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GHANA TARIFF REVIEW

ANALYSIS OF REGULATORY/RATE MAKING ISSUES

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SECTION 1 - EXECUTIVE SUMMARY

1.1. Introduction

In June 1999, a consulting team comprised of experts from PricewaterhouseCoopers LLP, Resource Management International (Navigant Consulting) and Bechtel National met with the Public Utilities Regulatory Commission to initiative a Tariff Review project under the sponsorship of the U.S. Agency for International Development. The project is now ongoing with its conclusion expected in September 1999.

The overall objective of the Tariff Review project is to provide knowledgeable assistance to the Public Utilities Regulatory Commission (PURC) with initiating its process and methods for the establishment of electric rates. The experts from the consulting team have undertaken the advisory work of the project by analysis of the proposed methods of the PURC, having meetings with the PURC staff, the VRA and ECG, as well as other stakeholders, and by research into methods used by others internationally.

An initial phase of the consulting team's work was to review and critique the draft "Guidelines" document prepared by the PURC which set forth a description of the proposed rate setting process and methods. The team's observations on that document are contained in its report "Ghana Tariff Review – Comments on Rate Setting Guidelines", issued in early July 1999. A workshop on the draft "Guidelines" with the "stakeholders" was held in late July, at which the Team's comments were presented. These "Guidelines" when finalized in September will set forth the ratemaking process the PURC will pursue, commencing later this year.

The focus of this report is to offer the team's comments and advice on a number of key issues confronting the PURC in establishing its regulatory rate setting system. These "issues" were discussed and identified by the PURC in establishing the work plan for this project. The team's comments and suggestions which follow are its observations and recommendations relating to these "issues" based on the conferences and meetings held in Ghana as well as its extensive familiarity with regulatory/rate setting processes internationally. It is the intent of the team that its comments will be helpful in providing the PURC with additional experience based perspectives on the tasks it is embarking upon, and not to be proscriptive of any particular approach.

1.2. Issues Addressed

The review and analysis undertaken by the consulting team focused on four rate making "issues" categories:

- Adequacy of revenues
- Appropriateness of cost analysis
- Manner of setting prices
- Implementation of the tariff

Contained within each of these categories the PURC raised a number of specific questions, which the team has addressed in this report. The team has conducted its review in close collaboration with the PURC and has offered support for the undertakings of the PURC staff, as well as numerous suggestions for improvements during the course of its onsite work.

It is the consulting team's understanding that the rate making process, the team's support and recommendations and stakeholder comments will be the subject of a further workshop to be held later this year in September. The final version of the "Guidelines" would be presented at that time.

In addition to the questions on ratesetting issues the PURC has expressed a number of questions regarding the impacts on customers and business activities that any new regulatory method of ratesetting will have. They are being addressed by the team in a separate part of its efforts, wherein a spreadsheet forecast is being made of the overall results of the methodology proposed for a five-year period (1999 – 2004) and data collected on effective usage for a number of customer sectors. The results of this forecast and an evaluation of impacts of the prospective rates will be presented by the team in a separate report.

1.3. Approach and Methodology

The consulting team conducted its review and analysis of the "issues" and other topics of concern to the PURC in a multi-phased integrated manner. The first phase was to gain a firm foundation on the regulatory process existing and proposed in Ghana. This was basically accomplished in undertaking its first task, which involved a comprehensive review at the "Guidelines for Rates Changeable for Electricity Services", which was the subject of the team's first report, and a "workshop" session with stakeholders in July 1999.

The second phase of the team's work, which is contained in this report, was to evaluate specific "issues" relating to the methods proposed by the PURC for rate making in contrast to the experiences of regulatory bodies internationally. This effort seeks to help reassure that the proposed methods are workable, and to offer alternatives for consideration, as deemed appropriate. The comments and suggestions produced are based on the team's experience and reviews of the topics in available literature.

The third phase was to establish an understanding of the impacts of the proposed rate setting process. This task involved two tracks of analysis; first to approximately quantify the expected overall rate prices changes going forward based on the proposed ratemaking methods. Secondly, to use these forecasted prices to assess customer impacts based on historical or other available customer sector data. In undertaking this phase the team developed a draft spreadsheet model analysis of the future aggregate price of electricity over a year period, based on the readily available data from VRA, ECG and the PURC. While there exists considerable imprecision, in these future prices estimates, and the observations on customer impacts they are viewed as a useful jumping off points to help frame the extent of issues looking forward.

1.4 SUMMARY OF SIGNIFICANT FINDINGS

The following are the major recommendations the team makes with respect to the issues it has examined in this report;

- The PURC needs to act in concert with the Energy Commission to ensure that system enhancing and expansion programs are identified and provided for in rates on a timely basis.

- The return allowed for ratemaking on revalued assets will need to be in the range of 10-12%, or more to reflect other international opportunities. It may require several rate increases to achieve this.

- The determination of asset values and allowable expenses for ratemaking should be done at least biannually to start.

- A formalized scheme of periodic management audits is not necessary. However some methods of viewing management's effectiveness will be needed to appropriately set "performance" measures.

- The costs included in tariffs for Generation /Power Supply should be based on estimated Long-Run Marginal Costs (LRMC) ,as open markets are impractical for

the forseeable future. Transmission and Distribution costs should be based on revalued assets with efficient operating costs determined.

- The ratemaking needs to include allowances in costs for Working Capital, Construction Work in Progress and Uncollectables.

- The costs of the "non-core" utility businesses of the VRA need to be better identified and excluded where these can be stand-alone enterprises. With some certainty it appears the Cable, Hotel and Farms businesses can be separated at the present time.

- A class cost of service study needs to be undertaken to develop the proper pricing differentials for HT, MT and LT voltage services. Accounting and data collection systems need to be identified and established to support this effort.

- The value for the use of water should be determined from its marginal utility by dispatch simulations. This cost should be reflected in the rates at the earliest possible time; the funds derived therefrom could be "taxed" away from VRA and applied as offsets to needed programs by the government (e.g. "lifeline" rates).

- The potential effectiveness of seasonal and time-of-use pricing is doubtful in the near term. A further study of this would be useful.

- An expansion of the first rate step of the Residential rate to accommodate a higher amount for compound houses is recommended.

SECTION 2 - REVENUE REQUIREMENTS

2.1. Introduction

In this section the consulting team will discuss the questions raised by the PURC on issues regarding the determination of the appropriate total revenues to be received from electric tariffs. There are two primary areas of the PURC's questions, the first concerns issues relating to the amount of revenues required adequately meet costs and to help assure the financial health of the utilities, and the second concerns the projected amounts of revenues and analysis of impacts. The first area is addressed in the following section and it focuses on the specific questions poised by the PURC in its request for assistance. The second area will be addressed in a separate report. It will reflect the team's efforts to quickly analyse and model the past and prospective changes in rates, based on readily available data.

2.2. Specific Revenue Requirements Questions

The following are the consulting team's comments relating to the ratemaking revenue requirement questions posed by the PURC. As indicated in the following responses the team's comments are based both on its experience and of the undertakings it has observed internationally.

The questions follow those set forth in the initial outline of the project.

- **What long-range financial planning process should the PURC implement to allow the regulated entities to build capacity and increase their equity?**

  Overall, the financial planning process of the PURC should attempt to clearly articulate to consumers the expected prices of energy and validate the going forward investment requirements of the utilities. This undertaking should be closely co-ordinated with the Energy Commission (EC).

  To form an outline of future price expectations, the planning process needs to define future resource requirements, by type and time schedule, as accurately as possible, as such expansion will have significant price implications. Identifying these will also allow utilities to make the contractual

commitments necessary to assure timely additions. A defined plan together with a clear regulatory process will go a long way towards helping prospective investors become involved.
As Ghana has a relatively small-sized market place the team believes its not be advisable for the PURC to leave the identification of needs for capacity expansion and system reinvestment solely to competitive or profit motive induced factors, particularly at its outset. Even in much large international energy markets, the team notes that expansion expected to be controlled by open-market forces have gone astray with uncertainly of price-signals and needs, or by lack of timely investor interests. The team believes that the PURC's role should be such that it maintains together with the Energy Commission (EC), an ongoing oversight of the expansion of the country's electric system (generator transmission of distribution). The method to do so, has examples in a number of existing regulatory jurisdictions, such as in Canada where its is normal for the regulatory body to annually approve both of rates and capital expenditures of utilities for the upcoming year. Rates established reflect facilities costs both for those in service and under construction (CWIP). Making the capital plans a part of the periodic ratesetting process provides both a vetting of needs for approvals and improved financial security, as costs of borrowing can be reflected more currently. Such a system can exist in both a competitive and regulated environment, as the PURC deems appropriate.

The planning process in support of the above would likely require the PURC in conjunction with the EC to request annual updates of multi year financial and load forecasts from the utilities; the forecasts of loads would serve to help proscribe the generation sector requirements. The PURC/EC would analyse those forecasts in the rate establishment process, or independently in non-ratesetting hearings; ultimately approving the near term programs, and reflecting these in pricing, when appropriate.

The ability of utilities to have capital requirements "approved" and/or acknowledged by regulatory bodies in advance will significantly increase the ability to arrange competitive supplier interests and finance on a timely basis.

