WHITE PAPER:
MPACT OF TWO PART MARKET MODEL:
PRELIMINARY ESTIMATE

This White Paper briefly analyzes the potential impact on revenues to the generation sector in Georgia of the Ministry of Energy of Georgia's proposed two-part market model. The analysis shows that the existing tariffs and prices are not even adequate to pay for the least cost dispatch operation of the existing market. A full pure market model would raise prices by about 44%. Using the price caps proposed by the Ministry, the impact would be an increase of less than 30%.

The Present Wholesale Power Market In Georgia

The present structure of the wholesale electricity market of Georgia is a partially centralized market, in which all transactions are made through a single market operator, the GWEM. While originally structured only to manage transactions by others, instead, the GWEM has become much more like the supplier to the market. As there are certain "direct sales" made by generation companies or importers to larger industrial companies or to distributors, the market is not a true "sole supplier" market. None the less in many ways it acts like one. Major supply contacts are made to the GWEM, not to direct buyers. The generation prices which comprise the average price are based on tariffs, which in turn are set by the sector regulator, the GNERC. Actual prices charged by the GWEM however are not the hourly or even monthly transaction clearing prices normal to such markets. Instead, the GWEM price is set by rule as an annual average price, of 2.51 tetri/kwh. Due to market rules, this price is effectively charged even to the direct contract buyers. Thus, despite some diversity in the market transactions, no price competition is allowed to exist. In addition, the underlying tariffs have not been changed since 2001.

But electricity operational decisions are in fact made on moment to moment conditions, as prices and customer demands change. Other systems that use wholesale price averaging recognize at least monthly or seasonally adjusted wholesale (and retail) prices. The effect of this GWEM pricing system is therefore to completely remove all market actions which lead to efficient operations. Because price is set too low in winter, winter demand exceeds winter supply and thus shortages exist in winter. While the Georgian power system also has operational problems especially in winter, this price mechanism assures there will be shortages in winter even if the operational problems did not exist. At the same time, because prices are set too high in summer, excess capacity exists and has no market. On some occasions, inter-seasons barters with neighboring countries are made, but this at best is based on estimated values, not true market conditions, and are ad hoc actions, not a normal part of market operations.

Also as a result of these conditions, the generation companies are badly under funded. They do not have sufficient revenues to do adequate capital maintenance, let alone new investment. This condition would be true even if collection rates were better, since prices are controlled at 2001 levels, and are based on tariff notions that may have little relationship to economic requirements.

Ministry of Energy Proposed Market Structure

To correct these conditions, the Ministry of Energy of Georgia has proposed that the market should operate as it was designed, with the GWEM as the market operator of a bi-later transactions based market. In such market, the distribution companies and other wholesale customer transact directly with generators, importers or other suppliers.

To reach that condition certain transitional issues must be resolved. These include that there is believed to be a potential surplus of hydro generation

capacity, and at the same time, constraining contracts for thermal generation. It is feared that without some form of restraint, that some party might monopolize the hydro capacity (at its presumed low prices) and that no one will be willing to inherent the existing thermal generation capacity contracts.

Therefore, the Ministry has proposed to create three forms of sub-markets, with somewhat different pricing rules. These require classifying generation capability as follows:

- Non-competitive plants are any thermal plants, any imports, and any new construction hydros for their first seven years. The non-competitive plants will be free to contract with any party at any price up to a price cap set by the GNERC. Each market buyer will be required to take annually a minimum percentage of non-competitive power, which percentage also to be set by GNERC;
- Controlling plants are any hydro units large enough to control the market; at present this essentially means the Enguri hydro facility. The price for controlling plants will be set at the market average for all other plants; and
- Competitive plants, which effectively means all other existing hydro capacity. These will be able to compete at any price up to a price cap set by the GNERC.

Analysis of the Proposed Market Structure

To estimate the impact of these structures, CORE has created a simulation model of the operation of the Georgian power market, as a pure hourly bid least price dispatch market of the all of the generation units in, and import capacities to Georgia, and summarizes the results for 12 months In essence, we created a "pure market model" of the Georgian wholesale power system. The model is based on estimated monthly plant availabilities, estimated unit output prices, and uses actual system typical daily load patterns for each month. For purposes of this analysis, we set as the unit prices, the tariffs set by the GNERC for each unit.

We then computed three different scenarios.

First, we looked at what the total costs would be if the rates paid to each generation unit (or import) were based on the tariff rates, taking units in least cost to highest cost order that just clears (just satisfies the hourly market demand) the market in each hour. We have summarized the annual total revenues thus generated to each plant classification at the tariff rates, on the least cost dispatch order.

