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ELECTRICITY PRICING IN GEORGIA

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EXECUTIVE SUMMARY

This report sets out a methodology for calculating tariffs for the electricity sector in Georgia We developed a set of assumptions and used them to determine prices for capacity and energy at various transmission and distribution voltages following the implementation of a wholesale market The tariff calculations reflect the wholesale market rules to be adopted by power sector licensees through the signing of a Market Members Agreement

The Georgian electric system is approaching crisis condition due to the technical and financial decline in the power sector The failure to finance maintenance and new investment has led to electricity rationing and load shedding on a daily basis due to a decline in generating capability Unless facilities are rebuilt and replaced, the system will deteriorate further

The World Bank conditionalities to the second Structural Adjustment Credit included the introduction of an electricity tariff methodology The U S Agency for International Development asked Hagler Bailly to conduct an electricity tariff study to help Georgia meet this conditionality A rough draft of this report was translated and given to the GNERC in January to aid in their development of a tariff methodology

The findings and conclusions of this study reflect the independent opinion of Hagler Bailly consultants The actual methodology adopted by the GNERC does not correspond to that presented in this report However, this report provides a general framework for the GNERC as it prepares to develop electricity tariffs for Georgia

S 1 Methodology Employed in this Report

We envisioned a tariff reform process in which prices paid to generators will be determined in a new wholesale market Transmission tariffs and tariffs to retail customers will continue to be subject to GNERC regulation

For this tariff study we assume that electricity is a commercial product that should be provided only to customers who pay for it No subsidies to the power sector are included in our tariff calculations, and the accounts payable accumulated by public sector enterprises are not identified as a cost component to be recovered in tariffs

The tariff methodology is a *long-run economic cost* methodology because it is based on projections of the long-run economic cost of supplying electricity through networks in Georgia The idea behind this approach is that the cost of service to a class of customers can be estimated by calculating energy flows, energy losses replacement costs of the network, and marginal costs and average costs of generation Taxes are omitted from the calculation although the cost of capital should include a tax component

It will be necessary to calculate tariffs for Georgia before there is a sound basis for electric utility accounting and sufficient information for forecasting long-run supply and demand Although it would be desirable to have detailed cost data, financial information, and technical information on capacity and energy flows, it was necessary to estimate tariffs on the basis of the "best available" data This report is based on the data available to Hagler Bailly

Tariffs based on long run economic costs may be considered a basis for determining the relative level of tariffs and the structure of tariffs They can be used to allocate total revenue requirements between various customers and levels of service

S 2 Generation Tariffs

The end goal of the electricity market reform is to create a wholesale electricity market where competition between electricity suppliers serves to control prices and provide incentives for efficient performance Given the lack of a market-based economic tradition in Georgia, a gradual transition to a market-based wholesale pool is recommended The wholesale electricity market will evolve through several phases of development, from regulated cost-based energy and capacity prices to spot market hourly pricing without a capacity price

The initial wholesale pool price determination methodology will be cost-based, and tariffs would be approved and regulated by GERNC The cost of service approach to wholesale pool pricing is recommended during Phase I to ensure that all generators initially have the funds to cover their costs of operation as well as their cost of capital During Phase I the wholesale pool tariff will include two components, a capacity price per kW per month and an energy price per kWh Both of these components will be cost based and specific for each generating facility on the Georgian power system

The government of Georgia agreed to set regulated tariffs to at least cover operating, maintenance costs, interest, bad debts and depreciation based on revalued assets by December 31, 1998 The revaluation of assets could have a major effect on generator tariffs There are a number of alternatives which can be applied to revaluating existing assets replacement cost, Soviet cost, estimated current value, zero value The replacement cost of hydroelectric stations could be as high as $2 7 billion and the replacement cost of thermal stations $1 2 billion We used the replacement cost to revalue assets in our calculation

Combining data received from the World Bank and from Sakenergo, we have constructed a schedule of generation, imports, and exports This schedule shows an annual average supply cost (excluding the cost of transmission, dispatch, and other wholesale market services) of only 1 26 cents/kWh or 1 63 tetri/kWh,[1] which is very low by international standards For 1999 we project an increase in the average cost of hydro generation to 2 5 cents/kWh or 3 25 tetri/kWh and the average sales price of thermal generation is projected to be 4 16 cents/kWh or 5 4 tetri/kWh The annual average cost of electricity generation and imports purchased in 1999 for resale to the distribution companies is projected to be 2 89 cents/kWh or 3 76 tetri/kWh

S 3 Transmission Tariffs

For the purposes of developing a transmission tariff methodology we assume that there will be a single enterprise providing transmission services to distribution companies, to Abkhazia and South Ossetia, to foreign power systems, and to industrial customers receiving energy at 35 kV or higher voltage

The transmission services market in Georgia may be divided into three components international transit, delivery of energy to Abkhazia and South Ossetia, and delivery of energy to distribution companies and high voltage industrial customers Turkey receives two billion kWh, Abkhazia and South Ossetia receive roughly one billion kWh, while distribution companies and high voltage customers receive over five billion kWh and technical and commercial losses are roughly one billion kWh

International transit tariffs should be based on the cost of the high voltage networks but not the cost of service at lower voltages On the other hand, all transmission services in the third component involve the 110 kV and 35 kV grid The second component is less clear The Transmission Licensee should be compensated for the cost of building and maintaining transmission capacity needed to supply Abkhazia and South Ossetia

For the initial phase of tariff reform we recommend a transmission tariff consisting of a two-part tariff consisting of a capacity payment and an energy loss allowance For subsequent tariff development the operating expenses should be divided into costs which vary in relation to the peak load, recovered through the capacity payment per kW, and costs which vary in relation to the number of kWh transmitted, recovered through a charge per kWh The data necessary to distinguish these categories were not available for this study Therefore, we allocated all operating expenses to the capacity payment

The capacity payment for transmission service is a payment for use of the network We recommend the coincident peak load basis - each customer pays for a share of the capacity cost of the network according to his share of the coincident peak load – to allocate costs among

[1] In this report an exchange rate of 1 3 tetri to the dollar is used Since the time that the calculations presented in the report were performed the exchange rate has fallen to 1 34 tetri to the dollar

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customers This approach is reasonable, although it does not reflect the complexities of transmission system planning

To calculate transmission capacity charges it is necessary to calculate the revenue requirements for the VHV network and the HV network The revenue requirement is the projected annual cost of building and operating the networks excluding the energy losses that are recovered through energy loss allowances When this is divided by the coincident peak load measured at delivery points, the result is the annual capacity payment, in Lari/kW

Revenue requirements include operating expenses, depreciation of assets based on replacement cost, plus an allowance for a reasonable rate of return on revalued net assets At a minimum, transmission tariffs will need to be established at levels that will permit the Transmission Licensee to conduct capital repairs on the VHV and HV networks

We estimate that in the four-year period 1998-2001 there is a need to invest about 138 million Lari ($106 million) in the VHV network and 90 million Lari in the HV network The total revenue requirement for the combined VHV and HV networks is estimated to be 119 million Lari in 1998, rising to 141 million Lari in 2001 The total replacement cost of the VHV network is $361 million and the replacement cost of the HV network is $367 8 million These figures essentially reflect the infrastructure that was in place in 1990, they do not reflect a grid that has been "downsized" to meet the present level of electricity demand

We calculated a Very High Voltage (VHV) tariff for customers who receive energy at 220 kV or higher voltage and a High Voltage (HV) tariff for customers who receive energy at 35 kV or 110 kV For the VHV network we calculate that the capacity payment in 1998 should be 2 45 Lari ($1 88) per kW per month For service to HV customers we calculate that the capacity payment in 1998 should be 6 71 Lari ($5 15) per kW per month This tariff level is equivalent to 1 05 tetri per kWh of domestic consumption (excluding Abkhazia and South Ossetia)

Electricity losses should be accounted for in the cost per kWh for the wholesale customer At the delivery point, the Transmission Licensee delivers a quantity of energy that is less than the quantity measured at the receipt point The difference should equal the amount of energy consumed in technical and commercial losses

S 4 Distribution and Retail Tariffs

In this study it is assumed that the distribution sector will be owned and managed by eight joint stock companies that will begin operating on a commercial basis within the next three years Private investors will have an opportunity to buy shares in these companies

As a business entity, a disco is a combination of a "wires" business and a "retail supply" business, with an emphasis on the metering and billing functions of a supplier Within a defined geographic region, the disco has a monopoly over the supply of electricity through wires that are operated at 10 kV, 6 kV, or 0 4 kV and are supplied by electricity from the high voltage grid The tariff calculations are based on the assumption that a disco that has been privatized will have an obligation to offer firm service to retail customers

The average annual cost of energy supplied to the VHV and HV grid for resale to the distribution companies was determined Customer classes were defined and the "target" level of tariffs for each customer class including two-part tariffs, where appropriate, was calculated

Retail tariffs were calculated based on economic costs, given estimates of the marginal cost and average cost of generation The starting point for the calculation of tariffs is an estimate of electric energy sales and losses Data on peak load are used to estimate the capacity cost per kW of each level of the network Data on energy losses are used to calculate tariffs at each voltage level based on the losses at each level It is assumed that the retail tariff will be based on reasonable and achievable target levels of technical and commercial losses

Data on annual energy sales are used to weight the tariffs for each customer class, to come up with a projection of total revenue The weights are only approximate, as a result of the paucity of data For any voltage level, the coincidence factor is the ratio of the contribution to the coincident peak load on the network (from sales customers) to the non-coincident peak load (from sales customers)

The marginal capacity cost is an estimate of the annual cost per kW of building and maintaining a new gas-fired combustion turbine The marginal energy cost during peak periods is based on the existing energy price for sales from Gardabani The marginal energy cost during off-peak periods was selected to yield a generation cost component of 2 9 cents/kWh for supplies to distribution companies

The existing tariff of 4 5 tetri/kWh for medium voltage customers is close to the economic cost tariff of 5 36 tetri/kWh On the other hand, the low voltage customers should have much higher tariffs, to pay for the low voltage network (at a 40 percent load factor) and compensate for losses The tariff increase required to reach economic cost is 123 percent for the low voltage customers - an increase from 4 5 tetri/kWh to 10 02 tetri/kWh

S 5 Recommendations

Any international financial institution providing power sector loans to Georgia would have to be concerned about the sector's ability to meet loan obligations Clearly a very high priority must be the reduction of commercial losses and an increase in collections rates In parallel with programs to improve collections, it will be necessary to determine the tariff levels needed to recover the true economic costs of generation, transmission, and distribution

The prices produced by our calculations can be considered the economic cost which could be used for the target level of tariffs over the long term These prices could not be implemented suddenly without a substantial political resistance The present financial requirements are below the level implied by long run prices, permitting a gradual increase in the tariff over time As new investment occurs, financial requirements will increase, eventually rising to the level of long-run economic costs The timing of tariff increases is a complex issue requiring negotiation between the Government, potential investors and multilateral development banks

CHAPTER 1
INTRODUCTION

The quality of supply of electricity from the Georgian electric grid to consumers has deteriorated sharply since 1989 There are several reasons for the technical and financial decline in the power sector widespread non-payment for electricity, theft of electricity, lack of routine maintenance, and lack of money to pay for salaries, fuel and other expenses [1] Since 1991 the system has been operated at frequencies below 50 Hz for extended periods - at 45 Hz during the 1996-97 winter, and sometimes as low as 42 Hz Electricity rationing and load shedding varies in severity in different parts of the country and varies from month to month Firm service to retail customers is not legally available Service to retail customers ranges from zero to about 12 hours per day Voltage is not stabilized at 220 V but fluctuates from 160 V to 240 V, although distribution system failures occasionally cause voltage spikes of 300 kV The range of voltage fluctuation exceeds the specifications of many surge protection devices manufactured in Western Europe Many small businesses and some residential customers have purchased diesel generators for backup generation

Although there is no precise measure of the peak capability of the system today, we estimate that the combined effect of deterioration of the generation, transmission, and distribution system is a loss of roughly 1000 MW of peak load capability since 1989, when the maximum load was 3,060 MW The biggest decline appears to be in generating capability, which is effectively about 1,800 MW despite an installed capacity of 3,650 MW (excluding the 220 MW Tvarcheli power station in Abkhazia, which was destroyed by civil war) Even if the lower level of generation were offset by imports, it is doubtful that the distribution system could meet the 1989 peak load Unless facilities are rebuilt and replaced, the peak capability of the system will deteriorate further Georgia has a large hydroelectric potential which is roughly ten times larger than installed hydroelectric capacity, but there is a shortage of capital in the power sector

Recognizing that the absence of reliable electricity supply is an impediment to Georgian economic growth, the World Bank included power sector reform targets in the conditionalities to the second Structural Adjustment Credit (SAC) Among these targets was the introduction of an electricity tariff methodology by the end of February 1998[2] and the implementation of cost-based rates by the end of December 1998

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[1] In the early 1990s civil war destroyed a thermal power station in Abkhazia However, war-related damage is not a leading cause of the deterioration of the power sector

[2] The deadline for adoption of the tariff methodology was subsequently extended several times

The U S Agency for International Development (USAID) offered to fund technical assistance in this area Hagler Bailly, Inc was already active in Georgia as the USAID contractor for institutional-based reforms in the power sector and the oil and gas sector USAID therefore asked Hagler Bailly to conduct an electricity tariff study, to be initiated at the end of September 1997

This study involves the development of tariff methodologies and the calculation of tariff levels The study objectives defined in October 1997 included the following tasks

- Recommend and implement a methodology for calculating the regulated prices of capacity and energy sold by generation licensees,
- Recommend and implement a methodology for calculating transmission tariffs,
- Develop a set of assumptions regarding prices for capacity and energy sold by distribution licensees, following the implementation of a wholesale market Develop assumptions regarding the types of meters used by different groups of customers Identify customer classes, different types of meters and tariffs offered to customers,
- Recommend and implement a methodology for calculating the regulated prices of capacity and energy sold by distribution licensees, and,
- Draft a final report describing the work conducted, and provide this report to the Commission, to USAID, and to the World Bank

It is intended that this report will be used by the World Bank in monitoring the progress of electricity tariff reforms needed to meet SAC loan conditionalities This report may also be useful to the Ministry of Fuel and Energy and the Ministry of Privatization, which are responsible for developing policies for privatization and restructuring of the power sector In addition, this report should be useful for the Georgian National Electricity Regulatory Commission (GNERC) The tariff methodologies used in this report could be implemented by GNERC and later revised and updated as additional accounting information and more detailed technical data become available All the spreadsheets used in this study have been translated into Georgian and delivered to the Commission However, the data used in this report were not obtained from GNERC, and the findings and conclusions of this study reflect the independent opinion of Hagler Bailly consultants rather than the policies of GNERC

To develop estimates in this report of the cost of wholesale power supplied to the distribution companies and to understand the economic dispatch of supply sources, it was necessary to collect and analyze information on import, export, and transit of electricity from Russia to Turkey

Hagler Bailly is conducting two other tariff-related activities that are designed to help the Government of Georgia meet the power sector reform objectives of the SAC II loan [3] One is a program of technical assistance to help GNERC establish procedures and rules for tariff-setting The preliminary results of this program are presented in Appendices J-N The objectives of this program are to [4]

- Recommend procedures and rules for submission, evaluation, approval, application and revision of generation, transmission, and retail tariffs,

- Recommend the financial and technical information that the generation, transmission, and distribution licensees should provide to GNERC for the process of tariff revision and approval and for enforcing tariff regulations, and,

- Draft regulations with the rules, procedures and methodologies proposed to be used to regulate electricity prices Prepare draft documents for consideration by GNERC

The other related activity is the development of new wholesale market rules to be adopted by power sector licensees through the signing of a Market Members Agreement The principal counterpart for this activity is the Ministry of Fuels and Energy One of the draft chapters in the market rules is a chapter on price determination Among the objectives of this program are the following

- Develop market rules pertaining to generation licensees, and a conceptual framework concerning the way the market will set prices,

- Develop market rules pertaining to transmission services provided by the transmission licensee,

- Develop market rules pertaining to the sale of capacity and energy to wholesale customers, and,

- Develop procedural rules defining the scope of Commission regulation of prices for sales by generation licensees, transmission services, and sales to wholesale customers

Some results of this work are presented in Chapter 3

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[3] In July 1997 the World Bank drafted terms of reference (TOR) for consultant services in *Technical Assistance for Regulation of Electricity Prices in Georgia* The overall program of technical assistance conducted by Hagler Bailly for USAID covers most of the topics in the TOR drafted by the World Bank but the draft TOR is not part of the USAID contract

[4] This wording is taken from the draft TOR dated July 1997 The draft TOR described these tasks separately for generation transmission, and distribution

Any international financial institution providing power sector loans to Georgia would have to be concerned about the sector's ability to collect revenues that are adequate to repay the loan obligations Clearly a very high priority must be the reduction of commercial losses and an increase in collection rates In parallel with programs to improve collections, there is a need for a program to determine the tariff levels needed to recover the true economic costs of generation, transmission, and distribution

1 1 Status of tariff reforms

In the negotiation of a Power Rehabilitation Project loan in the Spring of 1997, the Government of Georgia agreed to implement the following reforms requested by the World Bank

a) increase average residential tariffs to 4 5 tetri/kWh by June 30, 1997 at which time the average wholesale tariff will be 3 5 tetri/kWh and will fully cover operating and maintenance costs, depreciation based on historical asset values, interest on borrowed capital, and partial provisioning for bad debts,

b) by September 30, 1997, the Government (and the regulatory authority) would issue a decree defining the rules for setting regulated electricity prices, and the schedule to achieve full recovery of reasonable costs and eliminate any remaining cross-subsidies between different categories of consumers by December 31, 1998 The decree would include rules for asset revaluation, depreciation, profit levels, allowances for technical losses and writing off of bad debts,

c) by December 31, 1998 set regulated tariffs to at least cover all operating and maintenance costs, interest on borrowed capital, full provisioning for bad debts, and depreciation based on revalued assets, and,

d) to the extent that other measures have not been effective in securing payments from Abkhazia, South Ossetia and state enterprises of national interests, Sakenergo's average wholesale tariffs effective on January 1, 1998 and 1999 will be set to recover unpaid electricity supplies (defined as accounts overdue by more than 90 days) for the previous year from these entities [5]

With regard to item a), the Government increased residential tariffs (and all other retail tariffs) to 4 5 tetri/kWh on July 28, 1997 However, the "average wholesale tariff" is probably closer to 3 1 tetri/kWh - the price for Sakenergo sales to distribution companies at 6 or 10 kV Barter is used for a portion of sales to high voltage industrial customers, and possibly for import and export sales, but the concept of "average wholesale tariff" is difficult to apply to a barter economy

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[5] World Bank *Staff Appraisal Report Georgia Power Rehabilitation Project*, Report No 16224-GE, May 8, 1997, pages 31 and 45-46

With regard to item b), the Government has not issued a decree defining the rules for setting regulated electricity prices It is too early to determine whether regulated tariffs will cover the costs cited in item c) by December 31, 1998 However, the GNERC has committed to raising the residential rate to six tetri by October 1, 1998 With regard to item d) we have no evidence that Sakenergo's average wholesale tariffs effective January 1, 1998 have been set to recover the cost of unpaid supplies to Abkhazia and South Ossetia The cost of supplying Abkhazia and South Ossetia is 29 to 30 million Lari per year if priced at 3 1 to 3 3 tetri/kWh

The average level of prices to industry in Georgia is below the level of western European countries and even below the level of central European countries (see Exhibit 1 1) Electricity prices in Georgia are far below the level in Turkey, its western neighbor Based on international comparisons one would expect cost-based prices to industry to be at least four cents/kWh for the largest customers and roughly six cents/kWh for customers at 6 kV or 10 kV Similarly, prices to households should be at least seven cents/kWh, the level in Hungary at the beginning of 1997, if these prices are going to achieve full recovery of reasonable costs However, it is unrealistic to expect prices in Georgia to reach the high end of either price range, industry or household, shown in Exhibit 1 1

The Commission does not have complete information on electricity prices in Georgia [Import and export prices have not been regulated by the Commission and the Electricity Law does not explicitly require such regulation] Some hydro stations have direct contracts for the sale of electricity to distribution companies or industrial companies, without the payment of a transit fee to Sakenergo A few generators have yet to receive their interim licenses Similarly, direct sales by Sakenergo to high-voltage industrial customers are supposed to be subject to Commission review and approval, but Sakenergo does not yet have a license The Commission cannot effectively control unlicensed entities

Electricity prices in Georgia are lower than prices in Armenia [6]

- The price of Sakenergo sales to distribution companies is either 2 38 or 2 54 cents/kWh, depending on voltage, but the price of comparable sales by Armenergo is about 3 1 cents/kWh on average, despite the fact that Armenia has some nuclear generation which is cheaper than thermal generation

- The price to low voltage (0 4 kV) customers in Georgia is 3 46 cents/kWh, while the price to non-residential customers in Armenia is 5 0 cents/kWh and the price for residential consumption above 250 kWh per month in Armenia is also 5 0 cents/kWh

[6] There is an exception retail tariffs in Armenia include a lifeline block for residential consumption below 100 kWh per month Georgian tariffs do not have a lifeline block and therefore Georgia has a higher price for this category of consumption

Exhibit 1.1
Average Electricity Prices in Different Countries

Country	Average price for industry [1] c/kWh	Effective date of industry price level	Average price for households [1] c/kWh	Effective date of household price level
Georgia	3.5	Aug-97	3.5	Aug-97
Central European countries				
Poland	4.0	4Q 1996	6.5	4Q 1996
Slovak Republic	5.0	1996	3.2	1996
Czech Republic	5.9	4Q 1996	4.1	4Q 1996
Hungary	6.3	1Q 1997	7.0	1Q 1997
Turkey	8.5	4Q 1996	8.9	4Q 1996
Western European countries				
Sweden	4.5	4Q 1996	11.3	4Q 1996
Greece	5.9	4Q 1996	11.5	4Q 1996
France	6.0	1995	16.7	1995
Finland	6.3	3Q 1996	11.1	3Q 1996
Ireland	6.5	2Q 1996	13.3	2Q 1996
Belgium	6.8	1995	20.3	1995
Netherlands	7.0	4Q 1996	14.4	4Q 1996
Denmark	7.2	4Q 1996	21.3	4Q 1996
United Kingdom	7.4	4Q 1996	12.6	3Q 1996
Spain	7.9	1996	19.1	1996
Austria	8.1	1995	16.6	1994
Germany	10.1	1995	20.4	1995
Italy	11.0	4Q 1996	17.3	4Q 1996
Portugal	11.1	1Q 1997	17.7	4Q 1996
Switzerland	11.5	4Q 1996	15.3	4Q 1996
Other countries				
Japan	18.5	1995	26.9	1995
United States	4.2	4Q 1996	8.2	4Q 1996

[1] Prices are converted to U.S. dollars using exchange rates
Source: International Energy Agency, Energy Prices and Taxes, Fourth Quarter 1996, pages 325-326, 416

In our judgment, Georgia is lagging behind Armenia in electricity tariff reform Comparison with prices in western market economies suggests that the true economic cost of wholesale power to the distribution companies is at least four cents/kWh and the cost to residential customers is at least seven cents/kWh One of the objectives of this tariff study is to determine more precise numbers that might be used as preliminary targets for Georgia, based on the data available, and might be adjusted in the future, based on data requested and filed according to formal tariff-setting procedures

1 2 Contents of this report

This report focuses on the structure of tariffs and the calculation of tariff levels The broader issues regarding tariff structure and timing are discussed in Chapter 2 We envision a tariff reform process in which prices paid to generators will be determined by a Market Members Agreement in a new wholesale market Transmission tariffs and tariffs to retail customers will continue to be subject to GNERC regulation Chapter 3 describes the conceptual framework for the determination of prices in the proposed wholesale market, during its initial phase

Our principal focus in this report is on the sectors that will continue to be regulated - transmission and distribution - rather than the generation sector, which will move to market-based pricing The Commission has already set tariffs for individual generating stations, including separate capacity and energy tariffs for thermal generators The hydro tariffs appear adequate to cover the operating costs and at least the routine maintenance expenses of hydro stations The energy tariff for Gardabani appears to be adequate for recovery of fuel cost on Units 9 and 10, and perhaps Units 3 and 8 as well The next step in tariff reform is for the Commission to gather the data necessary to set tariffs "to at least cover all operating and maintenance costs, interest on borrowed capital, full provisioning for bad debts, and depreciation based on revalued assets" as the Government agreed with the World Bank Therefore, we prepared *Schedule A Cost Data for Generation Licensees*, shown in Appendix L

In Chapter 4 we analyze the mix of generation sources - hydro, thermal, and imports - to provide an estimate of the average cost of wholesale power to the distribution companies The accuracy of the price assumptions for individual generators is less important than (1) the percentage share of thermal generation and imports, and (2) the accuracy of the projection of import prices

In Chapter 5 we present a calculation of transmission tariffs that can be implemented in the wholesale market Chapter 6 describes the terms of service to retail customers, including the definition of customer classes Finally a spreadsheet model to calculate retail tariffs is presented in Chapter 7 The retail tariff calculations in Chapter 7 include an allowance for transmission costs that is based on the same data as the transmission tariff calculation in Chapter 5 Therefore the transmission tariff is effectively "included" in the retail tariff

The results in Chapter 7 suggest that the price of wholesale power sales to the Telasi distribution company should be about 4 9 cents/kWh and the residential tariff should be about 7 7 cents/kWh, which is between the price level in Hungary and the price level in Turkey These calculations are based on long run marginal costs, without a projection of the financial revenue requirements of the transmission licensee and the distribution companies based on international accounting standards Detailed financial projections require a level of accounting reform that has not yet been implemented in the power sector

CHAPTER 2
RECOMMENDED APPROACH TO PRICE REFORM

The purpose of this chapter is to discuss the need for electricity tariff reform in the context of commercialization and privatization of the power sector Although it would be desirable for GNERC to have detailed cost data, financial information, and detailed technical information on capacity and energy flows, it may be necessary for the Government of Georgia to establish tariffs on the basis of preliminary or "best available" data so that the commercialization and privatization process is not slowed down This report is based on the data available to Hagler Bailly and therefore this chapter presents the context in which the quantitative results contained in Chapters 4, 5, 6, and 7 may be reviewed

2 1 Commercialization of the power sector

Like many other countries of the former Soviet Union, Georgia has electricity tariffs that are low by international standards, and the sector experienced a financial crisis following national independence Unfortunately, Georgia's power sector never emerged from a financial crisis In most enterprises and companies in the power sector there is not enough cash flow to purchase parts and supplies for normal maintenance, to pay salaries, and to fund capital expenditure programs The power sector does not provide firm service Customers experience power outages lasting several days (in Tbilisi) or several weeks (in Gori, for example) Only a few small hydro stations have been privatized, and the total amount of money received through privatization of small hydro stations is insignificant in relation to the investment needs of the generation sector

If the entire economy were stagnant or declining, the poor performance of the power sector and the slow pace of privatization might be considered unavoidable However, real GDP grew by 2 4% in 1995 and 10 5% in 1996, with economic recovery led by an emerging private sector in agriculture and services Small-scale privatization is virtually complete and about 75% of medium and large-scale enterprises have been privatized [1] Informal indicators of consumer spending in Tbilisi, such as the amount of traffic and the number of new shops and cafes, suggest that the purchasing power of Georgian consumers is rising The public sector is also making its own "economic recovery" in a modest way Tax revenues rose from 2% of GDP in 1993 to 7 2% of GDP in 1996, and the Government is able to borrow enough money to fund public

[1] World Bank *Background Information to the Consultative Group for Georgia The Economic Reform Program and The World Bank Group s Assistance Strategy*, Paris, December 11, 1997, pages 2 and 5 Georgia has a significant underground economy and therefore economic statistics must be viewed with caution

expenditures at 14% of GDP without a high level of inflation Public expenditure was about 14% of GDP in 1996 and is not expected to exceed 14-16% of GDP during the next three years [2]

Today the power sector infrastructure is in such bad condition, and the cost of rebuilding is so large in relation to the Government's financial resources, that it may appear obvious to western advisors that improvement will require "financial rehabilitation" and "an appropriate regulatory framework to promote efficiency and attract private investment "[3] However, many Georgians appear to believe that the delivery of electric power to the population is the responsibility of the Government Our impression is that some Georgians, including decision makers in the Government, are unsure whether electricity is a product or service that should be provided by the Government to the citizens of the country, or a commercial product that should be provided only to customers who pay for it As a result, there is no real consensus regarding the financial performance targets that should be met by electricity tariffs

In setting tariffs the Commission is required by the Electricity Law to

- Take into account State Policy in regard to priority consumers for electricity supply, provided, that it shall not prevent a Licensee from exercising any rights granted in its License to disconnect any Legal Person or individual for failure to meet its payment obligations under any contract or approved terms and conditions of service,

- Take into account State Policy in regard to subsidies, but it is prohibited to subsidize any category of the consumers on account of Licensee or any other category of consumers [4]

These words might be viewed in the context of the Government's track record regarding energy sector debts When the Government became independent in December 1991 it had no external debt, but by the end of 1994 it accumulated almost $1 billion in external debt, including debts to FSU countries and Iran, under repayment terms that could not be met The bulk of the obligations to FSU countries arose from non-payment for natural gas imports from Turkmenistan [5] A portion of this gas was used by power sector enterprises to generate electricity or provide district heat The power sector accumulated a debt to Russia (roughly 45 million Lari) for the delivery of electric energy to Abkhazia, and accumulated debts for natural gas and mazut delivered to Gardabani Tbilsresi has never purchased mazut on the basis of a competitive tender and has never paid for fuel using power station revenues At the beginning of 1998 the

[2] Tax revenues were 30% of GDP in 1991 World Bank, *Background Information to the Consultative Group for Georgia* pages 1, 4, 5, 11

[3] World Bank *Background Information to the Consultative Group for Georgia*, page 6

[4] Georgian Electricity Law of 1997, Clauses 36 (1) f and 36 (1) g

[5] World Bank, *Background Information to the Consultative Group for Georgia*, page 9

Government was attempting to obtain fuel for Gardabani by incurring an obligation to deliver electric energy to Turkey - incurring a "debt" in barter terms - under a contract with a British-Georgian firm Informal reports suggest that in January 1998 the Government agreed to receive 4 million kWh per day from Russia without paying for it, and accepted an obligation to give Russia a larger equity share of the transmission system

Sakenergo has a *de facto* obligation to deliver energy to Abkhazia and South Ossetia but it is not clear whether Sakenergo submits an invoice for the cost of energy delivered, or if the invoice is paid The private firm Energia-Plus is responsible for collecting money to pay for this electricity Our understanding is that the delivery of energy to Abkhazia and South Ossetia is an obstacle to the commercialization of Sakenergo

GNERC has not clarified the relationship between electricity tariffs and power sector indebtedness The Commission has not issued a resolution or decision setting the level of retail tariffs, transmission tariffs, generation tariffs for direct sales to distribution companies, import prices, export prices, or the average price of electricity purchased by Sakenergo

For this tariff study we assume that electricity is a commercial product that should be provided only to customers who pay for it No subsidies to the power sector are included in our tariff calculations and the accounts payable accumulated by public sector enterprises are not identified as a cost component to be recovered in tariffs Because accounts payable are not a source of funds for capital expenditure programs, we do not consider the interest rate on accounts payable as a component of the cost of capital

2.2 Which comes first - new tariffs or new investors?

Large investments will be needed to rebuild the power stations and networks of the Georgian power system, and we assume that most of the investment over the next ten years will come from the private sector At each level - generation, transmission, and distribution - the tariff has to be high enough to attract investment, and has to be implemented under a procedure that will attract investment

If future investments could be predicted, and there were accurate data concerning the value and condition of existing assets, it would be easier to set tariff levels in the early stages of privatization However, not only are there problems with data availability, but rehabilitation is not simply a matter of replacing existing equipment Georgia's power sector was a small component of an integrated Caucasus power system Georgia's economy was built around command decisions based on the assumption that electricity was almost costless The result is that the future structure of Georgian electricity demand will differ substantially from past patterns of demand One consequence is that it may be necessary to sharply reduce the amount of 0 4 kV line owned by the distribution companies

In generation and distribution the Government is planning to privatize many of the existing companies To be fair to potential investors, the Government (GNERC, Ministry of Fuel and Energy, and the Ministry of Property) should establish standard procedures regarding tariff-setting for companies to be privatized The following questions need to be decided

- Should a generation tariff for an existing station be established before it is privatized, so that the investor can estimate the present worth of the asset, or after the investor has purchased the station and submitted plans for rebuilding or expanding the station?

- Should a distribution tariff be established before a distribution company is privatized, so that the investor can estimate the present worth of the company, or after the investor has purchased the company and submitted plans to build and operate a specific set of assets - overhead lines, underground cables and transformers?

The answers to these questions have an effect on the choice of tariff methodology If the tariff is raised before the investor has purchased the company, the objective of the tariff calculation is to make an estimate, based on limited data and assumptions, of the price level that will be high enough to attract the necessary level of investment If the tariff is raised after the investor has presented a plan describing exactly what he will build and operate, the data will be more precise

The calculations in Chapters 6 and 7 provide tools that could be used to implement the first alternative - establishment of a tariff prior to privatization - or perhaps an early application of the second alternative This report is not intended to provide a substitute for the normal regulatory process of gathering, auditing and validating the numbers used to establish tariffs

It is quite possible that new facilities will be built only on the basis of a competitive wholesale market in which capacity prices are administered by Market Members and energy prices are set by a competitive spot market Because this wholesale market has not yet been established, however, GNERC should consider the possibility that it will need to set the tariff for a new power station The tariff must be high enough to attract investment, and the following question arises

- If a generation tariff for a new power new station is subject to GNERC regulation, should the tariff be established before the plant is built, or after the facility starts operation?

If the tariff is established before the plant is built, all that is needed is GNERC approval of the power purchase agreement between the licensee and the entity responsible for purchasing the plant's output In the United States this type of Generation Licensee would be considered an independent power producer and not a regulated public utility The licensee would not be expected to file applications for tariff changes Alternatively, if the tariff is established after the facility starts operation, the Licensee would be considered a regulated public utility and would have the right to file applications for tariff changes Ideally a decision on this issue should be taken by the appropriate governing body according to the Market Members Agreement In our view, however there is no need for any new Generation Licensee to be a regulated public utility, and therefore GNERC should either deregulate the prices charged by these stations or limit its regulatory review to the approval of power purchase agreements

In the transmission sector the Government is not planning any privatization, and therefore it is not necessary to consider the bidding strategies or needs of equity investors There is a possibility, however, that Sakenergo will attempt to borrow money (or the Government will borrow money and on-lend it to Sakenergo) for the reconstruction and expansion of the very high voltage network (500 kV, 330 kV and 220 kV) and the high voltage network (110 kV and 35 kV) One possibility is that GNERC can raise transmission tariffs quickly so that Sakenergo can start capital repairs and begin negotiations with possible lenders Another possibility is that GNERC can make a commitment to raise transmission tariffs as necessary to implement a least-cost plan for the transmission network, but before approving the plan, GNERC will need to know the sources of financing and will need to evaluate the effect of alternative plans on the level of tariffs The policy question can be stated as follows

- Should a transmission tariff be established before or after a capital expenditure plan and a financing plan for the transmission system are approved?

The calculations in Chapter 5 provide tools that could be used to implement the first alternative, that is, setting a transmission tariff before a detailed capital expenditure plan and financing plan are provided by Sakenergo

CHAPTER 3
TRANSITION TARIFFS FOR THE WHOLESALE MARKET

The purpose of this chapter is to describe the initial structure of prices and tariffs in the wholesale market after the Market Members Agreement (MMA) is signed and the power pool starts to operate A copy of the market rules is provided in Appendix O

The end goal of the electricity market reform is to create a wholesale electricity market where prices are determined through the competitive interaction of supply and demand In such a market competition between electricity suppliers serves to control prices and provide incentives for efficient performance This is a sophisticated market model which embodies many market-based concepts and institutions Given the lack of a market-based economic tradition in Georgia, the rudimentary managerial, technical, and information systems in the existing power sector enterprises, and the payments and related financial problems in the electricity supply industry, a sudden leap to such a sophisticated, technology-laden wholesale market model is not feasible or recommended at this time For this reason a gradual transition to a market-based wholesale pool is recommended

In order to successfully develop a competitive wholesale electricity market based on free market principles, the current wholesale market must evolve through several steps, or phases, of development The initial phases of the wholesale market development process are designed to educate the wholesale market members in basic commercial practices such as contracting, marketing corporate control, fiscal control and accountability, and cost-based as well as competitive pricing At the same time the initial phases of the market will work to ensure sufficient and reliable cash flow to wholesale market members This will place wholesale market members in the position to procure and install the necessary technology (communications, computers, hourly meters) to move towards a more sophisticated market model At least three distinct phases are currently envisioned to achieve this goal

Phase I - Regulated cost-based energy and capacity tariff

Phase II - Spot market hourly marginal pricing based on actual, auditable energy costs with a regulated capacity price

Phase III - Spot market hourly marginal pricing based on value without a capacity price

3 1 Phase I Wholesale Tariffs

In order to mitigate the possibility of rate shock to the power customers as the result of introducing market reform, it is recommended that the initial wholesale pool price determination methodology embodied in the MMA follow a cost-based model which will be approved and regulated by GNERC This regulated price will be based on the actual cost of service of each of the generators The wholesale market customer would pay a weighted average of the various costs of service

Due to current metering constraints, the regulated wholesale pool tariff will be set monthly on an *ex post* basis At the start of the wholesale electricity market, power generators in Georgia must provide the GNERC with their appropriate cost of service data The GNERC will then determine the appropriate cost of service tariff Once the initial cost of service tariff is adopted, the Settlement Manager will collect electricity production and consumption data from the wholesale meters and calculate the wholesale electricity price based on the average cost of service submitted by all generators producing in that time period If a supplier's cost of service exceeds its allowable price, due to reasonable changes in fuel and other variable costs, the supplier can reapply to GNERC to have its tariff adjusted Billing and payments will be based on actual costs and production within a specific month

The simplified example provided in the table below illustrates this concept At the end of the month the Settlement Manager collects cost of service data from all generators which sold electricity to the wholesale pool during that time period as well as metered data on the amount each generator actually produced These figures, in conjunction with the consumption metered data are then used to calculate the average cost of service for the industry

Exhibit 3-1

Hypothetical Wholesale Power Cost Calculation

Plant	Energy Cost of Service ($/MWh)	Energy Output (MWh)	Revenue	Average Cost of Service for Energy ($/MWh)
Gardabani	50	10,000	$ 500,000	
Inguri	17	100,000	$1,700,000	
Small Hydros	10	52,000	$ 520,000	
Total Production		162,000	$2,720,000	
Losses		32,000		
Total Consumption		130,000	$2,720,000	$20 92

25

The wholesale electricity price in this example is $20 92 per MWh Each wholesale electricity customer which purchased electricity from the pool during the month will be billed the amount they purchased times the wholesale electricity price Payments will then be collected and divided among suppliers by the settlements agency on a *pro rata* basis according to their individual cost of service and their amount of actual production

The cost of service approach to wholesale pool pricing is recommended during Phase I to ensure that all generators initially have the funds to cover their costs of operation as well as their cost of capital Their revenue stream will also be stabilized by adding a regulated capacity price for each plant selling to the wholesale market Thus, in the example above, wholesale customers will pay $20 92 per MWh plus a capacity payment (and dispatch service provider fees) The capacity payment will provide generators with a stable revenue stream throughout the time period, while the energy component provides suppliers with variable revenue according to actual costs of operation In addition, by requiring cost of service pricing, the power suppliers will be encouraged to begin implementing real cost accounting standards This will enable the power generators to better understand their business costs, a critical step for entering Phase II in which power generators must offer their units according to marginal cost calculations

Before the wholesale market is able to move to Phase II, it is recommended that the industry operate under the Phase I conditions for a period of time (two to three years) sufficient to allow participants to adjust to the new market concepts and procedures and to build up the technology capabilities needed to progress to the next step During this period the payments and other financial problems plaguing the industry must be successfully resolved in order to make the move to a more competitive market feasible It is recommended that market performance targets be set specifying collections levels and other key benchmarks that must be met before the transition to Phase II can begin

Once the market has implemented the proper technological requirements (i e , communications and metering) and certain market performance benchmarks have been achieved, the wholesale market will move to Phase II - implementation of a wholesale spot market The treatment of wholesale pricing under Phase II and Phase III will be discussed in later documents The following sections define a number of issues central to wholesale pricing during Phase I

3 2 Identification of buyers and sellers in the wholesale market

The Market Members Agreement governs the activities of several different kinds of buyers and sellers in the wholesale market The following entities will be sellers to the pool

- Generation licensees, and,
- Import Trader licensees, which represent the Georgian interface for foreign sellers

Generation licensees and Import Trader licensees are collectively known as *Wholesale Suppliers*

The following entities will be buyers from the pool

- Large industrial customers, known as *High Voltage Customers*, who are directly connected to the high voltage grid and do not receive electricity from distribution licensees,

- Distribution licensees, including enterprises with local Government ownership, joint stock companies with private ownership and joint stock companies with a mixture of local Government and private ownership, and,

- Export Trader licensees, which will represent the Georgian interface for foreign buyers

High Voltage Customers, Distribution licensees and Export Trader licensees are collectively known as *Wholesale Customers*

The wholesale market includes four service providers the Transmission Provider, the Dispatch Provider, the Settlement Manager, and the Market Funds Manager None of these service providers can be a buyer or seller of electricity Regardless of the wholesale customer's source of supply, the customer must pay the Settlement Manager for all of the services offered by the service providers, including transmission service, dispatch service, settlement, and market funds management

3 3 Types of wholesale market transactions

The wholesale market includes four kinds of transactions which will be subject to price regulation by GNERC

- Purchases and sales of electricity through the pool by members of the wholesale market that are governed by the rules of the MMA,

- Transmission services provided to Wholesale Customers under the rules of the MMA,

- System security services provided to Wholesale Customers under the rules of the MMA, and,

- Service Provider fees for the Scheduling/Dispatch, Settlement and Market Funds managers that are charged to Wholesale Suppliers and Wholesale Customers

In addition, the wholesale market has two types of transactions in which GNERC would not directly regulate the price of electricity sold

- Transactions between the Import Trader licensees or the Export Trader licensees and foreign entities, and,

- Transactions between an Import Trader licensee and an Export Trader licensee Such transactions are effectively transiting through Georgian The fee for the transmission service provided to these transactions will be regulated by GNERC

Notwithstanding the Electricity Law, it is recommended that direct contracts not be regulated by GNERC In lieu of regulation by GNERC, it is recommended that a Generator Licensee s direct contracts be limited to a maximum of 20% during the first three years, 60% during the following two years, with limitations removed for the subsequent years of market operation It is also recommended that direct contracts be limited during Phase I to a maximum length of one year Reducing the length of the direct contracts will provide the flexibility needed to make the move to Phase II in the future

In addition, it is strongly recommended that an industry-wide training program take place before direct contracting in the wholesale market is allowed Wholesale Market Members must understand the business consequences of the direct contracts that they negotiate as well as gain an understanding of necessary contractual terms, clauses, and formats Without proper training, inexperienced wholesale market members could negotiate unfavorable contracts, worsening their financial positions This could potentially sour the Government's support of direct contracting in the future

3 4 Commodities sold in the wholesale market

To describe the wholesale market in simple terms, one can say that there are five commodities being bought and sold

- Capacity, which is measured in kW,
- Energy, which is measured in kWh,
- Transmission service, which is measured in kW,
- System Security services, which will be allocated on a kWh basis, and,
- Service providers fees, which will also be allocated on a kWh basis

To describe the wholesale market more precisely, it is necessary to distinguish between the capacity and energy purchased and sold through the Pool and that which is purchased and sold through Direct Contracts During Phase I the wholesale pool tariff embodied in the MMA will be a fully regulated tariff The tariff will include two components, a capacity price per kW per month and an energy price per kWh Both of these components will be cost based and specific for each generating facility on the Georgian power system GNERC will be responsible for approving both the methodology and the tariff rates

The capacity price will be a specific price per KW per month for available capacity provided by a generating facility The capacity price serves to provides a stable stream of revenue that can be used to help the generator obtain bank financing for new generating capacity or major rehabilitation of existing capacity The MMA will specify the manner in which the monthly available capacity of all generating facilities will be determined

The wholesale price for energy provided by each generator in each time period will be set by a predetermined rate based on its historical variable fuel cost and variable operating and maintenance costs GNERC will set the energy rate for each generating facility Generators will receive payment for the kWh sent out from their facilities for each trading period at the approved rate based on actual generation during the time period

Wholesale Customers will pay the average of all the generators' capacity and energy rates weighted by the monthly available capacity and the total kWh delivered to the wholesale market These amounts will be based on actual consumption by Wholesale Customers in the trading period rather than estimated consumption

The objective of this approach is to permit the transition to a competitive, unregulated market Although in theory the best energy price would be one that varies hourly, the Georgian power sector is not currently equipped to implement hourly spot pricing

The supply of capacity and energy adequate to meet the needs of wholesale customers will depend on the following assumptions

- Wholesale customers must send payments for capacity and energy to the Market Funds Administrator on a timely basis, to avoid interruption of energy supply,
- The price of Pool Wholesale Energy should be set to cover the fuel cost and variable operation and maintenance cost of each generating facility,
- Power sector reforms in Georgia, including privatization and the implementation of the Market Members Agreement, are expected to enable generators and distribution companies to attract foreign investment and support for improvements to plant, technology, and management, and,
- It is assumed that Russia will be able to provide enough capacity and energy to Georgia to make up the difference between the amount of capacity needed to provide a reliable supply of electricity in the wholesale market, and the total capacity available from generators and from Armenia and Azerbaijan

If the MMA enforces payment for electricity in the wholesale market and neighboring countries are willing and able to sell capacity under contracts with a term of one year or less, the power system should not have a deficit of capacity

CHAPTER 4
MARGINAL COST AND AVERAGE COST OF SUPPLY

This chapter presents a discussion of issues involved in regulation and deregulation of the prices of electricity sold by generating stations in Georgia A supply forecast for 1999 is used to project the average cost of electric generation and imports purchased for resale to the distribution companies in 1999 The marginal cost of energy during peak periods is estimated on the basis of a ranking of supply sources by energy price This analysis of the cost of supply is an input to the calculation of retail tariffs in Chapter 7

4 1 World Bank loan conditionalities

In the negotiation of the Power Rehabilitation Project loan in the Spring of 1997, the Government of Georgia agreed to implement various measures requested by the World Bank, including the following

- By December 31, 1998 set regulated tariffs to at least cover all operating and maintenance costs, interest on borrowed capital, full provisioning for bad debts, and depreciation based on revalued assets,

- To take all actions necessary for Tbilsresi to be fully paid by Sakenergo for electricity supplied at the rates established under the Power Purchase Agreement between Sakenergo and Tbilsresi [1]

The World Bank envisioned a Power Purchase Agreement which would specify

- Annual capacity and energy to be contracted and the proportion from old and new units,

- Capacity charge and projected fixed costs covered by this charge (depreciation, maintenance, interest, provisions for bad debts for the previous year, and wages),

- Energy charge covering fuel costs (including fuel consumption per kWh) and other variable costs, and provisions for adjustment,

- Metering, reporting and auditing requirements, and,

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[1] World Bank *Staff Appraisal Report Georgia Power Rehabilitation Project* Report No 16224-GE, May 8, 1997 pages 31 and 45-46

- Invoicing requirements supply and payment terms, and penalties and remedies for non-compliance with the contract [2]

In the recommendations supporting the Second Structural Adjustment Credit, the World Bank recognized that the Electricity Law "opens the way to competition in the production and distribution of electricity "[3] The Government of Georgia has agreed that by December 31, 1998 regulated tariffs will cover certain cost categories listed above, including depreciation based on revalued assets

4 2 Regulation and market structure

In Resolution #4 dated October 8, 1997 (see Appendix E) the GNERC set regulated tariffs for generators representing most of the generating capacity in the country The tariffs are valid until April 1, 1998 and applications for new tariffs were to be submitted to GNERC by February 15, 1998 Resolution #4 covers all generating stations except the Tblisi thermal station, which is covered by Decision #4 dated November 25, 1997, and a few small hydro generators The GNERC issued a decree establishing an Electricity Tariff Methodology on July 1, 1998 (See Appendix P)

The Commission faces the question how to test the information submitted by generation licensees to determine whether the costs are reasonable [4] The Commission may also need to determine whether a reasonable effort is being made by Sakenergo, or by distribution companies with direct contracts to obtain energy supplies at least cost Although Georgia has low-cost hydro resources, some of its supply-side resources are expensive For example, the price of electricity imported from Russia during Russian peak periods is reported to be 5 4 cents/kWh[5] and in the first quarter of 1996 the price of electricity imported from Azerbaijan to Georgia was 5 cents/kWh [6]

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[2] World Bank, *Staff Appraisal Report Georgia Power Rehabilitation Project*, page 26

[3] World Bank *Report and Recommendation of the President of the International Development Association to the Executive Directors on a Proposed Second Structural Adjustment Credit in an Amount of SDR 44 2 Million to Georgia*, Report No P-7165-GE, August 11, 1997, p 7

[4] See Appendix K, *Statement and Request for Comments of the Georgian Electric Regulatory Commission Regarding Proposed Rule and Terms of Tariff Setting*, pages 3-5

[5] According to information provided by Sakenergo on 28 November 1997, a peak period multiplier of 1 8 can be applied to an import price of 3 0 cents/kWh The actual price in an agreement between Russia and Georgia could be different from this quoted price

[6] This is the price shown in paragraph 2 2 of the contract No 1611/95 dated 16 November 1995, for delivery and exchange of electric energy, between Azerenerghy and Sakenergo

If there were a small number of standard power station designs used in all countries and a standard mix of technologies, it would be possible to compare generating costs in different countries and come up with guidelines to determine whether the costs reported by domestic generating companies are reasonable in comparison with international experience However there are many designs and many technologies, and costs vary widely Normally a regulatory authority or central authority needs some sort of assurance that generation and import costs are reasonable [7]

Until generating stations are privatized by investors with significant capital resources, the scope of the Commission's review of generating costs will be simplified by the poor financial condition of the generation sector A financially healthy generating company (or companies) would face the following questions

- How much new generating capacity is needed to provide firm service to customers? When should it be built, and what type is needed?
- What is the best mix of imported electricity versus domestic generation?
- Which generating units are so old and worn out that they should be permanently shut down?
- Which thermal units are so inefficient that they should be replaced by new combined cycle plants or other technologies with low heat rates?