- **Have past increases made utilities more viable?**

From the limited view the team has of the historical financial results of the utilities, and the factors affecting those, it appears that the rate increases in the past have cumulatively failed in financially improve the utilities. The utilities have, and appear to continue to need governmental or financial

subsidies to continue. The factors causing poor results have been many but principal ones appear to be:

(1) continuing depreciation of the cedi to foreign currencies (i.e. $US)
(2) high in country inflation
(3) Significant, unpredicted increases in bulk power supply costs
(4) increasing levels of bill non- payments/late payments
(5) Infrequent and insufficient sized rate increases

The team notes that the problem of bill payments has been, and continues, to be quite significant. This significantly subverts the intended impacts of the increases granted. For example, in 1995 a 40 million cedi increase to the ECG was effectively cut in half as the customer debtor account rose by 20 million. Since 1993 the average collection days for bills has risen from 109 t0 134 (1997), further illustrating this collections problem.

To be effective increases must anticipate these problems, in addition to accurately forecasting the other values, and providing for adjustments when forecasts are in significant error.

- **What is the effect of a high debt/equity ratio?**

  The effects of a high debt ratio in a utility will likely be adverse for several reasons. First, a high debt ratio will transfer the market and financial risks from investors to bondholders, and possibly taxpayers (with government back debt). In the case of bondholders, risk transfers will mean higher debt rates. In the case of government backed securities, taxpayers will bear the risk, without compensation. Secondly a high debt ratio will constrain internally generated funds. With more debt less of the gross income will be available for reinvestment. Such constraint will slow growth of capital and acerbate foreign exchange debt exposure.

Debt ratios for utilities internationally can vary considerably, however we observe norms would approach the following:

Utility Function	Debt ratio
• Generation (w/long term contracts)	75-80%
• Generation (at market)	70-75%
• Transmission/Distribution	55-65%

In the United Kingdom, regional distribution companies were initially privatised with lower levels of debt (higher equity), as these were viewed as risky

investments. Subsequently, as experience was gained and capital markets adjusted, its debt ratios were raised to currently be around 60%.

- **Is an 8% return on revalued assets (for World Bank loan) sufficient and appropriate to use in evaluating electric utility financial health?**

  The World Bank requirement of an 8% return appears to be at the low end of that commonly expected, but perhaps a reasonable target for the initial ratesetting process. We note that even such a target has not been met by either VRA or ECG since the early 90's.

  Internationally, in jurisdictions that set overall prices by including a return on revalued assets we note the following examples:

	Return
AUSTRALIA	10%
CHILE	10%
COLUMBIA	9%
PERU	12%
INDIA	16% (on equity)
SOUTH AFRICA	16 % (Annuity)

  Based on these examples it may be that Ghana's allowed return may need upward adjustment to a 10 – 12% range to be competitive with investor expectations. As return can be substantially effected by local, country conditions, we believe this would best be measured, going forward as the results of corporatization and the new date pricing schemes take effects. We further believe it is reasonable to set differing returns by utility functional sector (generation, transmission, distribution), reflecting both risks and investor expectations in each.

- **Should "bad" investments be included in (utility) revenue requirements, or charged to equity holders?**

  As a general rule "bad" investments are charged to the equity holders to the maximum possible extent. Regulatory history in cost-plus, or incurred cost, jurisdictions such as the United States is replete with issues and cases involving "bad" investments. These have proved very difficult to resolve, as a basic "regulatory compact" was implicit in the undertaking at the outset. This was– that if the investment was reasonable and must be made by the utility, the regulator would assure a fair return. The long history of such regulation in U.S. substantiates that this invokes uneconomic results and disincentives to efficiency; this is therefore being unwound in the U.S. and elsewhere, being

replaced by market/performance based pricing schemes. Going forward most all new regulatory schemes are focused on requiring the equity holders to bear the risks of "bad" investment decisions.

In jurisdictions first embarking on a corporatisation/privatisation of assets, it is common for all "bad" investments to be written-off to the current owner. This occurs either in the transfer of the ratebase for ratesetting purposes, or via the "auction" price paid. Ultimately, in any change of ownership transaction, "bad" investments are recognized, to the detriment of the current holder.

This may not, however, be the cause of overall loss, as it has also become common that "bad", below-market asset values have been netted against above-market valued assets by the regulatory schemes or in the marketplace, thereby providing moderation of financial impacts to the existing owners.

In U.S. jurisdictions where the market value of assets in a purchase, e.g. an accounting of one utility by another has been less than the book value (original cost), it is common for the regulatory agency to adopt the lower value for ratemaking. Thus, the "bad" or below market costs are disallowed and absorbed the investors.

As the "Guidelines" for ratesetting in Ghana establish that the costs for assets to be included will be the "revalued" asset amounts, the team believes that consideration of "bad" investments would be incorporated in that process. The "revaluation" process should consider both the current costs for assets and the relevance of these versus the system's needs and current technology options.

- **What approach should be taken to revalue utility assets, and how should the results be included in the tariff?**

The team believes that the revaluation approach broadly outlined in the PURC's recent "Guidelines" is basically reasonable and appropriate. The proposed process for doing so however still lacks definition. The process definition may best be accomplished over time by the PURC, starting with the existing values now reported and allowing all parties to refine theses and the method in an orderly fashion. The team is uncertain however, that a full revaluation every five years will be frequent enough, and recommends that in its initial start-up of ratesetting, the PURC have a two-year cycle of revaluation. Doing so initially will help the PURC to better define the methods and to determine if an indexation method for long periods of interim years would be reliable.

The team recommends that the asset revaluation approach consider replacement costs taking into account the need for the assets, as well as technological and efficiency improvements that may occur over time, and be available in the country.

Given that rates will be set on a forward -looking basis it is appropriate the Construction Work in Progress be included in the calculation of assets.

The inclusion of the revalued assets costs in the tariff by use of a annuity factor recognizing the appropriate asset lives and adequate rate of return, as outlined in the "Guidelines" draft is similar to regulatory processes in a number of other countries with recently privatized utilities.

- **What would be the role of a management audit in establishing the utility revenue requirement?**

Management audits have risen to prominence in some jurisdictions (especially in US) as a surrogate method to inject economic efficiency/market place competitive factors into an otherwise "cost-plus" environment.

Such undertakings are typically periodic (e.g. every 4 years) or based on specific problems as they arise. Being inherently backward looking, these audits are usually controversial and potentially biased. It is unclear from U.S. experience that they are anything but punitive, politically influenced and ineffective in fostering ongoing, self-sustaining efficiency in operations. Current regulatory approaches are replacing these with Performance Based Regulatory (PBR) schemes, which result in ongoing incentives (not solely penalties) and a reduced need for regulatory oversight, with its attendant controversies.

Without effective PBR schemes, regulation may be forced to continue to relay on "audit" for review purposes. Such are best focused on problems as these arise, where the price setting is a reasonably repetitive process, such as proposed for Ghana. When effectuated, the audit and cost results are reflected in the ongoing revenue requirement determinations.

- **How should need to build working capital be reflected in the tariff?**

Working capital may be usefully defined as "the average amount of capital provided by investors in the company, over and above the investments in plant and other specifically identified rate base items, to bridge the gap between the time that expenditures are required to provide service and the time collections

are received for that service". (Ohio PURC-1992). In most jurisdictions an investment amount for working capital is allowed in the utility rate base (Assets) used to establish rate prices. These funds are treated as any other asset investment in the ratesetting process, and costs for the annual cost of capital associated therewith are included in the revenue requirements on which the tariff is established.

A principal of an allowance for working capital in that it will exclude non-cash expenses, such as depreciation and return on equity and be offset by any sources of cost-free capital such as customer deposits.

Working capital funds are typically allowed for average balances of:

(1) Fuel inventories
(2) Materials and supplies inventories
(3) Prepayments (eg. insurance)
(4) Working cash

The allowances for inventories, materials and prepayments (if any) are Commonly taken as annual average amounts based on the averaging of Monthly values. The allowance for "working cash" has several methods of Determination ranging from detailed studies of the "lead-lag" of revenue/expenses actually experienced, to formula estimates. Formula estimates, typically allow a period of days, such as 45, of average O&M expense to be counted as outstanding, based on "lead-lag" between incurrance of expense, billings and revenue receipts.

The team would recommend that an allowance for working capital be included in the establishment of the "assets" for ratesetting in Ghana. Providing a cost allowance for the investments associated with working capital in the rates will permit the finance costs to be covered and capital to be raised. If capital for these accounts cannot be raised in the normal fashion, an alternative would be to have the rates set higher specifically so as to accumulate the necessary capital through retained funds annually over several years, with such accumulated amounts treated as cost free capital, going forward.

- **Should cost items not related to the core utility business of VRA, such as a township and medical facilities be included in the tariff revenue requirements?**

As a general proposition costs not related to the core utility business should be excluded from tariff revenue requirements, particularly those which could be

stand-alone business operations. Within the restructure of utility companies taking place worldwide to disengage the vertical integration of these , there is increased emphasis on eliminating "non-related" items from all sectors of the core utility businesses. Inclusion of non-related business costs/income into the core utility requirements, produces either subsides or a surplus which will distort real economic electricity prices, discouraging economic customer choice. Thus, as possible, non-related business costs should be removed, or at least isolated, such that they can be viewed openly and charged or credited separately.

