GJ
	NOx	0.62	0.55	kg/GJ
Annual Emissions				
	SO2	18,732	2,006	tonnes
	NOx	7,493	7,221	tonnes
Annual Emissions prorated to same generation				
	SO2	18,732	1,761	tonnes
	NOx	7,493	6,340	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:	Proposed Fuel:
Kakanj	**Kakanj (Vrtliste)**
Unit 7 - 230 MW	

COST	Net Present Value (thousands DM)
Capital	94,597
Fuel	476,508
O&M	158,193
Total Costs	729,298
BENEFITS	
Increase in Capacity	177,437
Availability Improvement	19,701
Increased Electric Generation	288,631
Increased Heat Production	0
Alternative Fuel Cost	204,536
Alternative O&M Cost	73,202
Total Non-Environmental Benefits	763,507
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	17,377
NOx	515
Total Benefits	781,400

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	1.05	1.07
Economic Rate of Return	15.5%	17.8%
Incremental Levelized Cost of Electr	8.14 Pf/kWh	
Full Levelized Cost of Electricity	15.99 Pf/kWh	

94

REHABILITATION OPTION SCREENING ANALYSIS

		Existing Fuel:
Power Plant:		**Tuzla (Visca)**
Ugljevik		Proposed Fuel:
Unit 1		**Tuzla (Visca)**

CURRENT ASSET VALUE 412.5 milion DM (est.)

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	66,500,000	DM
Domestic Component	16,500,000	DM

Note: 50 mil. DEM for FGD

Capital cash flow (%)

year	1	2	3	4
Import Component	50%	50%		
Domestic Component	50%	50%		

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

	Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity	268	268	MW
Number of Similar Units	1	1	
Heat Rate	12021	12000	kJ/kWh
Availability	72.0%	80.0%	
Remaining Life	10	23	years
Thermal Generation (total)	0	0	GJ/yr
Fuel Type	6	6	
Fuel Cost	4.92	4.92	DM/GJ
Variable O&M Cost	10.0	9.5	DM/MWh
Fixed O&M Cost	48.6	45.0	DM/kW-yr
Hours of Operation: (per year)	5256	5840	hours
Generation	1,408,608	1,565,120	MWh
Fuel Use	16,932,877	18,781,440	GJ/yr
Emission Rates			
SO2	3.81	0.38	kg/GJ
NOx	0.76	0.69	kg/GJ
Annual Emissions			
SO2	64,506	7,155	tonnes
NOx	12,901	12,879	tonnes
Annual Emissions prorated to same generation			
SO2	64,506	6,439	tonnes
NOx	12,901	11,591	tonnes

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:	Proposed Fuel:
Ugljevik Unit 1	**Tuzla (Visca)**

COST	Net Present Value (thousands DM)
Capital	87,980
Fuel	713,219
O&M	207,847
Total Costs	1,009,046
BENEFITS	
Increase in Capacity	117,195
Availability Improvement	20,994
Increased Electric Generation	214,546
Increased Heat Production	0
Alternative Fuel Cost	470,719
Alternative O&M Cost	153,240
Total Non-Environmental Benefits	976,694
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	93,050
NOx	1,036
Total Benefits	1,070,780

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.97	1.06
Economic Rate of Return	8.3%	21.4%
Incremental Levelized Cost of Electi	9.34 Pf/kWh	
Full Levelized Cost of Electricity	12.76 Pf/kWh	

qb

REHABILITATION OPTION SCREENING ANALYSIS

Power Plant:
Gacko
Unit 1

Existing Fuel:
Gacko
Proposed Fuel:
Gacko

CURRENT ASSET VALUE 363 milion DM (est.)

INVESTMENT COST ASSOCIATED WITH PROPOSED CHANGES FOR ALL UNITS

Import Component	10,000,000	DM
Domestic Component	8,000,000	DM

Note: no FGD required

Capital cash flow (%)

year	1	2	3	4
Import Component	100%			
Domestic Component	100%			

PERFORMANCE CHARACTERISTICS ASSOCIATED WITH PROPOSED CHANGES

		Before Proposed Changes	After Proposed Changes	Units
Net Electric Capacity		230	230	MW
Number of Similar Units		1	1	
Heat Rate		11200	11200	kJ/kWh
Availability		75.0%	80.0%	
Remaining Life		22	27	years
Thermal Generation (total)		0	0	GJ/yr
Fuel Type		7	7	
Fuel Cost		4.72	4.72	DM/GJ
Variable O&M Cost		10.0	10	DM/MWh
Fixed O&M Cost		47.4	47.4	DM/kW-yr
Hours of Operation: (per year)		5475	5840	hours
Generation		1,259,250	1,343,200	MWh
Fuel Use		14,103,600	15,043,840	GJ/yr
Emission Rates				
	SO2	3.81	0.38	kg/GJ
	NOx	0.76	0.69	kg/GJ
Annual Emissions				
	SO2	53,728	5,731	tonnes
	NOx	10,746	10,316	tonnes
Annual Emissions prorated to same generation				
	SO2	53,728	5,373	tonnes
	NOx	10,746	9,671	tonnes

97

ECONOMIC SUMMARY FOR SCREENING ANALYSIS

Power Plant:	Proposed Fuel:
Gacko	**Gacko**
Unit 1	

COST	Net Present Value (thousands DM)
Capital	18,000
Fuel	563,976
O&M	193,274
Total Costs	775,250
BENEFITS	
Increase in Capacity	14,487
Availability Improvement	11,588
Increased Electric Generation	54,240
Increased Heat Production	0
Alternative Fuel Cost	508,896
Alternative O&M Cost	179,619
Total Non-Environmental Benefits	768,830
ENVIRONMENTAL BENEFITS	
Reduction in Air Emissions:	
SO2	104,409
NOx	953
Total Benefits	874,192

ECONOMIC INDICATORS

	Without Environmental Benefits	With Environmental Benefits
Benefit/Cost Ratio	0.99	1.13
Economic Rate of Return	9.5%	79.6%
Incremental Levelized Cost of Electı	8.32 Pf/kWh	
Full Levelized Cost of Electricity	11.73 Pf/kWh	