There are different ways to address the issue of cost control in the generation sector The policy alternatives generally include either some form of market mechanism, cost regulation or direct Government control

1 *Establish a wholesale market under a set of market rules* If there are many generating companies and many wholesale market customers (distribution companies and large industrial customers) connected by a high-voltage network, it is possible to have a Market Members Agreement under which generators sell electricity to wholesale market customers In the initial stage of the market, energy and capacity prices for each generator may be set by the regulatory authority, later, energy prices may be determined by competitive spot market bidding and an administered capacity price may be set by the regulatory authority It is also possible to have a wholesale market in which energy is sold in the spot market and there is no capacity price

2 *Allow a direct contract market to develop* If there are many generating companies and many wholesale market customers (distribution companies and large industrial

[7] GNERC has a responsibility to ensure that generating costs reflected in regulated tariffs are reasonable The Government of Georgia has a responsibility to ensure that the average cost of supply (including imports) is reasonable

customers) connected by a high-voltage network it may be possible to establish rules and conditions for the use of the high-voltage network so that generators compete for the opportunity to sell electricity under direct contracts with wholesale market customers The Government can make the assumption that market competition will prevent the generators from charging excessive prices Alternatively, the Government can make the assumption that market competition will prevent generating companies from investing in high-cost or inefficient technologies, but price regulation is needed to prevent the generating companies from making excessive profits

3 *Regulate expenditures and investment* It is necessary to identify a regulatory authority responsible for establishing an annual budget for each generating company (genco), or a budget for each power station Each genco or power station must be required to submit a budget request including the amounts necessary for fuel, operation and maintenance, capital repairs and capital investment The regulatory authority will decide whether the submitted expenses are prudent and conduct inspections or audits to ensure that the cost estimates are reasonable and money is not wasted

4 *Develop and implement a least-cost plan* For this option it is necessary to identify a central authority responsible for establishing an annual budget for the generating sector, based on a least-cost plan or Integrated Resource Plan for a vertically integrated power company or for the power sector of the country The least-cost plan should determine whether to repair old generating stations, rebuild them with different technology, replace them with completely new stations or increase the level of electricity imports The central authority will decide which repairs or investments deserve the highest priority The plan should compare demand-side investment with supply-side investment The central authority would approve construction of new stations consistent with the plan, under some form of ownership and investment that is politically acceptable - public sector ownership, or private ownership based on competitive tender, or power purchase contracts with independent power plant developers

The Georgian power sector is moving in the direction of the first option - the establishment of a wholesale market under a set of market rules Ultimately generation prices should be set by competitive forces, but in the interim until the current supply deficit is eliminated, regulated tariffs will be necessary It is difficult to predict the competitive market price level at which supply and demand for electric energy will be in balance, once wholesale retail customers are forced to pay for electricity received, but our understanding is that GNERC would prefer to keep prices under regulatory control to "protect" the consumer from a situation in which generators are allowed to charge whatever the market will bear To some extent this assumption is already being challenged by the negotiation of direct contracts between generators and wholesale customers

There exists some political support for the second option - allowing a direct contract market to develop The direct contract market is developing because Sakenergo is not providing enough money to the generating stations, who would like to be paid for electricity delivered to the grid To the extent that the central Government fails to deliver 24-hour electricity supply to the country, local Governments may try to obtain more supply by negotiating directly with generating stations If the wholesale market can be formed on the basis of market rules that enable wholesale customers to obtain a firm supply of electricity, the need for direct contracts will diminish

The third option - regulating expenditures and investment - will be required for the transmission and distribution sectors As natural monopolies, these two subsectors must be regulated to protect consumers A generation market, given a sufficient number of generators, will provide protection for consumers The advantage of markets over regulation include the avoidance of "capture" of the regulatory agency, a shift of investment risk from the consumers to private investors, and competitive pressure for efficient operation

The fourth option - to develop and implement a least cost plan - does not appear to be viable in Georgia because the Government is planning to privatize many of the generating stations and establish a wholesale market that will promote competition among generating companies

Operation and repair of existing stations is attractive to Government authorities who do not have the funds or resources to build power sector facilities but want to preserve the appearance of maintaining control It can be effective during a transition period of two or three years, but it does not work well over long periods of time

During the next five to ten years it will be necessary to provide the generation sector with enough money to rebuild and recover from many years of inadequate maintenance and lack of investment Although the Soviet economy had a strong capability to build new generating stations and transmission lines, the quality of power station maintenance was uneven What was "inherited" from the Soviet Union was already in need of repair, in some regions, and for several years the economic crisis following the breakup of the Soviet Union made it difficult to repair and rebuild the assets that were inherited As time passes, it becomes increasingly difficult to maintain transmission and generation capacity without a major capital investment program

4 3 Regulation of tariffs for generators

Hagler Bailly is assisting the Commission in the development of procedures for tariff-setting (see Appendices J-L) This technical assistance should help the Commission to implement new generation tariffs in accordance with the December 31, 1998 target which was accepted by the Government of Georgia

In Georgia the Government has made no attempt to form generation companies with ownership of two or more hydro stations As a result, the financial data and other information needed to prepare a tariff application must be assembled by a large number of power station managers For the smaller stations it will be difficult to prepare tariff applications that meet international accounting standards (as required by the Electricity Law) and therefore the Commission may want to consider a fixed tariff (for example, two tetri/kWh) for small hydro generators

The revaluation of assets could have a major effect on generator tariffs There are a number of alternatives which can be applied to revaluating existing assets replacement cost, Soviet cost, estimated current value, zero value

According to the Kantor report on electricity tariffs, the replacement cost of hydroelectric stations was $2 672 billion while the replacement cost of thermal stations was $1 211 billion [8] These numbers suggest that in 1999 the depreciation expenses of generating stations may be much larger than they are today If balance sheets of generating companies are going to be revised on the basis of replacement cost, it would be desirable for an architect/engineering company to conduct site-specific evaluations of the replacement cost of hydro stations

The Soviet book values could be maintained, since they are roughly based on the original cost of assets Alternatively, the book value could be sent to zero since these assets were transferred to the Georgian Government at no cost Finally, the current value could be estimated, either through an audit of assets or by application of some formula to account for excessive depreciation For example, replacement costs might be adjusted to account for a general lack of maintenance and repair over the last decade

A high value of assets will result in large cash flows from depreciation and a return on assets, if applicable Setting the value of assets at a lower level will mean smaller cash flows to the company owning the assets In the case of Government-owned companies, given the lack of accounting controls and the instability of the financial sector at the current time, large cash flows may result in substantial waste Setting low asset values would reduce the cost of purchasing the companies when privitized

Although the Government has approved the concept of partial privatization of the generation sector, the distribution sector is planned to be the first to be privatized Because the Enguri reservoir is in Abkhazia, it is unlikely that Enguri will be privatized for the foreseeable future Without private investors the Generation Licensees may be at a disadvantage in arranging financing for capital repairs, negotiating power purchase agreements, and bidding effectively in a competitive market

[8] Kantor Management Consultants *Electricity Tariffs and Collection Mechanism*, Final Report April 1996 Appendix C 'Review of Asset Condition and Value ' Table C-2 This report was prepared for the EBRD and for Sakenergo

4 4 Data needed to calculate retail tariffs

The amount of information on generation and import costs needed to calculate the retail tariff depends on the level of sophistication of the retail tariff structure In Georgia, the retail tariff for all customers served by distribution companies is now 4 5 tetri/kWh There are no monthly adjustments, seasonal adjustments, or time of use tariffs Even the wholesale tariff charged by Sakenergo does not have monthly adjustments, despite the fact that the average cost of power purchased by Sakenergo varies substantially from month to month The very simple tariff structure currently implemented in Georgia does not promote economically efficient use of electricity The price signal to the retail customer does not reflect any fluctuations in the economic cost of electricity, except the change in price level that occurs when the Government sets new retail tariffs

For the purposes of calculating retail tariffs (described in Chapter 7) a spreadsheet model was used The model accepts the following inputs

- the marginal cost of generating capacity in dollars per kW of gross generating capacity,
- the marginal cost of energy generated or imported during peak periods, in cents per kWh,
- a price for the cost of energy generated during off-peak periods, in cents per kWh,
- load factor assumption and energy loss data that are used to calculate an average annual cost of energy supplied to the very high voltage (VHV) and high voltage (HV) grid for resale to wholesale customers such as distribution companies

Ideally, the first three inputs should be derived from a computer simulation model which would determine the economic dispatch of generating units and calculate the long-run marginal cost of supply at each generation level [9] The price for energy generated during off-peak and peak periods should be the average of hourly marginal costs for such periods over at least one year

The implementation of such a model was outside the scope of this study In addition, we do not recommend the use of marginal costs unless they are adjusted (that is, scaled up or down) according to a financial forecast of revenue requirements Therefore, it was decided to forecast the average annual cost of energy supplied to the VHV and HV grid in 1999, and use this figure to set the off-peak price level (item 3 above) The off-peak energy price is not a marginal cost, but a figure that is selected so that the retail tariffs and the tariff for sales to distribution companies are based on the average annual cost of energy supplied to the VHV and HV grid in 1999

[9] USAID is planning to fund a least cost plan for Georgia, to be executed by Burns and Roe The findings of this study could be the starting point for a calculation of long run marginal cost

The year 1999 is the first year in which generator tariffs should "at least cover all operating and maintenance costs, interest on borrowed capital, full provisioning for bad debts and depreciation based on revalued assets " In other words, we assume that full cost recovery will not be reflected in tariffs until December 31, 1998 The forecast of the annual average cost of energy supplied to the grid is based on a projected increase in the cost of generation from Gardabani, an estimate of the increase in the average cost of domestic hydro generation needed for full cost recovery and an assumption that import prices (measured in cents/kWh) will not increase The calculation of tariffs for individual generators was not possible within the time frame of this study

4.5 Projected demand growth

One of the difficulties facing the distribution companies (other than Telasi) is that they have inherited an infrastructure of overhead lines, transformers, and underground cables designed to meet 1990 level of peak load and annual kWh sales, but the 1996 level of peak load and annual kWh consumption was at least 60% below the 1990 level It is difficult to set tariffs at a level that will cover the cost of capital repairs, operation and maintenance for a network that is 2 5 times "larger" than it should be

One possible strategy is to increase collections rates, provide firm service to retail customers, and hope that electricity demand will increase sharply or even return to the 1990 level so that there will be enough revenue to pay for the reconstruction of the 1990 network [10] If this strategy is to be pursued, however, it will be necessary to rely on expensive thermal generation and imports while hydro stations are under construction or expansion (assuming that capital resources will be available to expand Georgia's hydroelectric capacity) Georgia has a very large technical hydroelectric potential which is estimated at about 88 TWh annually, of which only about 10% has been developed [11] In theory Georgia could have high per capita levels of electricity consumption based on low-cost hydropower, if capital resources become available to support the development of the country's hydroelectric potential Regulating hydro would be needed to achieve national self-sufficiency in electricity supply, but run of river hydro could be used in connection with a seasonal exchange of energy with neighboring countries

For the purposes of developing an estimate of the average cost of supply in 1999, we assumed that hydroelectric generation will not increase from 1996 to 1999, but electricity supply to Georgia will grow 6% from 1996 to 1997, from 1997 to 1998, and from 1998 to 1999 Consequently we project an increase in thermal generation (from Gardabani Units 9 and 10) and an increase in imports These assumptions are intended to be part of a "most likely" scenario

[10] An increase in electric water heating and space heating load is more likely to occur if gas distribution networks will not be supplying gas and if district heating networks will not be supplying heat [These conditions are not part of a recommended strategy]

[11] World Bank, *Staff Appraisal Report Georgia Power Rehabilitation Project*, page 2

Higher demand growth will yield higher average costs per kWh due to greater reliance on thermal generation and imports With lower demand growth it is possible to eliminate imports by 1999

4 6 Resources to be dispatched

Generating resources and import resources available during peak periods can be ranked in order of energy price, as shown in Exhibit 4 1 This ranking is not representative of economic dispatch, because the run of river hydro should always precede regulating hydro, but the result is reasonably close to economic dispatch at the national level because the thermal generation (Gardabani and Tblisi ThermoCentral) has separate capacity and energy charges In theory it would be possible to have economic dispatch at the regional level (uniting Turkey and Iran with the region formerly known as the Caucasus Interconnected Power System) so that the benefits of regional cooperation would be precisely measured and shared among the participants [12] In the context of Exhibit 4 1 we assume that this level of regional cooperation will not exist in the near future, and that the ranking according to price per kWh (as shown) is an indicator of the dispatch order

The maximum capacity available from Russia during peak periods is estimated to be the full capacity of the Kafkasioni 500 kV line, or 1,200 MW The amount of "reasonably assured 1998 peak capacity" is only half this value, or 600 MW Even with this 50% reduction, the supply from Russia is the largest single import source during peak periods For peak loads over 2,000 MW the only sources we place in the ' reasonably assured" category are Azerbaijan and Russia

Energy can be imported from Turkey in winter under a barter arrangement in which Georgia delivers 1 8 kWh in summer for every 1 kWh received from Turkey in winter The value of the energy delivered in summer is assumed to be the average price of run of river generation, so the price of the energy received in winter is 1 8 times this price Therefore "Turkey (barter)" appears as a relatively cheap source of energy in Exhibit 4 1 [We assume that this Turkish import is not "reasonably assured" during Georgia's peak hours]

The "reasonably assured capacity" data in Exhibit 4 1 are used to generate a ranking of supply sources as shown in Exhibit 4 2 We estimate that in 1999 the actual peak load will fall somewhere in the range of 1,400 to 1,750 MW, that is, the range in which the marginal cost of energy is 3 3 tetri/kWh or 2 54 cents/kWh (supplied by Gardabani) For 1998 this is the marginal cost of energy during peak periods (Exhibit 7 10) and we assume that it will be the same in 1999

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[12] In principle the price paid for a particular source of imported energy does not need to equal the value per kWh used to determine the dispatch order The New England Power Pool is an example of a pool in which economic dispatch is implemented and the savings associated with regional cooperation are precisely measured

Exhibit 4 1
Peak Generating Resources Ranked by Energy Price, 1998

Station name or source of imports	Resource no	Type of resource	Ownership	Purchaser	Installed capacity MW	Working capacity in 1996 MW	Availability in 1998	Capacity derating for 1998 peak %	Reasonably assured 1998 peak capacity MW	Cumulative assured 1998 peak capacity MW	Energy price tetri/kWh	Capacity charge Lari/kW/ month	Basis for price	Energy price cents/ kWh
Russia (off peak)	66	import	foreign	Sakenergo	0			100%		1 396 0	2 34		not identified by Sakenergo	1 80
Russia (off peak)	66	import	foreign	Sakenergo	1200			100%		1 396 0	2 34		not identified by Sakenergo	1 80
Gardabani 10	43	thermal	Tbilsresi	Sakenergo	300	0	not working	100%	0 0	1 396 0	3 30	2 50	GNERC Res 4 and contract	2 54
Gardabani 3	40	thermal	Tbilsresi	Sakenergo	150	0	working	40%	90 0	1 486 0	3 30	2 50	GNERC Res 4 and contract	2 54
Gardabani 8	41	thermal	Tbilsresi	Sakenergo	160	100	working	44%	90 0	1 576 0	3 30	2 50	GNERC Res 4 and contract	2 54
Gardabani 9	42	thermal	Tbilsresi	Sakenergo	300	250	working	33%	200 0	1 776 0	3 30	2 50	GNERC Res 4 and contract	2 54
Russia (shoulder)	65	import	foreign	Sakenergo	0			100%		1 776 0	3 90		not identified by Sakenergo	3 00
Russia (shoulder)	65	import	foreign	Sakenergo	1200			100%		1 776 0	3 90		not identified by Sakenergo	3 00
Armenia	69	import	foreign	Telasi	100		planned	0%	100 0	1 876 0	3 90		contract	3 00
Armenia	68	import	foreign	Sakenergo	15		working	0%	15 0	1 891 0	5 46		contract	4 20
Iran	70	import	foreign	Sakenergo	200			100%		1 891 0	5 50	-	contract	4 23
Tbilisi ThermoCentral	44	CHP	#N/A	Telasi (?)	18	6	working	65%	6 3	1 897 3	6 00	2 50	GNERC Decision 4	4 62
Azerbaijan	67	import	foreign	Sakenergo	0		working	100%		1 897 3	6 50		contract	5 00
Azerbaijan	67	import	foreign	Sakenergo	330		working	50%	165 0	2 062 3	6 50		contract	5 00
Russia (peak)	64	import	foreign	Sakenergo	0			0%	0 0	2 062 3	7 02		not identified by Sakenergo	5 40
Russia (peak)	64	import	foreign	Sakenergo	1200			50%	600 0	2 662 3	7 02		not identified by Sakenergo	5 40
Tkvarcheli	72	thermal	Abkhazia	Abkhazia	220	0	not working	100%		2 662 3	3 30	2 50	Gardabani price	2 54
Sum					8 218 0	1 896 1			2 662 3					

Exchange rate 1 3

sign #N/A refers to absence of reliable data

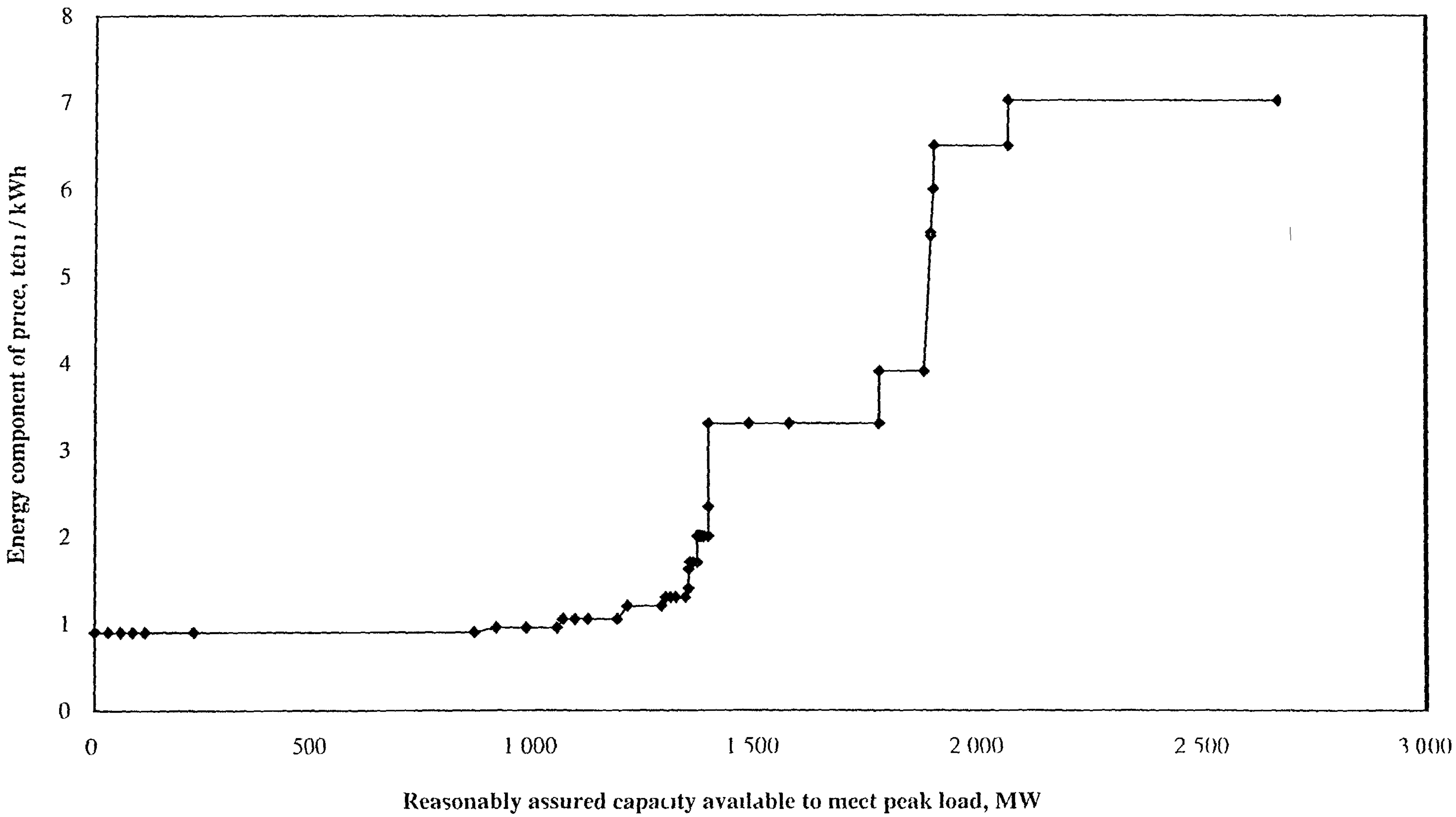
Exhibit 4 1
Peak Generating Resources Ranked by Energy Price, 1998

Station name or source of imports	Resource no	Type of resource	Ownership	Purchaser	Installed capacity, MW	Working capacity in 1996 MW	Availability in 1998	Capacity derating for 1998 peak %	Reasonably assured 1998 peak capacity MW	Cumulative assured 1998 peak capacity MW	Energy price tetri/kWh	Capacity charge Lari/kW/month	Basis for price	Energy price cents/kWh
Vardnili 2	3	daily regulating	Sakgeneratsia	Sakenergo	40	0	*Abkhazia*	100%			0 90		GNERC Res 4	0 69
Vardnili 3	4	daily regulating	Sakgeneratsia	Sakenergo	40	0	*Abkhazia*	100%			0 90		GNERC Res 4	0 69
Vardnili 4	5	daily regulating	Sakgeneratsia	Sakenergo	40	0	*Abkhazia*	100%			0 90		GNERC Res 4	0 69
Vartsikhe 1	6	run of river	Sakgeneratsia	Sakenergo	46	30	working	40%	27 6	27 6	0 90		GNERC Res 4	0 69
Vartsikhe 2	7	run of river	Sakgeneratsia	Sakenergo	46	30	working	40%	27 6	55 2	0 90		GNERC Res 4	0 69
Vartsikhe 3	8	run of river	Sakgeneratsia	Sakenergo	46	30	working	40%	27 6	82 8	0 90		GNERC Res 4	0 69
Vartsikhe 4	9	run of river	Sakgeneratsia	Sakenergo	46	30	working	40%	27 6	110 4	0 90		GNERC Res 4	0 69
Vardnili 1	2	daily regulating	Sakgeneratsia	Sakenergo	220	110	*Abkhazia*	50%	110 0	220 4	0 90		GNERC Res 4	0 69
Enguri	1	annual regulation	Sakgeneratsia	Sakenergo	1300	860	working	50%	650 0	870 4	0 90		GNERC Res 4	0 69
Tkibuli	12	annual regulation	Sakgeneratsia	Sakenergo	80	15	working	40%	48 0	918 4	0 95		GNERC Res 4	0 73
Khrami 2	11	annual regulation	Sakgeneratsia	Sakenergo	110	80	working	40%	66 0	984 4	0 95		GNERC Res 4	0 73
Khrami 1	10	annual regulation	Sakgeneratsia	Sakenergo	113 45	70	working	40%	68 1	1 052 5	0 95		GNERC Res 4	0 73
Gumati 2	15	run of river	Sakgeneratsia	Sakenergo	22 8	10	working	40%	13 7	1 066 2	1 05		GNERC Res 4	0 81
Gumati 1	14	run of river	Sakgeneratsia	Sakenergo	44	19	working	40%	26 4	1 092 6	1 05		GNERC Res 4	0 81
Rioni	16	run of river	Sakgeneratsia	Sakenergo	48	36	working	40%	28 8	1 121 4	1 05		GNERC Res 4	0 81
Lajanuri	13	daily regulating	Sakgeneratsia	Sakenergo	111 84	65	working	40%	67 1	1 188 5	1 05		GNERC Res 4	0 81
Shaori	17	annual regulation	Sakgeneratsia	Sakenergo	38 4	15	working	40%	23 0	1 211 5	1 20		GNERC Res 4	0 92
Jinvali	18	annual regulation	lease	various	130	70	working	40%	78 0	1 289 5	1 20		GNERC Res 4	0 92
Atskhesi	28	run of river	lease	Sakenergo	16	12	working	40%	9 6	1 299 1	1 30		GNERC Res 4	1 00
Ortachala	25	run of river	lease	Sakenergo	18	12	working	40%	10 8	1,309 9	1 30		GNERC Res 4	1 00
Chitakhevi	27	run of river	privatized	Sakenergo	21	10	working	40%	12 6	1 322 5	1 30		GNERC Res 4	1 00
Zahesi	26	run of river	lease	Sakenergo	36 8	29	working	40%	22 1	1,344 6	1 30		GNERC Res 4	1 00
Bjuja	29	run of river	privatized	Sakenergo	12 224	2	working	40%	7 3	1 351 9	1 40		GNERC Res 4	1 08
Turkey (barter)	71	barter	foreign	Sakenergo	0		working	100%		1 351 9	1 62		contract & Res 4	1 25
Turkey (barter)	71	barter	foreign	Sakenergo	100		working	100%		1 351 9	1 62		contract & Res 4	1 25
Alazeni	31	run of river	privatized	Sakenergo	4 8		working	30%	3 4	1 355 3	1 70		GNERC Res 4	1 31
Sioni	30	run of river	privatized	Sakenergo	9 14	4	working	30%	6 4	1 361 7	1 70		GNERC Res 4	1 31
Tetrikhevi	32	run of river	privatized	Sakenergo	13 6		working	30%	9 5	1 371 2	1 70		GNERC Res 4	1 31
Achara	45	run of river	Sakgeneratsia	#N/A	0 17		*Abkhazia*	100%		1 371 2	2 00		max hydro price	1 54
Zvareti	57	run of river	Sakgeneratsia	#N/A	0 218	0 1	not working	100%		1 371 2	2 00		max hydro price	1 54

Source data from Saqkenergo Generatsia and 1996 Sakenergo annual report

Exhibit 4 2

Peak Generating Resources Ranked by Energy Price, 1998



We assume that the full capacity of the Kafkasioni line can be used during off-peak periods to import energy from Russia at the "official" price of 1 8 cents/kWh This assumption has the effect of flattening the curve representing off-peak supplies (Exhibit 4 3) so that Gardabani is never dispatched during off-peak periods For off-peak loads below 1,500 MW there is no need to import from Russia For off-peak loads above 1,500 MW, Russian power is available Even in the winter season, Gardabani could be run in cycling mode, that is shut down during the hours when Russia offers off-peak power at 1 8 cents/kWh The 1,500 MW figure is imprecise because this analysis does not reflect seasonal variations in the flow of water to the run of river hydro stations, nor does it reflect the optimal use of storage reservoirs The basic concept is an interesting one, however, suggesting that off-peak energy should be priced below two cents/kWh in the Winter and at some very low level in the Summer, given the large amount of run of river hydro available during the summer

Combining data received from the World Bank and from Sakenergo, we have tried to construct a table of monthly data on generation, import, and export (see Exhibit 4 4) We use the World Bank figure of 6,861 GWh for total supply to the VHV and HV network [13] By dividing domestic generation into the portion needed to supply distribution companies and the portion used for export, we constructed a simplified table showing the monthly average cost, at December 1997 prices of the quantities of electricity generation and imports purchased in 1996 for resale to the distribution companies (Exhibit 4 5) This table shows an annual average supply cost (excluding the cost of transmission, dispatch, and other wholesale market services) of only 1 26 cents/kWh or 1 63 tetri/kWh, which is very low by international standards

For 1999 we project an increase in the average cost of hydro generation to 2 5 cents/kWh or 3 25 tetri/kWh to provide a 125 million Lari revenue increase for the hydro stations This additional revenue will be needed to cover the cost of depreciation based on the replacement cost of assets, plus an allowance for a return on the value of hydro stations that are privatized or selected for privatization For example, a revenue increase of 60 7 million Lari is needed to provide a 10% rate of return on the depreciated asset value of hydro stations other than Enguri and Vardnili, using estimates by Kantor Management Consultants

For 1999 the average sales price of thermal generation is projected to be 4 16 cents/kWh or 5 4 tetri/kWh the Gardabani price level projected by the World Bank for the year 2000 [14] The annual average cost of electricity generation and imports purchased in 1999 for resale to the distribution companies is projected to be 2 89 cents/kWh or 3 76 tetri/kWh (see Exhibit 4 6) This price level is reasonable by CIS standards, it is below the average price of thermal generation in Ukraine, and below the prices paid to thermal stations in Armenia

[13] World Bank *Staff Appraisal Report Georgia Power Rehabilitation Project*, page 7

[14] World Bank, *Staff Appraisal Report Georgia Power Rehabilitation Project*, Table 3 1 page 23

Exhibit 4 3
Off-Peak Generating Resources Ranked by Energy Price, 1998

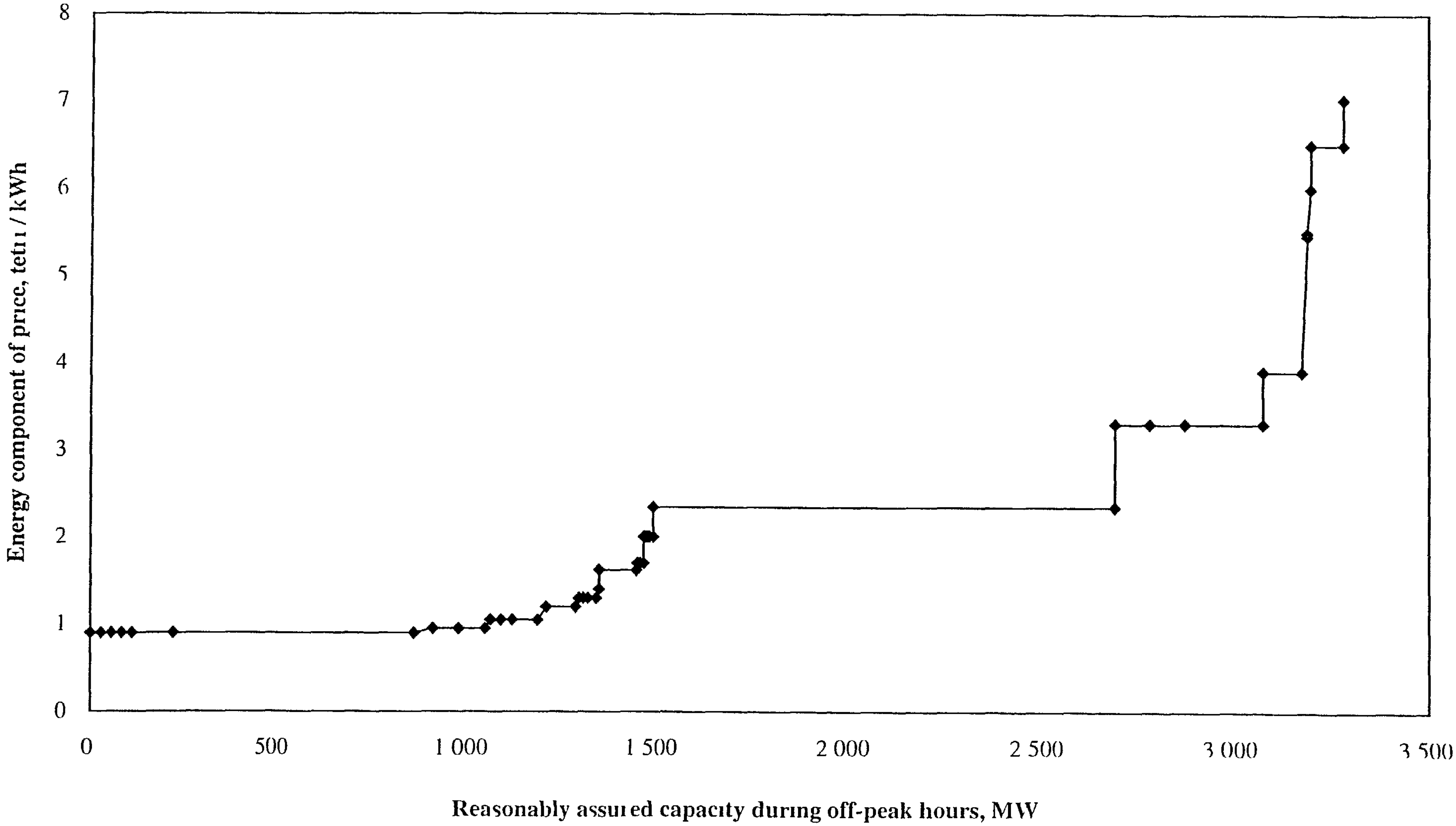


Exhibit 4 4
Electricity Supplied in 1996, in Million kWh

Month	Thermal generation gross	Regulating hydro power gross	Run of river hydro power gross	Import from Russia	Import from Azerbaijan	Gross generation plus import	Power station consumption	Export to Russia	Export to Turkey	Export to Azerbaijan	Net supply to Georgia
Energy supplied in 1996, million kWh											
January	**215**	**210**	**120**	**75 0**	**11 0**	631 0	8 5	-	-	**11 0**	611 5
February	**225**	**130**	**120**	**45 0**	**11 0**	531 0	7 4	-	-	**11 0**	512 6
March	**200**	**130**	**120**	**50 0**	**11 0**	511 0	7 0	-	-	**11 0**	493 0
April	**150**	**210**	**160**	**60 0**	**11 0**	591 0	8 1	-	-	**11 0**	571 9
May	-	**380**	**210**	-	-	590 0	9 2	-	-	**11 0**	571 9
June	-	**420**	**220**	-	-	640 0	10 0	-	**10 0**	**5 0**	565 8
July	-	**500**	**210**	-	-	710 0	11 0	**3 1**	**50 0**	**5 0**	571 9
August	-	**370**	**140**	**3 1**	**7 0**	520 1	7 9	**29 0**	**61 0**	**4 0**	605 0
September	-	**400**	**140**	-	**7 0**	547 0	8 4	-	-	**7 0**	505 2
October	**10**	**380**	**160**	-	**10 9**	560 9	8 6	-	-	**7 0**	531 6
November	**130**	**350**	**147**	**10 0**	**11 0**	648 0	9 8	-	-	**10 9**	541 4
December	**175**	**400**	**150**	**10 0**	**11 0**	746 0	11 3	-	-	**11 0**	627 2
1996 total	1 105	3 880	1 897	253 1	90 9	7 226 0	107 0	32 1	121 0	104 9	6 861 0
Source of data for annual total	Sakenergo			Sakenergo	Sakenergo		World Bank	Sakenergo	Sakenergo	Sakenergo	World Bank

Exhibit 4 5
Cost of 1996 Electricity Supply at December 1997 Prices

Month	Thermal generation net	Regulating hydro power net	Run of river hydro power net	Import from Russia	Import from Azerbaijan	Net generation plus import	Average cost
Energy supplied for domestic consumption in 1996, million kWh							
January	211 7	206 7	118 1	75 0		611 5	
February	221 5	128 0	118 1	45 0		512 6	
March	196 9	128 0	118 1	50 0		493 0	
April	147 7	206 7	157 5	60 0		571 9	
May		374 1	191 7	-		565 8	
June		413 5	158 5			571 9	
July		492 2	112 7			605 0	
August		364 2	137 8	3 1		505 2	
September	-	393 8	137 8	-		531 6	
October	9 8	374 1	157 5			541 4	
November	128 0	344 6	144 7	10 0		627 2	
December	172 3	393 8	147 7	10 0		723 7	
Total 1996	1 087 8	3 819 7	1 700 4	253 1		6 861 0	
December 1997 prices of energy supplied, tetri/kWh							tetri/kWh
	4 392	**0 954**	**1 050**	**3 900**			1 631
December 1997 prices of energy supplied, cents/kWh							cents/kWh
	3 379	0 734	0 807	3 000			1 255
Cost of 1996 energy supply at December 1997 prices, million Lari							tetri/kWh
January	9 30	1 97	1 24	2 93		15 43	2 524
February	9 73	1 22	1 24	1 76		13 94	2 720
March	8 65	1 22	1 24	1 95		13 06	2 649
April	6 49	1 97	1 65	2 34		12 45	2 177
May		3 57	2 01			5 58	0 986
June		3 94	1 66	-		5 61	0 980
July		4 70	1 18			5 88	0 972
August		3 47	1 45	0 12		5 04	0 998
September		3 76	1 45			5 20	0 979
October	0 43	3 57	1 65			5 65	1 044
November	5 62	3 29	1 52	0 39		10 82	1 725
December	7 57	3 76	1 55	0 39		13 26	1 833
Total	47 78	36 44	17 85	9 87		111 94	1 631

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Exhibit 4 6
Projected Cost of 1999 Electricity Supply at 1999 Prices

Month	Thermal generation, net	Regulating hydro power, net	Run of river hydro power, net	Import from Russia	Import from Armenia	Net generation plus import	Average cost
Increase in energy supplied for domestic consumption, 1999 relative to 1996							
	50%	**0%**	**0%**	**100%**		19 0%	
Energy supplied for domestic consumption in 1999, million kWh							
January	317 5	206 7	118 1	150 0	150 0	942 4	
February	332 3	128 0	118 1	90 0	90 0	758 4	
March	295 3	128 0	118 1	100 0	100 0	741 4	
April	221 5	206 7	157 5	120 0	120 0	825 7	
May	-	374 1	191 7	-	-	565 8	
June	-	413 5	158 5	-	-	571 9	
July	-	492 2	112 7	-	-	605 0	
August	-	364 2	137 8	6 2	6 2	514 5	
September	-	393 8	137 8	-	-	531 6	
October	14 8	374 1	157 5	-	-	546 4	
November	192 0	344 6	144 7	20 0	20 0	721 2	
December	258 4	393 8	147 7	20 0	20 0	839 9	
Total 1996	1 631 7	3 819 7	1 700 4	506 2	506 2	8 164 2	
Increase in prices, 1999 average relative to December 1997							
	23%	**241%**	**210%**	**0%**			
1999 average prices of energy supplied, tetri/kWh							tetri/kWh
	5 40	3 25	3 25	3 90	3 90		3 763
1999 average prices of energy supplied, cents/kWh							cents/kWh
	4 16	2 50	2 50	3 00	3 00		2 89
Cost of 1999 energy supply at 1999 average prices, million Lari							tetri/kWh
January	17 15	6 73	3 84	5 85	5 85	39 42	4 183
February	17 95	4 16	3 84	3 51	3 51	32 98	4 348
March	15 96	4 16	3 84	3 90	3 90	31 76	4 284
April	11 97	6 73	5 12	4 68	4 68	33 18	4 018
May	-	12 17	6 24	-	-	18 41	3 253
June	-	13 45	5 16	-	-	18 61	3 253
July	-	16 01	3 67	-	-	19 68	3 253
August	-	11 85	4 48	0 24	0 24	16 82	3 269
September	-	12 81	4 48	-	-	17 29	3 253
October	0 80	12 17	5 12	-	-	18 09	3 311
November	10 37	11 21	4 71	0 78	0 78	27 85	3 861
December	13 96	12 81	4 80	0 78	0 78	33 14	3 945
Total	88 15	124 26	55 33	19 74	19 74	307 22	3 763

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CHAPTER 5
TRANSMISSION TARIFFS

The purpose of this chapter is to present a methodology for calculating transmission tariffs and to provide input data and results based on the information available to the consultant The methodology presented here is similar to the transmission cost calculation in Chapter 7, which contains a methodology for calculating sales tariffs to wholesale customers and retail customers

5 1 Separation of transmission from other functions

During the Soviet period the power sector of Georgia was a Government-owned, vertically integrated generation, transmission, and distribution system which formed part of the interconnected power system of the Caucasus region The Caucasus grid was, in turn, part of the unified power system of the Soviet Union There was no need to have a transmission tariff within the Soviet Union, and the Soviet Union did not provide significant transmission service to other countries

After Georgia achieved independence, Sakenergo was formed as a state enterprise responsible for generation, transmission, and distribution Following civil conflict, power sector assets located in Abkhazia and South Ossetia were effectively taken away from Sakenergo and placed under the management of Abkhazia and local municipalities in South Ossetia Then in March 1995 the Government of Georgia restructured the power sector so that responsibility for distribution of electricity at 10 kV, 6 kV, and 0 4 kV was removed from Sakenergo and transferred to the local municipalities Sakenergo retained ownership of the 500 kV, 330 kV, 220 kV grid and nearly all of the 110 kV and 35 kV grid plus substations directly connected to these lines [1] Sakenergo also formed a joint venture with RAO Unified Electric System of Russia, called SakRusenergo, to jointly operate the 500 kV "Kafkasioni" line from the Enguri power station to the Centralnaya substation in Russia, near Krasnodar [2]

In October 1995 the Government of Georgia created a Committee on Power Sector Restructuring The Committee's recommendations became the basis of a July 4, 1996 Presidential Decree on Power Sector Reforms (see Appendix A) which divided the power sector into three subsectors generation (in which power stations are structured as joint stock companies), transmission and dispatch (owned by Sakenergo), and distribution (in which low-

[1] All transmission lines in Georgia are overhead lines There are no underground cables at 35 kV or higher voltages