Having the above in mind, it is not, however, altogether uncommon for social program or other "non-core" costs to be added to utility requirements and prices. Sales or use taxes relating to utility sales are an obvious example. Equally, it is, not uncommon that "franchise" fees, demand-side program fees and environmental costs become recognised utility tariff costs. These are essentially forms of "social taxes" for the conduct of the business. However these are also not enterprises, which could be readily undertaken by others.

In the case of VRA there are a number of interrelated businesses, which have existed for some time and have historical origins that are not readily resolvable. Based on the team's limited understandings, however several items seem clear. The VRA's operation of a separate enterprise such as Volta Telecommunications Company (VOLTACOM) , Kpong Farms and the Volta Hotel are examples. These are, separate businesses, largely unrelated to the electricity business, which commonly are stand-alone enterprises, capable of being self-supporting. These likely should be separated from the utility business as soon as possible. Less clear, and complicated by historical reasons, but also likely candidates for exclusion would be VRA's operations of its Township activities, Hospitals and Volta Lake Transport. These would appear to be only remotely related to the utility activities (generation, transmission, and distribution). However it is unclear that these would be able to be stand-alone enterprises at the present without subsidy. Therefore it may be prudent for the PURC to allow these to remain in the utility costs for the near term, but to be as separately stated as possible. Far less clear for exclusion would be VRA's involvements with remote worker housing, the environment of Volta Lake, Fisheries, and hydrobiology, all of which may be reasonably related to the utility function, and not businesses readily undertaken by others. In the U.S. costs such as these are many times carried in the revenue requirements of the utilities, and included in the rates.

In the final analysis it could be stated that if the item (business) is a necessary undertaking to allow the conduct of the core utility enterprise and not capable of

being supplied by others, the cost of the item would be includable in the utility revenue requirements and rates. This however, should require substantiation from a project economic basis. Thus, the team believes that the PURC should explicitly require the VRA ,or other utilities ,to support the needs to include any "interrelated" business enterprises in the costs of rates, as well as to demonstrate that appropriate costs are eliminated for any "unrelated" businesses.

As it may be impractical to eliminate "legacy" problems of the non-core VRA activities immediately, the PURC should view the continuation of historical practices, not clearly related, as a short-term allowance, recognizing, with a view towards an increasingly private and competitive nature to the utility business.

It would be inappropriate and diseconomic to raise national/regional social program costs solely from all, or a subset of utility users, or suppliers. In the ratesetting process, the team recommends that the costs and incomes from non-core enterprises be separately identified to the extent possible, even if these are to be included in the rates.

SECTION 3 COST ANALYSIS

3.1. INTRODUCTION

In this section the consulting team discusses the issues and questions raised by the PURC and various stakeholders relative to the determining of costs of providing utility service. The focus of these questions is on the proper determination of such costs for inclusion in the tariff revenue requirements in accord with sound economic and ratemaking principles.

3.2. COST ANALYSIS QUESTIONS

The following are the consulting team's comments on the questions posed. The team's responses are based on its experience and similar undertakings it has observed internationally.

- **What is the economic cost of service and how should that cost be calculated?**

  The team believes "economic cost of service" is best reflected by the LRMC (Long Run Marginal Costs) of the utility. In theory, appropriate application of LRMC to pricing will yield the most economic balance of supply and demand and foster proper economic choice of consumers and suppliers. Ghana's ratemaking process has previously recognised this, but application has lagged. However, the team realizes that recognising LMRC based costs in rates is recognisably difficult to completely achieve in reality, as accurate estimation of LRMC for all components is quite difficult, as is also its application to meet the overall, ongoing financial requirements. Internationally few utilities accomplish this successfully.

  The pricing on marginal cost theory is founded on the replication of an open, efficiency market place for the services. Creating open markets is the basic objective that the current world-wide trend to unbundling of vertically integrated utility services, concurrent with privatisation and creating open access to customer markets is aimed.

  The team believes that the new regulatory pricing regime of the PURC in Ghana could reasonably attempt to approach LRMC pricing in two ways. First, by unbundling utility services (e.g. generation, transmission, distribution, customer etc) to the extent practical, allowing each to be "contestable" where possible and practical. Secondly, by establishing an

open, bid-based, market for the unbundled services, or by factoring prices in relationship to estimated marginal costs.

Based on the team's review of circumstances in Ghana, it believes that the following method of determining marginal costs could be pursued. This largely matches the approach outlined by the PURC in its "Guidelines":

(1) The utility services of generation/power supply, transmission and distribution, be unbundled into separate business entities.
(2) The transmission function be made an "open-access" service under a single, independent entity, available to any qualified user, without prejudice. The revenue requirement be based on efficient, incurred costs, using revalued assets, modified by performance improvement measures.
(3) Generation/power supply services revenue requirements to be based on marginal cost principles, using modelling of the future, until a bid-based power exchange ("Spot market") is reasonably establishable.
(4) Distribution system services revenue requirements to be based on efficient, incurred costs using revalued assets, modified by performance improvement measures.

In the near term, until operating experience is gained, the team believes annual recalculation of costs and performance measures would be most desirable. It notes that efficient incurred costs need to be established by estimating current costs (eg. revalued assets) with recognition of technological improvements, and by factoring year to year changes based on performance.

- **Should costs of service be analysed on a seasonal and/or time-of-use basis?**

Yes, these should be analyzed, but implemented only to the extent that marginal costs vary by season or time of use, <u>and</u> these can be effectively reflected in prices. In Ghana, it is clear that generation costs can vary significantly due to hydro conditions by both season and time-of-use when abnormal hydro water reservoir conditions occur. Therefore these should be analysed on such a basis. It is less clear, however, those transmission and distribution services vary by season or by time-of-use; analysis of ongoing system constraints will be necessary to derive any conclusion.

Examination of monthly (kWh) usage patterns over the year reveals fairly minor (<10%) variations by months for ECG's and NED's sales, as well as

for VRA in total. Seasonal weather or business cycle induced load changes do not appear prelevant. Examination of the daily load patterns of the VRA reveals a very short, pronounced evening peak, but one that is commonly less than 20% of the total load.

Despite some customer comments that time of use pricing would be desirable, both the seasonal and daily usage patterns suggest to the team that economic justification and effective application reasons for seasonal or time-of-use pricing may be limited. The impacts of doing so may just be "windfall" benefits to a few customers with particular, existing usage patterns. Illustrative graphs of the monthly energy sales and a daily load profile are included in Appendix II of this report.

- **How can the value of water be imputed and incorporated into costs?**

To foster economic efficiency, the "value" of water should be included in the costs charged for hydro operation, reflective of its marginal utility, or opportunity costs, and included in rates. The "value" of water in a run-of-the river hydro facility (i.e., one without any significant storage capability) has an opportunity cost equal to the short-run marginal cost of the next dispatchable resources available only at a point in time. The "value" of water in a dam based (storage) hydro facility, however, has an opportunity cost based either on a point in time or on its marginal value in the future, reflective of the timeframe of its reservoir cycles. Further, short-run marginal "values" of water can be zero, where there is a "must run" condition prevailing, such as water flowing over a dam, or ample run-of river capacity to meet all loads. Based on the teams' understanding of Ghana's system, all three types of these value conditions can exist in the country.

To calculate "values" for water it is common that dispatch simulation modelling of the system be undertaken, using varying assumptions on hydrological conditions to develop the relationship of hydro's water" value" based on the next dispatched units (marginal) to meet the demand, over time. Valuing water at an amount just below its rival's short run marginal cost in the merit dispatch would be efficient and appropriate.

Incorporation of water "values" in rates would be automatic in open bid based market wherein all suppliers are paid the marginal bid price. However, as such is not a near-term realistic expectation in Ghana, an estimate based on modelling, implemented with a forward-looking adjustment mechanism, to

account for abnormal conditions when these occur, appears a reasonable alternative.

- **What principles of cost allocation should be used to assign costs to customer classes?**

It is widely accepted that technical cost causation factors should underly the allocation of costs to classes of customers. Such "technical" factors are primarily based on maximum demands (for rate classes, and for individual users in classes), energy use over time, and numbers of consumers served. Secondary factors considered may include risk, rates of growth, income, interuptability and service quality.

Ideally, costs should be categorised and allocated in groupings that will be reflected in the rates, using the appropriate costs causation factor (cost driver). As noted above, there are three widely recognised cost drivers:

Customer -- Costs which vary in accordance with the number of customers served, regardless of consumption.

Energy ---Costs which vary with consumption of energy (kWh)

Demand ---Costs, which are caused by the amount of the customer's demand, both individually and collectively as a part of a group.

In order to minimise cross-subsidisation between customer rate classes, in the cost allocation process it is appropriate to group costs initially according to the cost functions (functionalization). This functional categorisation basically follows the system's technical components. It commonly considers the four major functions Generation/Power Supply, Transmission, Distribution and Administrative/General. It further considers and groups costs within each according to existing or prospective customer usage. For example, within Generation, if an off-peak pricing were to be offered, then Generation function costs would be sub-grouped by "on" and "off" peak functions. Similarly, and commonly, it is appropriate to functionalise costs in subgroups according to voltage levels, such that the rates serving customers at certain voltages can be properly distinguished.