Second, we estimated a pure market model, o marginal prices, and payments to generators at their hourly marginal price. The model structure also identifies the unit which is the last one dispatched (the highest cost unit dispatched) to just clear the market in each hour. This is the marginal cost (hourly marginal price) for each hour, assuming the tariff-based prices reflect a reasonable estimate of costs. Based on this, we computed the total revenues to each generation unit if it received the marginal price. We then also summarize that data into annual total revenues

Finally, we estimated price caps for the major sub-markets, competitive and non-competitive power. To do this, we classified each plan by the three classes (controlling, competitive, non-competitive). Within the units dispatched at each hour, we then looked at the "sub-market marginal price" for each classification, defined as, the unit price of the highest cost unit of that type, dispatched in each hour. That is, we estimate the price cap method to be to use the simulated the sub-market marginal price. We then computed unit revenues at their relevant sub-market marginal prices.

Results of Market Model Analysis:

The results of this analysis, including VAT, are summarized on an annual basis in the table below. Both the pure market (pure marginal cost) and the sub-market price cap marginal cost models show increases in the total revenues created, and this also, in the average hourly prices for the year. (We use average hourly price here simply to characterize impact; we do not advocate nor endorse average annual cost as a pricing method.). Increased revenue are one intended effect of the change to proper market operations. The present system is badly maintained and badly capitalized since the prices themselves are inadequate.

The estimated impact of tariff based pricing is what would be the result under current pricing methods if the least cost dispatch were the only actually used. This shows an average annual cost of 31.13 Lari/MWH (or, 3.1 tetri/KWH). This price is very much higher than the current GWEM annual average tariff of 2.13 tetri/kwh. This result demonstrates that the current wholesale tariffs and pricing methods are not even adequate to pay for the least cost operation of the Georgian power grid. The under funding of generation is even worse than shown here, since the current tariffs used for this analysis are themselves below the actual present costs. This analysis and result is therefore a major motivation for the Ministry's proposed wholesale market reforms.

The second method used here, marginal cost pricing, estimates the total revenues that would occur from a pure market if the bid pries were the present tariffs. It is an estimate of the true economic costs of operating the Georgian power generation system to meet wholesale level market demands for one year. This form of market pricing would increase the average annual cost to of 44.95 Lari/MWH (or, 4.5 tetri/KWH).. This would increase total annual billing revenues to generators by about 110,477,000 Lari, an increase of about 44%. That is, to meet the real economic costs of the energy consumed in Georgia, would require raising the existing GWEM tariff by an average of 44%. This difference accounts in part for the severe capital shortage of the Georgian power market.

The third method, using sub-market marginal costs as price cps, estimates the maximum impacts if that method is used to set the price cap. The two major sub markets selected are the "competitive" generation units (essentially, existing hydro plants other than Enguri), and "non-competitive" meaning thermal power and imports. The sub-market marginal price for competitive power especially is less than the full market marginal price. Therefore, this method will create lower prices for at least some units, and have a lower impact on consumers. Also, since the sub-market marginal prices are taken as price caps, not as actual prices, it is possible that negotiated prices in real operations may be less than these price caps. This if all prices went to the price caps, the effect would be to increase wholesale prices on average by 29% to of 40.09 Lari/MWH (or, 4.0 tetri/KWH).

Note that this result also implies that if a 32% market share were allocated to the non-competitive market, would produce the same resulting usage of non-competitive plant, as would as a least cost dispatch allocation. Therefore, much of the public discussion of this method has used a 30% allocation as an illustration of what level the GNERC would need to set this allocation percentage to have the desired allocation effect.

COMPARISON OF ESTIMATED ANNUAL GENERATION REVENUES AND AVERAGE ANNUAL COSTS OF THE GEORGIAN WHOLESALE POWER MARKET BASED ON THREE FORMS OF PRICING

	Total	Controlling	Competitive	Non Competitive
Total MWH	7,993,608	2,163,075	3,261,670	2,568,863
Annual Revenues Based on:	Lari:	Lari:	Lari:	Lari:
Tariffs	248,801,442	54,366,733	54,890,290	139,544,419
Pure Marginal Cost	359,278,376	82,758,263	135,672,295	140,847,817
Sub-Market Marginal Cost	320,473,408	54,366,733	125,258,858	140,847,817
Average Revenue Per MWH:				
From Tariffs	31.13	25.13	16.83	54.32
At Pure Marginal Cost	44.95	38.26	41.60	54.83
At Sub-Market Marginal Cost	40.09	25.13	38.40	54.83
Increment in Revenues Over Tariffs				
From Pure Marginal Cost	110,476,933	28,391,531	80,782,005	1,303,397
From Sub-Market Marginal Cost	71,671,966	-	70,368,568	1,303,397
Percent Change in Average Revenue:				
Due To Pure Marginal Cost	44%	52%	147%	1%
Due To Sub-Market Marginal Cost	29%	0%	128%	1%