[2] The Georgian portion of this line is shown in the transmission system map in Appendix I

voltage local networks are structured as joint stock companies) Section 8 of the Decree states that

> Sakenergo's Transmission and Dispatch Structure should be transformed into united commercialized, financially self-governing treasury enterprise "Sakenergo," which will be supervised by the Ministry of Fuel and Energy and will not be the subject of privatization at the current stage

In fact, the state enterprise Sakenergo is responsible for not only transmission and dispatch but also purchases of wholesale power from generating companies, imports from foreign power systems, sales of wholesale power to high voltage customers and distribution companies, exports to foreign power systems, and transit of power across Georgia Sakenergo is a monopoly buyer/seller in the wholesale market, as well as a transmission and dispatch service provider In addition the various generating companies have been operated under the management of a state enterprise called Sakenergo Generation which is not required by the Decree on Power Sector Reforms During 1997 the technical departments of Sakenergo and Sakenergo Generation jointly produced an annual technical report on 1996 power sector operations

On June 27, 1997 the Georgian Electricity Law was signed Sections 32 1 and 33 1 of the Electricity Law separate the functions of Transmission Licensee and Dispatch Licensee as follows

> The Commission may issue a License granting a Legal Person the exclusive right to provide transmission service using the Transmission Grid
>
> The Commission may issue a License granting an Individual or Legal Person the right within Georgia to purchase and resell electric capacity and/or electricity and/or transmission services to Distribution Licensees, Direct Consumers, and other foreign or domestic Legal Persons or individuals as required or permitted by the Commission, and the exclusive right to operate a central dispatching control center for Georgia's electricity system

The law does not explicitly state how the existing enterprises Sakenergo and SakRusenergo will be restructured so that the Transmission Licensee, the Dispatch Licensee, and other entities will be created The initial structure of the wholesale market under the Market Members Agreement (as described in Chapter 3) will establish a much more limited role for the Dispatch Licensee, that is, the exclusive right to operate the national dispatch center The Market Members Agreement will require a transmission tariff to be implemented

Sakenergo provides transmission services for foreign power systems On October 15, 1997 Sakenergo and SakRusenergo concluded a contract with Cateco & Kalyon Adı Ortalıgı, a private firm based in Ankara, Turkey, to provide transmission services to Cateco & Kalyon during the period October 10, 1997 through December 31, 1998 Electric energy generated in Dagestan is transmitted to the Russia-Azerbaijan border, then transmitted by Azerenerzhy to the Azerbaijan-

Georgia border, then transmitted by Sakenergo to the Georgia-Turkey border, then delivered to consumers in Turkey The contract states that in 1998 Sakenergo is scheduled to receive 2 36 billion kWh at the Azerbaijan border and deliver 2 0 billion kWh to Turkey Instead of a transit tariff for this amount, Georgia receives 0 4 billion kWh and is permitted to take these kWh during the months of November 1997 through April 1998 and October through December 1998 according to a schedule In principle a contract for 1999 could include a cost-based transmission tariff

In Georgia the concept of direct sales by a generating station to a distribution company or industrial customer is not clearly defined, but in general direct sales are accomplished without transmission contracts Direct sales are permitted *de facto* under the following conditions

- when the generating station is located in the distribution company's territory and has a direct connection to the distribution company's low voltage network, or
- when the parties to the contract agree to build a power line connecting the generating station to the customer, or
- when the parties use networks owned by Sakenergo or by a distribution company and do not pay for wheeling services [3]

The first alternative is perfectly reasonable by international standards The second alternative is reasonable when the customer is located near the generating station but not when the distances are large The third alternative is unfair to wholesale electricity customers, who must pay for the networks being used by wheeling customers Some sort of transmission tariff is needed to enable Sakenergo to receive payment for wheeling services

For the purposes of developing a transmission tariff methodology we assume that there will be a single enterprise providing transmission services to distribution companies, to Abkhazia and South Ossetia, to foreign power systems, and to industrial customers receiving energy at 35 kV or higher voltage [It is assumed that there will be only one Transmission Licensee under the Electricity Law] The methodology in this chapter is based on the assumption that it is not necessary to establish a separate transmission tariff for the portion of the 500 kV system owned by SakRusenergo In other words the methodology has been developed to suit a power sector structure in which some of the 500 kV lines and substations are owned by SakRusenergo, but SakRusenergo provides transmission services only for the Transmission Licensee, which owns all 330 kV, 220 kV, 110 kV, and 35 kV lines existing in Georgia at 1 January 1998, together with substations connected to these lines but not owned by SakRusenergo If there are a few exceptions to this guideline - if a few kilometers of 110 kV or 35 kV line are owned by a distribution company - the tariff calculation for the national grid will be affected only slightly

[3] We have very limited information about this alternative To our knowledge Sakenergo does not receive payment for energy sold by Jinvali hydro station to Akmeta and Telali distribution companies

The tariff calculation will be simplest if the existing grid is placed under the ownership and control of one company or enterprise [4]

Because the existing Sakenergo is a buyer and seller in the wholesale market and not simply the Transmission Licensee described in the Electricity Law, it is not clear that the Transmission Licensee will be responsible for the $180 million in power sector accounts payable that was assigned to Sakenergo in February and March 1997 In the following analysis we have assumed that the transmission tariffs will not be raised to cover this debt obligation If this assumption is incorrect, the transmission tariffs are underestimated A comprehensive restructuring of Sakenergo is necessary to clarify the question of how much debt will be borne by the Transmission Licensee

5 2 Separation between VHV and HV

The transmission services market in Georgia may be divided into three components

- Transit between Azerbaijan and Turkey, and any other international transit that might be arranged in the future,

- Delivery of energy to Abkhazia and South Ossetia, which are not licensees subject to GNERC regulation,

- Delivery of energy to distribution companies and high voltage industrial customers, which in principle should be licensed by the GNERC

Together the first and second components account for one-third of the energy flowing through the transmission network in 1998 Turkey receives two billion kWh and Abkhazia and South Ossetia receive roughly one billion kWh, while distribution companies and high voltage customers receive over five billion kWh and technical and commercial losses are roughly one billion kWh [5]

The first component clearly does not require the use of the 110 kV or 35 kV network If international transit requires cost-based tariffs, these tariffs should be based on the cost of the 500 kV 330 kV, and 220 kV networks but not the cost of service at lower voltages All transmission services in the third component involve the 110 kV and 35 kV grid

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[4] In the simplest case, the Transmission Licensee is the owner of all 500 kV, 330 kV, 220 kV, 110 kV, and 35 kV lines existing in Georgia at 1 January 1998, together with substations connected to these lines

[5] The amount of energy to be delivered to Turkey in 1998 under the Cateco & Kalyon contract is specified exactly but the other values are rough estimates based on the 1996 data shown in Exhibit 7 1

The second component is less clear Sakenergo has a *de facto* obligation to the Government of Georgia to deliver electric energy to Abkhazia and South Ossetia Deliveries to Abkhazia could be made from the Enguri power station and from the 220 kV line from Vardnili to Tkvarcheli, Sukhumi, Bziphi, and Gantiadi Regardless who owns this line, Sakenergo should be compensated for the cost of building and maintaining 220 kV and higher voltage transmission capacity needed to supply Abkhazia from stations other than Enguri Deliveries to South Ossetia involve the 110 kV grid but they are small in relation to deliveries to Abkhazia [6]

For calculation of transmission tariffs, the electric networks in Georgia can be divided into three groups, according to voltage

- VHV group 500 - 330 - 220 kV lines and cables, together with the substations connected to these lines and cables,
- HV group 110 - 35 kV lines and cables, together with the substations that are connected to these lines and cables but are not part of the VHV group,
- Distribution voltage group 10 - 6 - 0 4 kV lines and cables, together with transformers that are not part of the VHV group or HV group

The methodology in this chapter is designed to calculate two transmission tariffs

- a VHV tariff for international transit and for customers who receive energy at 220 kV or higher voltage This tariff excludes the cost of the 110 kV and 35 kV grid Electricity is delivered to VHV customers at *VHV delivery points*
- a HV tariff for customers who receive energy at 35 kV or 110 kV Electricity is delivered to HV customers at specific locations called *HV delivery points*

If Georgia can develop a more reliable electric network, it has the potential to develop an international transit business in the power sector which will benefit domestic customers by paying for a portion of the cost of the VHV grid Unfortunately the present situation, as described in the World Bank *Staff Appraisal Report*, does not allow the transit business to achieve its full potential

[6] In 1995 Abkhazia consumed 707 GWh and South Ossetia 118 GWh See World Bank, *Staff Appraisal Report Georgia Power Rehabilitation Project*, May 8 1997, page 6, footnote 6

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> Imports are effected in so-called "radial" regime where consumers, fed through an import line, are cut off electrically from the rest of the Georgian power system which consequently, continues to operate in the "island" mode [7]

Therefore the development of firm service and reliable power supply would probably lead to a greater level of VHV transmission service A very rough indicator of the capacity the network was designed to support is the total supply to the high voltage network in 1990, which was 2 5 times the 1996 level [8]

5 3 Two-part tariffs

For the initial phase of tariff reform we recommend a transmission tariff consisting of a two-part tariff consisting of a capacity payment and an energy loss allowance For subsequent tariff development the operating expenses should be divided into two categories

- operating expenses which vary in relation to the capacity of the transmission system or the peak load These expenses should be recovered through the capacity payment per kW per month
- operating expenses which vary in relation to the number of kWh transmitted These expenses should be recovered through a charge per kWh

The data necessary to distinguish these categories were not available for this study To make the tariff simple, we have allocated all operating expenses to the capacity payment per kW per month

The capacity payment for transmission service is a payment for use of the network There are different ways to address the question of how this use should be measured and how the cost should be allocated among customers For example, the following alternatives may be considered

- *Coincident peak load basis* Under this approach, each customer pays for a share of the capacity cost of the network according to his share of the coincident peak load The capacity payment is a mechanism for spreading the fixed cost of transmission capacity among customers, according to each customer's load at the time of the coincident peak load in the grid

[7] World Bank *Staff Appraisal Report Georgia Power Rehabilitation Project*, May 8, 1997 page 9, footnote 10 Georgia "often operates several electrically independent subsystems, with certain power plants supplying certain limited geographical areas " *Staff Appraisal Report* page 9

[8] Total supply to the high voltage network was 17 402 GWh in 1990 and 6,861 GWh in 1996 *Staff Appraisal Report* page 7

This approach is reasonable, although it does not reflect the complexities of transmission system planning In reality the transmission system must be designed to accommodate a variety of load flows, during all of the hours of the year that can be considered peak periods The load flow at the coincident peak offers only a snapshot of transmission capacity requirements

- *Transactional basis* Under this approach, a transmission tariff is calculated for each transaction Each transaction has a maximum capacity, a receipt point, a delivery point, and a *contract path* along which the electric energy is assumed to flow The customer pays for a portion of the capacity of the lines and substations located along the contract path, and he pays for the estimated energy losses along that path

  This approach is suitable for a small number of international or inter-regional transactions, particularly when new transmission facilities are constructed to make a transaction possible It is not suitable for a wholesale market with a large number of direct sales agreements

We recommend the coincident peak load basis - the first approach - because it gives the most accurate reflection of the true cost of providing transmission capacity in an interconnected network

Under the coincident peak load approach, every electricity consumer directly or indirectly pays a price which includes a share of the cost of the VHV network This tariff policy spreads the cost of the VHV network across all electricity consumers - a policy which is equitable because of the voltage and frequency stabilization, dispatch services, and other benefits made possible by the VHV network Therefore, the HV capacity payments cover a portion of the cost of the VHV network

Electricity losses should be accounted for in the cost per kWh for the wholesale customer At the delivery point, the Transmission Licensee delivers a quantity of energy that is less than the quantity measured at the receipt point The difference should equal the amount of energy consumed in technical and commercial losses

5.4 Components of the revenue requirement

To calculate transmission capacity charges it is necessary to calculate the revenue requirements for the VHV network and the HV network The revenue requirement for VHV capacity charges is the projected annual cost of building and operating the VHV network, excluding the energy losses that are recovered through energy loss allowances When this is divided by the coincident peak load measured at VHV delivery points, the result is the annual VHV capacity payment, in Lari/kW The monthly capacity payment is simply one-twelfth of the annual number Similarly the revenue requirement for HV capacity charges is the projected annual cost of building and operating the HV network, excluding the energy losses When this is divided by the coincident peak load measured at HV delivery points, the result is the annual HV capacity payment, in Lari/kW The monthly capacity payment is one-twelfth of the annual capacity payment

In the United States regulatory agencies must determine a *revenue requirement* for a regulated company, that is, the total annual revenue which must be collected through electricity sales and electric transmission services The revenue requirement is measured in dollars per year When the revenue requirement is divided by the total quantity of electricity sold, the result may be called the *average tariff* The average tariff is meaningful when it is calculated for an enterprise which provides sales service but not transmission service The concept of revenue requirement can be used more broadly - for example, in calculating capacity charges for transmission service

In the Soviet Union, average tariffs were normally calculated to provide for depreciation of assets on the basis of historical costs, with no allowance for a rate of return on assets We propose a different financial criterion depreciation of assets based on replacement cost, plus an allowance for a reasonable rate of return on revalued net assets The calculation of the average tariff is similar, except for the difference in financial criteria The "reasonable" rate of return should be selected by a regulatory agency, and in principle this rate of return should equal the minimum rate of return needed for the transmission company or enterprise to finance the capital required to fulfill its investment plans

To select a rate of return it is necessary to have a general understanding of the amount of capital investment needed in the high-voltage grid, and the likely sources of funds for these investments If a large amount of investment is needed, the tariff must be developed to support a strategy for obtaining the necessary investment funds At a minimum, transmission tariffs will need to be established at levels that will permit the Transmission Licensee to conduct capital repairs on the VHV and HV networks The Transmission Licensee will need to receive a significant cash flow through depreciation charges It may be possible for the transmission enterprise to raise capital through long-term borrowing in international capital markets If the public sector is unable to provide the necessary capital, privatization is one of the policy alternatives to be considered Privatization would enable equity investment by shareholders, particularly foreign firms that are selected as strategic investors However, privatization of the transmission grid is not one of the Government's near-term policy objectives

For the VHV network, the revenue requirement for capacity charges includes three components

- *Operating expenses* These expenses include labor costs and employee welfare expenditures, parts and materials, and all other operation and maintenance expenses except energy losses in the networks The repair fund is included in operating expenses, but the repair fund should not include major replacement and reconstruction of older transmission lines that have reached the end of their useful life

- *Depreciation* This can be measured by depreciating the gross value of each asset on a straight-line basis over its economic lifetime The Georgian tax code has adopted the declining balance method of depreciation The rate of depreciation on most electricity sector assets will be 8% The advantage of adopting the tax code depreciation rate would be to avoid recording a tax deferral liability

- *Return on net asset value* This amount equals the net asset value at the beginning of the year multiplied by the *allowable rate of return*, that is, the rate of return allowed by the regulatory agency or Government body

The methodology presented here is based on accounts that are maintained for tariff-setting purposes *Gross asset value* is the estimated replacement cost of assets that are currently being used to provide transmission service Capital investments in new facilities (such as overhead lines, substations and underground cables) create additions to gross asset value when construction is completed and the new facilities are placed in operation We recommend the use of one of the traditional principles of ratemaking in the United States, that is, the principle that the customer should pay a tariff based on the cost of assets for which construction is completed and the assets are being used in day-to-day operation *Net asset value* equals gross asset value minus accumulated depreciation based on the economic lifetime of the assets The *economic lifetime* of an asset is the number of years that it can remain in operation before it must be replaced or completely rebuilt

5.5 Allowance for a modest level of non-payment

Any revenues in excess of operating expenses provide a possible source of funds for investment in construction projects such as those listed in Exhibit 5 4 Given the seriousness of non-payment problems in the power sector it is clear that the actual level of cash collection will not match the projected revenue requirement However, it is possible to calculate a tariff which reflects an allowance for a modest level of non-payment One way to do this is to make a simple projection of sources and uses of funds, without external financing, as follows

	Depreciation
Plus	Return on net asset value
Minus	Increase in accounts receivable
Equals	Sources of funds

	Additions to gross asset value (completed construction)
Plus	Work in progress (construction projects not completed)
Equals	Uses of funds

Therefore, it is possible to calculate the level of work in progress that can be supported without loans or external financing

	Sources of funds
Less	Additions to gross asset value
Equals	Work in progress on construction projects

The results for 1997 and subsequent years can be summed on a cumulative basis, as follows

	Cumulative depreciation beginning with 1997
Plus	Cumulative return on net asset value, beginning with 1997
Minus	Cumulative increase in accounts receivable, beginning 1997
Equals	Cumulative sources of funds
Less	Cumulative additions to gross asset value, beginning 1997
Equals	Work in progress on construction projects

This type of calculation is shown in Exhibit 5 7 If the result (Work in progress) is positive and growing, it indicates that the tariff can support investment in projects that are under construction and not yet in service In other words it indicates that the Transmission Licensee can achieve a degree of self-financing rather than relying on transfers from the Government budget

5 6 Steps in the calculation of transmission tariffs

The transmission tariff methodology used in this chapter can be described in terms of the following step-by-step procedure

1 Divide transmission service customers into two groups (1) foreign countries or customers that are connected to the VHV network only, and (2) customers that are connected to the HV network

2 Select a basis for measuring each wholesale customer's capacity requirement in MW Options are (1) measure the capacity of transformers used to supply the customer, or (2) estimate the customer's share of coincident peak load, including export load Estimate 1998 VHV and HV transmission system demand in MW

3 Estimate operation and maintenance (O&M) expenses for 1997, for the VHV and HV network (See Exhibit 5 1)

4 Estimate the replacement cost of the lines and substations at 1 January 1997 and the average economic lifetime of new lines and new substations Estimate the level of physical depreciation (as a percentage of the economic lifetime of the assets) Calculate the value of the physical assets that are in use, i e , replacement cost less depreciation at 1 January 1997 (See Exhibit 5 2)

5 Allocate total O&M expenses to VHV and HV on the basis of gross asset value Calculate the ratio of annual O&M to gross asset value (See Exhibit 5 2)

6 Calculate the ratio of VHV losses (in kWh) to VHV transmission system input (in kWh) for 1996 (or 1997 if possible) Calculate the ratio of HV losses to HV transmission system input for 1996 (or 1997) Estimate these ratios for 1998 Include both technical and commercial losses (See Exhibit 5 3)

7 Estimate the level of capital expenditure needed in the VHV system in 1998 and in the HV system in 1998 To accomplish this task it will be necessary to identify the new lines and substations that are most urgently needed (See Exhibit 5 4)

8 Select the allowable rate of return on net asset value in 1998 (See Exhibits 5 5 and 5 6) This rate of return should be based on the opportunity cost of capital to the Government of Georgia and it should be no lower than the interest rate on long-term loans to the power sector

9 Estimate the cost of new lines and substations completed in the VHV system and in the HV system in 1997 Estimate the value of lines and substations that were replaced or retired in 1997 - assets that will not be used or useful in 1998 [9] Calculate the gross asset value at the start of 1998 (See Exhibits 5 5 and 5 6, line showing "Additions to gross asset value")

10 Project O&M expenses in 1998 O&M expenses equal the gross asset value at the start of the year, multiplied by the ratio of annual O&M to gross asset value (See Exhibits 5 5 and 5 6)

11 Calculate depreciation in 1998 Depreciation equals the gross asset value at the start of the year, divided by the economic lifetime (See Exhibits 5 5 and 5 6)

12 Calculate the return on net asset value The return on net asset value equals the net asset value at the start of the year, multiplied the allowable rate of return on net asset value (See Exhibits 5 5 and 5 6)

13 Calculate the total 1998 revenue requirement The total revenue requirement equals the sum of O&M expenses plus depreciation plus return on net asset value (See Exhibits 5 5 and 5 6)

14 Calculate the capacity payment per kW per month (See Exhibits 5 5 and 5 6) This equals the 1998 revenue requirement divided by 12, divided by the 1998 transmission system demand in MW (See Exhibits 5 5 and 5 6)

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[9] Assets that will not be used to provide service to customers during 1998 should be excluded from gross asset value For example lines that are damaged and will not be returned to service in 1998 should be excluded

15 Project the increase in accounts receivable in 1998 In other words, project the portion of accrued capacity payment revenue in 1998 that will not be included in cash revenue This money will not be available to pay for capital expenditures in 1998

16 Calculate the level of construction work in progress (CWIP) at 1 January 1999, assuming 100% reinvestment of depreciation and return since 1 January 1997, using the following formula (see Exhibit 5 7)

CWIP = Cumulative depreciation and return - Cumulative additions to gross asset value - increase in accounts receivable

17 If the level of CWIP is negative, change one or more input parameters until the level of CWIP is positive One possibility is to increase the allowable rate of return on assets Another possibility is to lower the level of projected capital expenditure Another possibility is to assume that cash will be made available from loans to the Transmission Licensee

18 Calculate the capacity charge for HV customers This capacity charge reflects the combined VHV and HV network capacity costs

Capacity charge for HV customers =
Capacity charge for VHV / (1 - VHV loss ratio) + Capacity charge for HV

19 For VHV customers, the energy charge equals the ratio of VHV losses (in kWh) to VHV transmission system input (in kWh) for 1998 This may be called the VHV loss ratio (See Exhibits 5 3 and 5 8)

20 Calculate the energy charge for HV customers This energy charge equals the combined VHV and HV network losses (see Exhibits 5 3 and 5 8)

Energy charge for HV customers =
1 - [(1 - VHV loss ratio) * (1 - HV loss ratio)]

21 Identify peak and off-peak periods, based on the load curve for the day with the highest peak load in 1997 (or the day with the highest peak load in 1996)

22 Estimate the VHV loss ratio and the HV loss ratio for off-peak periods Decide whether the transmission tariff should distinguish peak and off-peak periods and have different energy charges for these periods (See Exhibit 5 8)

23 By repeating these steps, calculate tariffs for 1999, 2000 and 2001 to develop a projection of transmission tariffs over a four-year period

Exhibit 5 1
Operating Expenses for Networks Owned by Sakenergo and Sakrusenergo, 1997

Cost category	Sakrusenergo (500 kV)	Sakenergo transmission (330, 220 110 35 kV)	Total for Sakrusenergo and Sakenergo	Sakenergo Dispatch department
Annual exploitation costs of high voltage networks, million USD	**4 6**	**24 8**	29 4	**1 2**
Annual exploitation costs of high voltage networks thousand Lari	5 980	32 240	38 220	1 560

Source Data provided by Sakenergo on 5 December 1997 Hagler Bailly assumes that these figures are for 1997, these are estimated costs and not actual expenditures, and depreciation is excluded

Exhibit 5 2
Estimate of the Value of Lines and Substations for Ratemaking Purposes

Network component	Replacement cost		Georgia, total					
			Sakenergo + SakRusenergo		Very High Voltage (VHV)		High Voltage (HV)	
			Quantity	Cost	Quantity	Cost	Quantity	Cost
Overhead lines			km	million USD	km	million USD	km	million USD
500 kV	**0 2**	$million/km	**572**	114 4	572	114 4		
330 kV	**0 1**	$million/km	**21**	2 1	21	2 1		
220 kV	**0 07**	$million/km	**1565**	109 6	1565	109 6		
110 kV	**0 045**	$million/km	**3924**	176 6			3924	176 6
35 kV	**0 025**	$million/km	**3147**	78 7			3147	78 7
Total			9229	481 3	2158	226 1	7071	255 3
Substations			kVA		kVA		kVA	
500 kV	**0 02**	$million/kVA	**2153**	43 1	2153	43 1		
330 kV	**0 02**	$million/kVA	**0**	-	0	-		
220 kV	**0 02**	$million/kVA	**4595 1**	91 9	4595 1	91 9		
110 kV	**0 02**	$million/kVA	**4116 5**	82 3			4116 5	82 3
35 kV	**0 02**	$million/kVA	**1510 33**	30 2			1510 33	30 2
Total			12374 93	247 5	6748 1	135 0	5626 83	112 5
Total replacement cost, million USD				728 8		361 0		367 8
Total replacement cost, 000 Lari				947 445		469 316		478 129
Hagler Bailly estimate of physical depreciation of assets at 1 1 97				**65%**		**65%**		**65%**
Accumulated depreciation 000 Lari				615 839		305 055		310 784
Replacement cost less depreciation, 000 Lari				331 606		164 260		167 345
Net book value at 1 1 97 based on Georgian government regulations				**#N/A**				
Projected 1997 operating expenses				38 220				
Ratio of operating expense to gross asset value Replacement cost basis (Hagler Bailly)				4 0%				
Economic lifetime assumed for depreciation years				**30**		**30**		**30**
Annual depreciation rate based on economic life				3 33%		3 33%		3 33%
Average age of assets, years				19 5		19 5		19 5

Exhibit 5 2b
Kantor Estimate of the Replacement Cost of Network Capacity

	Replacement cost		Quantity	Replace-ment value	Remaining useful life	Total useful life	Equivalent net value	Equivalent net value
Overhead lines			km	million USD	years	years	million USD	million Lari
500 and 330 kV	0 150	$million/km	**593 0**	**89 0**	**20**	**35**	51	66
220 kV	0 150	$million/km	**1 565 0**	**235 0**	**0**	**35**	-	-
110 and 35 kV	0 080	$million/km	**7 320 0**	**586 0**	**5**	**35**	84	109
Total lines	0 096		9 478 0	910 0			135	175
Substations			kVA					
500 kV	0 150	$million/kVA	**2 153 0**	**323 0**	**20**	**35**	185	240
220 kV	0 150	$million/kVA	**4 555 1**	**683 0**	**0**	**35**	-	-
110 and 35 kV	0 035	$million/kVA	**5 837 4**	**204 0**	**5**	**35**	29	38
Total substations			12 545 5	1 210 0			214	278
Total transmission system				2 120 0			348	453

Source Kantor Management Consultants, "Electricity Tariffs and Collection Mechanism " Final Report, April 1996 Appendix C, "Review of Asset Condition and Value," Table C 2

Exhibit 5 3
Electric Energy Losses in Networks in Georgia in 1996

	Energy losses in million kWh											
	Very High Voltage				High Voltage			Distribution			Total	
	500 kV	330 kV	220 kV	Total 500 330 220 kV	110 kV	35 kV	Total 110 and 35 kV	10 and 6 kV	0 4 kV	Total 10 6 0 4 kV	500 330 220-110 35 10 6 0 4 kV	Data source
Input to the network at each level												
% of domestic supply at VHV				75 0%								HB
% of import supply at VHV				100 0%								HB
% of export at VHV				80 0%								HB
Domestic supply to network				5 094 8			1 698 3			-	6 793 0	IBRD
Plus import supply to network				343 0			-				343 0	IBRD
Plus supply from higher voltage				-			4 839 1			4 184 0		
Equals total supply to network				5 437 8			6 537 3			4 184 0		
Less exports				220 0			55 0				275 0	IBRD
Less techn + comm losses				378 7			558 6			491 0		
Less Abkhazia + South Ossetia				-			922 0					HB
Less Consumption				-			817 7			3 693 0	4 510 7	HB
Equals supply to lower voltage				4 839 1			4 184 0					
Technical losses												
Lines and cables												
Load losses	70 2	0 6	166 4	237 2	210 0	43 0	253 0	42 2	39 0	81 2	571 4	SakE
Losses on busses	14 0	0 1	15 9	30 0	-	-	-		-	-	30 0	SakE
Substations and transformers												
Load losses	16 1	0 4	35 5	52 0	77 0	18 0	95 0	8 0	-	8 0	155 0	SakE
Idle run losses	17 4	0 6	35 0	53 0	76 0	18 0	94 0	7 0	-	7 0	154 0	SakE
Self consumption of the stations	2 0		3 2	5 2	6 5	1 0	7 5	0 3		0 3	13 0	SakE
Synchronic compensator and generation for compensation	-			-								SakE
Reactors	0 2		0 5	0 7	3 5	0 5	4 0		-		4 7	SakE
Measuring devices current and voltage transformers	0 1		0 5	0 6	2 0	0 7	2 7				3 3	SakE
Technical losses (subtotal)	120 0	1 7	257 0	378 7	375 0	81 2	456 2	57 5	39 0	96 5	931 4	
Commercial losses in VHV and HV		-			80 0	22 4	102 4					SakE
Commercial losses in distribution								197 3	197 3	394 5	496 9	IBRD and HB
Technical plus commercial losses												
in kWh	120 0	1 7	257 0	378 7	455 0	103 6	558 6	254 8	236 3	491 0	1 428 3	
As a % of total losses	8 40%	0 12%	17 99%	26 51%	31 86%	7 25%	39 11%	17 84%	16 54%	34 38%	100 00%	
As a % of input to the network at each level				6 96%			8 54%			11 74%		

Exhibit 5.3b

Diagram of Electric Energy Losses in Networks in Georgia 1996

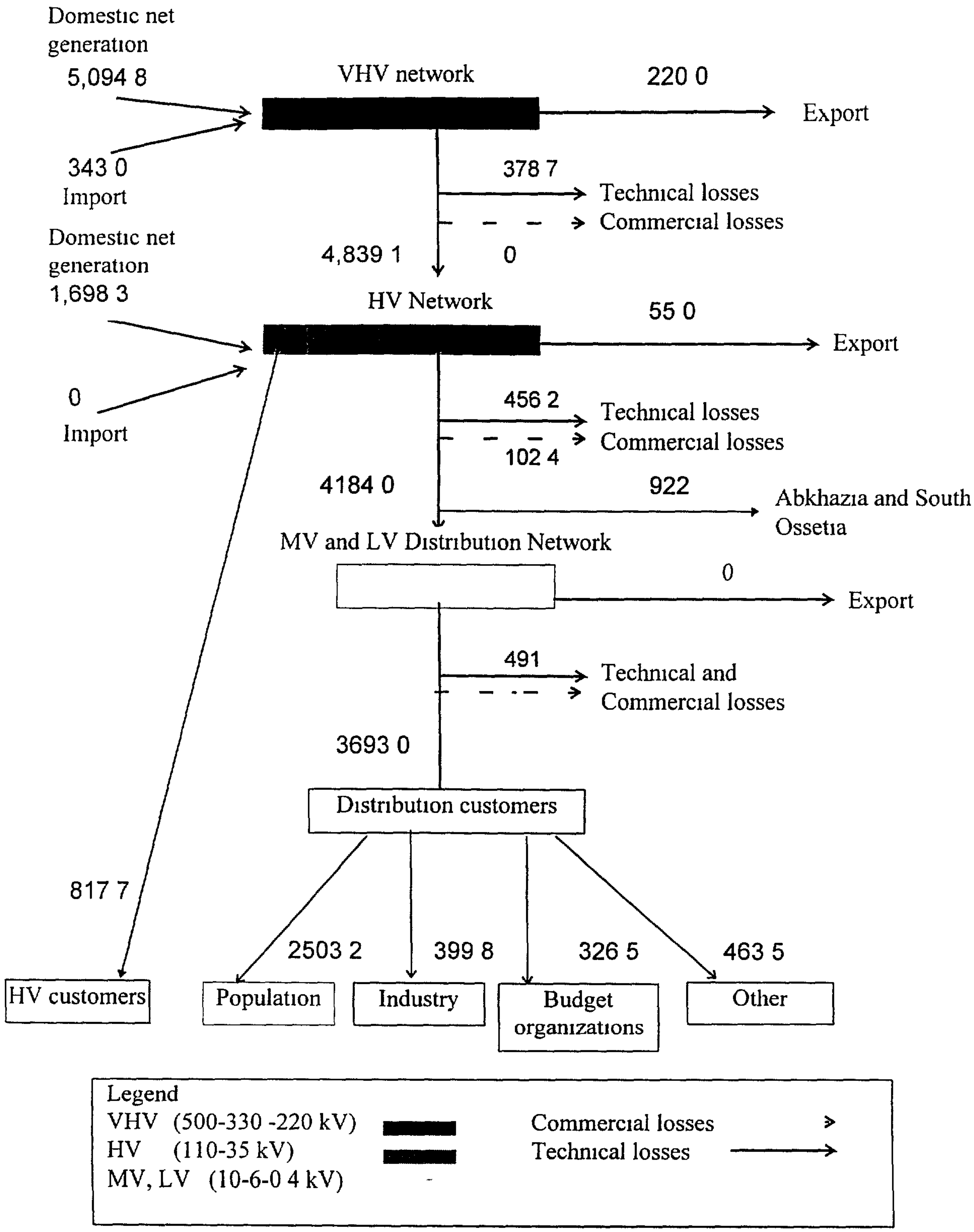

Exhibit 5 4
Construction of New Transmission Lines, January 1998 to January 2010

From substation -	To substation -	Priority	Number of units	Voltage kV	Length km	Maximum current A	Maximum capacity, MW	Construction cost per km $million/km	Total cost of construction $million *	Cumulative total cost $million
Enguri HPS	Menji	High	2	220	**77 0**	**680**	299	**0 1**	5 4	5 4
Khashuri	Tchatura	High	2	220	**60 0**	**680**	299	**0 1**	4 2	9 6
Menji	Ozurgeti	High	1	220	**48 0**	**825**	182	**0 1**	3 4	13 0
Tchiatura	Zestafoni	High	2	220	**45 0**	**680**	299	**0 1**	3 2	16 1
Gldani	Varketili	High	1	220	**12 7**	**945**	208	**0 1**	0 9	17 0
Navtlugi	Varketili	High	1	220	**5 0**	**945**	208	**0 1**	0 4	17 3
Enguri HPS	Zestafoni	High, for transit to Turkey	1	500	**194 0**	**2 067**	1 034	**0 2**	38 8	56 1
Akhaltsikhe	Tbilisi TBS	High for transit to Turkey	1	500	**178 0**	**2 190**	1 095	**0 2**	35 6	91 7
Akhaltsikhe	Zestafoni	High for transit to Turkey	1	500	**73 0**	**2 190**	1 095	**0 2**	14 6	106 3

Exhibit 5 4
Construction of New Transmission Lines, January 1998 to January 2010

From substation -	To substation -	Priority	Number of units	Voltage, kV	Length, km	Maximum current A	Maximum capacity MW	Construction cost per km $million/km	Total cost of construction $million *	Cumulative total cost $million
Enguri HPS	Sokhumi 500	Medium	1	500	**101 5**	**2 400**	1 200	**0 2**	20 3	126 6
Dedoplistskaro	Tbilisi TPS	Medium	1	220	**100 0**	**690**	152	**0 1**	7 0	133 6
Ozurgeti	Vardnili HPS I	Medium	1	220	**92 6**	**825**	182	**0 1**	6 5	140 1
Gurjaani	Tbilisi TPS	Medium	1	220	**80 0**	**690**	152	**0 1**	5 6	145 7
Akhalkalaki	Khrami HPS II	Medium	1	220	**72 0**	**825**	182	**0 1**	5 0	150 8
Akhalkalaki	Akhaltsikhe	Medium	2	220	**57 0**	**680**	299	**0 1**	4 0	154 8
Batumi	Ozurgeti	Medium	2	220	**55 0**	**825**	363	**0 1**	3 9	158 6
Dedoplistskaro	Gurjaani	Medium	1	220	**50 0**	**690**	152	**0 1**	3 5	162 1
Moliti	Zestafoni	Medium	1	220	**48 0**	**825**	182	**0 1**	3 4	165 5
Enguri HPS	Khudoni	Medium	1	500	**47 0**	**2 040**	1 020	**0 2**	9 4	174 9
Bziphi	Sokhumi 500	Medium	1	220	**42 0**	**825**	182	**0 1**	2 9	177 8
Sokhumi 220	Sokhumi 500	Medium	1	220	**42 0**	**825**	182	**0 1**	2 9	180 7
Khashuri	Moliti	Medium	1	220	**33 5**	**825**	182	**0 1**	2 3	183 1
Lajanuri	Namahvani HPS	Medium	1	220	**23 0**	**945**	208	**0 1**	1 6	184 7
Sokhumi 220	Sokhumi 500	Medium	1	220	**23 0**	**825**	182	**0 1**	1 6	186 3
Tkibuli TBS	Zestafoni	Medium	2	220	**18 0**	**690**	304	**0 1**	1 3	187 6
Joneti HPS	Tskaltubo	Very low needed after HPS is built	2	220	**22 0**	**945**	416	**0 1**	1 5	189 1
Joneti HPS	Namahvani HPS	Very low needed after HPS is built	2	220	**7 0**	**945**	416	**0 1**	0 5	189 6

Source Verbundplan Gmbh and Lahmeyer International "Study of the Interconnection of the Caucasus Countries with Turkey' Draft Final Report 21 March 1997 page A 1 20

Exhibit 5 5
Calculation of the Capacity Payment Required for the Very High Voltage Network

	1997	1998	1999	2000	2001
Rate of return on net asset value (revalued)	**0 0%**	**15 0%**	**15 0%**	**15 0%**	**15 0%**
Exchange rate Lari per USD	**1 3**	1 3	1 3	1 3	1 3
Annual depreciation rate	3 33%				
Operating expenses / Gross asset value	**4 0%**				
Balance sheet items, in thousand Lari					
Gross asset value at start of year	469 316	484 316	519 316	554 316	589 316
Plus Additions to gross asset value	**15 000**	**35 000**	**35 000**	**35 000**	**35 000**
Less Subtractions from gross asset value	-	-	-	-	-
Equals Gross asset value at end of year	484 316	519 316	554 316	589 316	624 316
Gross asset value at start of year	469 316	484 316	519 316	554 316	589 316
Less Accumulated depreciation at start of year	305 055	321 199	338 510	356 987	376 631
Equals Net asset value at start of year	164 260	163 117	180 806	197 329	212 685
Revenue requirement, in thousand Lari					
Operating expenses	18 773	19 373	20 773	22 173	23 573
Depreciation	15 644	16 144	17 311	18 477	19 644
Return on Net asset value at start of year	-	24 467	27 121	29 599	31 903
Total revenue requirement	34 416	59 984	65 204	70 249	75 119
Tariff calculation					
Peak load at VHV delivery points MW	**1 967**	**2 042**	**2 122**	**2 178**	**2 237**
VHV capacity payment Lari/kW/month	1 46	2 45	2 56	2 69	2 80
VHV capacity payment USD/kW/month	1 12	1 88	1 97	2 07	2 15
Cost per kWh sold in Georgia					
Total sales to end users billion kWh	**5 302**	**5 620**	**5 957**	**6 195**	**6 443**
Peak load at VHV delivery points MW	**1 256**	**1 331**	**1 411**	**1 467**	**1 526**
Capacity payment revenue per kWh sold tetri/kWh	0 41	0 70	0 73	0 76	0 80
Sales to VHV industrial customers					
Contribution to coincident peak load MW	**0**	**0**	**0**	**0**	**0**
Capacity payment revenue 000 Lari	0	0	0	0	0
Coincident peak load factor (assumed)	**85%**	**85%**	**85%**	**85%**	**85%**
Annual energy consumption GWh	0	0	0	0	0
Average cost of capacity tetri/kWh	0 23	0 39	0 41	0 43	0 45
Average cost of capacity cents/kWh	0 18	0 30	0 32	0 33	0 35

Exhibit 5 6
Calculation of the Capacity Payment Required for the High Voltage Network

	1997	1998	1999	2000	2001
Rate of return on net asset value (revalued)	0 0%	15 0%	15 0%	15 0%	15 0%
Exchange rate Lari/USD	1 3	1 3	1 3	1 3	1 3
Annual depreciation rate	3 33%				
Operating expenses / Gross asset value	**4 0%**				
Balance sheet items, in thousand Lari					
Gross asset value at start of year	478 129	483 129	498 129	523 129	548 129
Plus Additions to gross asset value	**5 000**	**15 000**	**25 000**	**25 000**	**25 000**
Less Subtractions from gross asset value	-	-	-	-	-
Equals Gross asset value at end of year	483 129	498 129	523 129	548 129	573 129
Gross asset value at start of year	478 129	483 129	498 129	523 129	548 129
Less Accumulated depreciation	310 784	326 888	343 493	360 930	379 201
Equals Net asset value at start of year	167 345	156 241	154 637	162 199	168 928
Revenue requirement, in thousand Lari					
Operating expenses	19 125	19 325	19 925	20 925	21 925
Depreciation	15 938	16 104	16 604	17 438	18 271
Return on Net asset value at start of year	-	23 436	23 195	24 330	25 339
Total revenue requirement 000 Lari	35 063	58 866	59 725	62 693	65 535
Tariff calculation					
Peak load at HV delivery points MW	**1 135**	**1 203**	**1 275**	**1 326**	**1 380**
HV capacity payment Lari/kW/month	2 57	4 08	3 90	3 94	3 96
VHV + HV capacity payment Lari/kW/month	4 14	6 71	6 66	6 83	6 97
VHV + HV capacity payment USD/kW/month	3 19	5 16	5 12	5 25	5 36
Cost per kWh sold in Georgia					
Total sales to end users billion kWh	5 302	5 620	5 957	6 195	6 443
Capacity payment revenue per kWh sold tetri/kWh	0 66	1 05	1 00	1 01	1 02
Sales to HV industrial customers					
Contribution to coincident peak load MW	**0**	**0**	**0**	**0**	**0**
Capacity payment revenue 000 Lari	0	0	0	0	0
Coincident peak load factor (assumed)	**85%**	**85%**	**85%**	**85%**	**85%**
Annual energy consumption GWh	0	0	0	0	0
Average cost of capacity tetri/kWh	0 41	0 66	0 63	0 63	0 64
Average cost of capacity cents/kWh	0 32	0 51	0 48	0 49	0 49

Exhibit 5 7
Financial Indicators for the Combined Networks (35 kV and Higher)

	1997	1998	1999	2000	2001
Balance sheet items, in thousand Lari					
Gross asset value at start of year	947 445	967 445	1 017 445	1 077 445	1 137 445
Plus Additions to gross asset value	20 000	50 000	60 000	60 000	60 000
Less Subtractions from gross asset value	-		-	-	
Equals Gross asset value at end of year	967 445	1 017 445	1 077 445	1 137 445	1 197 445
Gross asset value at start of year	947 445	967 445	1 017 445	1 077 445	1 137 445
Less Accumulated depreciation	615 839	648 087	682 002	717 917	755 832
Equals Net asset value at start of year	331 606	319 357	335 443	359 528	381 613
Cumulative depreciation and return	31 581	111 733	195 964	285 808	380 965
Less Cumulative additions to gross asset value	20 000	70 000	130 000	190 000	250 000
Less Increase in accounts receivable	11 581	**40 000**	**40 000**	**20 000**	-
Equals Work in progress (assuming 100% reinvestment of depreciation and return)	-	1 733	25 964	75 808	130 965
Revenue requirement, in thousand Lari					
Operating expenses	37 898	38 698	40 698	43 098	45 498
Depreciation	31 581	32 248	33 915	35 915	37 915
Return on Net asset value at start of year	-	47 904	50 316	53 929	57 242
Total revenue requirement	69 479	118 850	124 929	132 942	140 655
Balance sheet items, in million USD					
Gross asset value at start of year	729	744	783	829	875
Plus Additions to gross asset value	15	38	46	46	46
Less Subtractions from gross asset value	-	-	-	-	-
Equals Gross asset value at end of year	744	783	829	875	921
Gross asset value at start of year	729	744	783	829	875
Less Accumulated depreciation	474	499	525	552	581
Equals Net asset value at start of year	255	246	258	277	294

Exhibit 5 7, continued
Financial Indicators for the Combined Networks (35 kV and Higher)

	1997	1998	1999	2000	2001
Cumulative depreciation and return from 1997	24	86	151	220	293
Less Cumulative additions to gross asset value	15	54	100	146	192
Less Increase in accounts receivable	9	31	31	15	-
Equals Work in progress (assuming 100% reinvestment of depreciation and return)	-	1	20	58	101
Revenue requirement, in million USD					
Operating expenses	29	30	31	33	35
Depreciation	24	25	26	28	29
Return on Net asset value at start of year	-	37	39	41	44
Total revenue requirement	53	91	96	102	108

Exhibit 5 8
Recommended Transmission Tariffs for 1998

	Tariff for customers connected to the VHV network	Tariff component associated with the HV network	Tariff for customers connected to the HV network
Delivery voltage	500 330 or 220 kV	110 or 35 kV	110 or 35 kV
Basis for capacity charges	Customer load at the time of the annual coincident peak load	Customer load at the time of the annual coincident peak load	Customer load at the time of the annual coincident peak load
Capacity payment, Lari/kW/month	2 45	4 08	6 71
Capacity payment, USD/kW/month	1 88	3 14	5 16
Energy charge given as a percentage of energy received by the networks	7 0%	8 5%	14 9%
Energy charges based on time of use			
Peak energy charge given as a percentage of energy received by the networks during peak periods*	7 0%	8 5%	14 9%
Off-peak energy charge given as a percentage of energy received by the networks during off peak periods*	**5 0%**	**6 5%**	11 2%

* Peak periods are 7 am - 10 am and 7 pm - 12 pm Monday through Friday

5 7 Results of the tariff calculation

The projection of operating expenses is based on the assumption that the ratio of operating expenses to gross asset value is fixed For 1997 the ratio is about 4 0% (see Exhibit 5 2), so this figure is used in the projections for 1998-2001 (see Exhibits 5 5 and 5 6)

On the basis of Exhibit 5 4, we estimate that in the four-year period 1998-2001 there is a need to invest about 106 million USD or 138 million Lari in the VHV network This is equivalent to roughly 35 million Lari per year, so we assume that additions to gross asset value of the VHV network will be 35 million Lari in each year, 1998 through 2001 (see Exhibit 5 5) For the HV network we assume that additions to gross asset value will be 15 million Lari in 1998 and 25 million Lari in 1999, 2000, and 2001 (see Exhibit 5 6) These assumptions produce an increase in the net asset value of the VHV network and produce a relatively stable net asset value for the HV network If there were no new investments in the network, net asset values would decline over the forecast period and the transmission system would deteriorate and would fail to provide a reliable supply of electricity for domestic consumers or reliable transit service for other countries