With respect to Ghana's system, based on our brief review, the following types of allocation are suggested:

Function/Service	Allocation Basis
Generation – capacity	Class coincident kW
- energy	Loss adjusted kWh usage (seasonal)
Transmission – capacity	Class coincident kW
- energy	
Distribution (primary voltage)	
- capacity	Class maximum kW
- customer*	No. of customers
Distribution (secondly voltage)	
-capacity	Customer maximum kWh
-customer*	No of customers
Administrative & General	
-labour related**	Labour by function
-investment related	Plant allocation
-other	Special basis, as appropriate

- **What cost allocation methods should apply for Distribution costs?**

With respect to the allocation of Distribution costs, the team suggests that the allocation factors used recognize both the customer contributions at the time of the maximum demand for the class (maximum non-coincident) and the customer's individual maximum demand (customer maximum). For allocation of costs attendant with the "primary" voltage (MT) system, the class maximum non-coincident demand factor if commonly used, as this gives recognition to the facts that this system at this level is designed to meet the aggregate loads of customers. For allocation of the "secondary" (LV) system, use of the customer maximum demands, typically better reflects the more local load sizing conditions used in the design of that portion the system. The "primary" (MT) facilities and costs of the system typically include those associated with the distribution substitutions, primary voltage conductors and poles. The "secondary" (LV) facilities and costs typically include those associated with secondary voltage conductors, poles, line transformers and service lines.

Customer related costs typically include:

a)Investments (asset) costs associated with meters and services, and

b)Operating expenses associated with metering, billing, collections.

** Labour related costs typically include:

a) Supervision and Administration

b)Employee Benefits

c)Payroll Taxes

A further detailed outline for a cost study based on methods outlined by regulators in the U.S. is presented in the next section of this report (Section 3.3).

- **What data are needed to support the cost allocation process, and how can PURC obtain these data?**

Both cost detail and usage detail data are required for a cost allocation study. It is customary for the utility to prepare both the study and the data; the PURC normally requests this data, analyizes the method(s) and reviews the resulting calculations.

Data for costs (expenses and assets) are typically found from the utility financial book details such as specified in the Uniform System of Accounts (USoA), or its equivalent. The required details are typically specified similarly for all utilities within the jurisdiction of the commission. Given the tariff pricing scheme in Ghana, the cost data of particular detailed importance will be that necessary to separately identify the assets and operating costs attendant with primary voltage (MT) and secondary voltage (LT) in the distribution functions. The team recommends that a cost accounting system similar to the uniform system of account (USoA) in use in the United States, and elsewhere, be employed.

Data necessary for allocations based on usage are typically items by rate class such as:

- Class demands at monthly coincident (system) peaks.
- Maximum class demands, by month.
- Monthly kWh use by class.
- Number of customers by class.

Collection of this data is normally undertaken by the utilities on an ongoing basis. In doing so, as most customers are not demand metered, demand (kW) data is commonly developed from load research sampling. Sampling programs require that recording demand meters be installed on representative, sample customers of a class. Data of hourly use collected from these samples and aggregated over monthly and annual periods.

Such sampling programs are usually designed to reflect statistically valid sample populations for each class. An outline of the approach to undertaking load research prepared by the U.S. National Association of Regulatory Utility Commission (NARUC) is provided in Appendix I.

The team notes that the costs attendant with such load research can be high and that not all utilities afford to have such programs. Rather, in the team's experience it is somewhat common for data to be shared by utilities, where similar usage size classes and other factors effecting use (e.g. weather, climate) are deemed to exist. It is also common that load research sampling be done only periodically, as large class characteristics are typically quite slow to change. Such periodic analysis allows the same sample materially instruments to be used for analyses of differing classes.

Absent complete in-country data, the PURC must look to have the utilities organize the existing data for demand metered large users and initiate efforts to obtain data from utilities elsewhere, screening the data sources for similarities in class characteristics and factors effecting use (e.g. economic climate). As the Ghana system's total hours loads are known, as well as the usage of certain large accounts (e.g. VALCO, Mines, etc), accuracy of estimations for the balance can be checked by reference to the known totals.

- **How should the discount rate be calculated?**

The team understands that the "discount" rate is the estimated cost of capital rate will be included in calculating an annuity factor to be applied to the revalued assets to derive the annual cost of these for ratemaking revenue requirements. The annuity factor would thereby incorporate the expression of costs for capital (debt and equity) and depreciation. The team notes that using such a factor is increasingly common in recently formulated regulatory schemes, as regulation moves away from the traditional cost-plus accounting methods, which rely more upon separate amount calculations for costs of capital and depreciation, usually detailing depreciation by asset account.

The team recommends annuity rate utilised should reflect, on as current a basis as possible, its two elements relating to the service function: cost of capital and composite depreciation rate (i.e. asset life). In doing so particular concern should be given to development the appropriate depreciation factor (lives) for the business function (e.g. generation, transmission, distribution). A useful approach would be to derive the factor as a composite by reflective for each asset account the capital amount (revalued) and current life-estimate for that asset.

The team believes that to be effective, the factor for cost for capital will need to reflect investor expectations to assure the utility's continued access to necessary capital. As the investor market place is world-wide it would appear appropriate for the PURC to evaluate its allowances in light of those in other countries, particularly those with similar circumstances of development. It could also be useful for the Commission to consider, as a factor in establishing the proper rate, the relative risk faced by the utility. In a number of established jurisdictions the allowed cost of capital varies by the type of service, function, i.e., generation, transmission and distribution as the market/business risks and norms for capital structure differ.

In the initiation of the regulation process by the PURC it may be useful for the Commission to set a rate of return based only on its judgement, considering the returns earned and/or allowed elsewhere, as well as the impact the return allowance will have on the results. With the present returns of the utilities being very low/negative, a positive return allowance, with the stated objective of increasing it in later filings may be quite sufficient in the short run.

- **What is the appropriate, risk free rate of return to use in determining annual costs?**

In the team's experiences the common measure of "risk free" rate of return has been to have it related to high grade, long term governmental debt securities. The team's experience also suggests that this "risk free" return is not necessarily risk free, depending upon the government's standing (i.e. risk of default), and not the ultimate basis upon which utility rates are property set. Rather its important that the rate of return used reflect the realities of the investors (Equity and Debt) expectations where there are normal business risks, in addition to the underlying country's financial ratings. The "risk-free" rate of return is commonly used in the calculation of the cost of equity in CAPM and risk premium models, wherein the cost of equity is determined with reference to the "risk free" rate of return on an adjusted market risk premium.

In the USA which has both significant national financial integrity and extensive, active investor interests in the privatised utility business, high grade utility debt tends to be 100-200 basis points above the 30 year Government Securities rate, and equity approximately 300-500 basis points over the same.

3.3 Cost Allocation Process Outline

There are three principal components and steps to the utility cost allocation process, followed by a summarization of results, as outlined below:

COST FUNCTIONALIAZATION

In this step the costs from the utility's financial record cost accounts (assets and O&M) are separated into the business functions (Gen., Transm.,Distr.,etc) and by components within to be analyzed, as illustrated in the following outline.

- Generation
  - On-Peak
  - Off Peak
- Transmission/Distribution
  - Network (HT)
  - Ancillary Services
  - Connection
- Customer Service
  - Metering/Billing
  - Collection
  - Marketing
  - Administration - General

COST CLASSIFICATION

In this next step the functionalized costs are categorized, and subdivided as appropriate, into classifications which best describe the cost causality factor, as illustrated below.

- Bulk Power Supply (Gen. + Trans)
  - Capacity related (coincident kW)
  - Energy related
  - Customer related
- Distribution
  - Primary Delivery
  - Capacity related (class max. kW)
  - Secondary delivery
  - Capacity related (customer max. kW)

- Customer

  - Admin. – General
  - Labour related
  - Investment (Asset) related
  - Revenue related
  - Other

COST ALLOCATION

In this third step the functionalized, classified costs are allocated to the tariff classes, and subparts thereof, by use of allocation factors reflecting each class's responsibility for the overall amount of the demand, energy use, or the like in the system. Factors typically used are shown of the functional classified cost categories, below.

Bulk Power Supply (Gen.+Transm.)