The total revenue requirement for the combined VHV and HV networks of the North and South grid is estimated to be 119 million Lari in 1998, rising to 141 million Lari in 2001 (see Exhibit 5 7)

Our illustrative projection of the increase in accounts receivable is 100 million Lari over the 1998-2000 period (see Exhibit 5 7) Under these assumptions the projected level of work in progress is only 1 7 million Lari in 1998 but rises to 131 million Lari by 2001 These figures suggest that the capital investment program can be supported without external financing, if transmission tariffs are set at the levels shown in Exhibit 5 8 and if the Government compensates the Transmission Licensee for VHV transmission service to Abkhazia and South Ossetia If a substantially lower level of transmission tariffs is projected, there is no guarantee of the availability of external financing to support the capital investment program The power sector needs to "catch up" after several years in which capital repairs were postponed and routine maintenance was not conducted

For the VHV network, we calculate that the capacity payment in 1998 should be 2 45 Lari per kW per month, or about $1 88 per kW per month (see Exhibits 5 5 and 5 8) This estimate is based on the assumption that the peak load measured at VHV delivery points in 1998 will be 2,042 MW of which 1,331 MW is needed to serve the distribution companies and high voltage customers[10] and 711 MW is needed to make deliveries to Turkey, Abkhazia and South Ossetia

[10] See Exhibit 7 8 for a projection of VHV load and HV load needed to serve distribution companies and high voltage customers

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For service to HV customers we calculate that the capacity payment in 1998 should be 6 71 Lari per kW per month, or about $5 15 per kW per month (see Exhibit 5 8) This estimate is based on the assumption that the peak load at HV delivery points in 1998 will be 1,203 MW (see Exhibit 5 6) This tariff level is equivalent to 1 05 tetri per kWh of domestic consumption (excluding Abkhazia and South Ossetia)

It must be stressed that none of the calculations presented in this chapter should be considered a substitute for a tariff-setting procedure based on detailed data requests (as outlined in Appendices J-L) and supported by financial statements complying with international accounting standards A more accurate projection of revenue requirements should be developed on this basis

CHAPTER 6
SERVICE TO RETAIL CUSTOMERS

Through the Electricity Law and through presidential decrees the Government of Georgia has created the legal foundation for restructuring of the power sector To enable distribution companies to operate on a commercial basis as Distribution Licensees it will be necessary to review the definition of customer classes, clarify the terms and conditions of service, project the level of electricity sales in each customer class, and determine the technical infrastructure needed to provide distribution services A methodology for calculating tariffs must be based on some sort of assumptions regarding the way these tasks will be accomplished The purpose of this chapter is to present a set of assumptions about the distribution subsector that form the basis for the tariff calculations in Chapter 7

Just as it would not be logical for a Georgian telephone company to try to rebuild the telephone infrastructure that existed in 1990, one cannot assume that distribution companies should try to rebuild the electrical distribution infrastructure that existed in 1990 In the field of telecommunications, technology has changed, in the energy sector, prices have changed The older telephone infrastructure was limited to overhead wires, underground cables, switching equipment and desktop telephones to enable voice communications The older distribution network was designed to meet the targets of the command economy

6 1 Industry structure

In this study it is assumed that the distribution sector will be owned and managed by eight joint stock companies that will begin operating on a commercial basis within the next three years Private investors will have an opportunity to buy shares in these companies The geographic region served by a distribution company will be one of the eight groups identified in the privatization proposal developed by the Ministry of Fuel and Industry in September 1997 [1] Each distribution company (disco) will be a Distribution Licensee under Clause 34 of the Electricity Law and will be a Market Member under the Market Members Agreement

As a business entity, a disco is a combination of a "wires" business and a "retail supply" business, with an emphasis on the metering and billing functions of a supplier Although some discos have negotiated direct contracts with generating stations, they are not legally required to

[1] Abkhazeti may be considered the "ninth" group, which will not be privatized The Government has not firmly established the number of discos to be privatized, but for the purposes of this tariff study it is assumed that the September 1997 proposal will be followed

do so The rights and responsibilities of the discos as wholesale customers are to be defined by the Market Members Agreement (see Chapter 3)

Within a defined geographic region, the disco has a monopoly over the supply of electricity through wires that are operated at 10 kV, 6 kV, or 0 4 kV and are supplied by electricity from the high voltage grid No other company will receive a license to distribute electricity in the same geographic region [2] A retail customer does not have the right to purchase electricity supplies from a generating company or an independent supplier and pay the disco for wheeling the energy through the low-voltage grid If the customer believes that the prices charged by the disco are too high, the customer can consider installing a diesel generator or a small hydro generator [3] In some locations a customer may have an opportunity to construct a line which directly connects the customer to a transformer on the high voltage grid or to a generating station It is assumed that GNERC will limit the customer's right to install bypass lines, that is, lines that directly connect the customer to the high voltage grid or to a generating station For example, bypass lines may be limited to no more than 0 5 km in length and no less than 6 kV in voltage

The tangible assets owned by the distribution company may include some or all of the following

- overhead wires and underground cables at 10 kV, 6 kV, and 0 4 kV,[4]
- transformers which receive energy at 10 kV or 6 kV and reduce the voltage to 0 4 kV,
- meters located at transformers where energy is received from the high voltage grid or from generating stations,
- meters located at points where electricity is delivered to customers,
- computer equipment and communications equipment needed to maintain customer accounts and financial data, and to manage the construction and operation of the network, and,
- buildings vehicles, and other assets

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[2] The Electricity Law does not recognize the existence of low-voltage networks owned by industrial enterprises or agricultural collectives

[3] In principle there are a variety of renewable energy technologies that could become competitive with electricity supplied from the grid We assume that small-scale run of river hydro generation is the only renewable technology that will be competitive in the next few years

[4] Where a special situation exists and a disco owns 110 kV or 35 kV lines, the Commission could adjust the retail tariff to include an allowance for the cost of these lines It would be better to give the Transmission Licensee ownership of all existing 110 kV and 35 kV lines

The tariff should be high enough to enable the disco to attract the capital required to maintain these assets and provide firm service (as defined below)

In this study it is assumed that the disco is not legally required to own all of the 0 4 kV lines and customer meters within its service territory If a customer wishes to install a new meter, the disco is responsible for checking the accuracy of the meter If a customer wishes to replace a section of 0 4 kV line at the customer's expense (for example, the line between the customer s meter and the nearest transformer) the disco is responsible for ensuring that there is no theft of electricity (unmetered use) and ensuring that safety standards are observed

6 2 Standards of service quality

The following terminology may be used to distinguish different levels of service quality that might be provided by discos in the future

- *basic 24-hour service* The generation, transmission, and distribution system is designed to meet the peak demand and annual energy requirements of all customers who have paid their electric bills promptly However, voltage regulation and frequency regulation do not meet the standards of UCPTE (western Europe) and service is frequently interrupted by generating plant outages, transmission system failures, and distribution system failures

- *firm service* The generation, transmission, and distribution system is designed to meet the peak demand and annual energy requirements of all customers who have paid their bills promptly The disco has contracts for 24 hour supply to these customers, at price levels that support improvement in the reliability of power generation and transmission The disco has made investments to improve the reliability of the distribution network Voltage and frequency regulation are superior to basic 24-hour service

- *firm service backed by interruptible load* Customer load is classified as firm or interruptible, and interruptible load is metered separately Rate discounts are offered for interruptible load by reducing the capacity cost component Customers offer interruptible load on a voluntary basis The disco has made investments in control systems designed to shed interruptible load when needed

Basic 24-hour service requires very little investment in distribution infrastructure, other than metering and billing, and it can be started even before privatization, but it is suitable only for a transitional period in which firm service is not technically possible Basic 24-hour service can be implemented in Rustavi, for example, where a pilot project is underway The Rustavi disco has already negotiated a supply contract with Sakenergo, under which feeders will be energized on a 24 hour basis if collections are raised and payment targets are met at the wholesale level

All of the tariff calculations in Chapter 7 are based on firm service It is assumed that a disco that has been privatized will have an obligation to offer firm service to retail customers who pay for it according to the tariffs approved by the Commission If a disco does not provide firm service and has no serious plans to provide this service in the future, the Government has an obligation to revoke the license and find another company that is willing to purchase the distribution assets located within the geographic area described in the license and provide firm service [5]

In the near future there is no need to establish firm service backed by interruptible load To design a simple tariff reform plan in Georgia it is probably not necessary to introduce special tariffs to cope with a shortage of capacity during peak hours [6] Capacity-related tariff discounts appear to be less important than the development of an efficient wholesale market If the Georgian power system continues to be constrained by winter energy supplies and if the wholesale market develops properly, wholesale energy prices will reach high levels (for example, 6 cents per kWh) during winter peak hours This energy-related price signal will be an incentive for customers to reduce load during winter peak hours Indirectly this price signal tends to "interrupt" consumption during the winter peak Conversely, when there is a surplus of run of river hydro (during summer off -peak periods, for example) the wholesale energy price will be low and will give customers an incentive to increase consumption during those hours

In theory it might be possible for discos to define geographic areas in which the customer can receive low quality service, which might be called *low-price service*, based on a tariff that recovers the cost of energy purchased by the disco and the cost of customer metering and billing, but does not cover the cost of rebuilding and maintaining the low-voltage lines and transformers The customer is guaranteed nothing and eventually he will receive nothing In this study it is assumed that discos do not offer low-price service, because customers would rather have basic 24-hour service or firm service

6.3 Privatization

At present the national Government is the owner of more than 70 local distribution companies, most of which are operated by municipal Governments Exercising its rights as owner, the national Government tentatively grouped these into eight discos for the purpose of privatization National Government ownership is established by the decree on power sector restructuring issued on July 4, 1996

[5] The Electricity Law states that a license can be revoked by the Commission but it does not give the Distribution Licensee an obligation to provide firm service The licensee must obtain rights to sufficient transmission capacity and electricity " (Clause 34 3 b)

[6] The amount of peak capacity available from Russia and other neighboring countries is not known, but technically Georgia does not have to be operated as an isolated system

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> Shares of these Joint Stock Companies, until the decision on their disposition is made, will remain in Governmental ownership and given for management to the regional Governments, according to the established rules [7]

The tariff calculations in Chapter 7 are intended to support the process of privatization of the discos by providing a basis for preliminary evaluation of the tariff levels needed to pay for reconstruction and repair of the low-voltage networks In the following paragraphs we present assumptions about the terms of the privatization

It is assumed that each disco will be privatized through negotiation of an agreement between the Government of Georgia and a strategic investor The Government will give the investor the right to manage the disco, file applications for tariffs needed to make the disco profitable, and earn profits from the operation of the disco The investor will own at least 51% of the disco and have the right to fill top management positions In exchange the investor will make a commitment to implement a schedule of capital expenditures for the reconstruction of the network, and will make a commitment to provide firm service to at least a portion of the customers served by the disco The amount of money paid for the purchase of shares in the disco should be relatively small compared with the financial commitment reflected in the schedule of capital expenditures The objective of the privatization is to revitalize the distribution subsector and provide firm service to customers, not to provide a source of funds for general Government expenditures

It is assumed that even before the privatization is completed, the investor will develop a preliminary investment plan to provide firm service within a specified portion of the geographic area served by the disco In general the areas with the highest customer density and the highest ability to pay for electricity will be the first areas to be rebuilt so that firm service can be offered The extension of firm electric service is roughly comparable to the extension of modern, high-quality phone lines The reconstruction of the disco will take at least three years The investment plan should describe the firm service area, the capacity of the transformers, lines, and cables and the expected capacity utilization

The investor will want a high level of capacity utilization in the rebuilt portion of the distribution network, and will not want to build an expensive network that the majority of customers cannot afford The Government, on the other hand, will not want customers to experience frequent outages and rationing simply because the investor wants to recover his investment in a short payback period or is reluctant to risk a significant amount of money in rebuilding the network The preliminary investment plan therefore represents an important part of the negotiations between the Government and the strategic investor

One of the clauses in the privatization agreement should specify the service territory of the disco and state that one of the business objectives of the disco is to offer basic 24-hour service everywhere within this service territory The disco's obligation to provide basic 24-hour service

[7] Decree #437 of the President of Georgia *About Restructuring of the Power Sector*, Clause 10

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must be contingent on the availability of adequate supplies of energy and capacity in the wholesale market The private investor will want to limit the service territory to an area in which it will be possible to reduce or eliminate commercial losses (theft) and raise collections The selection of the service territory therefore represents an important part of the negotiations between the Government and the strategic investor

Where 24-hour service is offered but firm service is not yet available, the customer should have the right to upgrade the quality of his service by installing a new meter and, if necessary, replacing a portion of the 0 4 kV line connecting his meter to the distribution network In principle the customer should not have to make such investments, because they are the responsibility of the disco In practice, however, the disco may not have the money to pay for the new meter or the new line

It is assumed that after a disco is privatized, subsidies to the customers of the discos are implemented in the form of Government contributions toward the monthly electricity bills of "priority" customers The disco is required by the Electricity Law to charge tariffs that do not reflect a subsidy If the Government chooses to subsidize electricity use, it must pay the electricity bills of the neediest customers

6.4 Obligation to connect customers

According to the Electricity Law, the Commission may establish "eligibility criteria" that specify who is entitled to a connection to the distribution network The extension of distribution service to new customers must also be "consistent" with an investment program The law states that

According to the License Conditions, each Distribution Licensee shall, for the duration of the License

a Extend distribution services to consumers consistent with eligibility criteria established by the Commission and with the Licensee's investment program,

b Obtain rights to sufficient transmission capacity and electricity from the Transmission Licensee and/or the Dispatch Licensee, also from Generation Licensees, and other foreign or domestic Legal Persons,

c Establish and submit to the Commission for approval procedures for obtaining and terminating the rights to serve, metering, billing, and collections,

d Develop, provide to the Commission, and make publicly available an investment program, e Charge only those rates, and impose only those terms and conditions of service which are approved by the Commission [8]

In this study it is assumed that all customers who receive energy at 10 kV or lower voltage, meet technical standards associated with voltage regulation and reliability, and make prompt payments for electric service are eligible for extension of distribution service It is also assumed that basic 24-hour service should be available everywhere in the disco's service territory The extension of firm service should be consistent with the investment program

6.5 Actual versus target losses

It is assumed that the retail tariff calculation will be based on a target level of total losses at the distribution level, including technical and commercial losses Under this approach to tariff-setting the disco has an incentive to reduce its losses and ensure that actual losses are no higher than the target The target has to be set at a level that is reasonable and achievable If a disco is unable to reduce losses to the level in the tariff, the disco will have less money available for capital investment In extreme cases the disco will be forced into bankruptcy If the actual level of losses is below the target, and if collections are close to 100%, the disco will have higher profits than the level shown in the tariff calculation The disco is allowed to retain such profits, but GNERC may decide to lower the target level of losses on a prospective basis

The customer who pays his electricity bill based on accurately metered consumption may be asked to pay a tariff based on the true economic cost of the energy he receives, but it is not fair to ask him to pay a substantial premium to cover the cost of electricity that is stolen In addition it is not clear that the tariff levels needed to cover the cost of commercial losses are politically acceptable

6 6 Regional basis for tariff calculations

It is assumed that eight separate discos will be formed, plus a distribution enterprise for the Abkhazia region (see Exhibits 6 1 and 6 2) Preliminary tariffs are calculated for each disco, based on the technical characteristics of the preliminary investment plan for the distribution network in the service territory The number of kilometers of lines and cables in the preliminary investment plan does not have to match the 1990 level Instead, the investment plan can be adjusted so that the average tariff is kept down to an acceptable level

[8] Georgian Electricity Law of 1997 Clause 34 3

Exhibit 6 1

Proposed Grouping of Distribution Companies for Privatization

Regions included in the group	Group name used by Hagler Bailly	Municipalities included in the group	Corresponding number shown on the map
Adjara	Ajara	Batumi, Kobuleti, Keda,Shuakhevi, Khelvachauri, Khulo	8
Javakheti	Javakheti	Adigeni, Akhaltsikhe, Aspindza, Borjomi, Akhalkalaki, Ninotsminda	7
Guria, Samegrelo, Zemo Svaneti	Guria	Poti, Senaki, Mestia, Zugdidi, Chkhorotsku, Ozurgeti, Tsalenjikha, Martvili Lanchkhuti, Khobi, Abasha, Chokhatauri	2
Imereti, Kvemo Svaneti, Racha-Lechkhumi	Imereti	Kutaisi Khoni Zestaponi Tskaltubo Tkibuli Terjola Samtredia Tsageri Chiatura Vani Lentekhi Kharagauli Bagdadi Oni-Ambrolauri Sachkhere	3
Kvemo Kartli,Mtskheta-tianeti, Kazbegi	Kvemo Kartli	Rustavi Tsalka Dusheti Marneuli Dmanisi Kazbegi Bolnisi Gardabani Tianeti Tetritskaro Mtskheta Sagarejo	5
Kakheti	Kakheti	Akhmeta Telavi Kvareli Gurjaani Lagodekhi Dedoplistskaro Signagi	6
Abkhazeti	Abkhazeti	Gagra Sokhumi Gudauta Ochamchire Gali	1
Shida Kartli	Shida Kartli	Kaspi Gori Khashuri Kareli Akhalgori Tskhinvali Java	4
Tbilisi	Tbilisi	Tbilisi	9

Exhibit 6.2

Map of Distribution Companies

The tariff calculations in Chapter 7 are based upon the regional data contained in Exhibit 6 3, as well as data on the national power system The columns showing the length of overhead lines and underground cables and the capacity of transformers show amounts reported for 1990, the latest year for which data were available The amount of energy purchased by the disco in 1996 is used to estimate coincident peak load These data sources are both used to measure the replacement cost of the network in USD per kW of peak load Unfortunately, the use of the 1990 level of infrastructure to meet 1996 electricity demand results in a high capacity cost per kW and high tariffs All of the discos except Telasi have this problem they did not receive enough energy in 1996 to pay for the replacement cost of the 1990 network The right-hand column of Exhibit 6 3 reflects assumptions about the investment plan The length of 0 4 kV lines in the investment plan is assumed to equal the "0 4 kV multiplier" in the right-hand column of Exhibit 6 3, multiplied by the length of 0 4 kV lines reported in 1990 The level of the multiplier is simply a very rough estimate and therefore the only "accurate" results are those for Telasi

Data on 66 individual distribution companies are shown in Exhibit 6 4 There is no reason to calculate tariffs for these companies

The assumptions in this chapter are relevant to the distribution sector in all parts of Georgia except Abkhazia and South Ossetia Retail tariffs in Abkhazia and South Ossetia are outside the scope of this report

6 7 Tariff classes

It is assumed that tariff classes will be defined according to the voltage level at which the customer receives electricity, the ownership of the transformer, and the type of meter used to measure electricity consumption These are all technical parameters that define an objective basis for allocating customers to the various customer classes In addition there is a separate tariff class for residential customers, so that the GNERC can develop a tariff reform plan in which the necessary increase in residential tariffs is phased in gradually A total of five customer classes may be defined

- Customers with a peak load of 50 kW or larger, with a transformer owned by the customer, and with service at 6 kV or 10 kV These customers would have demand meters installed and would pay demand charges in addition to energy charges The demand charge is reduced because the cost of the transformer is borne by the customer

- Customers with a peak load of 50 kW or larger, with a transformer owned by the disco, and with service at 6 kV or 10 kV These customers would have demand meters installed and would pay demand charges in addition to energy charges The demand charge includes an allowance for the cost of the transformer

Exhibit 6 3
Data on Groups of Distribution Companies

Distco ID	Region or distco	Type of region	Overhead lines (km) 10 kV, 6 kV	Overhead lines (km) 0 4 kV	Underground cables (km) 10 kV 6 kV	Underground cables (km) 0 4 kV	Transformer capacity (kVA)	1996 purchases (GWh)	1996 losses %	1996 sales (GWh)	0 4 kV multiplier
1	Adjara	MFE group	**1,000 35**	**6,129 00**	**27 48**	**0 48**	**101,926**	**272 0**	**11 0%**	242	**0 4**
2	Javakheti	MFE group	**1,489 20**	**3,343 00**	**55 39**	**50 60**	**101,360**	**129 0**	**11 0%**	115	**0 4**
3	Guria group	MFE group	**3,114 09**	**11,678 01**	**#N/A**	**#N/A**	**250,696**	**325 4**	**11 0%**	290	**0 4**
4	Imereti group	MFE group	**3,785 67**	**16,554 74**	**#N/A**	**#N/A**	**310,424**	**786 9**	**11 0%**	700	**0 4**
5	Kvemo Kartli group	MFE group	**3,898 66**	**#N/A**	**#N/A**	**61 30**	**225,097**	**412 6**	**11 0%**	367	**0 4**
6	Shida Kartli	MFE group	**1,422 20**	**3,371 80**	**#N/A**	**59 40**	**132,073**	**182 8**	**11 0%**	163	**0 4**
7	Karkheti	MFE group	**3,324 40**	**5,827 60**	**#N/A**	**30 50**	**162,069**	**107 7**	**11 0%**	96	**0 4**
8	Telasi	MFE group	**164**	**1,615**	**1,821**	**1,211**	**928,000**	**1,982 0**	12 6%	1,733	**1**
9	Georgia	nation	18 559	56,946	1 968	1 541	2 195,077	4 184 0	11 7%	3 693	**0 4**

Sign N/A refers to absence of reliable data

Source Preliminary Assessment of Distrubution Sector for Privatisation, HB November 1997

Exhibit 6 4
Data on Individual Distribution Companies

Distco ID	Region or distco	Type of region	Overhead lines (km) 10 kV 6 kV	Overhead lines (km) 0 4 kV	Underground cables (km) 10 kV 6 kV	Underground cables (km) 0 4 kV	Substations transformers (kVA)	1996 purchases (GWh)	1996 losses %	1996 sales (GWh)
1	Batumi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	
2	Kobuleti	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	
3	Khelvashauri	Municipal	289	1,580	2	1	62,500	#N/A	#N/A	
4	Kedi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	
5	Shuakhevi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	
6	Khulo	Municipal	268	1 360	0	2	18 537	#N/A	13 0%	
7	Ozurgeti	Municipal	399	1,927	21	4	36,530	14	15 0%	
8	Lanchkhuti	Municipal	260	1,071	5	3	#N/A	16	20 0%	
9	Chokhatauri	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	11	#N/A	
10	Zugdidi	Municipal	423	2,183	12	4	150 000	116	#N/A	
11	Tsalenjikha	Municipal	158	714	55	60	#N/A	32	11 0%	
12	Chkhorotku	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	14	#N/A	
13	Senaki	Municipal	274	1,163	3	7	31 300	36	#N/A	
14	Martvili	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	11	#N/A	
15	Abasha	Municipal	295	960	0	0	#N/A	11	#N/A	
16	Khobi	Municipal	400	752	5	0	#N/A	13	15 0%	
17	City of Poty	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	42	#N/A	
18	Kutaisi	Municipal	56	1,232	268	420	#N/A	405	35 0%	
19	Tskaltubo	Municipal	345	1,480	54	71	75,548	61	#N/A	
20	Samtredia	Municipal	300	1,545	13	4	48,594	91	11 0%	
21	Khoni	Municipal	373	1,305	0	0	25 600	17	25 0%	
22	Vani	Municipal	250	777	0	0	19,496	10	#N/A	
23	Baghdati	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	11	12 0%	
24	Tkibul	Municipal	398	753	65	280	38,700	54	#N/A	
25	Tsageri	Municipal	197	516	0	0	8,995	8	#N/A	
26	Lentekhi	Municipal	193	234	2	0	10,700	4	10 0%	
27	Zestaponi	Municipal	359	1 872	4	4	37 159	41	25 0%	
28	Terjola	Municipal	169	1 084	0	0	19 870	22	25 0%	
29	Kharagauli	Municipal	214	981	1	11	14 174	8	18 0%	
30	Chiatura	Municipal	280	1,044	0	578	45,460	29	30 0%	
31	Satchkere	Municipal	362	978	3	0	15 900	10	22 0%	
32	Ambrolauri	Municipal	420	839	0	0	#N/A	11	16 0%	
33	Oni	Municipal	310	731	0	0	14 250	6	18 0%	

Source Preliminary Assessment of Distrubution Sector for Privatisation HB November 1997

Exhibit 6 4, continued
Data on Individual Distribution Companies

Distco ID	Region or distco	Type of region	Overhead lines (km) 10 kV 6 kV	Overhead lines (km) 0 4 kV	Underground cables (km) 10 kV 6 kV	Underground cables (km) 0 4 kV	Substations transformers (kVA)	1996 purchases (GWh)	1996 losses %	1996 sales (GWh)
34	Akhaltsikhe	Municipal	313	460	24	15	31 394	41	14 0%	
35	Akhalkalaki	Municipal	6	1,082	13	0	29 882	16	20 0%	
36	Adigeni	Municipal	165	305	0	2	12,000	4	#N/A	
37	Aspindza	Municipal	170	128	0	0	8,983	2	13 0%	
38	Ninotsminda	Municipal	188	360	1	0	6,700	7	20 0%	
39	Borjomi	Municipal	144	510	27	17	25 600	59	18 0%	
40	Gori	Municipal	866	1 822	64	37	97,138	76	11 0%	
41	Khashuri	Municipal	256	786	13	11	27,749	49	#N/A	
42	Kaspi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	46	#N/A	
43	Kareli	Municipal	277	656	5	0	20 345	10	#N/A	
44	Akhalgori	Municipal	167	448	0	0	8 269	2	#N/A	
45	Rustavi	Municipal	23	357	167	118	68,819	73	16 0%	
46	Mtskheta	Municipal	456	674	8	0	19,677	21	#N/A	
47	Dusheti	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	49	#N/A	
48	Sagarejo	Municipal	930	560	20	15	11 000	27	#N/A	
49	Tianeti	Municipal	170	409	2	4	8,520	9	#N/A	
50	Gardabani	Municipal	758	1,050	2	4	35,700	101	#N/A	
51	Marneuli	Municipal	2	2,200	440	150	59,500	78	#N/A	
52	Bolnisi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	15	#N/A	
53	Dmanisi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	11	#N/A	
54	Tsalka	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	14	#N/A	
55	Tetritskaro	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	12	#N/A	
56	Manglisi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	2	#N/A	
57	Gurjaani	Municipal	363	786	0	2	22,668	29	#N/A	
58	Sighnaghi	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	9	#N/A	
59	Dedoplis Tskaro	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	9	#N/A	
60	Telavi	Municipal	340	1,183	20	0	40,364	23	#N/A	
61	Akmeta	Municipal	#N/A	#N/A	#N/A	#N/A	#N/A	6	#N/A	
62	Lagodekhi	Municipal	252	717	0	0	10 930	8	15 0%	
63	Kvareli	Municipal	137	542	0	0	13,800	5	#N/A	
64	Mestia	Municipal	297	514	0	1	9 305	10	10 0%	
65	Kazbegi	Municipal	172	342	0	0	4 584	4	#N/A	
66	Telasi	Municipal	164	1,615	1 821	1 211	928 000	1,982	23 0%	

Source Preliminary Assessment of Distrubution Sector for Privatisation HB November 1997

- Customers with a peak load of less than 50 kW and with service at 6 kV or 10 kV These customers would not be expected to have demand meters Most of these customers would have three-phase meters that measure monthly energy consumption However, customers in this group would be permitted to install a demand meter and use a two-part tariff

- Non-residential customers with service at 0 4 kV These customers would have either three-phase or one-phase meters that measure monthly energy consumption The cost of the meter is either borne by the customer or recovered in a monthly customer charge that is not related to the amount of kWh consumed

- Residential customers with service at 0 4 kV These customers would have either three-phase or one-phase meters that measure monthly energy consumption The cost of the meter is either borne by the customer or recovered in a monthly customer charge that is not related to the amount of kWh consumed

In principle it would be possible to define additional subclasses and calculate different tariffs according to the load factor of each subclass, but there is no reliable way to forecast the load factors that will be achieved when 24-hour service is made available to customers We recommend that the tariff structure should not be complicated by the addition of subclasses unless data are available to distinguish the economic cost of service in different subclasses

For non-residential customers this set of customer classes is different from the set used during the Soviet period Each disco will therefore need to re-classify its non-residential customers

6 8 Monthly versus annual adjustment of retail tariffs

One of the problems facing the discos is that there are seasonal fluctuations in the monthly cost of electricity purchased in the wholesale market In principle it would be possible for each disco to re-calculate its retail tariffs every month, based on the cost of power purchased in the previous month Retail tariffs would be high in Winter and low in Summer

Our understanding is that monthly adjustment of retail tariffs is not politically acceptable and would impose a large administrative burden on the discos A more realistic approach to retail tariff adjustment is to plan on annual tariff increases

With the phase-in of a new wholesale market the discos will be responsible for timely payment of monthly bills for power purchased during the Winter Some form of financing will be required to pay these monthly bills during the Winter, using revenue collected on the basis of retail tariffs adjusted annually This issue should be resolved through the Market Rules established under the Market Members Agreement

CHAPTER 7
RETAIL TARIFFS

The objective of this chapter is to present stylized calculations of retail electricity tariffs in Georgia The chapter includes a proposal providing a two-year transition in which retail tariffs can be increased gradually to a level that reflects the estimated long-run economic cost of service This proposal is based on replacement cost valuation of assets These tariffs could be modified, given the method applied to revaluation of assets, the rate and extent of privatization, and the timing and amount of new investment

Pricing based on economic costs

The retail tariff methodology used in this chapter might be called a *long-run economic cost* methodology because it is based on projections of the long-run economic cost of supplying electricity through networks in Georgia The idea behind this approach is that the cost of service to a class of customers can be estimated by calculating energy flows, energy losses, replacement costs of the network, and marginal costs and average costs of generation Taxes are omitted from the calculation, although the cost of capital should include a tax component [1] The methodology consists of five components

1 *Energy flows* Calculation of energy flows in the Georgian power system, for two historical years (1996 and 1997) and two forecast years (1998 and 1999) Energy flows are estimated for the year as a whole and for the coincident peak hour, at four different voltage levels Very High Voltage (500, 330, and 220 kV), High Voltage (110 and 35 kV), Medium voltage (10 and 6 kV) and Low Voltage (0 4 kV) Technical and commercial losses are estimated at each voltage level [2]

2 *Network costs* Calculation of the levelized annual cost of the networks at each voltage level, based on the replacement cost of the existing infrastructure, the economic life of the assets, and the discount rate (that is, the rate of return on total capital invested in the networks) The levelized annual cost is the annual revenue needed to recover the capital and operating costs of the asset over its economic life, assuming that annual revenue is constant over the life of the asset Replacement cost should be calculated at each voltage level, for the overhead lines, underground cables,

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[1] The analysis in this chapter assumes a 15 percent rate of return on total capital invested in the networks, prices are expressed in constant 1997 dollars at an exchange rate of 1 3 Lari per dollar
[2] For the VHV and HV grid, the annual load flows are described in Chapter 5

substations, and transformers used to deliver energy from generating stations (or border points in the case of imports) to the customer

3 *Generation costs* Calculation of the average annual cost of energy supplied to the VHV and HV grid for resale to the distribution companies Projection of the marginal cost of generating capacity (in dollars per kW of gross generating capacity), the marginal cost of energy generated or imported during peak periods (in cents per kWh) and the price of energy generated during off-peak periods (in cents per kWh) [3]

4 *Customer classes* Definition of customer classes and selection of voltage level, class load factor and other parameters used to characterize each customer class Calculation of the "target" level of tariffs for each customer class including two-part tariffs, where appropriate

5 *Tariff reform plan* Selection of parameters defining the phase-in of tariffs over a two-year period Calculation of a set of retail tariffs at each stage, ending with the target level of tariffs

The economic cost methodology could also be called a modified long-run marginal cost (LRMC) methodology in which capital costs are included but forecasting is limited to the short term (two or three years) The LRMC approach is explained in the next section of this chapter

The calculation of electricity tariffs based on economic cost can be compared to the task of projecting the cost of producing and distributing natural gas in a country or region where there is no existing gas network In the natural gas system development this type of analysis is common, because many cities have no gas networks, but power sector development is nearly always based on the expansion or interconnection of existing networks

Average cost pricing

The standard approach to tariff-setting in the United States is *average cost pricing*, which is the practice of administratively setting prices so that the projected revenue from sales of electricity and wheeling of electricity matches the projected cost of serving customers, when these costs are measured according to the system of accounts set up by the regulatory authority [4] The annual financial revenue requirement is the total amount of revenue needed to pay operating expenses, debt service expenses, taxes and (if appropriate) an allowance for profit that is established by the regulatory authority and is intended to enable the company to obtain capital from equity investors through the issuance of stock The calculation is based on *financial costs*, that is, the

[3] All of these values were estimated in Chapter 4

[4] Although state regulatory commissions have the legal authority to set up their own systems of accounts, in practice all of the states use the national system known as the Uniform System of Accounts, which is defined in regulations issued by the Federal Energy Regulatory Commission

costs measured according to the system of accounts approved by the Government, the exchange rates faced by the power sector, the taxes in effect, and the Government price controls (if any) applied to fossil fuels and other goods and services used by the power sector The calculation is not based on *economic costs*, that is, estimates of the true cost to the national economy of the goods and services used in the power sector, but it is possible that financial costs and economic costs are nearly the same [5] The principles of average cost pricing can also be applied to electric companies that are not owned by private investors In this situation there is no profit component in the financial revenue requirement

After the financial revenue requirement is measured, it should be divided into three cost categories that are intermediate results in the tariff calculations energy-related costs (to be recovered through a price per kWh), capacity-related costs, and customer-related costs (to be recovered through a fixed minimum charge on the customer's monthly bill) [6] For a customer class with large industrial customers the capacity-related costs are recovered through a price per kW per month, and for a customer class with small customers the capacity-related costs as well as energy costs are recovered through a price per kWh The energy-related costs are allocated among customer classes, based on the number of kWh of energy consumed in each class The customer-related costs are allocated among customer classes according to estimates of the cost of metering and billing There are three alternative ways to allocate capacity-related costs among customer classes One method is to allocate capacity-related costs according to the contribution of each customer class to the coincident peak load of the power system A second method is to allocate capacity-related costs according to an analysis of the non-coincident peak load of each customer class The third method is a blend of the first two

Normally these calculations are applied to a *forecast period*, for example, the first twelve months following the date when a change in the tariff is expected to become effective The forecast is compared with a *test period* in which historical data are available In the simplest case, all of the revenue is sales revenue and there are no wheeling tariffs The average revenue per kWh (or "tariff yield") of a customer class is equal to the sum of energy, capacity, and customer-related costs allocated to that class, divided by annual kWh sales for that class To calculate a flat tariff, the sum of energy and capacity costs is divided by annual kWh sales and the result is a tariff per kWh The annual customer-related costs are divided by the number of customers and then divided by 12, the result is a monthly customer charge

The starting point of average-cost pricing is the calculation of the total revenue requirement to be collected from electricity consumers For this purpose it is necessary for the regulatory

[5] In developing countries the differences between financial and economic costs are usually attributable to (1) fuel price controls, (2) high inflation, (3) Government subsidies or special taxes affecting the power sector, and (4) artificial exchange rates In Georgia the major area of concern is likely to be inflation, which has caused the book value of assets to be too low

[6] A useful introductory book on electric tariff-setting in the United States is *The Art of Rate Design*, by Frank Walters (Edison Electric Institute, 1984) In 1993 a Russian translation was developed by Dispatch Center Baltija (Riga, Latvia) in collaboration with Hagler Bailly

commission to obtain a complete set of financial accounts for the distribution company In Georgia the Commission does not yet have this type of financial data, for several reasons

- The eight new distribution companies which have been proposed in connection with the privatization program have not been created The proposed discos do not exist in any legal form, and therefore they do not have consolidated financial accounts or consolidated energy purchase and sales accounts

- The Government has not issued a decree with "rules for asset revaluation, depreciation, profit levels, and writing off of bad debts "[7] The appropriate balance sheet treatment of debts caused by low collection rates during the 1991-1997 period is unclear

- Most of the municipal discos do not have the computer hardware and software needed to implement international accounting standards The present accounting system is based on reporting requirements for tax purposes

- GNERC has not issued regulations setting up a uniform system of accounts for companies in the power sector

- The discos have not been privatized and therefore it is difficult to forecast the profit component of the financial revenue requirement

For these reasons the tariff calculations in this chapter are not based on projections of the financial revenue requirements of the distribution companies During 1998 many of these issues should be clarified and many reforms could be implemented The documents presented in Appendices J-L were intended to help the Commission establish procedures and collect the data necessary to calculate the financial revenue requirements of Generation Licensees, the Transmission Licensee, and the Distribution Licensees

Revenue-neutral tariffs based on economic cost

The calculation of the total financial revenue requirement of each of the eight discos to be privatized is principally a question of accounting reform, and not a tariff issue If a forecast of the financial revenue requirement were available, it would be simple to adjust the level of tariffs based on economic costs so that the projected revenue would match the financial revenue requirement The spreadsheet model used to calculate tariffs based on economic costs contains calculations of the total revenue associated with these tariffs, assuming a collections rate of 100 percent for metered electricity sales The simplest way to meet a different revenue target - for example, a ten percent lower level of annual revenue - is to multiply all of the energy charges

[7] World Bank, *Staff Appraisal Report Georgia Power Rehabilitation Project*, May 8 1997, pages 31 and 45-46

and capacity charges by a multiplier - for example, 0 9 The resulting tariffs may be called *revenue-neutral* because they should enable the disco to achieve the financial revenue requirement The calculations in this chapter should not be interpreted as a basis for delaying the introduction of accounting reforms and regulatory procedures needed to determine the financial revenue requirements of the discos Rather, the tariffs based on economic costs may be considered a basis for determining the relative level of tariffs and the structure of tariffs and a set of preliminary targets during the period in which the necessary financial data needed to calculate revenue requirements for the discos are not available

Marginal cost pricing

The tariff methodology in this chapter is similar to *marginal cost pricing*, which is the practice of administratively setting prices on the basis of an estimate of the marginal cost of supplying goods and services The long run marginal cost of generation is defined as the lowest cost required to meet a sustained increment of load with no change in reliability In a wholesale market with competition among generators, the most common approach to the calculation of LRMC is to add the LRMC of generating capacity to the short run marginal cost (SRMC) of energy, which can only be projected using a simulation model of hourly economic dispatch over a period of at least one year

Since the 1970s, marginal cost pricing has been widely favored by the World Bank and other multilateral development banks, and many power sector loans have included conditionalities related to the implementation of marginal cost pricing, or have been issued only after the Bank has conducted a tariff study and recommended tariff reforms During the 1970s and 1980s marginal cost pricing was widely discussed in the United States, but not widely implemented [8]

In international practice there are two well-known forms of marginal cost pricing in the electric sector

- *Strict LRMC* In this approach, tariffs are set at the level of LRMC regardless of the profitability of the power sector enterprise In a power system with shortages of generating capacity or shortages of fuel, pricing based on strict LRMC can lead to a situation in which the power sector enterprise has a financial surplus, or extra profit, which might be taxed or transferred to the Government The revenue associated with LRMC tariffs will be larger than the amount needed to cover the enterprise's financial revenue requirements In a power system with large reserve margins and excess capacity, pricing based on strict LRMC could lead to a situation where the power sector enterprise has a financial deficit and requires some sort of subsidy

[8] There are several well-known reference books on the regulation of natural monopolies The first book to strongly recommend marginal cost pricing was *The Economics of Regulation*, by Alfred E Kahn (New York John Wiley & Sons, 1971)

- *Revenue neutral LRMC* In this approach, strict LRMC tariffs are multiplied by the ratio of the average tariff based on financial revenue requirements to the average tariff based on strict LRMC In other words a multiplier is used to lower all of the strict LRMC tariffs (or, if necessary, raise all of the strict LRMC tariffs) to the level that is consistent with the financial revenue requirements of the power sector enterprise

The use of revenue neutral LRMC is the appropriate method to use to scale rates up or down to assure that investors do not under or over collect due to inappropriate rates

Development of a spreadsheet model

All of the equations needed to calculate retail tariffs based on economic costs, given estimates of the marginal cost and average cost of generation, are included in a spreadsheet which was developed for this study on the basis of similar spreadsheets used by Hagler Bailly in tariff studies for Egypt, Kazakstan, and other countries In these exhibits, numbers shown in bold face are input data while other numbers are calculated values By changing any of the numbers shown in bold face it is possible to recalculate tariffs based on a different input parameter or parameters The magnitude of the effect of a change in the input assumptions can be determined very easily [9]

The starting point for the calculation of tariffs is an estimate of electric energy sales and losses, as shown in Exhibit 7 1 We have been able to obtain data in this form only at the national level The estimate of technical and commercial losses in distribution (line 6) is based on World Bank data and it is used as a target level of losses for the purpose of tariff-setting, regardless of regional variations in the actual level of losses

[9] The model was developed in Lotus Version 5 for Windows and it is being translated into an Excel version in the Georgian language, using Excel for Windows 95 The Georgian version will be provided to GNERC

Exhibit 7 1
Electric Energy Sales and Losses, 1996

		Data source	1996 sales GWh	Percent of distribution sales	Percent of total supply
1	Distribution company sales to the population		**2,503 2**	67 8%	36 5%
2	Plus Distribution company sales to industry	*calculated*	399 8	10 8%	5 8%
3	Plus Distribution co sales to budget organizations		**326 5**	8 8%	4 8%
4	Plus Distribution company sales to other customers	*calculated*	463 5	12 6%	6 8%
5	Equals Total distribution sales to consumers	*calculated*	3 693 0	100 0%	
6	Plus Technical and commercial losses in distribution	World Bank	**491 0**		7 2%
7	Equals Total supply to the distribution companies	Hagler Bailly survey	4 184 0		
8	Plus sales to HV industrials supplied by Sakenergo	*calculated*	582 8		8 5%
9	Plus direct sales to HV customers supplied by HPS		**134 9**		2 0%
10	Plus direct sales to Tbilisi water supply		**100 0**		1 5%
11	Equals Sales to distribution companies & HV customers	*calculated*	5 001 7		
12	Plus HV deliveries to Abkhazia and South Ossetia		**922 0**		13 4%
13	Plus HV commercial losses reported by Sakenergo	SakEnergo	**102 4**		1 5%
14	Plus HV technical losses	SakEnergo	**456 2**		6 6%
15	Plus VHV technical losses	SakEnergo	**378 7**		5 5%
16	Equals Total supply to the HV and VHV network	World Bank	**6,861 0**		100 0%
17	Sales to industry (total of line 2 plus line 8)		**982 6**		14 3%
18	Sales to wholesale customers (lines 8 9 10)	*calculated*	817 7		11 9%
19	Technical and commercial losses (lines 6 13 14 15)	*calculated*	1 428		20 8%
20	Deliveries to Abkhazia etc plus losses (lines 12 18)	*calculated*	2 350		34 3%

The tariff calculations in this chapter are based on the national grid for the costs of generation and imports, VHV networks, and HV networks, and are based on the Telasi grid, for costs associated with medium voltage (MV) and low voltage (LV) networks (see Exhibit 7 2) There are no VHV sales customers in Georgia although the model shows the level of VHV tariffs that could be offered if industrial customers connect directly to the 220 kV grid The HV tariffs may be described as national tariffs for sales by Sakenergo, but in the future restructuring of the wholesale market the cost of capacity and energy to HV customers will be established by the Market Rules Therefore the main focus of this chapter is on the MV and LV tariffs The spreadsheet model can be used very easily to calculate tariffs for different disco groups, among the eight groups identified by the Ministry of Fuels and Energy, but the results shown here are for Telasi because we consider the tariff levels most reasonable in the light of Georgian customers' ability to pay and the price levels prevailing in other countries

To calculate tariffs for all of the customer classes described in Chapter 6 it was necessary to divide MV service into two categories - MV1 service in which the customer owns the transformer, and MV2 service in which the disco owns the transformer (see Exhibit 7 3) The preliminary results indicate that the difference in tariffs is not very large, and therefore the Commission might consider combining the tariff classes for large MV customers, to simplify the tariff structure To give correct price signals to consumers, however, a price discount should be offered to those MV customers who install and operate their own transformers

Energy flows

Exhibits 7 4 through 7 8 show the calculation of annual energy sales and losses in GWh and coincident peak load in MW These tables serve three purposes

- Data on peak load are used to estimate the capacity cost per kW of each level of the network If a disco has a relatively modest peak load per unit of infrastructure - per kilometer of line, for example - the tariff will be high This is, in fact, a severe problem for the discos other than Telasi, and therefore the peak load forecast is important It is derived from the annual energy sales forecast and from load factor assumptions

- Data on energy losses are used to calculate tariffs at each voltage level based on the losses at each level In effect the price of energy delivered to the VHV and HV grid from domestic generation and imports must be "increased" to take into account the losses in transmission and distribution In Georgia, the total losses in the networks are relatively high and therefore this calculation has an important effect on the tariffs

- Data on annual energy sales are used to weight the tariffs for each customer class to come up with a projection of total revenue The weights are only approximate, as a result of the paucity of data, but it is fairly clear that residential load will form a major

Exhibit 7 2
Costs and Loss Factors Used to Calculate Tariffs Based on LRMC

Portion of the power system			Marginal cost of energy Energy costs	Energy loss factors Peak	Energy loss factors Off peak	Marginal cost of capacity Capacity costs Capital related	Capacity costs Operation and maintenance	Capacity loss factors
Generation		Power stations	Marginal energy cost (peak and off peak) *peak Gardabani* *off peak Engun* Exhibit 7 10	Station use (peak) *Gardabani* Exhibit 7 7	Station use (off peak) *Engun* Exhibits 7 5 and 7 7	Gas turbine cost adjusted by reserve margin *new gas turbine* Exhibit 7 10	Gas turbine O&M cost adjusted by reserve margin *new gas turbine* Exhibit 7 10	—
VHV	Very High Voltage	500 330 220 kV	—	Network losses (peak) *national grid* Exhibit 7 7	Network losses (average) *national grid* Exhibits 7 5 and 7 7	Replacement cost *national grid* Exhibits 7 9 and 7 10	Percentage of capital cost *national grid* Exhibit 7 10	Network losses (peak) *national grid* Exhibit 7 7
HV	High Voltage	110 35 kV	—	Network losses (peak) *national grid* Exhibit 7 7	Network losses (average) *national grid* Exhibits 7 5 and 7 7	Replacement cost *national grid* Exhibits 7 9 and 7 10	Percentage of capital cost *national grid* Exhibit 7 10	Network losses (peak) *national grid* Exhibit 7 7
MV1 MV2	Medium Voltage	10 6 kV	—	Network losses (peak) *Telasi* Exhibit 7 7	Network losses (average) *Telasi* Exhibits 7 5 and 7 7	Replacement cost *Telasi* Exhibits 7 9 and 7 10	Percentage of capital cost *Telasi* Exhibit 7 10	Network losses (peak) *Telasi* Exhibit 7 7
LV	Low Voltage	0 38 kV	—	Network losses (peak) *Telasi* Exhibit 7 7	Network losses (average) *Telasi* Exhibits 7 5 and 7 7	Replacement cost *Telasi* Exhibits 7 9 and 7 10	Percentage of capital cost *Telasi* Exhibit 7 10	Network losses (peak) *Telasi* Exhibit 7 7

* Tariffs are based on the assumption that Gardabani units 9 and 10 are the marginal source of supply during peak hours

Exhibit 7 3
Allocation of Costs to Different Voltage Levels

Voltage level	Overhead lines and underground cables for which costs are allocated to this voltage level	Substations and transformers for which costs are allocated to this voltage level	Geographic region*
Generation	None	None	national grid
VHV	500 330 220 kV	Substations with a primary voltage of 220 kV or higher	national grid
HV	110 35 kV	Substations with a primary voltage of 110 kV or 35 kV	national grid
MV1	10 6 kV	None The customer owns the transformer	Telasi
MV2	10 6 kV	Transformers with a primary voltage of 10 kV or 6 kV	Telasi
LV	0 4 kV	None	Telasi

* For the VHV and HV system LRMC is measured for the nation as a whole
At 10 6 and 0 4 kV LRMC is measured for a piliali or group of distribution companies

The identification number for Telasi is **7**

Economic assumptions used to calculate LRMC

Exchange Rate (Lari/USD)	**1 3**
Interest rate used to compute annual network costs	**15 0%**

2

> part of the total load If a major change in the mix of annual sales were projected, these figures would have an important effect on the tariff reform plan

The tariff reform plan in this chapter is concentrated in a two-year period, 1998 and 1999, and therefore there is no need for projections past 1999 In Exhibits 7 4, 7 6, 7 7, and 7 8 there are data rows for the year 2000 and future years to 2006 These rows are available if necessary for a longer-term tariff reform plan or for comparison with other demand projections, but they are not necessary in the context of the results in this chapter Only the data for 1996 through 1999 have an effect on the results shown here

The starting point for these calculations is Exhibit 7 1, which is used to develop a projection of sales by voltage level (Exhibit 7 4) The projection of six percent annual growth between 1996 and 1999 was selected so that the 1999 level of demand is consistent with the assumptions in Exhibit 4 6 concerning the average cost of generation (that is a 19 percent increase between 1996 and 1999) This growth rate appears to be realistic (that is, possible to achieve) but it is not large enough to compensate for the substantial decline in annual sales which occurred between 1990 and 1996 in regions outside of Tblisi

Most of the loss percentages in Exhibit 7 5 are taken from Exhibit 7 1 The assumptions have been selected to be consistent with Exhibit 5 3, where losses in the VHV and HV networks are shown, and Exhibit 4 4, where power station consumption is shown In CIS countries the concept of percentage losses is familiar to power engineers but load factors were sometimes expressed in terms of hours of annual generation (i e , the number of hours in which a generating unit could produce its annual output if the unit were run at full capacity) For any voltage level, the load factor may be defined as the ratio of the average annual load (in MW) to the coincident peak load (in MW) For any voltage level, the coincidence factor is the ratio of the contribution to the coincident peak load on the network (from sales customers) to the non-coincident peak load (from sales customers)

Exhibit 7 6 is a forecast of sales and losses by voltage level, based on assumptions from the previous exhibits The key input parameter is the estimate of the coincident peak load attributable to customers in Georgia (excluding Abkhazia and South Ossetia) in 1996 We use a value of 1,300 MW Exhibit 7 7 shows a projection of average losses and losses during peak periods Exhibit 7 8 shows a forecast of the composition of the 1,300 MW of peak load shown in Exhibit 7 6, by voltage level

Network costs

In Exhibit 7 9, the methodology for calculation of the replacement cost of the network is the same as in Exhibit 5 2 and therefore in both exhibits the total replacement cost of the VHV network is $361 million and the replacement cost of the HV network is $367 8 million These figures essentially reflect the infrastructure that was in place in 1990, they do not reflect a grid that has been "downsized" to meet the present level of electricity demand

Exhibit 7 4
Forecast of Energy Sales by Tariff Class for the Wholesale Market and for Telasi

	Wholesale market sales in GWh					Retail sales in Telasi in GWh							Wholesale market total
							MV1	MV2	MV2	LV	LV		
Year	Growth rate of total sales	VHV customers	HV customers	Distribution companies	Total sales	Growth rate of total sales	>=50 kW customer owned transformer	>=50 kW distco owned transformer	<50 kW 6 or 10 kV	Non residential 0 4 kV	Population 0 4 kV	Total sales	Increase over 1996
		0 0%	16 3%	83 7%			8 1%	8 1%	2 7%	13 3%	67 8%		
1996		0	817 7	4 184 0	5 001 7		140 8	140 8	46 9	229 9	1 174 8	1 733 2	
1997	**6 0%**	0	866 8	4 435 0	5 301 8	6 0%	149 2	149 2	49 7	243 7	1 245 3	1 837 2	6 0%
1998	**6 0%**	0	918 8	4 701 1	5 619 9	6 0%	158 2	158 2	52 7	258 3	1 320 0	1 947 4	12 4%
1999	**6 0%**	0	973 9	4 983 2	5 957 1	6 0%	167 7	167 7	55 9	273 8	1 399 2	2 064 3	19 1%
2000	**4 0%**	0	1 012 8	5 182 5	6 195 4	4 0%	174 4	174 4	58 1	284 7	1 455 2	2 146 9	23 9%
2001	**4 0%**	0	1 053 4	5 389 8	6 443 2	4 0%	181 4	181 4	60 5	296 1	1 513 4	2 232 7	28 8%
2002	**4 0%**	0	1 095 5	5 605 4	6 700 9	4 0%	188 6	188 6	62 9	308 0	1 573 9	2 322 0	34 0%
2003	**4 0%**	0	1 139 3	5 829 7	6 969 0	4 0%	196 2	196 2	65 4	320 3	1 636 9	2 414 9	39 3%
2004	**4 0%**	0	1 184 9	6 062 8	7 247 7	4 0%	204 0	204 0	68 0	333 1	1 702 4	2 511 5	44 9%
2005	**4 0%**	0	1 232 3	6 305 4	7 537 6	4 0%	212 2	212 2	70 7	346 4	1 770 5	2 612 0	50 7%
2006	**4 0%**	0	1 281 6	6 557 6	7 839 1	4 0%	220 7	220 7	73 6	360 3	1 841 3	2 716 5	56 7%

	Total retail sales by all distribution companies in GWh					
	MV1	MV2	MV2	LV	LV	
Year	>=50 kW customer owned transformer	>=50 kW distco owned transformer	<50 kW 6 or 10 kV	Non residential 0 4 kV	Population 0 4 kV	Total sales
1996	**300**	**300**	**100**	490	2 503	3 693

Exhibıt 7 5
Parameters Used to Forecast Energy Sales and Losses, by Voltage Level, for the Wholesale Market and for Telası

	Wholesale market			Telası			
	Power station use	VHV	HV	MV1	MV2	LV	Total
Statıon use as a percentage of gross generatıon + net ımports	**1 5%**						
Average losses as a percentage of net generatıon + net ımports		5 5%	8 1%				13 7%
Average losses as a percentage of supply to the dıstco		5 5%		**4 0%**	**4 0%**	8 6%	12 6%
Load factor for all sales at thıs voltage level		0 60	0 60	0 70	0 70	0 40	
Coıncıdence factor for all sales at thıs voltage level		0 80	0 80	0 80	0 80	0 80	
Ratıo of the average load (MW) at thıs voltage level to the contrıbutıon of thıs voltage level to the coıncıdent system peak (MW)		0 75	0 75	0 88	0 88	0 50	

Coıncıdent peak load factor assumptıons are rough estımates load factor data are not avaılable

Exhibit 7 6
Forecast of Energy Sales and Losses, by Voltage Level, for the Wholesale Market and for Telası

	Wholesale market			Telası		Energy sales to end users in GWh by voltage level					
						Wholesale market			Telası		
Year	Coincident peak load MW	Gross generation + net imports GWh	System load factor	Peak load MW	Purchases GWh	Sales at power stations	VHV	HV	MV1	MV2	LV
1996	1 300	5 200	45 7	495 5	1 982 0	0	0	818	140 8	187 7	1 404 7
1997	1 378	5 512	45 7	525 2	2 100 9	0	0	867	149 2	199 0	1 489 0
1998	1 461	5 843	45 7	556 7	2 227 0	0	0	919	158 2	210 9	1 578 3
1999	1 548	6 193	45 7	590 1	2 360 6	0	0	974	167 7	223 6	1 673 0
2000	1 610	6 441	45 7	613 8	2 455 0	0	0	1 013	174 4	232 5	1 739 9
2001	1 675	6 699	45 7	638 3	2 553 2	0	0	1 053	181 4	241 8	1 809 5
2002	1 742	6 967	45 7	663 8	2 655 3	0	0	1 095	188 6	251 5	1 881 9
2003	1 811	7 245	45 7	690 4	2 761 6	0	0	1 139	196 2	261 6	1 957 2
2004	1 884	7 535	45 7	718 0	2 872 0	0	0	1 185	204 0	272 0	2 035 5
2005	1 959	7 836	45 7	746 7	2 986 9	0	0	1 232	212 2	282 9	2 116 9
2006	2 037	8 150	45 7	776 6	3 106 4	0	0	1 282	220 7	294 2	2 201 6

	Energy losses in GWh by voltage level					
	Wholesale market			Telası		
Year	Power station use	VHV	HV	MV1	MV2	LV
1996	78	283	417	79 3	79 3	169 5
1997	83	300	442	84 0	84 0	179 7
1998	88	318	469	89 1	89 1	190 5
1999	93	337	497	94 4	94 4	201 9
2000	97	350	517	98 2	98 2	210 0
2001	100	364	537	102 1	102 1	218 4
2002	104	379	559	106 2	106 2	227 1
2003	109	394	581	110 5	110 5	236 2
2004	113	410	604	114 9	114 9	245 6
2005	118	426	628	119 5	119 5	255 4
2006	122	443	654	124 3	124 3	265 7

Note The coincident peak load excludes the load used by autoproducers Therefore sales at power stations are zero
The estimates of network losses are not affected by the exclusion of autoproducers own load

Exhibit 7 7
Losses Expressed as a Percentage of Energy Received at Each Voltage Level for the Wholesale Market and for Telasi

	Wholesale market						Telasi					
	Station use		VHV		HV		MV1		MV2		LV	
Year	Average losses	Peak losses	Average losses	Peak losses	Average losses (calculated)	Peak losses	Average losses	Peak losses	Average losses	Peak losses	Average losses (calculated)	Peak losses
1996	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
1997	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
1998	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
1999	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2000	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2001	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2002	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2003	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2004	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2005	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
2006	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	10 3%
Average	1 5%	2 5%	5 5%	6 5%	8 6%	9 6%	4 0%	5 0%	4 0%	5 0%	9 3%	9 3%

This table reflects the assumption that peak losses equal average losses plus **1 0%**

Exhibit 7 8
Forecast of Coincident Peak Load (MW) by Voltage Level

Wholesale Market

	Generation level			VHV			HV			
Year	Coincident peak load MW	Power station use MW	Sales at power stations MW	Network losses MW	Load at delivery points MW	Consumption by VHV customers MW	Network losses MW	Load at delivery points MW	Consumption by HV customers MW	Delivery to distribution companies MW
1996	1 300	33	0	83	1 185	0	114	1 071	124	946
1997	1 378	34	0	88	1 256	0	121	1 135	132	1 003
1998	1 461	37	0	93	1 331	0	128	1 203	140	1 063
1999	1 548	39	0	98	1 411	0	136	1 275	148	1 127
2000	1 610	40	0	102	1 468	0	141	1 326	154	1 172
2001	1 675	42	0	106	1 526	0	147	1 380	160	1 219
2002	1 742	44	0	111	1 587	0	153	1 435	167	1 268
2003	1 811	45	0	115	1 651	0	159	1 492	173	1 319
2004	1 884	47	0	120	1 717	0	165	1 552	180	1 371
2005	1 959	49	0	125	1 786	0	172	1 614	188	1 426
2006	2 037	51	0	130	1 857	0	179	1 678	195	1 483

Telasi

	Supply	MV1 and MV2				LV	
Year	Peak load MW	Network losses MW	Load at delivery points MW	Consumption by MV1 customers MW	Consumption by MV2 customers MW	Network losses MW	Load at delivery points MW
1996	495 5	24 8	470 7	18 4	24 5	44 1	383 8
1997	525 2	26 3	499 0	19 5	26 0	46 7	406 8
1998	556 7	27 8	528 9	20 6	27 5	49 5	431 3
1999	590 1	29 5	560 6	21 9	29 2	52 5	457 1
2000	613 8	30 7	583 1	22 8	30 3	54 6	475 4
2001	638 3	31 9	606 4	23 7	31 6	56 7	494 4
2002	663 8	33 2	630 6	24 6	32 8	59 0	514 2
2003	690 4	34 5	655 9	25 6	34 1	61 4	534 8
2004	718 0	35 9	682 1	26 6	35 5	63 8	556 2
2005	746 7	37 3	709 4	27 7	36 9	66 4	578 4
2006	776 6	38 8	737 8	28 8	38 4	69 0	601 5

Note The coincident peak load excludes the load used by autoproducers Therefore sales at power stations are zero
The estimates of network losses are not affected by the exclusion of autoproducers own load

Exhibit 7 9
Replacement Cost of Network Capacity

Network component	Replacement cost		Wholesale market VHV Quantity	VHV Cost $million	Wholesale market HV Quantity	HV Cost $million	Telasi MV lines and cables Quantity	MV lines and cables Cost $million	Telasi MV substations Quantity	MV substations Cost $million	Telasi LV Quantity	LV Cost $million
Overhead lines (km)												
500 kV	**0 2**	$million/km	**572 0**	114 4								
330 kV	**0 1**	$million/km	**21 0**	2 1								
220 kV	**0 07**	$million/km	**1,565 0**	109 6								
110 kV	**0 045**	$million/km			**3,924 0**	176 6						
35 kV	**0 025**	$million/km			**3,147 0**	78 7						
10 and 6kV	**0 018**	$million/km					164 0	3 0				
0 38 kV	**0 01**	$million/km									1 615 0	16 2
Total			2 158 0	226 1	7 071 0	255 3	164 0	3 0			1 615 0	16 2
Underground cables (km)												
110 kV	**0 18**	$million/km										
35 kV	**0 1**	$million/km										
10 and 6kV	**0 072**	$million/km					1,821 0	131 1				
0 38 kV	**0 04**	$million/km									1 211 0	48 4
Total							1,821 0	131 1			1 211 0	48 4
Substations (MVA)												
500 kV	**0 02**	$million/MVA	**2,153 0**	43 1								
330 kV	**0 02**	$million/MVA	**0 0**	0 0								
220 kV	**0 02**	$million/MVA	**4,595 1**	91 9								
110 kV	**0 02**	$million/MVA			**4,116 5**	82 3						
35 kV	**0 02**	$million/MVA			**1,510 3**	30 2						
10 and 6kV	**0 02**	$million/MVA							55 7	1 1	872 3	17 4
Total			6 748 1	135 0	5 626 8	112 5			55 7	1 1	872 3	17 4
Total replacement cost $million				361 0		367 8		134 1		1 1		82 0
Coincident peak load at delivery points MW			1 256 0		1 135 2							
Peak load at delivery points for Telasi MW							499 0		26 0		406 8	
Adjustment for load capability of the network			**60%**		**60%**		**40%**		**40%**		**40%**	
Estimated peak load capability MW			2 009 5		1 816 3		698 6		36 3		569 6	
Replacement cost $/kW				180		202		192		31		144

The levelized cost calculation in Exhibit 7 10 is very different from the methodology in Chapter 5 For levelized costs, the replacement cost is expressed in terms of dollars per kW of peak load capability, as shown at the bottom of Exhibit 7 9 If we were to use the 1996 level of peak load these costs per kW would be very high, because there were not enough kW being delivered in 1996 relative to the design capability of the grid The line marked "adjustment for capability of the network" shows the increase in peak load (above the 1996 level) that can be met by the existing infrastructure by the end of the tariff reform plan (in this case, by 1999) If it were possible to replace the entire transmission grid by 1999, probably an even higher level of load could be supported with the 1990 level of transmission line length and the 1990 level of substation capacity but Georgia faces a need to rebuild the network without having peak load rise to the design level in the next few years The "adjustment for capability of the network" is intended to reflect the increased load that can be met in the medium term

In the bottom half of Exhibit 7 10 there is a calculation of the levelized annual cost per kW of transmission and distribution capacity, by voltage level The interest rate in these calculations is a real interest rate (shown at the bottom of Exhibit 7 3) because the tariff reform plan is expressed in constant 1997 dollars The value selected for these calculations is 15 percent, which is intended to show a total cost of capital (a weighted average of interest on long-term debt and returns on equity) This figure may not be high enough to attract investment in the networks in Georgia However the use of significantly higher numbers leads to higher tariffs, and the objective of these calculations is not to show a cost level during a transition period but an economic cost that could be considered a basis for the target level of tariffs over the long term

Generation costs

The input assumptions developed in Chapter 4 are shown in Exhibit 7 10 The marginal capacity cost is an estimate of the annual cost per kW of building and maintaining a new gas-fired combustion turbine The marginal energy cost during peak periods is based on the existing energy price for sales from Gardabani The marginal energy cost during off-peak periods was selected to yield a generation cost component of 2 9 cents/kWh for supplies to distribution companies (the "total marginal cost" shown at the bottom line of Exhibit 7 13)

The data in Exhibit 7 10 and earlier exhibits are used to calculate the marginal cost of capacity, by voltage level, and the marginal cost of energy, by voltage level, as shown in Exhibit 7 11 The marginal capacity cost is the sum of the capacity cost at a given voltage level plus the capacity cost at all higher levels, adjusted for peak losses

Customer classes

The five customer classes were defined in Chapter 6 Target tariffs for these classes are shown in Exhibit 7 13, which shows the full economic cost of service to each customer class The load factor assumptions are very important to these results, and the values shown here are intended to

Exhibit 7 10
Marginal Costs of Capacity and Energy for the Wholesale Market and for Telasi

Generation Capacity and Energy

Marginal capacity cost	**100 00 $/kW-year**	130 0 Lari/kW-year
	8 33 $/kW/month	10 8 Lari/kW-month
Marginal energy cost peak	**2 54** Cents/kWh	3 30 tetri/kWh
Marginal energy cost off-peak	**0 40** Cents/kWh	0 52 tetri/kWh

Transmission and Distribution Capacity

Cost measure	Wholesale market		Telasi		
	VHV	HV	MV1	MV2	LV
Capital cost $/kW	179 7	202 5	191 9	30 6	144 0
Capital cost Lari/kW	233 5	263 2	249 5	39 8	187 2
Capacity life (years) used to compute annual cost	**30**	**30**	**25**	**25**	**25**
Interest rate used to compute annual cost	15 0%	15 0%	15 0%	15 0%	15 0%
Annual capital cost Lari/kW/year	35 6	40 1	38 6	6 2	29 0
Operation & maintenance cost % of capital cost	**2 0%**	**2 0%**	**2 0%**	**2 5%**	**2 5%**
Operation & maintenance cost, Lari/kW/year	4 7	5 3	5 0	1 0	4 7
Annual capacity cost Lari/kW/year	40 3	45 4	43 6	7 2	33 7
Annual capacity cost $/kW/year	31 0	34 9	33 5	5 5	25 9
Monthly capacity cost Lari/kW/month	3 4	3 8	3 6	0 6	2 8

This table shows the capacity-related cost of supplying 1 kW of the coincident peak load for the national grid and the capacity-related cost of supplying 1 kW of the peak load of the Telasi network

Exhibit 7 11
Marginal Cost of Capacity, by Voltage Level, for the Wholesale Market and for Telasi

Long Run Marginal Cost of capacity, in Lari per coincident kW per month

Grid region	Voltage level	LRMC of generation capacity	LRMC of transmission and distribution capacity						Generation transmission & distribution
			VHV	HV	MV1	MV2	LV	Total	
Wholesale market	Net generation	10 8						0 0	10 8
	VHV	11 6	3 4					3 4	14 9
	HV	12 8	3 7	3 8				7 5	20 3
Telasi	MV1	13 5	3 9	4 0	3 6			11 5	25 0
	MV2	13 5	3 9	4 0	3 6	0 6		12 1	25 6
	LV	14 9	4 3	4 4	4 0		2 8	15 5	30 4

Exhibit 7 12
Marginal Cost of Energy, by Voltage Level, for the Wholesale Market and for Telasi

Long Run Marginal Cost of energy, in tetri per kWh

Grid region	Voltage level	Peak	Off-peak
Wholesale market	Gross generation	3 30	0 52
	Net generation	3 39	0 53
	VHV	3 62	0 56
	HV	4 01	0 61
Telasi	Gross generation	3 30	0 52
	Net generation	3 39	0 53
	VHV	3 62	0 56
	HV	4 01	0 61
	MV1	4 22	0 64
	LV	4 65	0 70

Exhibit 7 13
Marginal Cost-Based Tariffs Without Adjustment for Revenue Requirements, 1997

	Voltage level	1997 sales GWh	October 1997 tariff tetri/kWh	Coincidence factor	Load factor	Peak energy share of total	Monthly capacity cost Lari/class kW/month Generation	Network	Total	Equivalent capacity cost tetri/kWh	Energy cost tetri/kWh	Total marginal cost tetri/kWh	Total marginal cost cents/kWh	Oct 1997 yield as a percent of LRMC	Tariff change needed to reach LRMC
Sales to wholesale market customers*															
VHV customers	VHV	0 0	**3 3**	**0 80**	**0 60**	**20%**	9 27	2 68	11 96	2 73	1 17	3 90	3 00	85%	18%
HV customers	HV	866 8	**3 3**	**0 80**	**0 60**	**20%**	10 26	5 99	16 25	3 71	1 29	5 00	3 85	66%	52%
Distribution companies	HV	4 435 0	**3 3**	**1 00**	**0 55**	**20%**	12 82	7 49	20 32	5 06	1 29	6 35	4 89	52%	92%
Wholesale customers total		5 301 8	3 30			20%			19 65	4 84	1 29	6 13	4 72	54%	86%
Sales to customers of Telasi															
50 kW or larger with a transformer owned by the customer 6 or 10 kV	MV1	149 2	**4 5**	**0 80**	**0 70**	**20%**	10 80	9 22	20 01	3 92	1 29	5 21	4 01	86%	16%
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	MV2	149 2	**4 5**	**0 80**	**0 70**	**20%**	10 80	9 70	20 49	4 01	1 35	5 36	4 13	84%	19%
Less than 50 kW with 6 or 10 kV service	MV2	49 7	**4 5**	**0 80**	**0 70**	**20%**	10 80	9 70	20 49	4 01	1 35	5 36	4 13	84%	19%
Non residential 0 4 kV	LV	243 7	**4 5**	**0 80**	**0 40**	**25%**	11 90	12 41	24 31	8 33	1 69	10 02	7 70	45%	123%
Population 0 4 kV	LV	1 245 3	**4 5**	**0 80**	**0 40**	**25%**	11 90	12 41	24 31	8 33	1 69	10 02	7 70	45%	123%
Retail customers total		1 837 2	4 5			24%			23 55		1 62	9 12	7 02	53%	103%
Components of the cost of sales to distribution companies															
Supply purchased from generators	Net generation			1 00	0 55	20%	10 83	0 00	10 83	2 70	1 10	3 80	2 92		
Cost of transmission to HV delivery points				1 00	0 55	20%	1 99	7 49	9 48	2 36	0 19	2 55	1 96		
Total	HV			1 00	0 55	20%	12 82	7 49	20 32	5 06	1 29	6 35	4 89		

represent the load factors that would exist in a power system with at least 24 hour service, if not firm service Naturally, the residential class has a lower load factor that the MV industrial customer classes

The existing tariff of 4 5 tetri/kWh for MV1 and MV2 customers is close to the economic cost tariff of 5 21 tetri/kWh (MV1) and 5 36 tetri/kWh (MV2), as shown in Exhibit 7 13 The tariff increases required to reach economic cost are only 16 percent and 19 percent respectively The low voltage customers should have much higher tariffs to pay for the low voltage network (at a 40 percent load factor) and to compensate for losses The tariff increase required to reach economic cost is 123 percent for the low voltage customers - an increase from 4 5 tetri/kWh to 10 02 tetri/kWh

Tariff reform plan

A possible tariff reform plan is shown in Exhibits 7 14 through 7 19, based on the assumption that the price levels shown in Exhibit 7 13 are politically unacceptable in the form of "shock therapy" - they could not be implemented suddenly without a substantial political resistance or else a continuing failure of the power sector to achieve collections rates close to 100 percent

In each phase of reform, Exhibit 7 14 through 7 17, the increase in the residential tariff is calculated by assuming that none of the customers that are presently paying 4 5 tetri/kWh will have a lower tariff This assumption can be modified, and the key input variable is the "Minimum percentage increase in tariff class yield" (see Exhibit 7 14, the seventh line of data for Telasi), that is the minimum increase applied to any non-residential customer class

The tariff reform plan is assumed to consist of four phases

1 *Tariffs Based on the October 1997 Wholesale Price Level* (Exhibit 7 14) In this initial phase the focus of tariff reform is the implementation of the new customer classes, with only a modest increase in the residential tariff The average yield in the wholesale market is fixed at 3 3 tetri/kWh, which is the existing tariff for sales by Sakenergo to the municipal distribution companies (at 10 kV or 6 kV) under GNERC Resolution #4 dated October 8, 1997 (see Appendix E) The wholesale market yield is calculated as though all customers were buying energy from Sakenergo, although in fact many of these customers have direct contracts The margin between the price paid by distribution companies (3 42 tetri/kWh) and the average retail price (5 08 tetri/kWh) is calculated as 60 percent of the LRMC of distribution In other words, only 60 percent of the full economic cost of distribution is reflected in the retail tariff at this stage

2 *Tariffs for 1998, Before a Power Pool is Created* (Exhibit 7 15) In this stage the average tariff in the wholesale market is raised substantially to five tetri/kWh, but the

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Exhibit 7 14

Tariff Calculations Based on the October 1997 Wholesale Price Level

Wholesale Electricity Tariffs

Average tariff in the wholesale market	3 30	tetri/kWh	53 8% of LRMC for 1997
Increase applied to LRMC	**0 0%**	relative to the LRMC for 1997	
Wholesale market sales (GWh)	5 302		
Wholesale market sales revenue (million Lari)	175 0		

Tariff class	1997 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	Energy charge tetri/kWh Peak	Energy charge tetri/kWh Off-peak	Demand Lari per coincident kW per mo
VHV customers	0	3 30	3 90	2 10	-36%	1 95	0 30	8 04
HV customers	867	3 30	5 00	2 69	-18%	2 16	0 33	10 94
Distribution companies	4 435	3 30	6 35	3 42	4%	2 16	0 33	10 94
Total	5 302	3 30	6 13	3 30	0%			

Telasi Tariffs

Increase applied to LRMC	0 0%	relative to the LRMC for 1997
Wholesale power cost + LRMC of distribution	6 19	tetri/kWh
% phase in of LRMC of distribution	**60%**	
Wholesale power cost + phased in LRMC of distribution	5 08	tetri/kWh
Telasi sales (GWh)	1 837	
Telasi sales revenue (million Lari)	93 35	
Minimum percent increase in tariff class yield	**0%**	

Tariff class	1997 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	0 percent adjusted yield tetri/kWh	Increase relative to Oct 97 prices	Ratio of strict LRMC yield
50 kW or larger with a transformer owned by the customer 6 or 10 kV	149	4 50	5 21	2 90	-36%	4 50	0%	0 86
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	149	4 50	5 36	2 99	34%	4 50	0%	0 84
Less than 50 kW with 6 or 10 kV service	50	4 50	5 36	2 99	-34%	4 50	0%	0 84
Non residential 0 4 kV	244	4 50	10 02	5 58	24%	5 58	24%	0 56
Population 0 4 kV	1 245	4 50	10 02	5 58	24%	5 15	14%	0 51
Total	1 837	4 50	9 12	5 08	13%	5 08	13%	0 56

Tariff class	Voltage level	Option 1 1 part tariff Energy charge tetri/kWh	Option 2 2 part tariff Energy charge tetri/kWh Peak	Option 2 2 part tariff Energy charge tetri/kWh Off peak	Option 2 2 part tariff Demand charge Lari per coincident kW /month
50 kW or larger with a transformer owned by the customer 6 or 10 kV	MV1	4 50	3 46	0 53	21 62
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	MV2	4 50	3 54	0 53	21 49
Less than 50 kW with 6 or 10 kV service	MV2	4 50	3 54	0 53	21 49
Non residential 0 4 kV	LV	5 58			
Population 0 4 kV	LV	5 15			

Exhibit 7 15
Tariffs for 1998, Before a Power Pool is Created

Wholesale Electricity Tariffs

Average tariff in the wholesale market	**5 00** tetri/kWh	81 6% of LRMC for 1997
Increase applied to LRMC	**0 0%** relative to the LRMC for 1996	
Wholesale market sales (GWh)	5 620	
Wholesale market sales revenue (million Lari)	281 0	

Tariff class	1998 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	Energy charge tetri/kWh Peak	Energy charge tetri/kWh Off peak	Demand Lari per coincident kW per mo
VHV customers	0	3 30	3 90	3 18	-4%	2 95	0 46	12 19
HV customers	919	3 30	5 00	4 08	24%	3 27	0 50	16 57
Distribution companies	4 701	3 30	6 35	5 18	57%	3 27	0 50	16 57
Total	5 620	3 30	6 13	5 00	52%			

Telasi Tariffs

Increase applied to LRMC	0 0% relative to the LRMC for 1997
Wholesale power cost + LRMC of distribution	7 95 tetri/kWh
% phase in of LRMC of distribution	**60%**
Wholesale power cost + phased-in LRMC of distribution	6 84 tetri/kWh
Telasi sales (GWh)	1 947
Telasi sales revenue (thousand Lari)	133 24
Minimum percent increase in tariff class yield	**0%**

Tariff class	1998 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	0 percent adjusted yield tetri/kWh	Increase relative to Oct 97 prices	Ratio of strict LRMC yield
50 kW or larger with a transformer owned by the customer 6 or 10 kV	158	4 50	5 21	3 91	-13%	4 50	0%	0 86
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	158	4 50	5 36	4 02	11%	4 50	0%	0 84
Less than 50 kW with 6 or 10 kV service	53	4 50	5 36	4 02	-11%	4 50	0%	0 84
Non residential 0 4 kV	258	4 50	10 02	7 51	67%	7 51	67%	0 75
Population 0 4 kV	1 320	4 50	10 02	7 51	67%	7 37	64%	0 74
Total	1 947	4 50	9 12	6 84	52%	6 84	52%	0 75

Tariff class	Voltage level	Option 1 1-part tariff Energy charge tetri/kWh	Option 2 2 part tariff Energy charge tetri/kWh Peak	Option 2 2 part tariff Energy charge tetri/kWh Off peak	Option 2 2 part tariff Demand charge Lari per coincident kW /month
50 kW or larger with a transformer owned by the customer 6 or 10 kV	MV1	4 50	3 46	0 53	21 62
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	MV2	4 50	3 54	0 53	21 49
Less than 50 kW with 6 or 10 kV service	MV2	4 50	3 54	0 53	21 49
Non residential 0 4 kV	LV	7 51			
Population 0 4 kV	LV	7 37			

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distribution margin is the same 60 percent of LRMC The result is a significant increase in the level of non-residential and residential tariffs

3 *Tariffs for 1998 After a Power Pool is Created* (Exhibit 7 16) In this stage the average tariff in the wholesale market is raised to the level needed to cover the average cost of generation and the economic cost of transmission, and all technical and commercial losses The target level of the average wholesale tariff is 6 13 tetri/kWh as shown in Exhibit 7 13 (in the column marked "Total marginal cost, tetri/kWh") The distribution margin is raised to 80 percent of LRMC, and the result is a slight increase in the MV tariffs and a further increase in the LV tariffs

4 *Tariffs for 1999 Based on Power Pool Prices* (Exhibit 7 17) In this stage the distribution margin is raised to 100 percent of LRMC and therefore all of the tariff numbers are consistent with the targets shown in Exhibit 7 13 This is the stage of tariff reform when tariffs should be at a level sufficient to rebuild the transmission and distribution grids

The percentage increases in tariffs are summarized in Exhibits 7 18 and 7 19, which merely restate the results shown in Exhibits 7 14 through 7 17 The residential tariff ultimately reaches 7 7 cents/kWh or 10 0 tetri/kWh The residential tariff increases (shown at the bottom of Exhibit 7 17) are 14 percent in Phase 1, 43 1 percent in Phase 2, 27 7 percent in Phase 3, and 6 5 percent in Phase 4 The tariff for electricity purchased by the distribution companies rises from 3 3 tetri/kWh to 6 35 tetri/kWh, a 92 percent increase

Clearly the timing of tariff increases is a complex issue requiring negotiation between the Government and potential investors in the power system, including multilateral development banks and strategic investors from the private sector The calculations presented here are merely intended to be illustrative The more difficult question facing the Government and GNERC, however, is the target level of tariffs for the discos other than Telasi The level of 1996 sales in these regions was low, relative to the infrastructure Preliminary calculations indicate that a residential price level of 11 to 12 cents per kWh will be necessary to rebuild the networks in these discos By western European standards this price level is not excessive, but by central European standards and even U S standards it is relatively high

The results shown in the exhibits to this chapter should be updated on the basis of more accurate data on energy flows, load factors, network replacement costs and other variables The assumed discount rate of 15 percent could be increased On the basis of electricity price levels in other countries it appears unlikely that Telasi will be able to provide electricity to residential customers for substantially less than 7 cents per kWh Therefore the "fine tuning" of the results for Telasi is not likely to change the general pattern of price increases needed to recover the economic cost of electricity supply

Exhibit 7 16
Tariffs for 1998, After a Power Pool is Created

Wholesale Electricity Prices

Wholesale market yield based on pool prices	6 13	tetri/kWh	100 0% of LRMC for 1997
Increase applied to LRMC	**0 0%**	relative to the LRMC for 1997	
Wholesale market sales (GWh)	5 620		
Wholesale market sales revenue (million Lari)	344 5		

Tariff class	1998 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	Energy charge tetri/kWh Peak	Energy charge tetri/kWh Off peak	Demand Lari per coincident kW per mo
VHV customers	0	3 30	3 90	3 90	18%	3 62	0 56	14 94
HV customers	919	3 30	5 00	5 00	52%	4 01	0 61	20 32
Distribution companies	4 701	3 30	6 35	6 35	92%	4 01	0 61	20 32
Total	5 620	3 30	6 13	6 13	86%			

Telasi Tariffs

Increase applied to LRMC	0 0%	relative to the LRMC for 1997
Wholesale power cost + LRMC of distribution	9 12	tetri/kWh
% phase in of LRMC of distribution	**80%**	
Wholesale power cost + phased in LRMC of distribution	8 57	tetri/kWh
Telasi sales (GWh)	1 947	
Telasi sales revenue (thousand Lari)	166 83	
Minimum percent increase in tariff class yield	**0%**	

Tariff class	1998 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	0 percent adjusted yield tetri/kWh	Increase relative to Oct 97 prices	Ratio of strict LRMC yield
50 kW or larger with a transformer owned by the customer 6 or 10 kV	158	4 50	5 21	4 89	9%	4 89	9%	0 94
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	158	4 50	5 36	5 04	12%	5 04	12%	0 94
Less than 50 kW with 6 or 10 kV service	53	4 50	5 36	5 04	12%	5 04	12%	0 94
Non residential 0 4 kV	258	4 50	10 02	9 41	109%	9 41	109%	0 94
Population 0 4 kV	1 320	4 50	10 02	9 41	109%	9 41	109%	0 94
Total	1 947	4 50	9 12	8 57	90%	8 57	90%	0 94

Tariff class	Voltage level	Option 1: 1 part tariff — Energy charge tetri/kWh	Option 2 2 part tariff — Energy charge tetri/kWh Peak	Option 2 2 part tariff — Energy charge tetri/kWh Off peak	Option 2 2 part tariff — Demand charge Lari per coincident kW /month
50 kW or larger with a transformer owned by the customer 6 or 10 kV	MV1	4 89	3 76	0 57	23
50 kW or larger with a transformer owned by the distribution company 6 o 10 kV	MV2	5 04	3 96	0 60	24
Less than 50 kW with 6 or 10 kV service	MV2	5 04	3 96	0 60	24
Non residential 0 4 kV	LV	9 41			
Population 0 4 kV	LV	9 41			

Exhibit 7 17

Tariffs for 1999 Based on Power Pool Prices

Wholesale Electricity Prices

Wholesale market yield based on pool prices	6 13 tetri/kWh	100 0% of LRMC for 1997
Increase applied to LRMC	**0 0%** relative to the LRMC for 1997	
Wholesale market sales (GWh)	5 957	
Wholesale market sales revenue (million Lari)	365 2	

Tariff class	1999 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	Energy charge tetri/kWh Peak	Energy charge tetri/kWh Off peak	Demand Lari per coincident kW per mo
VHV customers	0	3 30	3 90	3 90	18%	3 62	0 56	14 94
HV customers	974	3 30	5 00	5 00	52%	4 01	0 61	20 32
Distribution companies	4 983	3 30	6 35	6 35	92%	4 01	0 61	20 32
Total	5 957	3 30	6 13	6 13	86%			

Telasi Tariffs

Increase applied to LRMC	0 0%	relative to the LRMC for 1997
Wholesale power cost + LRMC of distribution	9 12	tetri/kWh
% phase in of LRMC of distribution	**100%**	
Wholesale power cost + phased-in LRMC of distribution	9 12	tetri/kWh
Telasi sales (GWh)	2 064	
Telasi sales revenue (thousand Lari)	18 828	
Minimum percent increase in tariff class yield	**0%**	

Tariff class	1999 sales GWh	Average yield at Oct 1997 prices tetri/kWh	Strict LRMC yield tetri/kWh	Revenue neutral yield tetri/kWh	Increase relative to Oct 97 prices	0 percent adjusted yield tetri/kWh	Increase relative to Oct 97 prices	Ratio of strict LRMC yield
50 kW or larger with a transformer owned by the customer 6 or 10 kV	168	4 50	5 21	5 21	16%	5 21	16%	1 00
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	168	4 50	5 36	5 36	19%	5 36	19%	1 00
Less than 50 kW with 6 or 10 kV service	56	4 50	5 36	5 36	19%	5 36	19%	1 00
Non residential 0 4 kV	274	4 50	10 02	10 02	123%	10 02	123%	1 00
Population 0 4 kV	1 399	4 50	10 02	10 02	123%	10 02	123%	1 00
Total	2 064	4 50	9 12	9 12	103%	9 12	103%	1 00

Tariff class	Voltage level	Option 1 1 part tariff Energy charge tetri/kWh	Option 2 2 part tariff Energy charge tetri/kWh Peak	Option 2 2 part tariff Energy charge tetri/kWh Off peak	Option 2 2 part tariff Demand charge Lari per coincident kW /month
50 kW or larger with a transformer owned by the customer 6 or 10 kV	MV1	5 21	4 01	0 61	25
50 kW or larger with a transformer owned by the distribution company 6 or 10 kV	MV2	5 36	4 22	0 64	26
Less than 50 kW with 6 or 10 kV service	MV2	5 36	4 22	0 64	26
Non residential 0 4 kV	LV	10 02			
Population 0 4 kV	LV	10 02			

Exhibit 7 18
Summary of the Tariff Reform Plan

		Tariffs based on October 1997 wholesale prices	Tariffs for 1998, before a pool is created	Tariffs for 1998, after a pool is created	Tariffs for 1999, based on a pool
Average price level in the wholesale market					
Average yield at October 97 prices	tetri/kWh	3 30	3 30	3 30	3 30
Financial revenue requirement	tetri/kWh	3 30	5 00		
Wholesale market yield based on pool prices	tetri/kWh			6 13	6 13
Average yield at October 97 prices	cents/kWh	2 54	2 54	2 54	2 54
Price level needed to meet financial revenue requirement	cents/kWh	2 54	3 85		
Price level based on pool prices	cents/kWh			4 72	4 72
Percent increase above October 97 prices		0%	52%	86%	86%
Percent increase with respect to the preceding period			51 5%	22 6%	0 0%
Wholesale market price for the distribution companies					
Average yield at October 97 prices	tetri/kWh	3 30	3 30	3 30	3 30
Financial revenue requirement	tetri/kWh	3 42	5 18		
Wholesale market yield based on pool prices	tetri/kWh			6 35	6 35
Average yield at October 97 prices	cents/kWh	2 54	2 54	2 54	2 54
Price level needed to meet financial revenue requirement	cents/kWh	2 63	3 98		
Price level based on pool prices	cents/kWh			4 89	4 89
Percent increase above October 97 prices		4%	57%	92%	92%
Percent increase with respect to the preceding period			51 5%	22 6%	0 0%
Average Price of Electricity Sold in Telasi					
LRMC of distribution	tetri/kWh	2 77	2 77	2 77	2 77
Percent phase-in of LRMC of distribution		60%	60%	80%	100%
Average yield at October 97 prices	tetri/kWh	4 50	4 50	4 50	4 50
Price level during the transitional period	tetri/kWh	5 08	6 84	8 57	
Price level based on pool prices and LRMC of distribution	tetri/kWh				9 12
Average yield at October 97 prices	cents/kWh	3 46	3 46	3 46	3 46
Price level during the transitional period	cents/kWh	3 91	5 26	6 59	
Price level based on pool prices and LRMC of distribution	cents/kWh				7 02
Percent increase above October 97 prices		12 9%	52 0%	90 4%	102 7%
Percent increase with respect to the preceding period			34 7%	25 2%	6 5%

Exhibit 7 19
Summary of Price Increases, by Customer Class

	Actual tariffs in October 1997	Tariffs based on October 1997 wholesale prices	Tariffs for 1998, before a pool is created	Tariffs for 1998, after a pool is created	Tariffs for 1999, based on a pool
Wholesale market customers - High Voltage					
Average yield tetri/kWh	3 30	2 69	4 08	5 00	5 00
Percent increase above October 97 prices		-18%	24%	52%	52%
Percent increase with respect to the preceding period			51 5%	22 6%	0 0%
Retail Customers in Telasi					
50 kW or larger, with a transformer owned by the customer, 6 or 10 kV					
Average yield tetri/kWh	4 50	4 50	4 50	4 89	5 21
Percent increase above October 97 prices		0%	0%	9%	16%
Percent increase with respect to the preceding period			0 0%	8 7%	6 5%
50 kW or larger, with a transformer owned by the distribution company, 6 or 10 kV					
Average yield tetri/kWh	4 50	4 50	4 50	5 04	5 36
Percent increase above October 97 prices		0%	0%	12%	19%
Percent increase with respect to the preceding period			0 0%	12 0%	6 5%
Less than 50 kW, with 6 or 10 kV service					
Average yield, tetri/kWh	4 50	4 50	4 50	5 04	5 36
Percent increase above October 97 prices		0%	0%	12%	19%
Percent increase with respect to the preceding period			0 0%	12 0%	6 5%
Non-residential, 0 4 kV					
Average yield tetri/kWh	4 50	5 58	7 51	9 41	10 02
Percent increase above October 97 prices		24%	67%	109%	123%
Percent increase with respect to the preceding period			34 7%	25 2%	6 5%
Population, 0 4 kV					
Average yield tetri/kWh	4 50	5 15	7 37	9 41	10 02
Percent increase above October 97 prices		14%	64%	109%	123%
Percent increase with respect to the preceding period			43 1%	27 7%	6 5%

APPENDIX A
DEGREE #437 OF THE PRESIDENT OF GEORGIA

Tbilisi, July 4, 1996

ABOUT RESTRUCTURING OF THE POWER SECTOR

According to the law of Georgia of June 26, 1996, the Ministry of Fuel and Energy has been established The Ministry will be responsible for determination and promotion of the State energy policy, strategy and priorities of development of the sector, investment policy and strategy of energy efficiency increase in the branches of the economy The Ministry shall also provide rational management of reforms in the sector, elaborates and implements personnel policy, develops the legal and standard framework for the sector, monitors financial and technical condition of the sector, plans and coordinates technical assistance and determines the state policy in emergency energy situations

Considering a special economic and social role of the energy sector and with the purpose of promotion of rational state energy policy, separation of regulatory and operational functions, demonopolization, development of private ownership and market relations in accordance with the recommendations of Georgian and foreign experts, the decisions of the Restructuring Committee of the Power Sector and Presidential Consultancy Economic Council

1 To consider the fuel and energy sector as a priority sector in order to create conditions favorable for overcoming the energy crisis and promoting development of the sector,

2 To establish a regulatory service - the Electricity Regulatory Commission, with the Ministry of Economy On the initial stage the Regulatory Commission will be responsible only for regulation of wholesale and retail tariffs in the power sector,

3 The Ministry of Economy together with the Ministry of Fuel and Energy shall propose candidates for the Commissioner positions by July 15, 1996,

4 The Ministry of Economy together with the Ministry of Fuel and Energy shall prepare and approve by October 1, 1996, a methodology and rules for setting retail and wholesale tariffs

5 The Ministry of Justice and the Ministry of Fuel and Energy shall set up a special working group and conduct systematic work on establishing a of legal and standard framework for the energy sector, primarily focused on improving the Georgian drafting the "Energy Law" to be submitted to the Parliament by November 1, 1996

6 On the first stage of the restructuring, reorganization of Sakenergo shall be performed Three financially independent subsectors shall be established On the base of Sakenergo - generation, transmission/dispatch and distribution

7 Enterprises which are components of the generation subsector of Sakenergo (e g individual power plants or groups of such plants, maintenance and other service utilities or groups of such utilities) shall be transformed into Joint Stock Companies Shares of such JSCs, prior to the decision on their disposition, will fully remain in Governmental ownership For management of the Governmental share of the stocks the Ministry of Fuel and Energy shall create a special service [similar to a holding company]

8 The transmission/Dispatch subsector of Sakenergo shall be transformed into a single, commercialized, financially autonomous state enterprise "Sakenergo", subordinated to the Ministry of Fuel and Energy and not subject to privatization during the period under review

9 The distribution subsector shall be completely separated from Sakenergo upon the territorial principle and transformed into Joint Stock Companies Shares of these JSCs, until the decision on their disposition is made, will remain in Governmental ownership and given for management to the regional governments, according to the established rules The Ministry of Management of the State Property together with the Ministry of Fuel and Energy, and with the regional governments shall prepare the privatization plan for these utilities within one month

10 With regard to the Georgian legislation and with the purpose of transformation of the generation and distribution subsectors into Joint Stock Companies, Sakenergo, together with the regional governments and personnel of the utilities, with approval from the Ministry of Fuel and Energy, shall prepare documents foreseen by Georgian Laws "About Entrepreneurs" and "About Privatization of Public Utilities" These documents [letters, evaluations, assessments] shall be submitted to the Ministry of Management of the State Property by August 1, 1996 They shall also elaborate a general plan for corporatization present it to the State Chancery by August 31, 1996

11 By September 1, 1996 the Ministry of Management of the State Property shall ensure transformation of the above utilities into JSCs with regard to the requirements of the Georgian laws "About Entrepreneurs" and "About Privatization of Public Utilities"

12 The Ministry of Fuel and Energy together with the regional governments and the personnel of the utilities shall prepare a plan of the transformation of registration, of financial and managerial activities of the unbundled utilities and distribution companies considering the accounting and other requirements Implementation of this process shall start before October 31, 1996

13 By October 31, 1996 The Ministry of Finance and the Ministry of Fuel and Energy, as well as the Department Sakenergo, together with the

regional governments, shall prepare a plan of accounts separation and inventory of assets and liabilities for the unbundled utilities The plan shall include debt restructuring and debt long- and short-term settlement schemes considering the impact of the tariff structure The plan shall be based on the results of measures, set by the corresponding Presidential Decree [#363] about ensuring payment for power consumption

14 The Ministry of Fuel and Energy together with the Ministry of Management of the State Property and with participation of the appropriate structures of the State Chancery shall prepare and submit [to the Chancery?]for deliberation a plan of privatization of the power sector by November 30, 1996 The plan shall consider the general state directions of privatization, including the essential importance of developing the investment environment in the energy, as well as feasibility of allocating privatization revenues primarily to the modernization and development of energy facilities Upon preparation of the plan of privatization, the conditions of free or reduced-price issuance of a part of shares to employees of a utilities shall be considered

15 The reform processes in the fuel and energy sector and the importance of these changes and expected results shall be widely highlighted by means of mass-media

E Shevardnadze

Translated by T Japaridze Editorial comments in [brackets]

APPENDIX B
GEORGIAN ELECTRICITY LAW OF 1997

(Final Version)

ARTICLE 1.