- Capacity – By class contribution to system coincident peak(s)
- Energy - - By energy usage, adjusted for losses
- Customer - By number of customers served

Distribution

- Primary Capacity - By sum of class maximum non-coincident demands.
- Secondary Capacity - By sum of individual customer maximum demands
- Customer - By number of customers served

Customer

- Customer - By number of customers served; or by a weighted number of customers served

Administrative – General

- Labour - By allocated labor expense (O+M) totals resulting to functions above
- Asset - By allocated assets totals resulting to functions above
- Revenue - In proportion to revenues received (Proposed)
- Other - Per special analysis of other casual factor(s)

SUMMARY OF RESULTS

In this final step the costing results are summarized by rate (revenue requirement) and expressed on a usage component basis (per unit costs). Typical summary details are illustrated below for a pole class:

Revenue Requirement

	Rate Class "X"	Rate Class "Y"
• O&M Expenses		
Generation Transmission	$X	$Y
Primary System	$X	$Y
Secondary System	$X	$Y
Customer	$X	$Y
Other (if any)	$X	$Y
• Asset Costs (at annual annuity rate)		
Generation	$X	$Y
Transmission	$X	$Y
Primary	$X	$Y
Secondary	$X	$Y
Customer	$X	$Y
Other	$X	$Y
• Revenue Requirements		
Present Revenues	$X	$Y
Excess/Deficiency	$X	$Y
• Per Unit Costs		
Billing – kWh	kWhx	kWhy
- kW	KWx	KWy
- # of customers	#x	#y
• Costs Per Unit:		
Generation per kW	$/kW$_x$	$/kW$_y$
" " kWh	$/kWh$_x$	$/kWh$_y$
Transmission per kW	$/kW$_x$	$/kW$_y$
" " kWh	$/kWh$_x$	$/kWh$_y$
Distribution		
Primary – per kW	$/kW$_x$	$/kW$_y$
KWh	$/kWh$_x$	$/kWh$_y$
Secondary – per kW	$/kW$_x$	$/kW$_y$
KWh	$/kWh$_x$	$/kWh$_y$
Customer – per customer	$/Cust$_x$	$/Cust$_y$
KWh	$/kWh$_x$	$/kWh$_y$
Other – per kWh	$/kWh$_x$	$/kWh$_y$
Total Revenue Requirement	$/kW$_x$	$/kW$_y$

SECTION 4 TARIFF DESIGN

4.1. INTRODUCTION

In this section the consulting team provides its comments on the issues identified by the PURC of concern regarding the development of prices and the tariff structure. The comments provided are based on the team's experience and inputs it has received from the PURC from various stakeholders. The issues reflect concerns on the goals of tariff design, the specific types of pricing to be offered, and to the impacts of expected price changes on consumers. In making its comments the consulting team recognises that tariff design is an ongoing process of balancing competing ideals, ranging from the financial health of the utility to impacts on the consumer and environment. The team can not possibly prescribe the balancing of these ideals, but hopes that its comments provide some insights as to possible paths to follow, based on its knowledge and experiences as to how these issues have been addressed elsewhere.

4.2. TARIFF DESIGN QUESTIONS

The following are the team's comments on the issues identified by the PURC relating to tariff design.

- **How can tariff design best reflect economic costs, while also considering other factors, such as necessary system development, expansion of universal service, minimizing impacts, economic conditions, social responsibilties and simplicity of administration?**

  The team believes that the "best" method to reflect the competing goals of ideals for tariff design is to first establish a benchmark of tariff pricing that is consistent with the financial health of the utility. It is the team's experience that financially strapped utilities can not effectively execute objectives of any type, financial, administrative or social and that is best to identify and quantify the deviations from the most desirable case. The primary goal is therefore for the utility system to achieve financial stability, wherein it is fully meeting its efficient costs with its revenues and consumers are receiving economically efficient price signals for the quality of service provided to them.

  To bring rates to the level that will ensure financial integrity presently in Ghana the team understands that significant increases may be required, and that this may be impossible to impose in any one step. Therefore, the team notes that, the most commonly used approach to deal with such circumstances is to detail a multi-step, multi-period plan for sequential

increases, such that the end result is an improved matching of revenues with costs. Doing so not only moderates impacts, but provides important clarity to all stakeholders of the rate price intentions, providing investors, financiers with a positive outlook, and notifying consumers of impending impacts. The tension between the financial needs of utilities and customer impacts is common, and frequently commonly resolved by moderation in any increase at one time, with subsequent increases announced but spread out (e.g. every 6 months, or 12 months). As a "yardstick" increases in excess of 10% (above inflation) have typically been moderated in the U.S.

The focus of moderation of increases has (most) commonly been with respect to low income, low usage residential consumers. Impacts on other, socially useful consumers (e.g. schools, hospitals, churches) have typically not achieved prominence in most jurisdictions, as many of these inherent have abilities to raise annual budgets. Where consideration has been given to these types of entities, it has sometimes taken the form of giving advanced notice, or delayed effect, of increases, such that the costs are included after annual budgets are approved.

- **Can the tariff best reflect economic costs by use of seasonal, time-of-use, or inverted block price steps?**

The use of seasonal pricing would appear to have its most meaningful applicability in Ghana to reflect the generation/power supply costs that vary significantly due to abnormal hydrological conditions. At the present, there is no indication of seasonal or time-of-day costs varying within the transmission and distribution sectors. As previously noted, the team's brief examination of system usage, over time, indicates fairly uniform conditions, which do not support seasonal/t-o-u pricing.

As the possible variance in generation costs can be significant, but not uniformly predictable, it appears that a rate adjustment mechanism could be a useful method to recognise these impacts. This adjustment could readily be added to all rate classes, and updated periodically, in advance, based on estimated conditions, with a true up at the subsequent change. Such adjustments commonly have a "dead-band" where minor changes are not reflected, and are typically calculated at least quarterly throughout the year, providing currency to the consumer's price-signal.

The presence of possible time-of-day variance in generation costs in Ghana is also noted. However, this will be effected by the "value" placed on water, if any. The tariff may be able to usefully reflect these differences as an option.

However, before doing so, it would be appropriate to attempt to discover which, if any, system loads are amendable to changing their present usage patterns, based on the possible pricing difference and time schedule, and what, if any, worthwhile effects such shifting of use would have on the system. Without significance to the probable load shifts, the hourly pricing scheme may only serve to improve the theoretical equity in pricing between customers, while providing essentially "windfall" benefits to same.

The pricing of "tail-blocks" in blocks to have an upward, more costly per unit price has same limited application, and theoretical support. Principles in support of this practice suggest that its application to this pricing step is to add marginal cost based (i.e. Higher per unit) pricing to more marginal, price sensitive usage. There is also some conceptual, but challenged, social support for this. For example, in some jurisdictions its been argued that low-income users are not exclusively confined to the initial rate block steps, as larger populations tend to exist under a single meter, and that options to energy supply are not as readily affordable. In addition, its been shown that relatively wealthy consumers in many instances have low usage bills, as their occupancy in a single location can vary. Further the choice of alternative energy options (including more efficient appliance) is more affordable, and alternative fuel uses are billed separately.

The monthly energy and typical daily load graphs included in Appendix II give insight into the system's present seasonal and time-of –day usage variations.

- **How should the lifeline rate be implemented? What other subsides should be used in the tariff?**

As a general proposition subsides, "lifeline" or otherwise imposed subsidies should be avoided and eliminated in the tariff to provide overall equity and foster economic efficiency. Subsides which must exist should be identified and limited. While "lifeline" is in place in the current Ghana tariffs, and likely merit continuation in the near-term, there are no apparent reasons for introducing any other subsides, and none are currently recommended.

With respect to "lifeline", the present rate form of a fixed payment for all residential customers for up to 50 kWh/month is now in place. It is simple to understand, but lacks a certain amount of internal equity, as customers using 25 kWh, pay the same as those using 50 kWh. A usage based charge, set so as to accomplish the same result would appear to be more economically

efficient, as cost would constantly increase with the use and be more equitable to consumers actually using less than the lifeline usage block limit.

The team understands that the "lifeline" quantity has been reduced from 100kWh to the present 50kWh amount within recent periods. While this undoubtedly helps to reduce the subsidy, it could work a cross purposes to enhancing financial integrity. Ideally the size of the "lifeline" usage block should be reflective of amounts minimally acceptable to support household basic needs. In the US, and developed countries where lighting, TV, refrigeration and other appliances are considered "essentials" monthly use for "lifeline" varies from 200-400 kWh. In Ghana, circumstances of essential needs use, would suggest a lower amount being essential. The team has seen no data to support any specific amount. Without further study, and reasons to do so, the team believes that the present amount of 50 kWh per month should be retained. However, it suggests that the PURC may wish to have the utilities make a study of the proper size of the lifeline step. Ultimately, the team believes that if the lifeline block is too small/large and/or too unaffordable it will probably be more disruptive than helpful.

With respect to affordability it is interesting to note that, at the U.S. minimum wage, approximately one day's labor would be necessary for the "lifeline" quantity (400 kWh). The circumstances in Ghana seem roughly comparable with the 50 kWh.

Implementation of the "lifeline" rate may be aided by the transfer of monies from the "value" ascribed to water in the generation costs of VRA by a taxing program.

Subsidies to attract industry, reflecting lower prices for a defined period have become increasingly popular in the U.S., and other jurisdictions where unregulated markets are still in the infancy. These pricing arrangements are typically focused on achieving a particular end result – e.g. increases in investment and jobs – and have discounted prices, which typically expire after an initial period (e.g. 4-5 years), sometimes in a stepped ("sunset") fashion. The typical justification for these subsidies range from the increased employment benefits to the territory, to increased utilization of temporary "idle" capacity. It is apparently recognised by a number of regulators that the maintenance of economic health of a utility's service territory is within the scope of the Commission's authority.

- **How should "lifeline" use for compound houses be treated?**

In most jurisdictions, it is increasingly typical for "compound" or multi-family housing to have each unit separately metered. Where this is impractical due to the economics of such separate installations, a block-step rate form would have each step multiplied by the number of dwelling units involved, typically within a limit (e.g.of 4-6 units maximum). Locations with more than the "maximums" are typically of a size justifying separate metering, or worthy of being considered a commercial enterprise, like a hotel. Other alternatives observed to address multi-family use included a separate, or optional, rate with either a larger initial step or a presumption of X% of the total use will fall in the "lifeline" block.

In Ghana the team understands that compound housing can vary considerably in the number of units involved, there appears to be no predictable basis upon which to establish, or verify the number thereof. The team believes therefore that special concern is merited, to both provide fairness, and not to promote unreasonable advantages. While it seems reasonable to extend any "lifeline" allowances to households living in compound housing, the team believes it also appears logical to infer that a lesser lifeline use would be necessary. In such a multi-housing circumstance, it would seem logical to assume that common use facilities are available, lessening each individuals need. This, of course, is an unchecked assumption, which validity could be examined further. However, taking this into account, an approach the team suggests would be to allow entities that would qualify to be considered "compound" houses to elect to be placed on a block multiplier provision of the present residential rate. This provision could allow qualifying locations to be conjunctively billed for up to example 10 units, with a provision of 50% of the present lifeline quantity (50 kWh) per unit. The method for validating the number of "units" claimed will need to be established.

Where the numbers of individual living units in a "compound" housing facility exceed the maximum established it is suggested that the enterprise existing be considered a commercial customer (e.g. a hotel), and treated in the tariff accordingly.

If it is impractical to determine the number of multi-housing "units" with any certainty, an option would be to offer an optimal rate with an expanded first block step, but shortened second block, e.g.:

Normal Rate	Optional Rate
First 50 kWh/mo.-"lifeline" pricing	First 150 kWh/mo.-"lifeline" pricing
Next 250 kWh/mo.	Next 150 kWh/mo.
Next 300 kWh/mo.	Next 300 kWh/mo.
Over 600 kWh/mo.	Over 600 kWh/mo.

- **Should schools and hospitals have special tariffs?**

  It is increasingly uncommon for preferential rates to be established in utility tariffs reflecting anything other than recognisable cost related usage differences. This is particularly true, as the vertically integrated utility enterprises are unbundled, as any created "subsidy" is not as easily redistributed. It is also more fully recognised that such pricing is an unfair economic policy, regardless of the overall social good.

  Schools and hospitals are socially recognizably meritorious enterprises, but these are not alone, as any and most forms of fraternal, religious or governmental enterprises could also readily pursue such claims. Thus, once embarked on recognising any preference in pricing for "socially" good use, the steam of potential applications is extremely long and would be potentially ruinous to the utility enterprise, as it would impose the subsides for social purposes as a "tax" on only the electric consumers. The team therefore does not recommend treating schools, hospitals, government institutions or the like to preferential rates based on any view of social needs/good. As an alternative, however, it may be quite possible to identify that schools, hospitals or other such enterprises have load usage patterns, which should distinguish pricing of costs to them, apart from the norms otherwise reflected in the existing tariff. As this can be done, it is only proper for more cost based pricing to be established in a separate tariff. It is quite conceivable that the electric loads of hospitals are distinctly different than the average commercial user, as they perform duties around the clock, likewise, to the extent schools may have loads differing from the normal pattern, which if significant, could be recognised as well.

- **What is the role of discretion in setting tariffs? What is the relative importance of technical vs. good subjective/social consideration in setting of rates?**

  Ratemaking has been frequently, and perhaps rightly, been called an "art", in that it recognisably must blend the technical factors with economic, social, political and environmental. It is always the role of the regulatory board to

hear the various competing goals or viewpoints of the ratesetting process, and arrive at a reasoned decision. This in itself, is recognition that compromise and discretion are necessary in arriving at proper results. It is the role of the regulatory body to integrate both the cost and non-cost factors and policy considerations in the ratesetting process. Regulatory law and decisions have consistently recognised that a commission is not required to adopt any particular rate design, but to consider the total effects of all reverent issues, and to make necessary pragmatic decisions.

Regulatory reforms underway in the mature jurisdictions, as well as newly instituted schemes, all tend to focus reforms on economic factors, such as by letting investors take greater risks with open-markets and establishing price/revenue caps in place of cost-plus to induce efficiency. These reforms have not however eliminated the important regulatory roles of establishing the public's belief in equity and fairness between customers, as well as promoting necessary social and environment goals, safety, universal service, and the like. Thus, discretion is clearly a continuing element of the ratesetting process.

Unfortunately, it is not possible to form a general rule as to quantify the use of discretion in ratesetting process, managing the subjective and objective factors. It will exist and will vary over time. However, it would appear that the best practices are to fully explore the objective or technical approaches and first obtain those results, and then to vet and resolve the more subjective against this background.

Well recognised sources of regulatory theory has identified that a sound rate/tariff structure will involve consideration of the following:

- Simplicity, understandability and feasibility of administration
- Freedom from controversies
- Effectiveness in yielding the fair revenue requirements
- Stability of revenue results, year to year
- Stability of the rates
- Fairness in allocation of costs
- Avoidance of undue discrimination
- Promotion of efficient use

SECTION 5 IMPLEMENTATION

5.1 INTRODUCTION

In this section the team addresses the specific questions raised by the PURC with respect to the implementation of the new ratesetting methods into the tariffs. Discussions the team has had with the PURC and stakeholders, as well as the comments provided by many parties at the July "workshop", clearly identify the implementation of new pricing as a key concern, particularly in light of expected significant increases it may produce.

This section deals with the general issues identified by the PURC, specific estimates of the rate changes expected are the topic of the team's "Impact Assessment Analysis", which will be detailed later in a separate report.

5.2 IMPLEMENTATION QUESTIONS

- **How will the tariff permit recovery of revenues that are sufficient to develop reliable service in the future?**

  The tariff can primarily help provide for the development of reliable service, by providing financial health to the utility with sufficient cash flows, coverages of debt , and internal generation of investment funds. The conditions existing in Ghana appear to be such that the utilities have insufficient returns to properly acquire and invest new capital to improve and expand the system. Utility operations are notably capital intensive and without reasonable access to the financial markets these will not prosper. The annual reports of both the VRA and the ECG for many years identify the capital constrained nature of the operations; any lack of reliability appears directly traceable to those circumstances. The primary way to permit development of reliable service is to provide the underlying financial integrity.

  The second way the tariff can assist in enhancing the utility systems reliability is by providing the utility management with appropriate financial rewards for improvements. It is increasingly common for performance based ratemaking schemes to include either target values for reliability performance

established in the revenues used for rates, or for the basis of penalties to be imposed.

In the "cost-plus" mode of utility ratemaking there has been limited inducement for utility management to improve results. The Performance-Based Ratemaking (PBR) methods are attempts to change that with rewards. A typical PBR scheme may not significantly reward improved efficiency as much as it would impose penalties for performance below the target values established with the pricing.

A third method the tariffs can address improvement in system reliability is to explicitly include reliability building capital projects as part of the revenue requirements to be met by the rates on a timely basis. As noted elsewhere in this report, in Canada the utilities commonly have annual ratesetting hearings in which the forecasted costs and major capital expenditures for the upcoming year(s) are setforth and ultimately approved. Non-revenue producing capital projects, as reliability may be considered (such as looping of circuits, enhanced control systems, etc.) are of particular interest therein and once approved, timely oversight is assured as the progress reviewed in the next year's filing.

- **How can the tariff provide the right incentives to move the industry towards greater private sector participation?**

  The simple answer is to have tariffs that adequately reflect costs of service and a regulatory process that is well defined and reliable. With such, investors will have the confidence that reasonable returns can be expected. Investors are not adverse to risks of recognised nature; they are adverse to uncontrolable, unpredictable risks. In most jurisdictions the investors are only seeking an opportunity to profit, not a guarantee.

- **How can the high rate of uncollectable accounts be resolved by the tariff structure?**

It is the team's experience that there are essentially four reasons for the occurrence of "uncollectable" accounts:

(1) inability of customer to pay

(2) unwillingness of the customer to pay

(3) theft

(4) slackness of the utility to pursue payments

Each of these causes can be addressed in the ratesetting/tariff pricing process, towards providing improvement of collections. First, as was mentioned in the "workshop" session in July, it is important that "lifeline" quantities be adequately sized and address the recipient's ability to pay. If "lifeline" is set at too small a quantity (kWh) and/or too high a cost, there is a considerable certainty of high uncollectibles following. Determining an adequate amount and having this be priced at a rational cost to low income consumers is the necessary approach. A specific study of this issue would be appropriate, with consideration therein of how the amounts/costs may properly vary by region.

An alternative approach to meet the inability to pay issue would be to not have a "lifeline" quantity exist within the tariff at all, but to have a "universal service" type cost added into the revenue requirements for ratesetting. The proceeds of such a cost collection would be transferred to an appropriate social agency to assist needy customers with electric bill payments. The team understands that this method, even though possibly more desirable, is not realistically possible in Ghana, as the social program network and administration do not reasonably exist.

To address the "unwillingness to pay" issue, the regulatory/tariff rules should clearly express that cut-offs of service will result, with attendant special costs assessed to the customer for reconnection. As an additional inducement the tariffs could also incorporate late payment charges (typically 1.5-3% per month), or a prompt payment discount (typically 2-3%) for payments within 10-15 days of issuance.