GENERAL PROVISIONS

Clause 1 Objectives and Purposes of Law

1 This law provides for the regulation of the activities of Legal and Individuals in generation, transmission, dispatch, and distribution services This Law is intended to promote the development of the electricity sector in Georgia on the basis of the principles of a market economy

2 The objectives of this Law, are

a Through synthesis of competition and regulation of non-competitive market, tariff system shall accurately reflect efficient generation, transmission, dispatch, and distribution costs,

b Provide the legal basis for reliable electricity supply for all categories of consumers, and

c Encourage domestic and foreign investment participation in rehabilitation and development of electricity sector

3 The purposes of this Law are to

a Assign responsibility for elaboration and implementation of State Energy Policy in the electricity sector to the Ministry of Fuel and Energy, and relieve the Ministry of Fuel and Energy from regulatory, ownership and operational responsibilities in the electricity sector,

b Determine the main principles of regulation for generation, transmission, dispatch and distribution and customers in the transparent and equitable manner and provide legal basis for establishment of independent regulatory body

c Promote efficiency in the generation, transmission, distribution, dispatch and consumption of electricity, and

d Promote competition in Georgia's electricity markets

Clause 2 Definitions

For the purpose of this Law, the following words shall have the following meanings

a "Transmission License" shall mean a License granted by the Commission under this Law to own or control, and operate, the Transmission Grid, but not to dispatch electricity over the Transmission Grid b "Transmission Licensee" shall mean a Individual or Legal Person who holds a Transmission License, for so long as the License is in effect

c "Transmission Grid" shall mean all the transmission facilities, which connect the Receiving Points to the Delivery Points, owned or controlled, and/or operated, by the Transmission Licensee Transmission grid includes all transmission facilities operating above 35kV, including substations, also electricity circuits operating at 35kV and relevant substations, that are specifically identified in the Transmission License Other 35 kV systems shall be included in distribution facilities

d "Distribution Grid" shall mean all the electricity distribution facilities, which connect the Delivery Points to consumers, owned or controlled, and/or operated, by the Distribution Licensee Distribution grid includes all 0 4 - 6 3 - 10 5 distribution facilities, which are not the part of Transmission grid As an exemption, upon Commission's permission, 110kw substation may be included in Distribution grid

e "Distribution License" shall mean a License granted by the Commission under this Law to receive electric capacity and energy deliveries from one or more Delivery Points and distribute electricity to consumers within a defined administrative or geographic area

f "Distribution Licensee" shall mean a Individual or Legal Person who holds a Distribution License, for so long as the License is in effect

g "Dispatch License" shall mean a License granted by the Commission under this Law to exercise dispatch rights over all Generation and transmission Licensees and, in order to meet the requirements of Distribution Licensees and Direct or other consumers According this Law the other rights may be granted to the Dispatch licensee h "Dispatch Licensee" shall mean a Individual or Legal Person who holds a Dispatch License, for so long as the License is effect

i "Commission" shall mean the Georgian Electricity Regulatory National Commission

j "License" shall mean a Generation License, a Transmission License, a Dispatch License, or a Distribution License granted by the Commission

k "Licensee" shall mean a Individual or Legal Person to whom the Commission has granted a License under this Law, for determined or not determined period of time

l "Receiving Point" shall mean a point at which the Transmission Licensee receives electric capacity and energy on the Transmission Grid, including import of electricity from foreign electricity systems

m "Delivery Points" shall mean the point, where the Transmission Licensee, from the transmission grid, supplies electricity to the Distribution Licensee's facilities, the facilities of any Direct Consumer and foreign electricity systems

n "Direct Consumer" shall mean a Individual or Legal Person directly connected to the Transmission Grid at a Delivery Point and is not a Distribution Licensee

o "License Fee" shall mean the fees imposed by the Commission on the Generation Licensee, Transmission Licensee, Dispatch Licensee and the Distribution Licensees, each year in order to reimburse the licensing service provided by the Commission p "Generation License" shall mean a License granted by the Commission under this Law to generate electricity and to connect electricity generation facilities to the Transmission and Distribution Grids at a Receiving Points

q "Generation Licensee" shall mean a Individual or Legal Person who holds a Generation License, for so long as the License is in effect

ARTICLE 2.

NATIONAL ELECTRICITY POLICY

Clause 3 Electricity Policy Formation and Implementation

1 The Ministry elaborates the main directions of the State Electricity Policy and upon approval by the Parliament of Georgia coordinates the implementation of the policy In this purpose, the main functions of the Ministry are, to

a Elaborate electricity programs based on the short, medium, and long term strategy and priorities and to coordinate their implementation,

b Promote an attraction of investments of the electricity sector in the short, medium, and long term,

c Promote the optimal management of processes on restructuring and privatization of State enterprises in the electricity sector and the promotion of competition in electricity markets, and establish strategies for the conservation or liquidation of State-owned electricity sector facilities,

d Participate in elaboration and development of legal and regulatory framework, monitor the technical and economic condition of the sector,

e Coordinate the elaboration and implementation of state program on efficiency in generation, transmission, distribution and consumption,

f Promote programs on scientific research, projection-construction and education in electricity sector

g Promote the environmental protection of all energy activities, and optimally incorporate environmental protection goals in the formulation and implementation of energy programs,

h Promote the establishment of relationships between Licensees and electricity sector entities in foreign countries, and promote the establishment of transit and import/export relationships in the electricity sector,

i Promote development of state strategies for electricity sector emergency situations, and

j Elaborate the policy on Georgia's energy security

2 The Ministry of Fuel and Energy shall relinquish ownership, regulatory and operational rights in the electricity sector

3 The Ministry of Fuel and Energy shall be responsible under the Laws of Georgia for granting permits regarding the siting of generation facilities and granting all licenses and permits for transmission facilities, which are not to be connected to the Transmission Grid

ARTICLE 3.

GEORGIAN ELECTRIC REGULATORY NATIONAL COMMISSION

Clause 4 Georgian Electricity Regulatory National Commission Status and Functions

1 The Georgian Electricity Regulatory National Commission ("Commission") is established as a permanent independent body with the status of a legal entity of public justice, and is not subordinated in any way in its activity to any other governmental or private agency or institution

2 The Legal base for Commission's activities is the Georgian Constitution, International Treaties, the Present Law, the Charter of the Commission, and other Legal Regulations

3 The Charter of the Commission shall be elaborated and approved by the Commission

4 The Commission has authority to regulate Licensees and grant Licenses, except Licenses mentioned in clause 3 3 of this Law

5 The main functions of the Commission are, to

a set the rules and requirements, grant, modify, discontinue and revoke generation, transmission, dispatch, distribution licenses, except cases mentioned in clause 3 of this Law,

b set and regulate wholesale and retail tariffs for electricity generation, transmission, dispatch, distribution and consumption,

c within its competence, resolve arguments between generation, transmission, dispatch, and distribution Licensees, and between Licensees and consumers,

d establish control over the conditions of the Licensing, and for violation of the conditions, shall combine the relevant administrative sanctions, which are determined by the existing Georgian Legislation

Clause 5 Rules and Regulations of the Commission

1 Commission within its competence issues Rules and Regulations The Rules and Regulations of the Commission are issued by Resolutions, The Commission by resolution approves the Charter, operational rules and procedures, rules for receipt and review of Licensing and tariff applications, rules and requirements for granting, modification, discontinuation or cancellation of the Licenses and procedures for consideration of the

arguments The resolution of the Commission also may be made in cases set by the present law and other legal regulations

2 On each particular issue, considered in the present Law, Commission within its competency makes decisions

3 Resolutions and decisions of the Commission are made on the meetings of the Commission by the majority of votes The meeting of the Commission is authorized if, at least two members of the Commission attend the meeting Resolutions and decisions of the Commission are mandatory for licensees and consumers

4 The Chairman of the Commission issues orders on administrative issues

Clause 6 Members of the Commission and Terms

1 The Commission shall consist of three members President of Georgia appoints and dismisses the members of the Commission

2 An individual may be appointed as a Commissioner if is a citizen of Georgia, is at least 35 years old, has a university degree, and is qualified by training and experience to discharge the duties prescribed by this Law

3 Terms for members of the Commission shall be six years A member who has served one complete six year term may be re-appointed for additional six year term Whenever a vacancy in the Commission exists prior to the expiration of a term, the President shall appoint a new member to serve for the remainder of the unexpired term

4 Each member shall have one vote in Commission decisions

Clause 7 The Discontinuation of Authority and Dismissal

1 Premature interruption of the terms of a Commissioner is due in cases as follows

a if voluntarily quits,

b if accusatory decision has been taken against him according to the Georgian legislation,

c if the court recognizes him disabled or missing,

d if his citizenship changes,

e if violation of the provisions given in clause 17 takes place,

f if does not perform his duties constantly, during four months period,

g if dies

2 The member of the Commission can only be dismissed according to the provisions mentioned above

3 The Member of the Commission has a right to appeal his dismissal according to the rules and procedures established by the existing legislation

Clause 8 Chairman, Duties of the Chairman

1 The Chairman of the Commission shall be appointed by the President from among the members of the Commission The Chairman of the Commission may resign from the position of the Chairman and remain a member of the Commission for the remainder of the member's term The Chairman of the Commission may, from time to time, designate one of the other Commissioners to serve as Acting Chairman

2 The Chairman of the Commission shall be responsible for presiding over the meetings of the Commission, for publishing and carrying out the Commission's decisions, and for the administration of the Commission

Clause 9 Employees to be Appointed, Dismissed by the Commission

For the proper discharge of the Commission's duties the Commission has the staff The Chairman of the Commission, in consultation with the Commission and according to the Georgian legislation, may appoint or dismiss any employee The employees of the Commission shall be equally subordinated to the members of the Commission, except the issues related to the administrative management

Clause 10 Political Activities of the Commissioner

The member of the Commission shall discontinue the membership of any party The creation of political or social organizations within the Commission is prohibited

Clause 11 Powers and Duties Generally

1 The Commission shall, give careful consideration to the main directions of the state energy policy, national security, economic, environmental, and other policies of the Government

2 The Commission shall in proceedings before it allow the interests of the consumers be represented

3 The Commission and each of its employ, within its competence shall have full and prompt access to the personnel and records of every Licensee

4 Within its competency, the Commission is authorized to conduct inspection of all presented records and data

Clause 12 Public Sessions, Exception for Confidential Information

1 The sessions of the Commission shall be public Commission's decisions and resolutions, shall be made published at the time decisions and resolutions are made

2 The Commission shall keep a record of all proceedings and other relevant documents for the period determined by the Commission A member of the Commission shall have open access to any information, records and documentation of the Commission

3 All resolutions and decisions, orders, records and other documents shall be open to public examination The Commission shall adopt appropriate rules to ensure confidential information received by it remains confidential, whenever confidentiality is necessary

Clause 13 Conducting Meetings of the Commission

Before promulgating any resolution or decision the Commission shall give reasonable notice of its contents and shall give interested Persons an opportunity to attend the meeting In order to keep information confidential, Commission is authorized to conduct meetings closed for the public The resolutions and decisions made on closed meetings shall be published

Clause 14. Liability for Violation of the Law

1 Commission, in accordance with the legislation, is authorized to hold liable all legal persons or individuals, who violates the provisions of this law or resolutions and_decisions made by the Commission

Clause 15 Appeals

1 A resolution and decision made by the Commission, may be appealed, by affected person, to the Constitutional or Supreme Court of Georgia, in accordance with the existing rules and procedures

Clause 16 Meetings and Communications between the Commission and Parties

1 The Commission shall promulgate rules controlling meetings between members or employees of the Commission and any other party The rules shall provide that no member of the Commission shall consult with any party or Legal Person or individual acting on behalf of any party with respect to such a proceeding without giving notice, and an opportunity to participate, to all parties

Clause 17 Conflicts of Interest

1 No member or employee of the Commission shall directly or indirectly own any securities of, have any economic interest in, or hold any position with any Licensee, nor shall any member of the Commission engage in any paid outside employment

2 This Clause shall not prevent any member or employee of the Commission from being a customer of any Licensee, but no Licensee shall offer, nor shall any member or employee of the Commission accept, free or discounted service

or service at other than the rates and conditions generally applicable to the public

Clause 18 Immunity

Threatening, violence or any other illegal actions against the member of the Commission, or its employ, while they are fulfilling their responsibilities, are prohibited Any person who violates this provision shall be prosecuted in accordance with procedures established by the existing legislation

Clause 19 Budget of Commission, License Fee

1 The Commission shall, by October 1 of each year, prepare its detailed budget for the following year, which shall indicate all the expenses of the Commission, including the salaries and benefits of the members and employees of the Commission On the basis of load forecasts for the following year received from the Licensees by September 15, the Commission shall establish a License Fee applicable to electricity deliveries of the Transmission Licensee and/or License Fees applicable to electricity deliveries of Distribution Licensees at a level sufficient to cover the budgeted expenses of the Commission for the next year The budget of the Commission shall published

2 License Fees shall be deposited in a separate account for the use of the Commission, which shall have sole access to the funds Any funds in the Commission account not used in one year shall be carried forward to the next year, and the next year's License Fees reduced accordingly The Commission shall be entitled to borrow from the State Treasury to meet capital or operating expenses that cannot be met from current License Fees, the Commission shall repay the loans, with interest at the appropriate government borrowing rate, from future License Fees The State Treasury may also deposit appropriated funds that are not subject to repayment by the Commission into the Commission's account at the State Treasury for the Commission's use

Clause 20 Financial Report, Audit

1 By March 31 of each year the Commission shall prepare and publish a financial report that shall include an accounting of the License Fees paid to the Commission's account and the Commission's expenses from this account, during the prior year The financial report shall also identify any loans taken during the year, and any other funds made available to, and/or used by, the Commission The Commission shall make financial report available to the public

2 Review of the fiscal activities of the Commission, shall be conducted in accordance with Georgian legislation and implemented by relevant authorized bodies, including independent auditors appointed by the Commission Review shall not cause the suspension of the Commission's ongoing activity

Clause 21 Annual Report

Each year the Commission shall make an annual report regarding its activities and present it to the President, the Parliament, and the Ministry Copies of the report shall also be made available to the public

ARTICLE 4.

LICENSES

AND

LICENSING PROCEDURES

Clause 22 Commission to Issue Licenses, Licensed Activities, Exceptions

1 The Commission is authorized to grant Licenses for electricity generation, transmission, dispatch, and distribution services pursuant to this Law and the procedures, rules, and regulations adopted by the Commission

2 No Individual or Legal Person, except those which are covered by clause 22 section 3, may engage in electricity generation, transmission, dispatch, or distribution activities without a relevant License issued by the Commission

3 No Individual or Legal person or individual, which generates electricity only for its own consumption and is not connected to the transmission or distribution grids, is required to obtain the license

Clause 23 Procedures

The Commission shall establish procedures necessary to implement requirements of the present Law The procedures shall specify the information required to obtain a License, including information regarding financial strength, credit rating, experience, and compliance with all Laws and regulations, and any application fee for the License established by the Commission

Clause 24 Competence Required, General License Provisions, Discontinuation of Service

1 The Commission shall issue Licenses only to Legal Persons who have established competence to operate within the electricity sector and to satisfy the service obligations under this Law and the conditions to be included in each License

2 Licenses shall describe the type of service to which the License applies, the location of the facilities or territory to which the License applies, the duration of the License, the requirement of timely payment of License Fees, and the conditions of License modification, suspension, or revocation

3 No Licensee shall be entitled to discontinue service under any License, except as permitted in the License for non-payment by the customer or technical or safety reasons In such cases The Licensee shall submit an application on discontinuation of the service to the Commission After Commission approves discontinuation of the service, the Licensee relinquishes the License

4 No Licensee shall be required by the terms of its License, by its tariff, or otherwise to continue supplying electricity or other electricity services in any case where another Licensee, a Direct Consumer, or any other Legal Person or individual has failed to meet its payment obligations under a contract or approved terms and conditions of service

Clause 25 Rights and Duties of Licensees, Information Filings

1 Each Licensee must comply with all conditions set forth in its License, the resolutions and decisions adopted by the Commission, and the Laws of Georgia

2 Licensees shall operate at least cost principle and in accordance with economic efficiency requirements

3 Each Licensee, with the exception set in clauses 25, section 4, shall submit to the Commission, to the Ministry, and make available to the public the following information

a An annual summary of the Licensee's activities for the past year,

b An annual work plan describing the Licensee's anticipated activities for the following year, and

c Other information as the Commission determines to be necessary or appropriate

4 Each Licensee who holds a Generation License, granted following a finding that the power sales contract was determined on a competitive basis, shall submit to the Commission any reports, statements, and information that the Commission, deems necessary for the safe and reliable operation of the Transmission Grid and connected facilities

Clause 26 Metering, Metering Equipment

Licensees shall measure the quantity of electricity flowing through their facilities by use of metering equipment and procedures that satisfy standards and requirements prescribed by Law The Commission is authorized to conduct inspections of metering equipment

Clause 27 Disputes

Any Licensee, Direct Consumer, or customer of any Distribution Licensee, may refer the dispute to the Commission for resolution, the Commission may in its discretion order the matter to be resolved through the court

Clause 28 Bonds

Before issuance of any License, or the reinstatement of a suspended License, the Commission may require a bond or any other form of financial security necessary to ensure adherence to this Law and the conditions of the License, including the payment of License Fees

Clause 29 Modifications, Suspensions, Revocations

Except where a License is modified pursuant to its terms and conditions or suspended or revoked for non-compliance with its terms and conditions, the Commission may modify, suspend, or revoke a License issued under this Law only with the prior consent of the Licensee, *provided,* that upon granting a License the Commission may require the Licensee to comply with different, or more stringent requirements than the requirements included in any prior License

Clause 30 Restrictions on Ownership of Shares and Licensees, Restricted Transactions

1 No Licensee may hold more than one License or own shares in any other Licensee without Commission approval No Legal Person or individual that exercises, directly or indirectly, owns or controls the shares of a Generation Licensee, the Transmission Licensee, the Dispatch Licensee, or a Distribution Licensee may, without Commission approval, own any shares of any other Licensee

2 A Licensee may not, without the Commission's prior approval, transfer its License in any form to any other Legal Person or individual The Commission, according this law or public interest, may approve, disapprove, or restrict, the following activities by Licensees

a Conducting a business merger or a major acquisition or sale of assets or securities,

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b Expanding the Licensee's business activities, and

c Undertaking a reorganization of the Licensee's corporate structure

ARTICLE 5.

LICENSES:

PROVISIONS AND CONDITIONS

Clause 31 Generation Licenses

1 The Commission may issue Licenses that in each case authorize a Legal Person to generate energy and connect specifically identified generation facilities to the Transmission Grid for the purpose of supplying electricity capacity and/or energy to a specific Receiving Point

2 The duration of each License shall be the expected useful life of the generation facility Commission may, for violation of the terms of the License, revoke the generation License

3 According to the License Conditions, each Generation Licensee shall, for the duration of the License

a Submit the rates, terms, and conditions for power sales contracts with other Licensees for review and approval by the Commission under Article 6, *provided,* that such review and approval shall not be required once the Commission has determined that the Generation Licensee is either intending (1) to produce electricity solely for his own consumption, (2) to produce electricity solely for export or (3) conducts power sales in the competitive conditions, and *provided further,* that each Individual or Legal Person applying for a Generation License shall also submit to the Commission the technical, safety, and interconnection standards for the proposed generation facility

b Make the licensed generation facilities available to the Dispatch Licensee at the Receiving Point for the safe, reliable, non-discriminatory, and economic dispatch and operation of the Transmission Grid and connected facilities, pursuant to the terms of its power sales contracts or its approved rates and terms and conditions of service,

c Comply with all applicable requirements regarding the coordination of the operation of generation facilities with the Transmission Grid and distribution facilities, including instructions issued by the Dispatch Licensee, and

d Timely pay the license fees set by the Commission and comply with all other terms and conditions of the License

Clause 32 Transmission License

1 The Commission may issue a License granting a Legal Person the exclusive right to provide transmission service using the Transmission Grid

2 The License shall identify the transmission system included in the Transmission Grid to be operated by the Licensee, which shall include the

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facilities between the Receiving Points and the Delivery Points Where a Generation Licensee's facility is to be directly connected to a Distribution Licensee's or a Direct Consumer's facilities, the Commission may deem the interconnection point a Receiving Point and a Delivery Point separated by a minimum section of the Transmission Grid for purposes of establishing parameters for transmission services

3 When a new transmission facility is required in the Transmission Grid, the Transmission Licensee shall apply for a modification to its License proposing the new transmission facility If, after notice and hearing pursuant to the rules promulgated by the Commission, the Commission determines that the new facility is required, and further determines that the proposed route for the facility, as may be amended at or following the hearing, will reasonably minimize adverse impacts on the area concerned, is consistent with the State Policy concerning the proposed route as expressed to the Commission during the proceeding, and complies with the requirements of Law, the Commission shall issue to the Transmission Licensee a modified Transmission License that includes the new transmission facility and authorizes its construction on the approved route

4 If, following the hearing described in present Clause, section 3, the Transmission Licensee is authorized to construct a new transmission facility along an approved route, the Transmission Licensee shall be entitled to acquire any lands required to construct this facility

5 The duration of a License shall be indefinite, but subject to revocation by the Commission for violations of the License

6 According to the License Conditions, the Transmission Licensee shall, for the duration of the License

a Develop and maintain the Transmission Grid in a manner adequate to support the needs of Generation Licensees, Distribution Licensees, and Direct Consumers,

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b Develop, submit to the Commission, and make publicly available an investment program,

c Develop and make available reasonable instructions for the safe, reliable, and non-discriminatory interconnection and operation of the transmission network and connected facilities,

d Charge only those rates, and impose only those conditions of service, approved by the Commission under Article 6, and

e Timely pay all License Fees imposed by the Commission and comply with all other terms and conditions of the License

Clause 33 Dispatch License

1 The Commission may issue a License granting a Individual or Legal Person the right within Georgia to purchase and resell electricity capacity and/or electricity and/or transmission services to Distribution Licensees, Direct Consumers, and other foreign or domestic Legal Persons or individuals as required or permitted by the Commission, and the exclusive right to operate a central dispatching control center for Georgia's electricity system

2 The duration of a License shall be indefinite, but subject to revocation by the Commission for violations of the License

3 According to the License Conditions, the Dispatch Licensee shall, for the duration of the License

a Plan for and secure adequate rights to electricity supplies, including rights to electricity supplies from foreign Individual or Legal Persons, and transmission services to satisfy the needs of Distribution Licensees and Direct Consumers at least cost principle, *provided,* that if any Distribution Licensee or Direct Consumer has contracted directly with one or more Generation Licensees or other foreign or domestic Legal Persons to meet part or all of its electricity supply requirements and/or the Transmission Licensee for transmission capacity, the Dispatch Licensee shall not be responsible for obtaining back-up or stand-by electricity supplies or transmission capacity unless the Distribution Licensee or Direct Consumer has paid the appropriate Commission approved rates for such services,

b Install, own, operate, and maintain facilities necessary for safe and reliable dispatch of the Generation Licensees' facilities in order to maintain electricity stability on the Transmission Grid, and create and implement appropriate dispatch protocols for the efficient satisfaction of electricity supply requirements of Distribution Licensees and Direct Consumers

c Develop and coordinate with all other Licensees, under the supervision of the Commission, emergency plans consistent with State Policy to be implemented emergency situations

d Develop, provide the Commission, and make publicly available an investment program,

e Charge only those rates, and impose only those terms and conditions of service which are approved by the Commission

f Timely pay all License Fees imposed by the Commission and comply with all other terms and conditions of the License

Clause 34 Distribution Licenses

1 The Commission may issue Licenses that in each case authorize a Individual or_Legal Person to exercise the exclusive right to engage in the distribution of electric power within a defined geographic region

2 The duration of each License shall be indefinite but, subject to revocation by the Commission for violations of the License

3 According to the License Conditions, each Distribution Licensee shall, for the duration of the License

a Extend distribution services to consumers consistent with eligibility criteria established by the Commission and with the Licensee's investment program,

b Obtain rights to sufficient transmission capacity and electricity from the Transmission Licensee and/or the Dispatch Licensee, also from Generation Licensees, and other foreign or domestic Legal Persons

c Establish and submit to the Commission for approval procedures for obtaining and terminating the rights to serve, metering, billing, and collections,

d Develop, provide to the Commission, and make publicly available an investment program, e Charge only those rates, and impose only those terms and conditions of service which are approved by the Commission, and

f Make available to the public for review in the Licensee's offices

(i) The License and approved tariffs,

(ii) The Licensee's approved terms of service governing procedures for obtaining and terminating services, metering, billing, and collections

(iii) A description of the performance standards applicable to the Licensee, including time required to connect new customers, and

g Timely pay all License Fees imposed by the Commission and comply with all other terms and conditions of the License

ARTICLE 6.

TARIFFS

Clause 35 Commission Authority for Tariff Setting

The Commission shall review and approve, modify, or disapprove the rates and terms and conditions of service provided by Licensees Except the cases which are covered by clause 31 section 3, subsection (a)

Clause 36 Tariff Setting Principles.

1 Tariffs for electric power services established by the Commission shall

a Protect consumers from monopolistic prices,

b Provide Licensees with an opportunity to recover their costs of providing service, including prudently incurred fuel, operating, and maintenance costs, the principal and interest costs of money borrowed for prudent investments and working capital At the same time Tariff shall imply just and reasonable profit on invested equity sufficient to attract financing for the rehabilitation and further development of the sector,

c Encourage efficiency in internal operations and management practices by allowing a Licensee's financial returns to increase as a result of the Licensee having minimized its costs of providing service, *provided,* that the Licensee meets all requirements of its License concerning the provision and quality of service,

d Encourage economic efficiency within the electricity sector by reflecting short run and long run marginal costs and by sending accurate price signals regarding the relative abundance or scarcity of the supply of electric power services,

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e Allow Licensees to cover all economically reasonable expenses, including expenses for acquiring licenses on relevant services and covering License fees,

f Take into account State Policy in regard to priority consumers for electricity supply, *provided,* that it shall not prevent a Licensee from exercising any rights granted in its License to disconnect any Legal Person or individual for failure to meet its payment obligations under any contract or approved terms and conditions of service,

g Take into account State Policy in regard to subsidies, but it is prohibited to subside any category of the consumers on account of Licensee or any other category of consumers

h Reflect cost differences between different categories of customers

2 Costs shall be recovered from each customer category in proportion to the costs of serving that category

3 Different tariffs may be established for each customer category to reflect the quantity of peak, average, or overall usage, the season, the time of day, the types of services purchased, or similar parameters Performance-based tariffs, including revenue indexing, price indexing, and other innovative tariff methodologies may also be used, if the Commission finds the use of such methodologies to be in the interest of Licensees and consumers

Clause 37 Rules for Tariff Setting

In the process of tariff setting the Commission relies on the following documents a Evidentiary requirements for tariff applications, including audited financial information,

b Time frames for tariff applications and decisions,

c Procedures for customers and other interested parties to comment on tariff applications,

d Procedures for the Commission to obtain additional information as necessary to evaluate tariff applications, and

e Setting procedures for financial reimbursement of licensing service

Clause 38 Effectiveness of Tariffs, Tariff Refund

Tariffs shall become effective 150 days after submission to the Commission for review, providing that such application complies with the Commission rules for tariff applications Licensee shall cover the expenses of the Commission on tariff approval

Clause 39 Uniform Accounting Standards

The Commission shall establish a uniform and standardized system of accounts to be based on internationally accepted accounting standards This system of accounts shall be used by all Licensees for financial and economic reporting to the Commission The Commission shall use the financial and economic reporting by Licensees, and its own analysis using the system of accounts, as the basis for calculating tariffs

ARTICLE 7.

TRANSITION PROVISIONS

Clause 40 Initial Terms of Commission Members

The initial members of the Commission shall be appointed as follows first member for 6 years, second member for 4 years and third member for 2 years

Clause 41 Interim Licenses

1 Each Legal Person engaged in activities requiring a License under this Law on the day this Law came into effect shall be deemed to hold an interim License ("Interim License") with a duration of two years Each Interim License shall allow that Individual or Legal Person ("Interim Licensee") to continue to undertake those activities requiring a License engaged in on the day this Law came into effect The Commission may issue additional Interim Licenses in special circumstances within two years of the day this Law came into effect Interim Licenses are not transferable

2 The Commission may, in case of necessity, impose on "interim licenses" the same requirements as in License The Commission may by decision, modify, or terminate any Interim License for the purpose of effecting a reorganization of the electricity sector and promoting transition to the market economy principles Interim Licenses may be modified or terminated by the Commission without suspending the performance of the Interim Licensee during the duration of the Interim License

3 Commission may on its own motion, establish a proceeding for the extension, modification, or termination of an Interim License Where the Commission is considering a modification or termination of an Interim License, the Commission shall provide advance notice to the Ministry of Fuel and Energy and the Interim Licensee and shall give an opportunity for the Ministry of Fuel and Energy and the Interim Licensee to attend the meeting

4 When the Commission has adopted rules and regulations pursuant to Clause 23, each Interim Licensee may apply for a License under Clauses 31-34, as applicable

5 All tariffs of Interim Licensees in effect when this Law-is adopted shall remain in effect until reviewed by the Commission, *provided,* that the Commission shall be deemed to have approved rate changes for each Interim Licensee in order to determine interim license fee

Clause 42 Interim License Fees

The Commission may establish Interim License Fees on Interim Licensees The Commission need not set Interim License Fees on the basis of load forecasts, and may set Interim License Fees for any period and calculated on any basis that the

Commission reasonably determines is likely to cover its budgeted expenses for its next budget period

Clause 43 Effecting the Law-

This Law shall be effective upon publication

Clause 44 The list of invalid Rules and Regulations

1 After this Law comes in effect, the following decrees are invalid

a) The Law of the Republic of Georgia On Energy, September 22, 1994 (Georgian Parliament Herald, 1994, # 19-20, Article 436) first clause of the Article 4 and second clause of the Article 5

b) The Law of the Republic of Georgia On Energy, Article 4, clause 7 October 11, 1994 (Georgian Parliament Herald, 1994, # 21-22, Article 446)

2) Executive Power shall adjust underlying regulations to this Law

The President of Georgia

E Shevardnadze

Tbilisi, June 27, 1997

APPENDIX C
DEGREE #389 BY THE PRESIDENT OF GEORGIA

July 28, 1997 Tbilisi

On the Additional Measures of Social Protection of the

Population and Stage by Stage Transfer to the

Market Economy Rules in Price Formation

In compliance with Article 14 of Georgian law “On the State Budget for 1997”, regarding the further improvement of the salary system for budget institution employees, also the current projects of energy sector rehabilitation and projects agreed upon with international financial-credit institutions, and in order to carry out stage by stage transfer to the market economy rules in price formation, promote privatization process, attract investments, improve the power consumption metering system and reduce power losses, the following shall come into force form August 1, 1997

1 A universal tariff system for purchasing electricity from distribution companies by electricity consumers of all categories, including the population, shall be accepted - 4 5 (four point five) tetries per kWh/h

2 Salaries and hourly fees for budget institution employees, including those of professors, teachers and other employees of the same category (except those whose benefits were increased by President’s Order N 549 of August 20, 1996) shall be increased by average 20% and calculated according to the rates, as it is stated in the Appendix

Benefits of budget institution employees that exceed those indicated in the Appendix, shall remain unchanged

3 The salaries of employees working at the Ministry of Defense, the Ministry of Internal Affairs, the Ministry of State Security, the State Department of the State Border Security, the Special State Security Service (except those whose benefits were increased by President's Order N 549 of August 20, 1996), shall be increased by average 10% and calculated according to the rates, as it is stated in the Appendix

4 All categories of pensions of retired citizens {except those provided for in the Georgian Law "On Pensions of Persons (and members of their families) Transferred to Reserve from Military Service and Institutions of Internal Affairs"} shall be increased by 2 (two) laries and equal 11 8 (eleven point eight) laries per month The amount of pensions for the participants of the World War 2 and others of the same category shall equal 15 (fifteen) laries per month

5 The assistance amounts of refugees (except those settled by the government) shall be increased by 2 (two) laries and equal 11 8 (eleven point eight) laries per month, while the expenses of the refugees settled by the government shall be increased by 50 (fifty) tetries and equal 8 8 (eight point eight) laries per month

6 The assistance amounts for unemployment shall be increased by 2 (two) laries and equal 11 8 (eleven point eight) laries per month, during the first two months, 9 8 (nine point eight) laries - during the fourth and the fifth months, 8 8 (eight point eight) laries - during the fifth and the sixth months

7 The scholarship funds of state universities shall be increased by 20% (twenty percent)

8 The minimum income of physical persons not liable to income tax shall remain unchanged and equal 9 (nine) laries

9 From August 1, 1997 new rates shall be used for vacation leave payments and sick leave payments

10 The measures provided for in the given Order shall be implemented through reducing the staff number in budget institutions and organizations

11 The Georgian Electricity Regulatory National Commission (E Eristavi) shall determine the different wholesale rates within the electric energy sector in one month period

12 State company "Sakenergo" (E Metreveli) and distribution companies shall work out and strictly observe the schedule of supplying electricity to consumers and the consumption limit

13 The Georgian Ministry of Social Security, Labor and Employment (T Gazdeliani), the Ministry of Finance (M Chkuaseli), the Ministry of Economy (V>Papava), the Ministry of Fuel and Energy (D Zubitashvili), the Ministry of Justice (T Ninidze), the Electricity Regulatory National Commission (E Eristavi), shall determine the categories of the population that will pay reduced electricity tariffs (indicating the funding source) and submit their proposed amendments to the current law no later than December 1, 1997

14 The Georgian Ministry of Finance, the Ministry of Economy, the Ministry of Fuel and Energy, the Ministry of Social Security, Labor and Employment, together with the Ministry of Refugees and Settlement, the Ministry of Defense, court and police institutions, the State Funds of Social Security and Health Insurance shall work out the rules of fund mobilization

necessary for covering the consumed electricity costs due to the transfer to the new tariff system The rules shall be mandatory for all institutions located in Georgia

15 Ministries, organizations, institutions, Autonomous Republics of Abkhazia and Achara, government bodies of other territorial entities shall be responsible for the enforcement of the Order

It must be noted, that the funds necessary for keeping the government offices, paying pensions and assistance, are provided for in the State Budget for 1997 and the budgets of the corresponding territorial entities

16 The State Office, the Ministry of Economy, the Ministry of Fuel and Energy, the Ministry of Social Security, Labor and Employment, the Ministry of Finance, the Electricity Regulatory National Commission shall be assigned to supervise the implementation of the given Order

E Shevardnadze

APPENDIX D
DECREE OF THE PRESIDENT OF GEORGIA

October 6, 1997 Tbilisi

On Improvement of Consumed Electricity Payment Collection Mechanism

Despite of certain improvements, achieved after the recent special organizational-technical and financial measures held in the power sector of Georgia, there still are various serious violations in the operation of municipal regional distribution companies The distribution companies spend the collected money non-purposely and the payments to the State company Sakenergo have "residual" character This put generation and transmission enterprises into a very difficult financial situation, as they have to solve complicated organizational-technical and financial problems during this year One of the major problem is a financial settlement with the government budget

Before the privatization of distribution companies, in order to improve a collection maximally, to spend collected money purposely, to accumulate funds, necessary for power sector operation during autumn-winter period, and to use accumulated funds according to the priorities, I order

1 Starting from October 10, 1997, as an impermanent measure, municipal distribution companies shall open special accounts in banks The whole payment for electricity, paid by all types of customers and all legal or physical persons taking part in the electricity distribution business, including cash payment, shall be transferred to this account According to the established tariffs and an agreement between a distribution company and Sakenergo, collected money shall be transferred from this account to the State Company Sakenergo's account during next two days The remained funds can be used by the municipal company

2 The National bank is requested to work out quickly and send to all banks the corresponding impermanent instructions to secure an implementation of this decree

3 The municipal and regional distribution companies are prohibited to use barter and all other kind of settlements with electricity consumers, also to use direct transfers to their creditors

Starting from October 20, 1997 all letters, obligations and contracts signed by the distribution companies on this subject, shall be rendered void and necessity of their renovation shall be subject of the Emergency Power Commission for reviewing

4 Every first day of a month, the central budget organizations shall submit to the corresponding treasuries their liabilities for consumed electricity and water supply for last month period The treasuries shall arrange for transferring of the corresponding amount of money immediately

5 Every first day of a month, the local budget organizations shall submit to the corresponding budgets (financial departments) their liabilities for consumed electricity and water supply for last month period The local government authorities shall arrange for transferring of the correspondent amount of money from the local budgets immediately

6 In case if Paragraphs 3 & 4 of this Decree are violated, the municipal electricity distribution and water supply system companies shall take adequate measures regarding the budget organizations

7 The urban and rural water supply system companies shall immediately use collected funds for electricity payments These funds shall be transferred directly to the State Company Sakenergo's account

8 The Ministry of Finance of Georgia (M Chkuaseli) is requested to give corresponding directions to the treasuries and local budgets and to control the implementation of the provisions specified in this Decree

9 The Chamber of Control of Georgia (R Shavishvili), the Ministry of Internal Affair (K Targamadze), together with the State Company Sakenergo are requested to control periodically the financial activities of the municipal and regional energy companies

10 The Councils of Ministers of Abkhazia and Ajara, the regional state authorities of the President, mayors of the cities, regional governments, together with their subordinated energy companies, shall work more efficiently to guarantee 70% payment rate to Sakenergo for electricity purchased during 1997

11 Fulfillment of this Decree shall be controlled by the Inter-department Emergency Energy Commission (D Zubitashvili)

E Shevardnadze

APPENDIX E
GEORGIAN NATIONAL ELECTRICITY REGULATORY COMMISSION

Resolution #4

October 8, 1997

Tbılısı

On Tarıffs wıthın the Electrıcıty Sector

Accordıng the Georgıan Electrıcıty Law and the Presıdentıal Order #389 "On Addıtıonal Measures of Socıal Protectıon of the Populatıon and Stage by Stage Transfer to the Market Economy Rules ın Prıce Formatıon" July 28, 1997, the following wholesale tarıffs shall be establıshed wıthın the Electrıcıty Sector

1 1 Tarıff for the Electrıcıty supplıed to the Dıstrıbutıon Companıes by Sakenergo

Average Voltage - (6 kV, 10 kV) - 3 3 Tetrı

Hıgh Voltage - (35 kV, 110 kV) - 3 1 Tetrı

1 2 Average Tarıff per kWh for the electrıcıty Supplıed to the Sakenergo by Generatıon Companıes ıs 0 98 Tetrı, of whıch

Sakenergo Generatıon

(Engurı, Vardnılı I, II, III, IV) - 0 9 Tetrı

Ortachala HPS - 1 3 Tetrı

Vartsıkhe HPS (cascade) - 0 9 Tetrı

Khramı - I HPS - 0 95 Tetrı

Khramı - II HPS - 0,95 Tetrı

Tkıbulı HPS - 0 95 Tetrı

Lajanurı HPS - 1 05 Tetrı

Gumatı HPS (cascade) - 1 05 Tetrı

Rıonı HPS - 1 05 Tetrı

Shaorı HPS - 1 2 Tetrı

Jınvalı HPS - 1 2 Tetrı

Kabalı HPS - 2 0 Tetrı

Satskhenısı HPS - 2 0 Tetrı

Dashbash HPS - 2 0 Tetrı

Mısaktsıelı HPS - 2 0 Tetrı

Tırıpon HPS - 2 0

Chkorotsku HPS - 2 0 Tetrı

Zahesı HPS - 1 3 Tetrı

Chıtakhevı HPS - 1 3 Tetrı

Atshesı HPS - 1 3 Tetrı

Bjuja HPS - 1 4 Tetrı

Sıonı HPS - 1 7 Tetrı

Alazanı HPS - 1 7 Tetrı

Tetrıkhevı HPS - 1 7 Tetrı

Kurzu HPS - 2 0 Tetrı

Dmanısı HPS - 2 0 Tetrı

Khertvısı HPS - 2 0 Tetrı

Rıtseula HPS - 2 0 Tetrı

Martkhopı HPS - 2 0 Tetrı

Squrı HPS - 2 0 Tetrı

Abhesı HPS - 2 0 Tetrı

1 3 The two-stage tarıff shall be applıed to the dırect contract between Sakenergo and Gardabanı Thermal Power Plant

1 kW of guaranteed capacıty - 2 5 Ları per month

for electrıcıty - 3 3 Tetrı kWh

2 The amount of Electrıcıty and the Tarıffs for the Dırect Customers of Sakenergo and/or Generatıon Plants, shall be establıshed by the Regulatory Commıssıon upon the applıcatıons receıved from both (supplıer and consumer) partıes

3 The tariffs established by this Resolution are valid till April 1, 1998 The entities of the Electricity Sector shall submit the applications on new Tariffs by February 15, 1998

The Chairman E Eristavi

APPENDIX F
GEORGIAN NATIONAL ELECTRICITY REGULATORY COMMISSION

Decision #4

November 25, 1997

Tbilisi

On Tariffs for Electricity and Heat, Generated by the Joint Stock Company Tbilisi Thermo Central Plant

The Regulatory Commission sets the tariffs for the Joint Stock Company Tbilisi Thermo Central and it shall be 6 Tetri per kW of electricity and 2,5 Tetri per kW of heat

The Chairman E Eristavi

APPENDIX G
GEORGIAN NATIONAL ELECTRICITY REGULATORY COMMISSION

Decision #5

December 4, 1997

Tbilisi

On Tariffs for Consumed Electricity by Poti Water Supply System

The Commission satisfies the request of the Poti Water Supply System and determines