To address "theft" of service (and sometimes known as "non-technical" losses), a program of increased inspections is commonly appropriate. One means the team has encountered to do so is for the utility to offer rewards to its meter readers to find and report bypasses or tampered meter locations. Another is to have a special team assigned to and locate investigate the primary areas of occurrences. This team may initiate its analysis by the metering of radial circuits and performing comparisons to the related customer meter sales totals. Based on this group analysis individual area inspections by customer could be established, where the results may be most meaningful.

Where theft or "unwillingness" issues are detected, a possible solution would be to use the cut-off/meter reconnection activity to replace the existing meter with a prepayment type, with the costs of doing so to be charged to the customer. This solution may, however, require a new, flat price rate format.

To address the issue of having the utility paying proper attention to bill collections, the tariff needs to establish goals for the utility to do so, or be penalized. This can most readily be done in the ratesetting by only permitting a reasonable quantity of "uncollectibles" for expense, and exclusion from the "sales" used to set per unit rate prices.

Ultimately, despite efforts to eliminate uncollectables, a residual amount will remain. It is therefore necessary and common for regulatory bodies to allow a level of uncollectable revenue as an expense for ratemaking purposes. Analysis of historical results is the common basis for the expense allowed, however, it is also common that unusual amounts or changes in previous % are challenged by regulators. It is also becoming common that " objective" values are being established for such allowances, based on the "best practices" of others.

APPENDIX I

Development OF LOAD DATA

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
Facsimile No. (202) 898-2213

Price: $25.00

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APPENDIX A

DEVELOPMENT OF LOAD DATA

The allocation of demand-related costs cannot be accomplished without determining, by some means, the demands of the various rate classes and their interrelationships with a utility's total system demand. Since demand-related costs constitute a large portion, if not a majority, of a utility's fixed costs, it is important that the means of determining these demands for a utility yield accurate results. The way a utility often estimates these demands is to conduct periodic research studies of its load.

Load research studies require sampling of customers in those rate or customer classes where it is too expensive to have time-recording meters on all customers. Time-recording meters are installed on the sample of customers selected for each class. The load data collected for the sample of a class is then used to estimate statistically the demands of that class by hour or for designated hours. If the test year of the cost of service study does not coincide with the year (or period) for which the load research was collected, demands for the test period will have to be estimated using load factors estimated from the load study or perhaps by using a model that estimates weather and customer mix changes over time.

This appendix will be divided into four sections consisting of the various phases of a load research study: (1) design of study; (2) collection of data, including installation of meters; (3) estimation of historic loads by class; and (4) use of data, including the projection of class demands for future test years.

Reference will be made throughout this appendix to the term "rate class", which will mean all customers served on a particular rate by that utility. One exception to this is the possible inclusion, for load study purposes, of one or more smaller rates from the standpoint of number of customers or kilowatt-hour use with a larger rate to be considered as a single rate class. Since load studies are essential for the allocation of costs, and it is most meaningful to spread or collect costs by rate classes, the term "rate class" or "class" will be used here accordingly.

Statistical inference is not possible for data collected for judgmental or purposive samples because there is no statistical basis or theory for measuring the precision or reliability of results of judgmental sampling. Since one cannot objectively measure the precision of the demands calculated from judgmental sampling, judgmental sampling should not be used for load research studies. Therefore, this appendix will discuss only probability sampling. In probability sampling, all members of a class have a known, nonzero probability of selection into the sample. The nonzero probability of selection is a consequence of an objective, random procedure of selection.

I. DESIGN OF STUDY

A. Data to be Obtained

The first step in a load study is to determine the load data which must be obtained. The particular methodologies selected for allocating production, transmission and distribution plant will determine the specific load data needed for the cost of service study. In addition to its essential need for cost of service studies, load data is useful in (1) designing rates; (2) evaluating conservation measures; (3) forecasting system peaks; and (4) marketing research studies. Generally, the following data is of interest for cost allocation and design of rates.

1. **Coincident Demand (system peak hours).** This is the demand of a rate class at the time of a specified system peak hour(s).

2. **Class Noncoincident Demand (class peak).** This is the maximum demand of a rate class, regardless of when it occurs.

3. **Customer Noncoincident Maximum Demand (nonratcheted billing demand).** For an individual customer, this is simply the maximum demand during the month for that customer. For the rate class, it is the sum of the individual customer maximum demand regardless of when each customer's maximum demand occurs.

4. **Coincident Factor.** This is the ratio of the coincident demand of a class to either its customer summed noncoincident maximum demands or class noncoincident demand (class peak). It is the percent of class or customer maximum demand used at the time of the system peak. As defined, this can never be greater than unity.

5. **Diversity Factor.** This is the reciprocal of the coincidence factor and is not used as frequently in load study analysis as the coincidence factor. It reflects the extent to which customers or classes do not demand their maximum usage at the same time. As defined, this can never be less than one.

mates would be within one standard error, or .13 of the per customer demand of the entire class, and about 95% of our estimates would be within two standard errors.

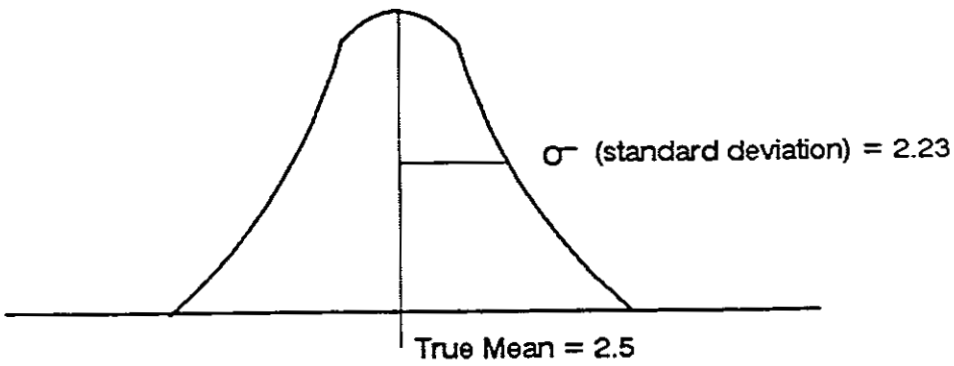
A confidence interval around an estimate is an interval which is designed to contain the class measured demand a specified percentage of the time. For example, an interval of two standard errors on each side of the estimated demand is approximately a 95% confidence interval. This means that if we hypothetically repeated our sampling procedure with new customers each time, about 95% of these calculated intervals around our estimates would enclose the actual class per customer demand. Thus, if our estimated demand were 2.96 KW per residential customer, we would be 95% confident that the interval 2.70 to 3.22 for our residential sample of 275 customers contains the actual class demand per customer. (Confidence interval = $\bar{x} \pm t_p$ (SE ($\bar{x}$); where t_p is a normal deviate which is set at the level of confidence one wants to use. This example is using 95% confidence or $t_p \simeq 2$. Therefore, the confidence interval is $2.96 \pm 2 \times .13$.)

The above confidence interval can be interpreted that our estimates are within $\pm$.26 KW of the true per customer demand for 95% of all possible samples. This .26 KW might be satisfactory precision if the true demand were 2 KW but not if it were 1 KW. In the former case, the relative precision would be $\pm$ 100 x (.26 $\div$ 2) or $\pm$ 13%; in the latter case 100 (.26 $\div$ 1) or $\pm$ 26%. (Relative precision = 100 [2 x SE ($\bar{x}$)/true per customer demand].) Relative precision expresses sampling error relative to the magnitude of the quantity being estimated. Load researchers generally prefer to choose their sample size on a specified relative precision rather than absolute precision because one relative precision level can be used for classes with very different demands. (Load researchers tend to use the terms accuracy or relative accuracy interchangeably when referring to relative precision of the sample design). However, accuracy refers to nonsampling errors in addition to the sampling errors that we have been discussing.) Sampling error can be reduced to zero by measuring all members of a class, but there can still be nonsampling errors such as meter malfunction, damage to meters, lost tapes and errors in tape translations. For example, if all the meters for a 100% time-recorded class measured .5 KW low, the relative precision of the mean demand estimate would be zero percent error but the accuracy would be minus .5. If the true demand were 2, the relative accuracy would be 100 [(1.5-2)/2] or -25%.

Many commissions require samples to be designed to yield estimates of peak hour demands with a relative precision of plus or minus 10% at a 90% confidence level. This is the standard established by the Federal Energy Regulatory Commission in its implementation of the Public Utility Regulatory Policies Act of 1978.