1 The water pumping stations of the Poti water supply system, which are receiving 6-10 kV from high voltage sub-stations of Sakenergo, shall be considered as a direct customers of Sakenergo

2 Poti water supply system, as a direct customer of Sakenergo, shall, starting from January 1, 1998, pay 3 3 Tetri per kW, according to the resolution #4 of the Georgian National Electricity Regulatory Commission, dated by October 8, 1997

The Chairman E Ersitavi

APPENDIX H
GEORGIAN NATIONAL ELECTRICITY REGULATORY COMMISSION

Decision #2

On Realization of the Electricity by the Generation Licensees

January 20, 1998

Tbilisi

According to the Georgian Law on Electricity and in order to overcome the crisis within the Sector, to promote the competition and to improve technical and economic performances of the enterprises within the Electricity sector

1 Allow the Generation Licensees to sell the electricity, on the contract basis, to the wholesale customer, by schedule agreed with Sakenergo-Dispatch Licensee, for those generation companies which generate 400 million kWh - 10% of the total amount delivered to the transmission grid, for companies which generate from 100 to 400 million Kwh - 15% and for companies generating less than 100 million kVh - 20 %

2 Each of these contracts shall be agreed with the Georgian National Electricity Regulatory Commission

3 The transmission-dispatch licensee - Sakenergo , together with the both parties, shall conduct an implementation of the accounting activities on delivery of the capacity to transmission and distribution grids

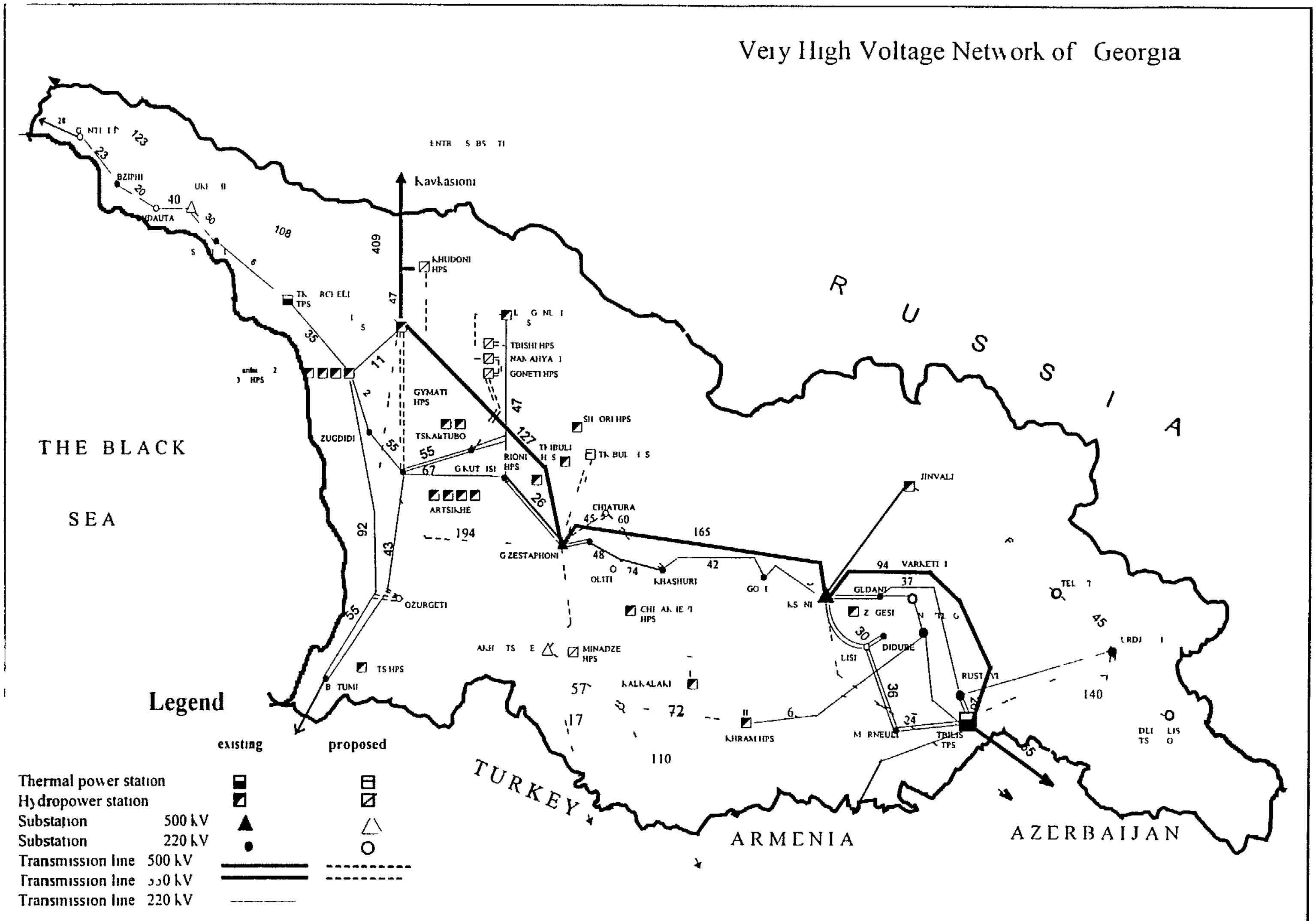
4 The state company Sakenergo shall provide a strict supervision over the schedule, of delivery and consumption of electricity, which shall be elaborated and agreed by parties

5 This Decision is valid till December 31, 1998

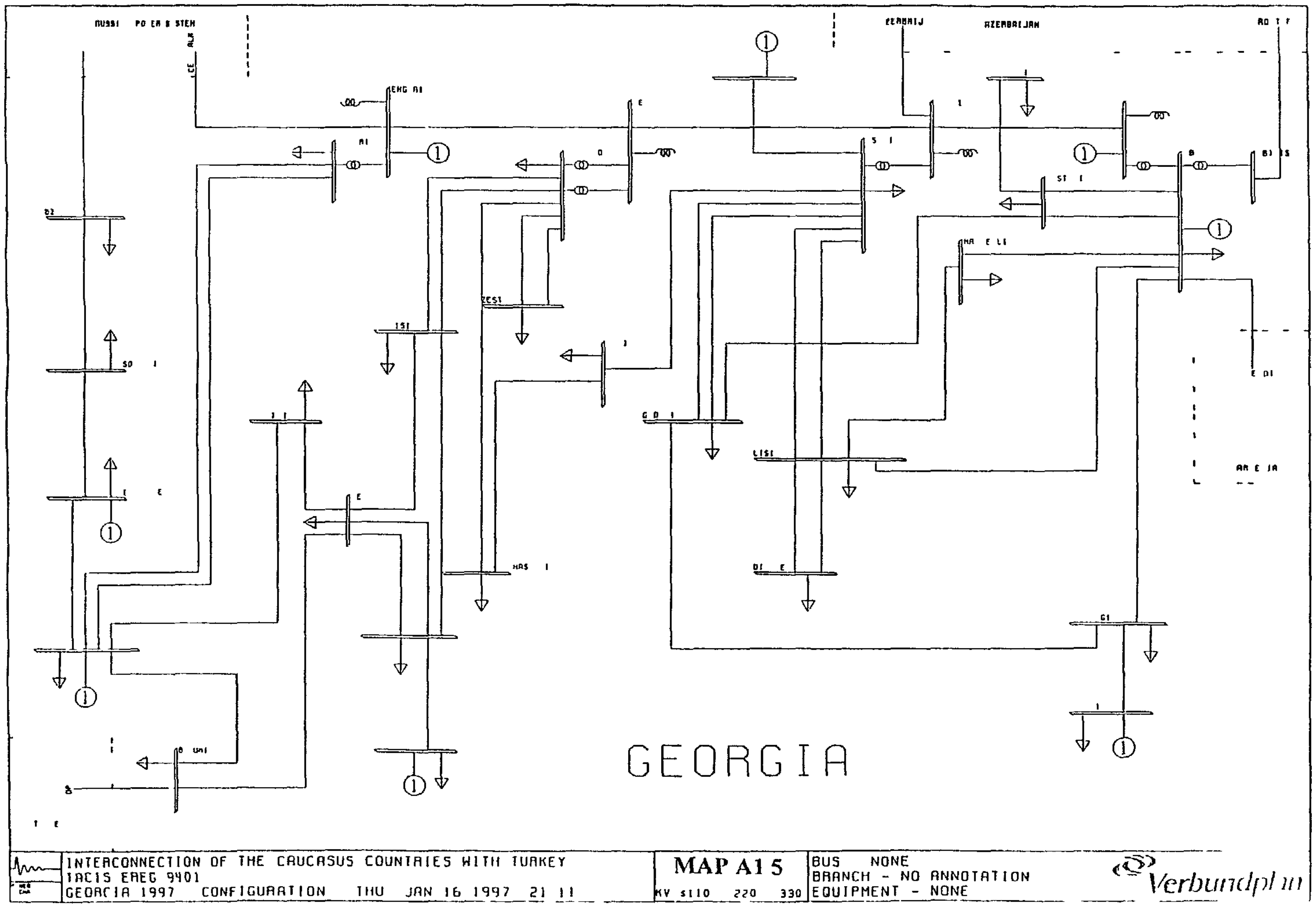
The Chairman E Ersitavi

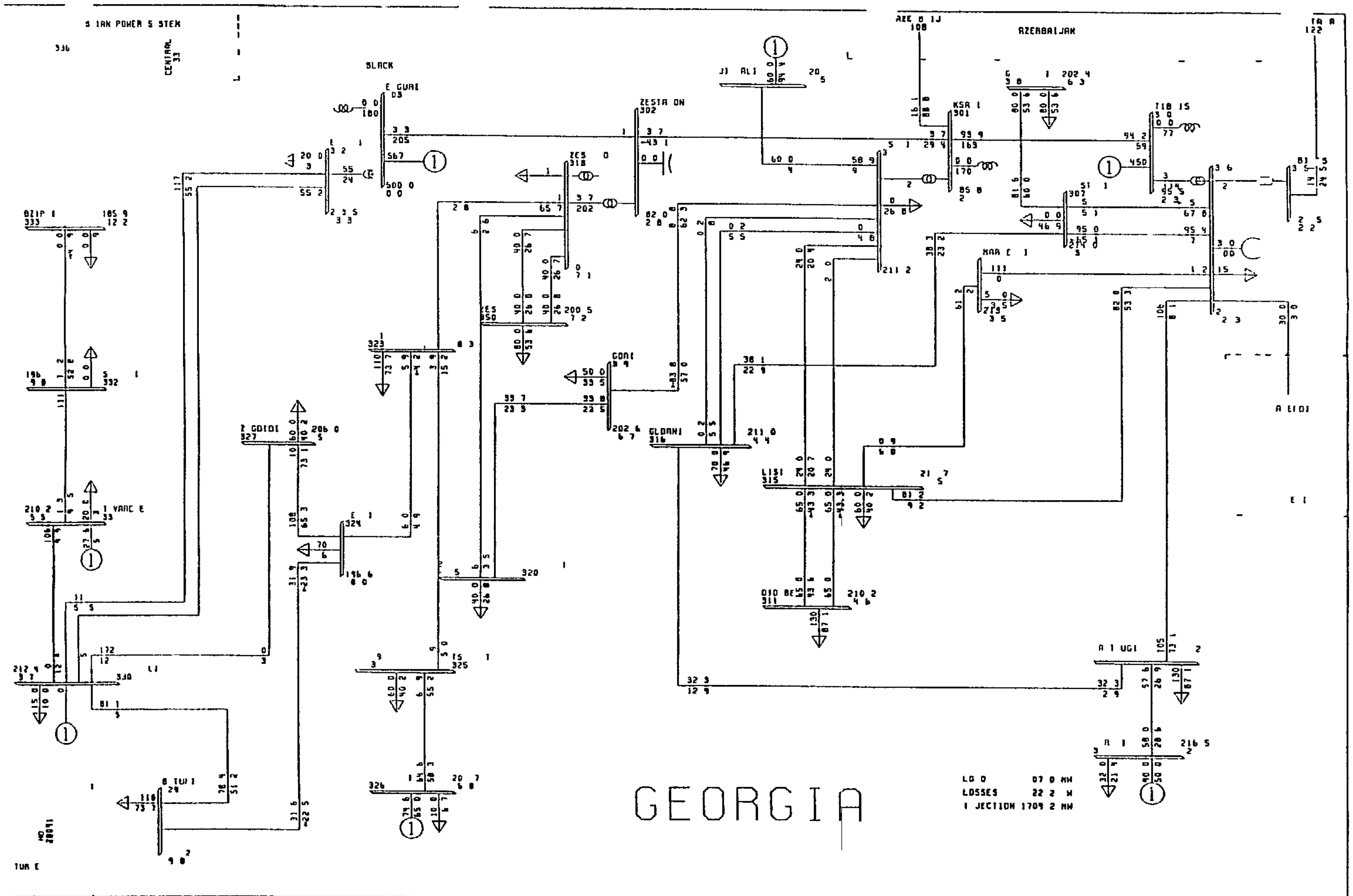
APPENDIX I
TRANSMISSION SYSTEM MAPS AND DIAGRAMS

Map of Electric System in Georgia



Very High Voltage Network of Georgia
RUSSIA
THE BLACK SEA
TURKEY
ARMENIA
AZERBAIJAN
Kavkasioni
KHUDONI HPS
TBISHI HPS
GONETI HPS
GYMATI HPS
TSKALTUBO
ZUGDIDI
RIONI HPS
ARTSKHE
TKIBULI HPS
CHIATURA
GZESTAPHONI
KHASHURI
JINVALI
VARKETI
GLDANI
DIDUBE
LISI
MTKVARI
RUSTAVI
TBILISI TPS
KHRAMI HPS
MINADZE HPS
OZURGETI
BATUMI
BZIPHI
Legend
existing
proposed
Thermal power station
Hydropower station
Substation 500 kV
Substation 220 kV
Transmission line 500 kV
Transmission line 330 kV
Transmission line 220 kV


AZERBAIJAN
GEORGIA
INTERCONNECTION OF THE CAUCASUS COUNTRIES WITH TURKEY
TACIS EREG 9401
GEORGIA 1997 CONFIGURATION THU JAN 16 1997 21 11
MAP A15
KV ≤110 220 330
BUS NONE
BRANCH - NO ANNOTATION
EQUIPMENT - NONE
Verbundplan



INTERCONNECTION OF THE CAUCASUS COUNTRIES WITH TURKEY TACIS EREG 9401 GEORGIA 1997/CAUC INTERCONN FRI MAR 21 1997 11 39	MAP A3 9 KV ≤110 ≤220 ≤330	BUS - VOLTAGE (KV) /ANGLE BRANCH MW/MVAR EQUIPMENT MW/MVAR

Verbundplan

APPENDIX J
RULES AND TERMS OF TARIFF SETTING

Draft

1 General Provisions

1 1 Terms and conditions of tariff setting constitute the requirements necessary for all licensees of the Georgian electricity sector while applying to the Georgian Electricity Regulatory Commission for setting tariffs for their services, as well as for the related rules and procedures

1 2 The Commission shall set electricity tariffs in accordance with the Law About Electricity and with the legal regulations of the Commission All physical persons and legal entities within the electricity sector shall perform their activity on electricity generation, transmission, dispatch and distribution based on the tariffs set by the Commission

2 Terms and Principles of Tariff Setting

2 1 Any licensee may request the Commission to set a tariff The licensee requesting the tariff shall submit the following to the Commission

a For generation licensees, the information contained in Schedule A

b For transmission licensees, the information contained in Schedule B c For distribution licensees, the information contained in Schedule C

d For all licensees, an explanation, with appropriate references to cost data, of why a change in the existing tariff is appropriate

2 2 The Commission may commence a tariff proceeding with respect to any licensee or group of licensees In such a case, the Commission will direct the licensee or group of licensees to file the information contained in Schedule A, B, or C, as appropriate, and give the date by which the information is to be filed

2 3 Each tariff application shall be signed by a representative of the licensee The person signing the application shall be responsible for supervising the collection of data for the application and the organization of the data according to the cost schedules The signature on the tariff application shall signify that the representative certifies, to the best of his or her knowledge after due inquiry, that the information submitted in the application is true, correct, and complete

2 4 The Commission shall be authorized to examine the documents received

2 5 While setting tariffs, the Commission shall apply both its own analytical systems and financial and economical calculations of the licensee

2 6 The basic principles of tariff setting are as follows

a Tariffs shall protect consumers from monopoly prices, while shall enable licensees to recover costs of their services This latter shall include costs of the fuel purchase at reasonable prices, operating expenses, maintenance and repair expenses, pay-back of principal and interest of the credit taken as a operating capital The tariff shall consider just and reasonable rate of return b Tariffs shall encourage growth of economic efficiency reflecting long and short-run marginal costs and forecasting dynamics of the prices

c Tariffs shall promote growth of the rate of return of the licensee increasing efficiency of operating and management and reducing the costs of the service

d Tariffs shall enable licensees to cover their reasonable costs, including license fees and other costs related to obtaining the license

e Tariffs shall consider the State policy towards priorities among the consumer types At the same time, licensee shall have a right to seek payment for his services from the consumers and in the case of failure of such payment—to cut the service with regard to the established rules

f Tariffs shall reflect different costs of serving different types of consumers

2 7 While setting the tariffs the Commission shall apply the methodologies that, in the Commission's opinion, are relevant for both the licensees' and consumers' interests For this purpose setting different tariffs by different types of the consumers may be made by peak and average rates, seasonal and daily nature of consumption, reflecting types and similar parameters of the services An innovative tariff methodology may also be applied that would reflect revenue requirement, price adjustment and other factors

2 8 Terms of the tariffs shall be no less than 6 months In specific case this term may be changed by decision of the Commission

3 <u>Rules and Procedures of Setting the Tariff</u>

3 1 The Commission will review each tariff application and, within thirty days

a Accept the application as complete If the Commission declares the application complete, it will so notify the licensee in writing, giving the date on which the application was accepted

b Request additional information When the Commission requests additional information, the application will not be deemed complete until the additional information has been submitted, to the Commission's satisfaction

3 2 When the Commission accepts an application as complete, it will give public notice of the application The public notice will summarize the tariff request, advise that the complete application is on file with the Commission and may be examined there during regular business hours, and specify a date by which interested members of the public, Ministries of government, and other licensees may submit comments on the application

3 3 Comments on a tariff application may consist of statements of fact, arguments, or evidence, as the commenter deems appropriate Comments may support or oppose the tariff request The party submitting the comments shall deliver a copy of the comments to the licensee that requested the tariff The licensee may respond to the comments within 15 days

3 4 Within three months of the date the Commission accepts the tariff application as complete, the Commission shall consider the request of the licensee and make possible decision as follows

a Approve the tariff request in whole or in part and set the tariff,

b Deny the tariff application

In specific cases the Commission shall have a right to prolong duration of application review in agreement with the enterprise

3 5 The Commission shall acknowledge the Licensee in 10 days advance about the day of tariff hearing so giving him an opportunity to attend the hearing

3 6 While setting the tariff the Commission shall use comments of the consumers and of other parties concerned, as will as procedures financial reimbursement of costs of obtaining additional information for assessment of the tariff application and of the license fees

3 7 In case of tariff approval by the Commission in whole or in part, the tariff shall become effective within 150 days after the Commission has accepted the application as complete, as provided in Rule 3 1 a

4 Reimbursement of Tariff Setting

4 1 The costs borne in connection with tariff setting shall be met by the applicant licensee Such costs shall be included into the costs of the enterprise and, eventually, into the tariff

4 2 Tariff setting fee shall be determined at a level 5% of an annual interim license fee for electricity (capacity) generation, transmission/dispatch and distribution, but no less that 100 GL The amount shall be paid by the enterprise within two weeks upon approval of the tariff

5 Cancellation of Terms and Conditions of Tariff Setting Amendments to Licenses

5 1 Cancellation of the present terms an conditions shall be made by the Commission

Appendix K
STATEMENT AND REQUEST FOR COMMENTS OF THE GEORGIAN ELECTRIC REGULATORY COMMISSION REGARDING PROPOSED RULE AND TERMS OF TARIFF SETTING

Clause 4 5 of the Electricity Law provides that one of the Commission's main functions is to "set and regulate wholesale and retail tariffs for electricity generation, transmission, dispatch, distribution, and consumption " With this Statement, we describe the cost-based tariff methodology that we propose to use in setting rates for generation, transmission, and distribution licensees, and set out the procedures that we propose to use in tariff cases We invite comments on the proposal from members of the industry, from Ministries of government, from consumers, and from any other interested members of the public Comments on this notice shall be submitted to the Commission not later than February __, 1998 Following our review of the comments and consideration of the issues, we propose to issue Final Rules and Terms of Tariff Setting by the end of February, 1998

K BACKGROUND

In August 1997, anticipating that the Commission would begin the process of formulating tariffs as provided by the Electricity Law, we released in draft form "Rules and Terms of Tariff Setting " Based on further consideration, we have decided to expand the rule, and to request comments This proposed rule will implement both clause 36 of the Electricity Law, which sets forth the principles of tariff setting, and clause 37 of the Electricity Law, which states the procedures for tariff setting

L THE RELEVANCE OF COSTS TO TARIFFS

The costs of providing electricity are fundamental to tariffs As Clause 1 2 of the Electricity Law states, "tariffs shall accurately reflect efficient production, transmission, dispatch, and distribution costs " Clause 36 of the Law, which sets out the principles for the Commission's establishment of tariffs, repeatedly refers to costs Clause 36 1 b, for example, instructs the Commission, in setting tariffs, to "Provide Licensees with an opportunity to recover their costs of providing service, including prudently incurred fuel, operating, and maintenance costs, the principal and interest costs of money borrowed for prudent investments and working capital" Clause 36 1 c states, as tariff policy, the encouragement of efficiency by licensees minimizing costs Clause 36 1 d instructs the Commission to encourage economic efficiency by employing short-run and long-run marginal cost concepts And Clause 36 1 e permits the recovery of prudent costs by Licensees

M THE COLLECTION OF COST DATA

The first step in determining costs is the collection of cost data We understand that in the West, costs are reasonably easy to determine because there, regulated utilities keep their books according to uniform accounting standards, and costs may easily be ascertained by reference to cost accounts Perhaps for that reason, clause 39 of the Electricity Law instructs the Commission to establish a uniform and standardized system of accounts for licensees based on internationally accepted accounting standards Clause 39 does not set a deadline for the Commission's adoption of accounting standards We will, in due time, establish such a uniform system of accounts In this first round of cost-based tariffs, however, we believe that a simplified cost basis is appropriate We propose, therefore, to require generation, transmission, and distribution licensees to submit the cost data specified in Schedules A, B, and C, respectively, in support of their tariff applications [1] We believe that compiling these data will not impose too heavy an initial burden on licensees, will get them to focus on their costs of service, and will give the Commission the basic information that it will need for the first round of cost-based tariffs We invite licensees, in particular, to comment on the proposed statements of cost

Our proposed rule requires that each licensee designate one person in the its organization to supervise the collection of the cost data, the organization of the data according to the schedules, and the submittal of the schedule to the Commission That individual should have sufficient knowledge of the licensee's organization sufficient so that he or she will know either where relevant information is or how it can be found, and sufficient authority to compel other employees or staff of the licensee to secure the necessary information The proposed rule provides that the person so designated shall sign the cost schedule, and by so signing certifies

[1] Schedules A (for generation licensees), B (for transmission licensees), and C (for distribution licensees) are attached to an part of the Rules and Terms for Tariff Setting

that, to the best of his or her knowledge after appropriate inquiry, the information submitted is true, correct, and complete The Commission proposes that it will contact the person who signs the Schedule to be the person whom it asks for additional information, for clarification, or for other follow-up regarding the cost data submitted by the licensee

N REQUESTS FOR CLARIFICATION AND ADDITIONAL INFORMATION

The Commission will review tariff applications when they are submitted The Commission anticipates that it may have questions or require clarification respecting the cost data The Commission proposes to review the submittals and to request additional information or clarification within 30 days of filing Until the licensee submits the additional information, the Commission will not deem the tariff submittal to be complete

O COMMISSION REVIEW OF THE COST DATA

Once the Commission is satisfied with the adequacy of the cost data submittals, it proposes to test those costs The Commission believes that licensees should be entitled to the opportunity to recover their costs of providing electric service But the Commission also believes that it should, in appropriate circumstances, test the licensees' statements of cost, to determine whether they are appropriate for payment by the consumer

The Commission proposes to test costs according to the "actual, legitimate, and prudent" cost standard That it, the Commission will allow licensees the opportunity to recover only those costs that are actual, legitimate, and prudently incurred The Commission invites comment on this standard

"Actual" costs The consumer is not obligated to pay for imaginary or overstated costs, or any other costs that a licensee does not actually incur Where a licensee records the purchase of equipment on its books as a cost, for example, the Commission will allow the cost only if the equipment was actually purchased at the price recorded For example, a licensee may report that it has purchased a certain number of transformers at a certain price Before allowing the purchase as a cost, however, the Commission may make inquiry as to whether the licensee in fact made the purchase at the recorded price For another example, a licensee may be obligated to pay employees a certain wage, and may record that wage as a cost But the Commission will only allow the wage as a cost to the extent that the licensee actually pays the wage [2]

<u>"Legitimate" costs</u> A legitimate cost is a cost incurred for property or services used or useful in the utility business of the licensee If a transmission or distribution licensee purchases transformers, we may assume almost without question that the licensee's cost for those transformers is a legitimate cost If, however, the licensee purchases chocolates, we may assume almost without question that those chocolates are not used or useful in the licensee's utility business Chocolates do not represent a legitimate cost for which electric consumers are obligated to pay

<u>"Prudently incurred" costs</u> A cost may be actual and legitimate, as for example the cost of actually purchasing a transformer, and yet be imprudent, as when too much is paid for the transformer In that case, the Commission should disallow part of the purchase price, the part above what the utility could have purchased the transformer for The same result would obtain whenever the utility paid more than it needed to for equipment or services, or when the utility purchased more of an item of equipment than it requires

When the Commission is satisfied that the Licensee's statement represents actual, legitimate, and prudently incurred costs, then the Commission will employ a tariff methodology to arrive at the appropriate rate

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[2] The disparity between wage obligations and actual payments of wages presents an issue that the Commission intends to address in individual rate or tariff cases not in this procedural rule The Commission is aware that some if not all, employees of licensees have been paid far less than they are due In addressing the issue, the Commission will have to be sensitive to the respective interests of Licensees, employees, and consumers On one hand, for example, the Commission does not want to require consumers to pay for employee labor costs which Licensees are not actually paying On the other hand, the Commission will not want to set a labor cost component so low that Licensees will have no incentive to pay proper wages As we say, we will take up this and similar issues when deciding individual tariff cases

P THE TARIFF METHODOLOGY

The cost data schedules separate costs into two categories, fixed and variable We will conduct our cost inquiry in those same two categories

Q FIXED COSTS

We propose that in this first round of tariffs, fixed costs will include three components the cost of electric plant in service, expressed as the depreciation cost of that plant, the cost of debt associated with plant in service, and the return, if any, on equity investment, if any, in the Licensee [3]

Basis for depreciation To establish the cost of electric plant in service, we first propose to calculate the value of existing assets There are several options for calculating such a value We might begin, for example, by estimating the replacement cost of the existing plant For generating facilities, the replacement cost would consist of the installed cost of similar capacity, on a per kW basis For transmission, the replacement cost would consist of the current construction cost per mile of line for transmission at different voltages We would then adjust these replacement costs to reflect the age of the assets For generating facilities, for example, we would discount the replacement cost to reflect the useful life actually remaining for the facility [4] Assume, for example, that the current replacement cost of an existing 10 MW hydropower facility is 25,000,000 Lari (10,000 kW x 2,500 Lari), that the plant was constructed in 1967, and has an estimated remaining useful life, in the absence of capital investment for rehabilitation, of 20 years We would calculate the current value of the facility as 10,000,000 Lari (25,000,000 x 2/5) We would then calculate annual depreciation cost, on a straight-line basis for the remaining

[3] Land, or a licensee's interest in land is ordinarily included in rate base as a fixed (original) cost, non-depreciable asset We have not included land as a cost component for licensees, because the ownership of land in Georgia is currently unsettled Should our licensees become the owners of land or interests in land some time in the future, and should there be costs associated with that ownership, then we will at that time consider the tariff implications of such costs

[4] In the case of generating facilities, the adjustment to reflect the remaining useful life of the facility consistent with clause 31 2 of the Electricity Law, which specifies, as to generation Licenses "The duration of each License shall be the expected useful life of the generation facility "

useful life of the facility, as 500,000 Lari (10,000,000/20) That cost represents a real cost of electricity

We note, however, that judgments as to actual cost numbers will in many cases be difficult As stated above, there are several options for determining the value of existing electric plant in service We invite interested parties to identify and describe such options

Debt Electric utilities often finance construction of new plant by borrowing The costs of such borrowing represent legitimate costs For that reason, we have requested licensees to submit data on debt in the cost schedules We do not expect that licensees will have assumed much debt, given the state of the industry at this time

Equity ownership In market economies, shares in electric utilities are often owned by investors In such cases, the regulated utility is permitted the opportunity to earn a return on investment From that return, the utility may earmark some amounts for the payment of dividends to investors, may retain some of the earnings as working capital, and so on Other utilities in market economies are owned by government entities These utilities are generally not permitted to recover a return on investment as a cost, because there are no investors as to whom the utility must earn a return

Our licensees fall somewhere in between They are stock corporations, but the shares in the stock are owned by the government There does not appear to be a cost component for return on equity for our licensees, but we have asked for data on equity ownership, so that we will be properly apprised of the facts

Summary The calculation of each of these cost components will present issues to be decided by the Commission, such as, for example, the appropriate basis for depreciation of electric assets for which original cost numbers are of doubtful accuracy We will consider and decide these issues in individual tariff cases, on the basis of actual cost data, and not now, on a theoretical basis In other words, we do not want at this time to hear argument on how such issues should be decided Rather, for now we are interested in whether commmenters believe that we should include additional categories of fixed cost, and if so, what those categories are and why we should include them

R VARIABLE COSTS

Fixed costs do not vary, as the name implies, from year to year for the asset in question Once a transmission line is constructed and placed in service, we may calculate the annual fixed cost for the line simply by dividing the total cost by the expected useful life of the line Our licensees will also, however, experience annual, variable costs, principally operating and maintenance expenses These must be calculated and allowed as costs

The variable cost component of rates will be based on actual historical costs, with perhaps some adjustment for anticipated contingencies in the licensees' first year of operating under the new tariff We have designed the variable cost portions of the cost data schedules so that licensees may identify such contingencies We request comment on whether we should include additional contingencies, as indeed we request comment on whether we have listed all appropriate areas of cost

S RATES FOR GENERATION LICENSEES

We propose that generation licensees will be paid a capacity charge, to allow them the opportunity to recover their fixed costs, and an energy charge, to give them the opportunity to recover their variable costs We propose to calculate the fixed charge by dividing the generation licensee's total annual fixed costs by its available capacity We will divide that total by twelve, and that amount will be the monthly capacity charge paid to each licensee

The energy charge will be designed to allow generators to recover their variable costs We propose to calculate the energy charge by dividing total variable costs into annual kWh generated The energy charge will, then, be expressed as a charge per kWh, and the generation licensee will be paid on the basis of kWh actually delivered

T RATES FOR TRANSMISSION LICENSEES

We propose a transmission tariff that will, as with generators, allow the transmitter to recover its fixed charges and, separately, its variable charges The total fixed, or demand, charges will be calculated by dividing the system's total annual fixed charges by the total MW of capacity on the system We propose to allocate these charges according to each distribution licensee's coincident peak demand That is, for the month in which the transmission licensee experienced its peak demand, the distributors will pay a demand charge equal to the ratio of their peak demand in that month to the total demand of all distributors on the system times the system's total demand charges We will divide that number by twelve, and the result will be the distributor's monthly demand charge for transmission service We believe that this demand allocation methodology will most closely assign the responsibility for transmission costs to those who are economically responsible for those costs

Distributors would pay a separate energy charge, which would be calculated simply by dividing the transmission licensee's total annual variable costs by the total annual MWh delivered to the transmission licensee by generators The resulting cost/MWh will be multiplied by the MWh actually delivered to each customer, and the resulting energy charge will be paid monthly

U RATES FOR DISTRIBUTION LICENSEES

The most direct method of calculating a distributor's rates might be to divide its total annual cost of operation by the total kWh purchased by the distributor's customer's Each customer would then be charged according to the kWh consumed, on a flat-rate basis This approach yields a uniform price for all customers It fails, however, to account for actual cost of service variations between customers and classes of customers caused, for example, by different load factors For this reason, retail tariffs as a rule generally differentiate customer classes for rate purposes, grouping industrial, commercial, and residential customers with reference to common costs

We propose to calculate retail tariffs based on three components capacity costs, energy costs, and customer costs Capacity costs represent the customer's peak demand on the system Energy costs generally relate to the kWh used by the customer Customer costs are the distributor's cost of operating and maintaining the distribution system that serves the electric consumers We will, however, await the submittal of cost data for different distribution licensees before making further decision on rate design for distributors

V PROCEDURE IN TARIFF CASES

W COMMENCEMENT OF A TARIFF PROCEEDING

Under our proposed rules, a tariff proceeding may be commenced in either of two ways a licensee may request a tariff proceeding, or the Commission may commence a tariff proceeding with respect to any licensee or group of licensees In either case, the licensee or group of licensees shall file the information contained in Schedules A, B, or C Where a licensee requests a tariff, it shall also submit an explanation with appropriate reference to cost data, of why a change in the existing tariff is appropriate No such explanation is required where the Commission itself commences the tariff proceeding, although the licensee may, at its option, file such an explanation

X PROCEDURE FOR SETTING THE TARIFF

Under the proposed rule, the Commission will examine the contents of tariff applications when they are filed Within 30 days, the Commission will either accept the application as complete, or request additional information from the licensee When the Commission requests additional information, the application shall not be deemed complete until the licensee has submitted the additional information, and the Commission has reviewed the information and found it acceptable

When the Commission accepts a tariff application as complete, it will give public notice of the application, summarizing the application's contents The public notice will advise that all interested persons may inspect the application at the Commission's offices, during business hours The public notice will invite comments on the application from interested members of the public, from Ministries of government, and from other licensees, and will specify a date by which comments must be filed Comments may consist of statements of fact, argument, evidence, or any combination of fact, argument, or evidence, at the discretion of the party filing the comments The party filing the comments shall deliver a copy of the comments to the licensee that requested the tariff The licensee may respond to the comments within 15 days

Under the proposed rule, the Commission will make a decision on the tariff application within three months of the date on which the Commission accepts the application as complete The Commission may, if the licensee agrees, extend the date for consideration of the application The Commission may grant the application, deny the application, or approve the application in part The Commission will take all comments filed into consideration in making a decision

If the Commission decides to hold a hearing on a tariff application, it will notify the licensee and any parties that filed comments 10 days in advance of the hearing, so that they will have an opportunity to attend

Y EFFECTIVE DATE OF TARIFFS

Clause 38 of the Electricity Law provides that tariffs shall become effective 150 days after submittal to the Commission, providing that the application conforms to the Commission's rules Under the proposed rule, the 150-day period will begin when the Commission has accepted an application as complete and given public notice, as provided in Rule 3 1 and 3 2 We believe that Parliament meant, in clause 38, that tariffs will become effective in 150 days only if, and to the extent, that the Commission approves the application In other words, if the Commission denies a tariff application, then the licensee's proposed tariff will not take effect If the Commission approves a proposed tariff only in part, then only the approved part will become effective on the 150th day

Z FEES FOR TARIFF APPLICATIONS

Clause 38 of the Electricity Law provides that licensees shall bear the Commission's expenses in tariff cases Proposed Rule 4 implements this requirement by setting a fee of 5% of the annual interim license fee (but not less than 100 GL), to be paid by the licensee within two

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weeks of approval of the tariff The proposed rule makes clear that the tariff fee is a regulatory expense that may be recovered by the licensee in its rates

AA TIMING OF TARIFF FILINGS

The Commission proposes to commence cost-based tariff proceedings for all licensees in time to complete action an the applications by the end of 1998 Because of the number of licensees, we find it appropriate to stagger the proposed filing dates, so that the Commission does not receive all of the tariff applications at one time Accordingly, we propose, and request comment on the proposal, to require tariff applications on or before the following dates

Distribution licensees	April 30
Transmission licensees	May 29
Generation licensees	June 30

BB CONCLUSION

CC

As noted above, the Commission requests comments on all or any part of the proposed tariff rule Comments should be filed not later than February __, 1998

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Appendix L
Cost Data for Generation Licensees

SCHEDULE A

1 0 General information

1 1 Name of licensee

1 2 Location of licensed generating facility

1 3 Name of licensee's manager

1 4 Legal address

1 5 Telephone number(s)

1 6 Bank data

1 6 1 Name of bank

1 6 2 Address of bank

1 6 3 Account number(s)

1 6 4 Account code(s)

1 7 Existing tariff level

1 8 Date of last tariff determination

2 0 FIXED COSTS

2 1 Electric plant in service

2 1 1 Identify your generating facility "Generating facility" is defined as the turbine-generator and all necessary ancillary facilities, including powerhouse, dams and associated civil structures, roads, stacks, fuel storage structures, and other structures, equipment, and components

2 1 2 State the number of units currently in service Exclude units that are not currently in service due to damage or age

2 1 3 State the installed capacity in kW

2 1 4 State the available capacity in kW

2 1 5 State the current replacement cost of the facility per kW of useful capacity Identify your source for this cost statement, and identify any assumptions underlying the cost statement

2 1 6 Estimate the average economic life That is, state the average operating life expectancy for the facility, beginning with the date it was placed in service

2 1 7 State the average level of physical depreciation That is, state in percentage terms the remaining average useful life of the facility

2 1 8 Identify by originally installed kW all generating units not currently in service due to damage or age

2 2 Equity and return on equity

2 2 1 Identify the owners of the generating facility and the form of ownership (for example, joint stock company) If the generating facility is owned by the Government of Georgia, identify the Ministry or other agency of government that owns or administers the shares on behalf of the Government

2 2 2 For each of the last two years, identify by date and amount any payments, in cash or in kind, made by the generating facility to the owners State the character of such payments (for example, dividends)

2 2 3 State whether the generating facility is obligated by contract, by charter, or by other legally binding document to pay dividends or otherwise to compensate the owners of shares in the generating facility If so, identify the document by title and date, and summarize the payment obligation

2 3 Existing Debt

For each item of debt for which the repayment period currently exceeds one year, or for which there is no repayment period

2 3 1 Identify by title and date the documents or documents representing the debt

2 3 2 Identify the lender or other entity to whom the debt is owed

2 3 3 State the principal amount of the debt

2 3 4 State, by beginning and end dates, the repayment period for the debt

2 3 5 State the interest rate on the principal amount of the debt

2 3 6 State the dates (for example, the 1st of each month) on which payments on the debt are due

2 3 7 State the amounts of principal and interest paid on the debt for the most recent 12-month period for which data are available

2 3 8 State the amounts of principal and interest expected to be paid on the debt in 1998 If the amount differs from the amount shown immediately above, explain the difference

2 4 Future debt

If you expect to borrow during the period 1998-2001

2 4 1 Identify by type (bank, government agency, or other institution) the lender from whom you expect to borrow

2 4 2 State the expected principal amount of the debt

2 4 3 State the expected repayment period for the debt

2 4 4 State the expected interest rate on the principal amount of the debt

2 4 5 State the dates (for example, the 1st of each month) on which you expect that payments on the debt will be due

2 4 6 State the expected amounts of payments on the debt

2 5 Capital repair

For purposes of this item, a "capital repair" or "capital maintenance" is defined as any repair or maintenance work that extends the useful life of a component or asset by ten years or more

2 5 1 Identify all capital repair and maintenance expenditures for each of the last two years

2 5 2 State the schedule, if any, for capital repair and maintenance expenditures for 1998

2 6 Capital expansion

2 6 1 State the investment in new generating capacity for each of the last two years, giving the total new capacity in kW installed, and the cost of such new capacity, per kW

2 6 2 State the schedule, if any, for capital investment in new generating facilities for 1998, giving the total new capacity to be installed, and the cost of such new capacity, per kW

3 0 VARIABLE COSTS

3 1 Labor

3 1 1 State the total number of persons employed by your organization during the most recent 12-month period for which data are available

3 1 2 Identify the employees listed above by job classification

3 1 3 For each category of job classification, state the aggregate in wages, salaries, and benefits that you were authorized to pay for the most recent 12-month period for which data are available

3 1 4 For the same 12-month period and for each of the job classifications identified immediately above, state the amount of wages, salaries, and benefits that you actually paid

3 1 5 State the amount of wages, salaries, and benefits that you expect to pay in calendar 1998

3 1 6 Identify, for each of the job classifications identified in your response to item 2 1 2, the gains or losses in numbers of employees that you expect by the end of calendar 1998 Explain the basis for any such gains and losses

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3 2 Fuel costs

For each generating unit, and for each of 1996 and 1997

3 2 1 State the type or types of fuel consumed

3 2 2 State the total weight of mazut or coal (in metric tons) and the total volume of natural gas (in million cubic meters) consumed

3 2 3 State the heat content of mazut or coal (in kcal/kg) and of natural gas (in kcal/thousand cubic meters) consumed

3 2 4 State the average weighted price (per metric ton or million cubic meters) of fuel consumed

3 2 5 For each type of fuel, state the specific fuel consumption in terms of kg of standard fuel/kWh delivered to the busbar ("standard fuel" shall mean 1 kg = 10 million kcal)

3 2 6 If you have performed capital repair (as defined in item 1 5) on a generating unit during 1997, and such repair will increase the unit's efficiency, provide a forecast of specific fuel consumption in 1998

3 3 Taxes

3 3 1 State, by category, each item of taxes paid in calendar 1997, and the taxing authority to whom the taxes were paid

3 3 2 Provide a forecast of taxes to be paid in calendar 1998

3 4 Accounts receivable and accounts not billed

3 4 1 State, for each month of 1997 and by name of customer, amounts billed for the sale of power and energy, but not paid within 120 days of billing

3 4 2 State the aggregate of accounts receivable accrued through January 1, 1996

3 4 3 State the aggregate of accounts receivable accrued through January 1, 1997

3 4 4 State the aggregate of accounts receivable accrued through January 1, 1998

3 4 5 State, for each month of 1997, amounts that could have been billed to customers for deliveries of power and energy, but were not Identify the customer to whom deliveries were made but not billed

3 5 Administrative and general

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3 5 1 State all costs incurred during calendar 1997 for

3 5 2 Rent or upkeep of buildings and other structures

3 5 4 Office equipment and supplies

3 5 5 Insurance

3 5 6 License fees and other regulatory expense

3 5 7 Travel expense

3 5 8 Other administrative and general costs

3 6 <u>Other operation and maintenance costs</u>

Using whatever cost categories the licensee currently uses, list all other costs of operating and maintaining the licensee's electric plant for each of 1996 and 1997

4 0 OTHER INFORMATION

For each of 1996 and 1997, state

4 1 MWh generated by your facility

4 2 MWh used by your facility

4 3 MWh delivered by your facility to the transmission licensee at the bus bar

4 4 Technical losses, if any, in MWh

4 5 Commercial losses, if any, in MWh

4 6 The price per MWh at which you delivered energy to the transmission licensee

4 7 Whether the price was authorized by tariff or contract

4 8 The price per MWh actually paid to you by the transmission licensee

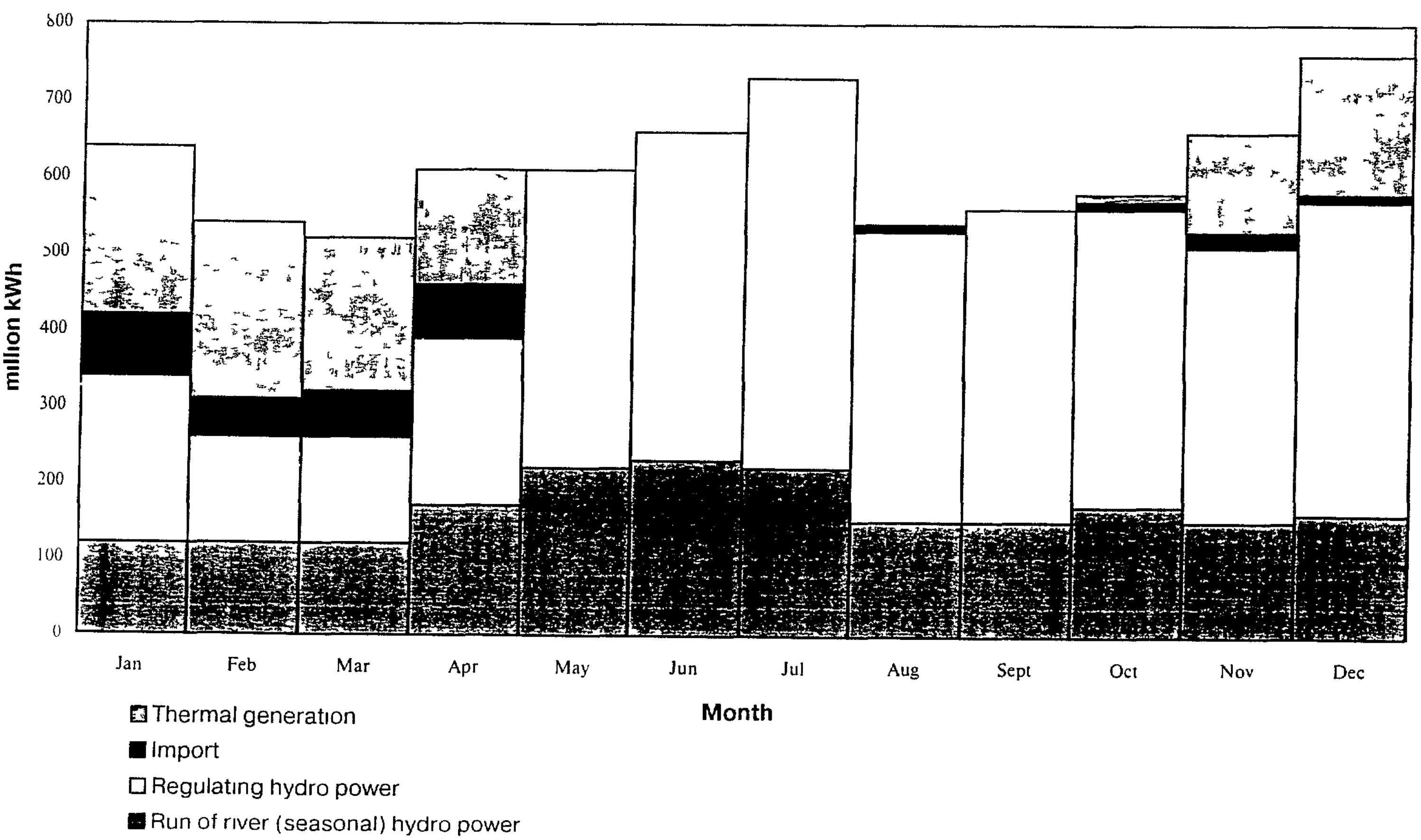
APPENDIX M
MONTHLY GENERATION AND IMPORT AND EXPORT IN 1996

Monthly Generation, Import and Export in 1996 in million kWh

Month	Run of river (seasonal) hydro power	Regulating hydro power	Import	Thermal generation	Total generation plus Import	Export	Net supply to Georgia
Jan	120	220	80	220	640	0	640
Feb	120	140	50	230	540	0	540
Mar	120	140	60	200	520	0	520
Apr	170	220	70	150	610	0	610
May	220	390	0	0	610	10	600
Jun	230	430	0	0	660	50	610
Jul	220	510	0	0	730	90	640
Aug	150	380	10	0	540	0	540
Sept	150	410	0	0	560	0	560
Oct	170	390	10	10	580	0	580
Nov	150	360	20	130	660	0	660
Dec	160	410	10	180	760	0	760

APPENDIX N
MONTHLY TOTAL GENERATION AND IMPORT IN 1996 IN MILION KWH

Monthly Total Generation and Import in 1996 in million kWh



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APPENDIX O
DECREE OF THE PRESIDENT OF GEORGIA #421

Decree #421

July 20, 1998, Tbilisi

On Main Principles of Georgian Wholesale Electricity Market Establishment

According to the "Law about Electricity" in order to establish competitive market in the electricity sector of Georgia

1 Approve attached Main Principles of Georgian Wholesale Electricity Market Establishment and Implementation Schedule for the Main Principles of Georgian Wholesale Electricity Market Establishment

2 In order to develop necessary legal basis for the wholesale market establishment Ministry of Fuel and Energy (T Giorgadze) and Georgian Electricity Regulatory National Commission (E Eristavi) shall prepare Draft Law on making changes in the Electricity Law of Georgia Development of Draft shall be based on the Main Principles of Georgian Wholesale Electricity Market Establishment

3 Georgian National Electricity Regulatory Commission shall approve Georgian Wholesale Electricity Market Rules after making appropriate changes in the Electricity Law of Georgia

E Shevardnadze

22/07/1998

Draft

Approved by the

President of Georgia

Decree #____, "__", 1998

The Main Principles of the Georgian Wholesale Electricity Market

Article I General Provisions

Clause 1 Objectives and Purposes

1 The purpose of this document is to define the framework of the Wholesale Electricity Market in Georgia and to set the strategy for implementation of Market Rules in the electricity sector

2 The objective of Market Rules is to create a competitive and economically efficient wholesale electricity market, to maintain the entire structure of the energy sector, to attract the necessary investment and to develop the relationships among market members, to promote the creation of a stable electric system, attraction of investments, and to facilitate more reliable and fair relationships among the market members

3 Market rules consistent with these principles shall be developed by the temporary executive board of Georgian wholesale electricity market establishment together with the Generation, Transmission, Dispatch and Distribution Licensees Market rules shall be agreed with the Ministry of Fuels and Energy and shall be approved Georgian National Electricity Regulatory Commission (GNERC)

Clause 2 Definitions

Defined Terms for the Georgian Electricity Market shall be as defined in the Electricity Law, and as follows a "Curtailment Block" shall mean the group of customers or feeders grouped together by the dispatch Licensee for the purpose of establishing a Curtailment List

b "Curtailment List" shall mean the list of Curtailment Blocks used by the Dispatch Licensee to ration electrical supply to wholesale Market buyers

c "Curtailment Plan" shall mean the plan developed by the Dispatch Licensee and approved by the Georgian National Regulatory commission to ration the supply of electricity to Wholesale Market Buyers during times of capacity shortages

d "Direct Contract" shall mean any agreement for the purchase and sale of electricity that is between a Generation Licensee or Import Trader Licensee and a Distribution Licensee, Export Trader Licensee, or Direct Consumer

e "Direct Transmission Contract" shall mean any agreement for the sell and purchase of electricity between a Distribution or Import Licensee on the one hand and Distribution or Export Licensee or Direct Consumer on the another

f "Electricity Law" shall mean the Georgian Electricity Law of 1997 and as amended

g "Executive Board" shall mean the board appointed to manage the Wholesale Market

h "Export License" shall mean the license granted by the Georgian National Electricity Regulatory Commission under the Electricity Law to receive electricity at a Delivery Point for the purpose of supply foreign countries

i "Export Licensee" shall mean the natural or legal person who holds a Export Trader License j “Import License” shall mean a License granted by the Georgian National Electricity Regulatory Commission under the Electricity Law to supply electricity generated in the foreign country at a Receiving Point

k “Import Licensee” shall mean an Individual or Legal Person who holds a Import Trader License

l GNERC - Georgian National Electricity Regulatory Commission

m “Licensee” - natural or legal person holding a license granted by the GNERC under the Georgian Electricity Law

n “Market Funds Manager” shall mean the Individual appointed to collect and disburse funds related to the purchase and sale of electrical capacity and energy and transmission capacity and usage in the Wholesale Market

o “Market Rules” shall mean the rules developed by the Executive Board and approved by the Georgian National Electricity Regulatory Commission for the commercial operation of the Wholesale Market including the determination of prices for electrical capacity and energy

p “Settlement Manager” shall mean the Individual appointed to determine the receipts and payments for the purchase and sale of electrical capacity and energy and transmission capacity and usage in the Wholesale Market

q Settlement Period - one calendar year

r “Technical Standard” shall mean the standard developed by dispatch licensee in agreement with the other licensees, that details the technical requirements for the operation of the wholesale market

s “Transmission System” shall mean all the transmission facilities owned or controlled, and/or operated by a Transmission Licensee

t "Wholesale Market Manager” shall mean the Individual appointed to manage the Wholesale Market on a day-to-day basis

u “Wholesale Market Buyers” shall mean all Wholesale Market Members who are Distribution Licensees, Export Trader Licensees or Direct Consumers

v “Wholesale Market Member” shall mean natural or legal Person holding either a Generation License, Distribution License, Export Trader License or Import Trader License or is a Direct Consumer

w “Wholesale Market Seller” shall mean all Wholesale Market Members who hold Generation or Import Trader Licenses

x “Wholesale Market” shall mean the Georgian Electricity Market, such market being for the wholesale purchase and sales of electrical capacity and energy and transmission capacity and usage

Article II

Membership of the Georgian Electricity Market

Clause 3 Members of the Georgian Electricity Market

1 All Individuals or Legal Persons connected to or capable of being connected to the Transmission Grid for the purpose of supplying electricity and who have been issued a Generation License will be required to be a member of the Georgian Electricity Market (Wholesale Market)

2 All Individuals or Legal Persons who receive electricity at a Delivery Point for the purpose of resale and who have been issued a Distribution License will be required to be a member of the Wholesale Market

3 All Individuals or Legal Persons connected to or capable of being connected to a Delivery Point for the purpose of receiving electricity for only their own consumption will be required to be a member of the Wholesale Market

4 All Individuals or Legal Persons who receive electricity at a Delivery Point for the purpose of resale to a Distribution Licensee, Direct Consumer or foreign entity and who have been issued either an Export Trader License or an Import Trader License will be required to be a member of the Wholesale Market

5 Wholesale Market membership will be limited to Georgian Individuals and/or Legal Persons

Article III

Trading Arrangements

Clause 4 Electrical Capacity and Energy

1 Wholesale Market Members will sell and purchase electrical capacity and energy through the Wholesale Market except for that amount of electrical capacity and/or energy that is sold or purchased through a Direct Contract

2 The amount of electrical capacity and/or energy that may be sold or purchased by Licensees through direct contracts will be established by the Georgian National Electricity Regulatory Commission

3 Electrical capacity and/or energy that is purchased either through the Wholesale Market or through a Direct Contract can only be purchased from a Generation Licensee or an Import Trader Licensee

4 Electrical capacity and/or energy that is sold either through the Wholesale Market or through a Direct Contract to other than a Distribution Licensee or a Direct Consumer can only be sold to an Export Trader Licensee

Clause 5 Transmission Capacity and Usage

Wholesale Market Members will purchase transmission capacity and usage through the Wholesale Market except for that amount of transmission capacity and/or usage that is purchased through a Direct Transmission Contract with the Transmission Licensee

Article IV

Terms for the Connection to the Transmission and Distribution System

Clause 6 Connection to the Transmission System

1 Transmission Licensees will connect to their Transmission system any Generator Licensee, Distribution Licensee or Direct Consumer in a manner that will meet their needs, provided that the entity requesting connection is a Wholesale Market Member and meets relevant technical standards

2 Transmission Licensees and Dispatch Licensees shall prepare an investment plan that details new transmission facilities that will be necessary to construct within the next five years and submit that plan to the Georgian National Electricity Regulatory Commission for approval

3 The Transmission Licensee will require the entity requesting connection to pay for the costs of connection and any new transmission facilities specifically required by that connection and submit to the Georgian National Electricity Regulatory Commission for approval

4 Transmission Licensees will have the right to terminate service to any Wholesale Market Member under the Electricity Law following procedures approved by the Georgian National Electricity Regulatory Commission

Clause 7 Connection to the Distribution System

1 Distribution Licensees will connect to their Distribution System any customer that meets relevant technical standards and financial criteria, as determined by the Georgian National Electricity Regulatory Commission

2 Distribution Licensees will require the customer requesting connection to pay for the costs of connection as approved by the Georgian National Regulatory Commission

3 Distribution Licensees will have the right to terminate service to customers under the Electricity Law following procedures approved by the Georgian National Electricity Regulatory Commission

Article V

Dispatch and Scheduling

Clause 8 Obligation of Supply

1 The Dispatch Licensee will be responsible for scheduling and dispatching the power system such that the frequency, voltage and quality of electrical supply meet the requirements specified in the Technical Standards

2 Wholesale Market Members and the Transmission Licensee will be responsible for providing to the Dispatch Licensee capability information and demand estimates in a form and for a time period specified in the Market Rules

3 The Dispatch Licensee will be responsible for preparing, in advance, in accordance with the principle of least cost, a schedule of generating facilities, including imports, that will be dispatched to meet consumer demand, including exports and reserve requirements

4 The Dispatch Licensee will be responsible for balancing the supply and demand on the Transmission system at every instance in time

5 All electricity, both that supplied through the Wholesale Market and that supplied through Direct Contracts will be dispatched by the Dispatch Licensee, in accordance with the principle of least cost

6 The Dispatch Licensee will be responsible for providing to the Settlement Manager the dispatch information as specified in the Market Rules

7 Wholesale Market Members shall follow instructions issued by the Dispatch licensee Instructions of the Dispatcher will be specified in the Market Rules

Article VI

Curtailments and Emergency Periods

Clause 9 Curtailment Plan

1 As long as there is an electrical capacity and energy shortage in Georgia it will be necessary to establish a Curtailment Plan to ration electricity on a regular basis

2 The Dispatch Licensee, in consultation with Wholesale Market Members, will be responsible for developing the details of the Curtailment Plan, following the principles outlined in this section The Curtailment Plan shall be submitted to the Georgian National Electricity Commission for approval

3 The Dispatch Licensee will ration electrical supply to Wholesale Market Buyers in accordance with the Curtailment Plan The Curtailment Plan will only be exercised after any disconnection of Wholesale Market Buyers who are in default of their payment or credit deposit obligations

4 The Dispatch Licensee will define the customers within Georgia who will be covered by the Curtailment Plan, the grouping of customer within a Curtailment Blocks and the maximum demand level of each Curtailment Block

5 The Ministry of Fuels & Energy determines certain customers who shall not be included in the Curtailment Plan as a matter of national security policy

6 At least once a year, the Dispatch Licensee will conduct an auction among the Wholesale Market Buyers for positions on the Curtailment List for that year Wholesale Market Buyers will bid a price for their respective Curtailment Block, or Blocks

7 The highest bid of the electricity buyer will secure the highest position on the Curtailment List and be the last Curtailment Block to lose electrical supply The lowest bid will be in the first position on the Curtailment List and be cut off first

8 In the application of the Curtailment List the Dispatch Licensee will develop procedures for applying curtailments to Curtailment Blocks that have the same bid price using the principle of non-discrimination among Wholesale Market Buyers These procedures will form part of the Curtailment Plan and be approved by the Georgian National Regulatory Commission

9 The Curtailment List will be published by the Dispatch Licensee

10 The moneys collected from the auction will be held in a separate account The Executive Board of the Wholesale Market will prepare a plan for the use of such moneys and will submit that plan to the Georgian National Electricity Regulatory Commission for approval

Clause 10 Emergency Periods

1 The Dispatch Licensee will declare an Emergency Period when due to the unimaginable failure of generating or transmission equipment the Dispatch Licensee will be unable to maintain a balance between supply and demand

2 During an Emergency Period, the Dispatch Licensee shall order the Wholesale Market Sellers and the Transmission Licensee to cancel maintenance outages and shall request the Wholesale Market Sellers to provide emergency supplies

3 During an Emergency Period the Dispatch Licensee will cut off Wholesale Market Buyers in a manner and amount detailed in the Emergency Procedures To the extent practicable, emergency cuts will be shared equally among all Wholesale Market Buyers, except cases indicated in the clause 9, section 5

Article VII Price Formation

Clause 11 Price Formation Methodology

1 Reform of the electricity sector from its current state to an open, competitive wholesale market will require substantial changes to the managerial, technical, financial, information and communication systems in the existing power sector enterprises

2 The price determination methodology will transition through at least three distinct Phases

Phase I will begin when the Georgian National Electricity Regulatory Commission approves the Market Rules and the wholesale market commences

Phase II will come into effect no later than two years after Phase I

Phase III will come into effect after a wholisic analysis of the institutional and technical structure of generation confirms the potential for competition

Clause 12 Phase I

1 Wholesale price determination for Wholesale Market Sellers will follow the regulated cost of service methodology described in the Tariff Document GNERC will approve a capacity amount, a capacity rate and an energy rate for each Wholesale Market Seller

2 Electrical Capacity payment is based on following principles

a Wholesale Market Sellers will receive compensation for capacity within a settlement period Capacity charges will be based on the guaranteed capacity of each facility Generating Units that are limited by fuel, or run of river hydro units, will have a capacity rating that reflects their limited production capability

b During the period of Phase I, the Wholesale Market Manager will monitor the level of guaranteed capacity and notify the Executive Board and the Georgian National Electricity Regulatory Commission if it appears that the guaranteed capacity is exceeding customer demand, including exports, and the reserve requirement The Executive Board reserves the right to request that the Georgian National Regulatory Commission reduce the capacity rates of facilities of Wholesale Market Sellers using the principle of least cost pricing, if excessive guaranteed capacity is continually present c Wholesale Market Buyers will pay a capacity charge within h Settlement Period

d Payment of capacity charges will be pro-rated among all Wholesale Market Buyers based on the ratio of their peak usage for a period and the peak usage of all Wholesale Market Buyers for that same period

e Payment of such capacity charges by a Distribution Licensee will be deemed to fulfill that Distribution Licensee's obligation to provide supply to their retail customers

3 Payment of Electricity Cost is based on following principles

a Wholesale Market Sellers will receive payment for the energy delivered to the Wholesale Market within a Settlement Period at a cost-based energy rate approved by the Georgian National Electricity Regulatory Commission

b Wholesale Market Buyers will pay an average rate for the all energy purchased, including a portion of transmission losses, from the Wholesale Market during a Settlement Period The average rate will be based the average cost of generation for that Settlement Period

4 Electrical capacity and/or energy that is purchased through a Direct Contract will be netted out of Wholesale Market Buyers' invoices and Wholesale Market Sellers' receipts

5 Wholesale Market Buyers will pay for transmission services in accordance with the cost based transmission tariff approved by the Georgian National Electricity Regulatory Commission

6 Wholesale Market Buyers will pay for the cost of dispatch, settlement and market funds services in an amount and manner approved by the Georgian National Electricity Regulatory Commission

Clause 13 Phase II

1 Capacity receipts and payments will be based on the marginal cost of capacity and the calculated requirement for capacity Wholesale Buyers will pay for capacity in the same manner as in Phase I

2 Electrical Energy receipts and payments will be based on the actual cost of energy of the marginal generating facility in each Settlement Period Wholesale Sellers will receive the marginal rate for actual energy delivered to the Wholesale Market Wholesale Buyers will pay the marginal rate for all energy purchased, including a portion of the transmission losses, from the Wholesale Market The marginal rate will be limited during times of energy shortage

3 Wholesale Buyers will pay for transmission services and dispatch, settlement and market funds services in the same manner as in Phase I

Clause14 Phase III

1 Payments for capacity will cease There will be a single Marginal Price for all energy sold and purchased from the Wholesale Market

2 The Marginal Price will fluctuate based on the supply and demand of electrical energy The Marginal Price will not be limited during times of energy shortage and will be allowed to rise to a level that ensures a balance between supply and demand

Article VIII Settlement and Invoicing

Clause 15 Settlement Mechanism

1 The Settlement Manager will determine the amounts of money owed for purchases from and receivable for sales to the Wholesale Market by each Wholesale Market Member

2 The Settlement Manger will be responsible for determining the amount of electrical capacity and/or energy sold and purchased by Wholesale Market Members for a Settlement Period Initially, the Settlement Period will be one calendar month The Settlement Period will be shortened to one hour as soon as appropriate metering and other equipment is installed at Receiving Points and Delivery Points and at the National Dispatch Center

3 The Settlement Manger will be responsible for determining the total amount of transmission losses that occurred during a Settlement Period The Settlement Manager will be responsible for allocating those transmission losses among the Wholesale Market Members in the manner prescribed by the Market Rules

4 Wholesale Market Members will be responsible for notifying the Settlement Manager of the amounts of electrical capacity and/or energy sold or purchased through Direct Contracts

5 Wholesale Market Members will be responsible for notifying the Settlement Manger of the total amount of energy supplied or consumed during a Settlement Period Such information will be based on approved metering equipment at Receiving Points or Delivery Points All metering equipment will be certified and registered with the Settlement Manager

6 The Settlement Manager will be responsible for providing the Market Funds Manager with the Settlement Period information as specified in the Market Rules

Clause 16 Invoicing and Funds Disbursement

1 The Market Funds Manager will receive moneys from Wholesale Market Buyers separately and disburse moneys to Wholesale Market Sellers the Transmission Licensees, and the dispatch Licensee

2 Wholesale Market Buyers will be invoiced and will submit moneys to the Market Funds Manager as prescribed in the Market Rules

3 Wholesale Market Sellers, Transmission Licensees and the Dispatch Licensee will receive moneys from the Market Funds Manager as prescribed in the Market Rules but no sooner than the Market Funds Manager's receipt of moneys from the Wholesale Market Buyers or their credit deposits The Market Funds Manager will not be liable for any payments to the Wholesale Market Sellers, Transmission Licensees or the Dispatch Licensee, if there is no payments received from Wholesale Market Buyers

4 Wholesale Market Members will have the obligation to examine their respective invoices or receipts issued by the Market Funds Manager Any disputes will notified to the Market Funds Manager In all instances of a dispute, the Market Funds Manager will request the Executive Board or its designee to examine the dispute and issue a decision

Clause 17 Events of Payment Default

1 Each Wholesale Market Buyer will be required to establish a credit deposit or letter of credit with the Market Funds Manager as security in the event of default of payment by a Wholesale Market Buyer The amount of the security requirement and the manner in which it may be used by the Market Funds Manager will be prescribed in the Market Rules

2 In the event a Wholesale Market Buyer defaults on a payment or fails to have a credit deposit the Market Funds Manager can request the Executive Board and the Georgian National Regulatory Commission to take appropriate action against the defaulting Wholesale Market Buyer Actions against a Wholesale Buyer may include the loss of their License, assignment of their License to another Individual or Legal Person, and/or disconnection from the transmission system

Article IX Management of Market

Clause 18 Executive Board

1 There will be an Executive Board responsible admission and termination of membership, rule development and rule changes for the Wholesale Market, rule interpretation and billing disputes, assuring compliance with the rules, monitoring the operation of the Wholesale Market and management of the Wholesale Market

2 The Executive Board will initially be composed of tvelve members as follows

Three members to be selected by the Generation Licensees,

Two members to be selected by the Distribution Licensees,

One member to be selected by Direct Consumers,

One member to be selected by the Transmission Licensees,

One member to be selected by the Dispatch Licensees,

One member to be selected by the Ministry of Fuels and Energy,

One member to be selected by the Ministry of Economy, One member to be selected the Ministry of Finance,

Independent Person who will serve as a Wholesale Market Manager

3 Executive Board members will serve for a fixed term as prescribed in the Market Rules The procedures the Licensees follow to select their Executive Board members will be based on licensees proposals and approved by the Georgian National Electricity Regulatory Commission

Clause 19 Wholesale Market Manager

1 The Wholesale Market Manager will be responsible for the day to day management of the Wholesale Market

2 The Wholesale market manager will oversee the services of the Dispatcher, Settlement Manager and Market Funds Manager

3 The Wholesale Market Manager will prepare the budget for dispatch, settlement, market funds and Wholesale Market administration fees and submit the fee schedule to the Georgian National Electricity Regulatory Commission for approval

4 The Wholesale Market Manager will be responsible for convening committees, panels, and working groups, for overseeing the work products and programs of such groups, and reporting to the Executive Board on the work progress of such groups Standing committees or panels for the Wholesale Market, if any, will be specified in the Market rules

Clause 20 Information Disclosure

The success of the wholesale market will depend on the wide dissemination of information to all the Wholesale Market Members and others who are involved in the wholesale market As a general principle, all information regarding purchases, sales, dispatch and transmission of electricity will be made available unless a specific exemption is granted by the Market Rules

Article X Regulatory Oversight

Clause 21 Monitoring of the Wholesale Market

The Georgian National Electricity Regulatory Commission will approve the Wholesale Market Rules, monitor the performance of the Wholesale Market and serve in an oversight role at all times, to ensure that the market matures and moves toward the competitive goals set forth in the Electricity Law

Clause 22 Tariffs for Licenses, Retail Tariffs

The Georgian National Electricity Regulatory Commission will approve generation, transmission, dispatch, distribution and retail tariffs after the establishment of the Wholesale Market

Clause 23 Approval of the Methodology

During all phase of the Wholesale Market for the wholesale tariff, the Georgian National Electricity Regulatory Commission will approve the electricity price determination principles and methodology

Implementation Schedule for the Main Principles of Georgian Wholesale Electricity Market Establishment

Description	Executive	Implementation Term
Prepare changes to the Georgian "Law about Electricity" and other corresponding laws necessary for the Wholesale Market Establishment and submit to the Parliament	Ministry of Fuel and Energy, GNERC, Ministry of Justice	September 15, 1998
Establish temporary Executive Committee of Wholesale electricity Market	Entities and organizations listed in the clause 18 of the Wholesale Market Principles GNERC and Ministry of Fuel and Energy supervise	August 15, 1998
Establish Market Rules Development Committee	Temporary Executive Committee, Ministry of Fuel and Energy and GNERC supervision	August 27, 1998
Assign Wholesale Market Manager for the fixed term	Temporary Executive Board	September 4, 1998
Signing of agreements by the wholesale market manager and Market Funds Manager	Temporary Executive Board	September 18, 1998
Develop detailed draft of Market Rules	Market Rules Committee	November 30, 1998
Develop draft of technical standards for the wholesale electricity market	Sakenergo	November 30, 1998

Issue permanent Licenses	GNERC	December 15, 1998 - August 1, 1999
Approve Market Rules	GNERC	December 20, 1998
Assign Wholesale Electricity Market Executive Committee	Entities and organizations listed in the clause 18 of the Wholesale Market Principles GNERC and Ministry of Fuel and Energy supervision	December 20, 1998
Approve Wholesale Electricity Market technical Standards	GNERC	December 20, 1998
Beginning of the first phase of Wholesale Electricity Market	Wholesale Electricity Market Executive Committee	1999

APPENDIX P
GEORGIAN NATIONAL ELECTRICITY REGULATORY COMMISSION

Decree

No 3 | 1 July, 1998 | Tbilisi

On the Approval of the Electricity Tariff Methodology, Setting Rules and Procedures

On the recent stage of the reform in the power sector the significant role shall play adoption of the number of normative acts, which from the legal stand point shall assure the introduction of the principles of market economy and the honest competition, creation of the attractive basis for investments and etc The most important is to work out and to implement the calculation of the tariff methodology, the setting rules and procedures for all the stages of the electricity generation transmission, dispatch and distribution

The defined (set) tariffs shall cover all the service costs related to all the stages started from the generation until consumption, shall assure the required income of the enterprise and the efficiency of the investments, also the recent economy of the country, its prospective, solvency of the customers and the aspects of social protection shall be taken into consideration

According to the above stated, the article 5 and chapter VI of the Electricity Law of Georgia

1 The Electricity Tariff Methodology, Setting Rules and Procedures shall be approved

Chairman | Elizbar Eristavi

Approved by Georgian National

Electricity Regulatory Commission by
Decree No 3, 1 July 1998

Electricity Tariff Methodology, Setting Rules and Procedures

Chapter I.

GENERAL PROVISIONS

The Aim of the Document

1 The objective of this document is to state the Rules and Methodology for Setting Generation, Dispatch, Transmission and Distribution Tariffs according to the "Georgian Electricity Law "

2 The Tariff Methodology (hereinafter Methodology) takes into account the present organizational, technical, economic and financial situation of the Georgian Electricity Sector The Methodology is instrumental for the first stage of development of a Wholesale Electricity Market, when the tariff methodology will be based on the full cost of service provided by an electricity supplier

Definitions

Terms used in present methodology have the following meaning

a) "Tax" - obligatory payment to the budget or special State Funds paid by taxpayer, having an obligatory, non quid-pro-quo, and gratuitous nature

b) "Transmission Tariff" - price of service provided by the transmission licensee

c) "Assigned debt" – the debt assigned in the period of state ownership of electricity sector

d) "Distribution Tariff" – price of service provided by the distribution licensee to the retail customer

e) "Generation Tariff" - price of electricity sold by generation licensee to any purchaser who will resell or consume electricity in Georgia

f) "Dispatch Tariff" – price of services provided by the dispatch licensee

g) "Electricity Tariffs" - price system, according which the settlement for electricity (capacity) is conducted on each stage of generation, transmission, dispatch and distribution services

h) "Electricity Customer" – legal or natural person, consuming electricity for its own purposes and is not engaged in electricity reselling business

i) "Licensee" - legal or natural person, which holds a license for specific activity during specific period, issued by the Georgian National Electricity Regulatory Commission according the Georgian Law on Electricity

j) "Annual Revenue Requirement of the Licensee" - total amount of revenue, based on projection, during 12 months, required to cover all the expenses related to the service providing and provide a reasonable profit

k) "Profit" - difference between the sales price of the product (energy) (excluding VAT) and the generating price of the product (or service) and the expenses related to its sales

l) "Peak Demand" shall mean the demand by each customer at the point in time when the electricity sector experiences the highest demand for electricity

m) "Privatized Company" enterprise in which less than 50 % of the shares are owned by government n) "License Fee" - a fee which shall be paid by the licensee to the Georgian National Electricity Regulatory Commission, for service related to issuance of the License

o) "Retail Tariffs" - Price of electricity sold by distribution licensees to the electricity consumers

p) "Market Rules" shall mean the rules developed by the Market Rules Committee and approved by the GNERC for the operation of the Wholesale Market

q) "Enterprises" - the legal and natural persons established according the Georgian legislation, which are conducting an entrepreneur activities or are established for this purpose

r) "GNERC" - Georgian National Electricity Regulatory Commission

Chapter II.

Methodological Basis and the Main Principles of Tariff Setting during the Transition Period

Methodological Basis

1 The GNERC's work on methodology for setting energy (capacity) tariffs is based on the Georgian Electricity Law, existing legislation and Decisions and Resolutions of the GNERC

2 In the conditions of market economy the electricity tariffs shall be determined on the basis of commercial and competitive relations between the generator and consumer Besides, the tariffs shall be regulated in accordance with other sources of energy For this purpose several stages of development are required

3 The tariff setting methodology (first stage) is based on cost and competition elements During this stage the electricity suppliers shall be provided with sufficient and reliable payments, financial and economical stabilization of the sector shall be achieved, there shall be the possibility of purchasing and installation of new equipment, and the environment shall be prepared for transition to another, more progressive model

4 During the first stage, the electricity tariff shall be calculated for each supplier and the tariff shall be paid monthly

5 The methodological basis for tariff setting is the full cost principle This includes capacity charge during the year for each customer for peak load and the cost of supplying energy Energy and capacity losses in the process of transmission and distribution shall be fully reflected in tariff

6 The full cost principle shall be enforced by January 1 1999 GNERC is authorized to make a decision on termination of the methodology

Main Principles

1 The basic principles of the tariff methodology are defined by 'Georgian Electricity Law" The objective of the tariff is to increase efficiency in Generation, Transmission, Dispatch, Distribution and Consumption, attract local and foreign investment for rehabilitation and development purposes, and to ensure competition within the Georgian electricity market

2 Tariffs established by the GNERC shall

a) Protect consumers from monopolistic prices, especially in those areas of the sector where competition does not exist,

b) Provide Licensees with an opportunity to recover their costs including market priced fuel costs, operating, current and capital maintenance costs, the principal and interest cost of money borrowed for working capital The Tariff shall provide a reasonable return on invested equity sufficient to attract financing for the rehabilitation and further development of the sector

c) Encourage financial growth of the licensee by increasing efficiency in operations and management practices and minimizing the cost of providing service The minimization of cost of service shall be conducted in the state of satisfied standards of service

d) Encourage economic efficiency within the electricity sector by reflecting short and long run marginal costs, prognosis of price dynamics and consideration of excess and shortage of energy generation

e) Give an opportunity to licensees to cover their economically prudent costs including costs related to obtaining license and license fees

f) Take into account State Policy in regard to discount tariffs, provided that none of the customer categories shall receive a discount tariff subsidized by another customer category

g) Reflect cost differences between different categories of customers

3 Costs of electricity service shall be recovered from each customer category in proportion to the costs of serving that category

4 The Electricity price shall vary in correspondence with different cost of services provided Subsidizing tariff discounts to any customer groups by other customer groups or licensees is unacceptable

5 Tariff shall promote the economical development of the enterprises For these purposes the actual net asset value of the assets used for generation, transmission, dispatch and distribution shall be determined

6 For attraction of the investors and creation of favorable environment for them the tariff shall allow an investor to receive return on assets This return shall be competitive with similar average returns in other neighboring countries for newly privatized energy sector

7 Return on net assets is the weighted sum of the company's return on equity and the interest on the licensee's debt

8 The equity of the Licensee for ratemaking purposes is determined as follows For a government owned Licensee, equity will consist of earnings plus investment For a privatized Licensee, equity will equal the funds invested by the stockholders in privatizing the Licensee, earnings, and additional investments financed by stockholders The return on assets shall be commiserate with the riskiness of the investment Due to the high risk factor return net asset, shall be higher than return on similar bank interest rate

9 The Import/Export tariff shall be set by GNERC, according to the contracts between the interested parties

10 All the decisions, resolutions and other documents of the GNERC, concerning tariff setting are available for public discussions

Chapter III

Determination of the Service Cost Components

Expenses and Payments

1 The service cost of the electric enterprise consists from gross revenue related expenses, taxes and profit The GNERC will allow licensees to recover those costs that are actual, legitimate, and prudently incurred

2 The service cost of the electric enterprises are calculated according the relevant calculating components set by the Ministry of Finance

a) Raw materials and spare parts for repairs, basic and additional supplies,

b) Repair expenses of fixed assets including the services by third parties (repairs and maintenance) Only 5 % of the fixed assets shall be included in the repair expenses, everything above 5 % shall increase the value of fixed assets

c) Operating and maintenance expenses, these expenses will be based on actual historical costs adjusted for reasonably expected changes Reasons for projected increases in operation and maintenance costs should be provided by the Licensee

d) Fuel for technological processes, electricity generation

e) Fuel for heating of the buildings and transportation service of the electric utility,

f) Electricity and heat purchased for the operational needs,

g) Salary fund for the staff and taxes (medical and social insurance, employment fund),

h) Maintenance of machinery

i) Depreciation of the main assets, in accordance with the methodology of the Georgian tax code

j) Other expenses including Leasing fee, Payment of interests on budget credits and loans, expenses on technical safety, expenses related to the replacement of the perishable goods and depreciation of the intangible assets, license fee, tariff setting fees, other expenses (shall not exceed 10 % of total expenses)

k) Taxes, including Common State Taxes, local taxes

3 For the purpose of consideration of the Value Added Taxes (VAT) in the Tariff, the VAT shall be calculated according the existing legislation This rule is applied for the whole tariff system within the electricity sector

Calculation of Return on Assets (Profit)

1 In order to calculate the annual revenue for the Licensees, GNERC shall evaluate rate of return on assets The return on assets is calculated by multiplication of the rate set by GNERC by net asset value, the result shall provide the minimum revenue requirement for the Licensee The rate of return of assets is weighted average of interest on investment debts and return on equity (profit)

2 If, it is impossible (complicated) to calculate the actual replacement cost of the assets, then GNERC, in order to provide a minimum annual revenue requirement, sets the efficiency rate to costs

3 The efficiency rate is determined by GNERC for each Licensee

4 In both cases, Licensee from revenue, after covering the operational expenses and taxes, shall be able to recover principal and reasonable return on equity

5 If the Licensee requests consideration of the funds for capital expenses, it is necessary to evaluate the relevant projects to determine the amount of the capital expenses which will be considered prudent Only after this GNERC makes its decision

Inclusion of Debt

1 For the purpose of improving the financial situation within the electricity sector, repayment of internal debts and debts to different creditors shall be considered in calculation of the tariffs for generation, transmission, dispatch and distribution sub-sectors

2 The terms, rules, and procedures of repayment these debts through the tariffs shall be determined by GNERC The tariff will include a surcharge dedicated to the repayment of these debts

Allowable Losses

1 The GNERC shall establish level of allowable technical and commercial losses at each voltage level of transmission and distribution for which a tariff is calculated

2 The allowance for technical losses will take in account the present condition of the transmission and distribution system, and the potential for technical improvement Transmission and distribution companies will be responsible for meeting these standards Financial losses due to a company's failure to reach obtainable technical performance will not be reflected in the tariff Financial gains due to a company exceeding GNERC targets shall be the property of the company or standards will not be subject to retroactive adjustments

3 The allowance for commercial losses reflects the current reality that collections of past and present sums owed by customers are below acceptable standards Companies have the right under the Electricity Law to disconnect all customers who fail to meet their payment obligations in a reasonable period of time The GNERC shall provide a schedule of reductions of commercial losses for transmission and distribution for which a tariff is calculated Financial losses due to a company's failure to reach established standards will not be included in the tariff Financial gains due to a company exceeding standards shall be the property of the company Standards will not be subject to retroactive adjustments

Incentive Regulation

1 To improve efficiency of the electricity sector the GNERC is eligible to use existing (accepted) methods of incentive regulation

Chapter IV

Calculation of the Electricity Tariffs

Generation Tariffs

1 Tariff for generation licensee may be either one-part or two-part tariff

2 Under Phase I of the market reform the tariff for the generation licensees will be a two part tariff The energy rate will be based on the licensee's average cost of producing energy, and the capacity charge will be based on the licensee's fixed costs Under Phase II, the generation licensees will receive the marginal energy cost and the marginal capacity charge In Phase III the generation licensees will receive a single marginal energy price

3 For calculation of the one-part tariff for the power stations, the annual revenue requirement shall be divided by generated (useful release) electricity

4 The monthly capacity payment per kW equals annual depreciation plus net asset value multiplied by the percent set by GNERC, plus other fixed expenses If fixed cost data is not available, half of the salary fund, taxes on salary fund, operation and maintenance, taxes, divided by guaranteed capacity which can be delivered to the high voltage grid The result is divided by 12 to obtain the monthly capacity rate per kW

5 The energy price per kWh generated at thermal power plant, equals fuel cost plus total variable expenses If fixed cost data is not available, half of the salary fund, taxes on salary fund, operation and maintenance taxes are added to the fuel cost The result is divided by amount of kWh delivered to the high voltage grid The final number is the energy rate of electricity generated at thermal power station

6 The calculation of the energy rate per kWh of electricity generated at hydro plants is similar, but fuel cost is not included in calculation

7 The rate of efficiency to costs defined by GNERC shall allow sufficient annual revenue In this case the requirement of annual revenue is defined as sum of production costs, taxes and profit One part tariff is calculated by dividing the sum by total generated energy (useful release)

Calculation of the Dispatch Tariff

1 The dispatch tariff equals the dispatch licensee's revenue requirement divided by total generation

Calculation of the Transmission Tariff

1 Transmission tariff will be a one-part tariff and it shall be calculated monthly similarly to a capacity charge

2 The losses occurring from electricity transmission shall be reflected in customer tariffs, but the transmission licensee will not receive any financial reimbursement for the losses

3 The annual revenue shall be divided by the peak demand on the transmission system This annual transmission charge shall be divided by 12 to obtain the monthly transmission tariff per KW of peak demand

4 The calculations shall be conducted separately, for two voltage groups for very high voltage network (500kV, 330kV, and 220kV) and high voltage network (110kV and 35kV)

Calculation of the Direct Customers Tariffs

1 After creation of the electricity market the cost of electricity purchased by direct customers will equal the cost of energy and capacity from the wholesale market, plus the dispatch tariff The cost of this electricity will be adjusted to account for allowable transmission losses

2 All direct contracts shall receive GNERC approval to be effective The price of electricity purchased from licensee is equal to average cost of generation Generation companies can contract for credit terms or other concessions of value, but they will not affect price, this will be done in return for provision of guaranteed supplies to the customer Contracts for guaranteed supply will be supported by the dispatcher as long as the customer has not

breached the contract These contracts will be provided a position at the high positions of the curtailment list, as specified in the Market Rules In case of a breach, the generating company shall inform the GNERC, which will inform the dispatcher of the change in customers

Calculation of the Distribution Tariff

The distribution tariff will equal the revenue requirement of the distribution licensee divided by the peak demand of the distribution licensee If data is available by voltage level, the tariff may be divided into medium voltage (6, 10 KV) and low voltage (380, 220 V) tariffs The tariffs will be calculated separately for each voltage level

Calculation of the Retail Tariffs

1 Based on GNERC decision the retail tariff will be either a single or two part tariff The retail tariff can be divided by voltage level

2 To calculate a single retail tariff, the cost of energy purchased by distribution company, capacity charge, and the distribution tariff, will be combined The tariff will be adjusted for allowable losses The tariff will be calculated for kwh energy consumed

3 To calculate a two part tariff for, the energy cost will be adjusted for allowable average losses Similarly to energy charge, the capacity charge will be adjusted for allowable average losses The capacity part of retail tariff equals capacity charge adjusted for allowable average losses, plus distribution tariff Resulting retail tariff will be two part tariff comprising of capacity and energy charge If information concerning peak for a class of customers is unavailable, the peak demand for that class of customers will be divided by the number of customers in that class which will result the customer charge within the class

4 Calculation of separate tariffs for low voltage and medium voltage customers will depend on the available data If data is available on costs, the distribution tariff can be calculated separately for low and medium voltage customers, the tariff will be calculated separately If data is available on losses, tariffs can be adjusted for each voltage Medium voltage customers should pay less in comparison with low voltage consumers to reflect the lower cost of supplying them with distribution services

Chapter V.

Initial Information

Data Base

1 The data required for tariff setting is presented in the appendixes (See tables 1h, 2h, 1d, 2d, 1t, 2t, 1g, 2g, 1c, 2c)

2 Firstly, it is important to make a forecast of the amount of generation For this purpose the demand on electricity shall be defined for the case of full payment, as well as conditions of the main assets and equipment, the generation capacity, and in case of thermal power plants, the possibility of purchasing different types (gas heavy oil) of fuel

In the conditions of market economy the options of fuel purchase are nearly unlimited The task is to determine the most efficient fuel in order to reach least cost

3 The fuel is one of the most important components of the generation cost In order to calculation the optimal rate of the Tariff, it is necessary to determine optimal type of fuel The optimal type of fuel means to choose the fuel with least cost specific fuel consumption (fuel used to generate unit of electric energy)

4 Depreciation is an important production cost component The depreciation rate is based on revalued net assets and it is calculated by established norms

5 The minimal sufficient number of employees and average salaries should be determined In the production cost calculations the actual historical data is used as baseline Total cost of salaries is determined by multiplication of average salaries by projected number of

employees The cost of labor to be included in production costs is determined by adding above the cost social taxes based on current regulation

6 According the existing legislation the presenting party is responsible for full and correct information

Chapter VI

Tariff Setting Rules and Procedures

Tariff Setting Conditions and Principles

1 Tariff setting rules and procedures define the necessary requirements, according which all the tariff applications to GNERC for generation transmission, dispatch and distribution shall be prepared

2 GNERC sets the tariff according the Georgian Law on Electricity, existing legislation, these rules and other legal documents issued by GNERC All the Licensees shall conduct a generation, transmission, dispatch and distribution activities only according the tariffs set by GNERC and all the customers shall conduct their payments according tariffs set by the CNERC

3 For the tariff setting purposes, the licensees and/or industrial customers (hereinafter customers) shall submit to GNERC a tariff application and all the necessary additional information An application shall contain the following information name of the applicant, kind of service, address, ownership form, banking data (name of the bank, address, account number and code), name of the manager, telephone number

The application shall be submitted in the form required by GNERC and also contain a note from the auditors on correctness of the information Technical-economical arguments for requested tariff shall also be provided by additions to annual balance sheet

4 Each tariff application shall be signed by a representative of the licensee The person signing the application shall be responsible for supervising the collection of data for the application The signature shall certify that the information submitted is correct, and complete

Tariff Setting Procedures

1 The GNERC will review submitted tariff application and, within thirty days

a) Accept the application as complete If the GNERC declares the application complete, it will so notify the licensee in writing, giving the date on which the application was accepted

b) Request additional information When the GNERC requests additional information, the application will not be deemed complete until the additional information has been submitted, to the GNERC's satisfaction

c) When the GNERC accepts an application as complete, it will give public notice of the application The public notice will summarize the tariff request, advise that the complete application is on file with the GNERC and may be examined there during regular business hours, and specify a date by which interested parties may submit comments on the application

d) Comments on a tariff application may consist of statements of fact, arguments, or evidence Comments may support or oppose the tariff request The party submitting the comments shall deliver a copy of the comments to the licensee that requested the tariff The licensee may respond to the comments within 15 days

In case of tariff approval by GNERC in whole or in part, the tariff shall become effective after 150 days after submission of tariff application

3 The GNERC shall within 3 (three) months, after an application is received, consider it and make one of the following decisions

a) satisfy a request and set a tariff

b) return an application for more information

4 In special cases the GNERC in agreement with the applicant may postpone a deadline for consideration of the application

5 The GNERC shall give an advance notice of 10 days to an applicant, concerning the day of request consideration, in order to allow an applicant to attend the meeting

6 The GNERC in the process of tariff setting accepts comments and concerns of customers or other interested parties, and is authorized to ask from all the parties all kind of information necessary for tariff setting

7 The Licensee, and other interested parties can file a request with the GNERC an application for a request for reversal or modification of the GNERC's decision on tariff setting The request for reconsideration of the tariff decision must contain a clear statement of

a) Any disputed facts

b) Any law or regulation supporting the applicant's request

8 The GNERC will review the application for reconsideration and, within ten days give public notice of the application The public notice will summarize the application, advise that the application is on file with the GNERC and may be examined there during regular business hours, and specify a date by which interested parties may submit comments on the application Comments will be limited to the disputed facts, laws or regulations

9 Within six days after public notice GNERC shall consider the request of the licensee and make a decision as follows

a) Approve the Reconsideration of Tariff request in whole or in part and reset the tariff,

b) Deny the Reconsideration of Tariff application

c) In specific cases the GNERC shall have a right to prolong duration of application review in agreement with the enterprise

The Tariff Setting Fee

1 Reasonable expenses for tariff setting shall be recovered by an applicant in the tariff The financial burden of the Reconsideration of Tariff shall be borne by the Applicant and included in the tariff only to the extent decided by GNERC

2 If the Tariff change or a request for reconsideration of a tariff decision is initiated by a customer, a fee for tariff setting shall be paid by a customer, according an agreement between a customer and GNERC prior to tariff setting

A fee for tariff setting shall be paid within two weeks after a tariff was set Tariff setting fee shall be calculated according annual license fee, complexity of the transmission and distribution networks, the number of the applications received by GNERC at that moment, time GNERC