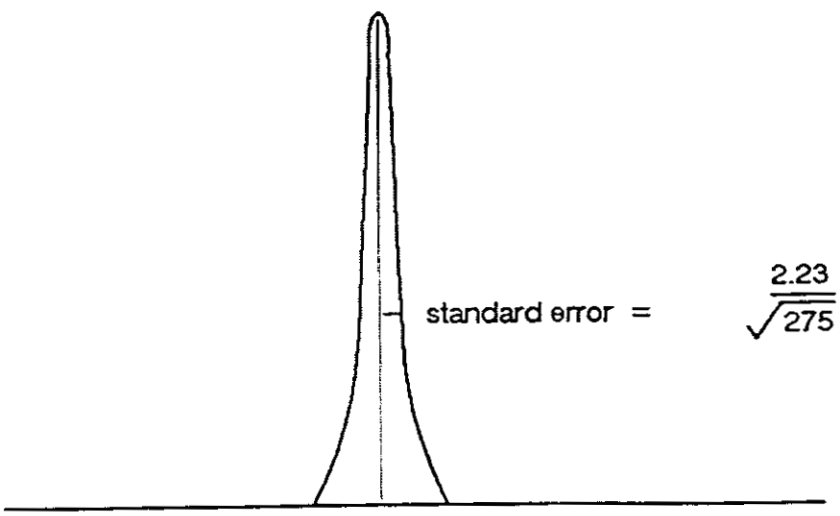
FIGURE A-1

DISTRIBUTION OF CUSTOMER DEMANDS AND AN ESTIMATOR OF CLASS DEMAND



Population of all demand measurements for the hour of interest.

Sample 1	$\bar{x} = 2.3$
Sample 2	$\bar{x} = 2.7$
Sample 3	$\bar{x} = 2.6$
.	.
.	.
.	.
.	.



Sampling distribution of $\bar{x}$'s.

C. Design of Sample

The precision of the demands estimated from a sample depends not only on the sample size, but also on the methods used to select the sample (i.e., the sample design) and the statistical procedure used to estimate demands. The primary aim of sample design is to choose the sample design with the smallest error. Two methods of random or probability sampling are used widely to select samples of rate classes: (1) simple random design; and (2) stratified sampling design.

In simple random sampling n (equal to the desired sample size) random numbers are taken from a table of random numbers with equal probability. These n selected random numbers then identify the customers (or premises) on the frame (numbered listing of all customers in the rate class) whose listing number corresponds to the selected random numbers. These identified customers constitute the selected sample. In simple random sampling each combination of n elements has the same chance of being selected into the sample as every other combination.

In a stratified sampling design the rate class is divided into distinct subgroups, called strata, on the basis of kilowatt-hour use or maximum demand. Within each stratum, a separate sample is selected using either simple random sampling or systematic random sampling,[1] most often the latter method. The primary reason for using stratification is to decrease the sampling error and thus increase the precision of the estimate. The use of stratification thus reduces the sample size needed for a specified level of relative precision. The increase or reduction in sample size for a set level of precision will depend on (1) how well the selected strata breakpoints decrease variability of demand within strata relative to the entire class; and (2) the allocation of the overall sample points to individual strata. Another reason for stratification might be to establish subgroups or domains which are of special interest. For example, customers in a metropolitan area may have special interest due to a proposed conservation of marketing program.

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[1] Systematic Random Sampling is an alternative to simple random sampling where by every Kth unit after a random start is selected. This method of probability sampling is commonly used in selecting customers for load studies due to its adaptability to computer selection from the company's billing records. Furthermore, systematic sampling yields a proportionate sample with respect to any ordering in the population. For example, if customers are listed by geographic region, a systematic sample will yield the same proportion of sample customers from each region. However, if the listing of customers reflects a trend or pattern in kilowatt-hour consumption or billing demand, the listing should be shuffled in some manner or the application of systematic sampling modified. (Statistics textbooks will discuss suggested modifications.) Systematic sampling is often used in conjunction with stratified sampling.

Since stratification will almost always be used in selecting samples of rate classes for load studies, the remainder of this appendix will discuss the development of the design of a stratified sample.

1. Analysis of Old Load Data and Customer Information on the Books and Records

Since the purpose of stratification is to reduce the sampling error by making the strata as homogeneous as possible on the particular hourly demands to be used in the cost study to allocate production plant, load data from past studies should be analyzed by class to identify all possible stratification variables. The variables under consideration for the stratification variable must have measurements in the billing or accounting records for every customer in that class. Correlations should be run for a number of variables, such as average monthly energy for twelve months, winter months, summer months, a combination of winter summer months and billing demand.

2. Selection of Stratification Variable

The correlation analysis will identify those variables which are most highly correlated with the demands to be estimated. The following steps are usually employed in the selection of the stratification variable:

- Choose possible stratification variable (from those variables which have higher correlations and have measurement values for most customers)
- Select tentative strata breakpoints
- Make a rough sample size calculation
- Allocate sample points to strata using Neyman allocation
- Check sample size calculation
- Try another design

In calculating the required sample size for a stratified sample, the standard deviation of the demand to be estimated must be used. Often the standard deviation of the variable of stratification is used erroneously. This will lead to sample size estimates that may be too small by an order of magnitude. Since the standard deviation of these demands for the entire rate class is unknown, an estimate from past load research for the class should be used. If no prior load research data is available, an estimate based on load research from a neighboring or similar utility should be used. After calculating the sample

size for the possible stratification variables, determine which variable(s) requires the smallest number of sample points for at least the summer peak and winter peak hours.

In two-dimensional designs, each customer has two numbers assigned to him for stratification purposes. Two-dimensional designs are recommended for rate classes with a seasonal pattern of energy and when estimated demands in more than one peak hour are important (i.e., peak winter and peak summer demands are both important). This is because the two-dimensional design is most likely to group together premises of similar load pattern rather than premises similar on a single design hour. Thus, the design can be expected to yield more precise estimates for various peak hours for a given sample size or reduce the sample size required for a given level of precision. A commonly used two-dimensional design for residential and small general service samples is winter month(s) consumption (high and low) and summer month(s) consumption (high and low).

A small but growing number of load researchers are advocating the use of model-based sampling plans to determine the best stratification structure and overall sample size. A model-based sampling plan as now advocated generally uses more strata than traditional methods and allocates equal sample points to each strata. While this approach is somewhat more complicated than traditional methods, one researcher has found a five to six percent saving in required sample size over more conventional methods now in use.

3. Selection of Strata Breakpoints

After determining the stratification variable(s), the dimension of the plan, and the number of strata to be employed, a decision must be made on how to "cut" the stratification variable(s) to form strata. In the past, most load researchers have used the Dalenius-Hodges procedure [1951, 1957] to determine costs which in theory minimize the variance (yield the most precise estimate of demands) when used in conjunction with the Neyman procedure for allocating the number of sample points to strata.

There are several problems associated with the use of this procedure. First, it assumes that a mean per unit estimator is employed in the estimation process while almost all load researchers use the ratio estimator. Second, it involves unrealistic assumptions regarding the knowledge and form of the distribution of the demands to be estimated. Third, the procedure does not produce near optimal breakpoints when, as is generally true, the within-strata correlations are made. Thus, the Dalenius-Hodges technique should be considered only a rough guide in developing stratum cuts.

When developing the stratification strategy for a rate class with a small number of very large customers, a considerable reduction in standard error may be achieved by me-

tering all these very large customers. This is because there is no contribution to the sampling error from any stratum that is 100% metered.

4. Determination of Sample Size

The size of sample required to achieve a specified precision with a specified level of confidence for a particular sample design is calculated using statistical formulas. The statistical formulas to calculate that sample size depend on the form of the estimator (i.e., ratio, mean per unit, or regression) since each estimator calculates variances or standard deviations differently. The sample size calculated will not assure that the specified level of accuracy will in fact be attained; it is a suggested guide. As mentioned previously, in calculating the required sample size, the estimate of standard deviation for the demand allocator in the cost of service study (i.e., the variable of interest) must be used, not the standard deviation of the stratification variable. If more than one hour is of interest, the required sample size should be calculated for various hours of interest from different seasons and the largest indicated sample size should be used. Since with many meter and recorder technologies there will often be missing data, the required sample size that has been calculated should be inflated by the usual percentage of missing data so that the expected number of good measurements will approximately equate to the required number of sample measurements. If there is a pattern to meter failure which is related to demand, bias (loss of accuracy) will result.

The question arises as to whether the sample size should also be inflated to account for customer refusals and sites where a load research meter cannot be installed. It is extremely important to develop field procedures which will keep non-response as small as possible because every non-response is a contributor to bias. There are generally two approaches to selecting alternate sample units for customers who refuse or for whom the meter cannot be installed. The first approach is to increase the calculated sample size to compensate for the expected loss of prime sample points and the second is to use a model to select alternates for each prime. The first method only compensates for the loss of precision due to a reduced sample size but does not address the bias caused by failing to measure certain types of customers. In the latter approach, a list of candidates located on the same or adjoining meter reader routes and having similar usage patterns is sometimes developed for each customer that cannot be used. From the list of suitable candidates for each sample prime customer lost, an alternate is selected randomly. This approach does not, however, totally eliminate the bias caused by non-response.

In stratified designs the sample points are generally allocated to strata where most of the variability exists. This method of allocation (sometimes called optimal allocation) is used to increase the precision of the sample or minimize the cost for a fixed level of precision. Generally, load researchers employ a form of optimal allocation called Ney-

man allocation, which maximizes the precision of the sample. A sample allocated in proportion to the number of customers is essentially equal to a simple random sample. The preferred minimum number of observations per stratum is approximately thirty so that the normal distribution assumption involved in the statistical estimation procedure can be expected to be met approximately. If domain analysis will be done with the strata, the minimum sample size per stratum should be increased.

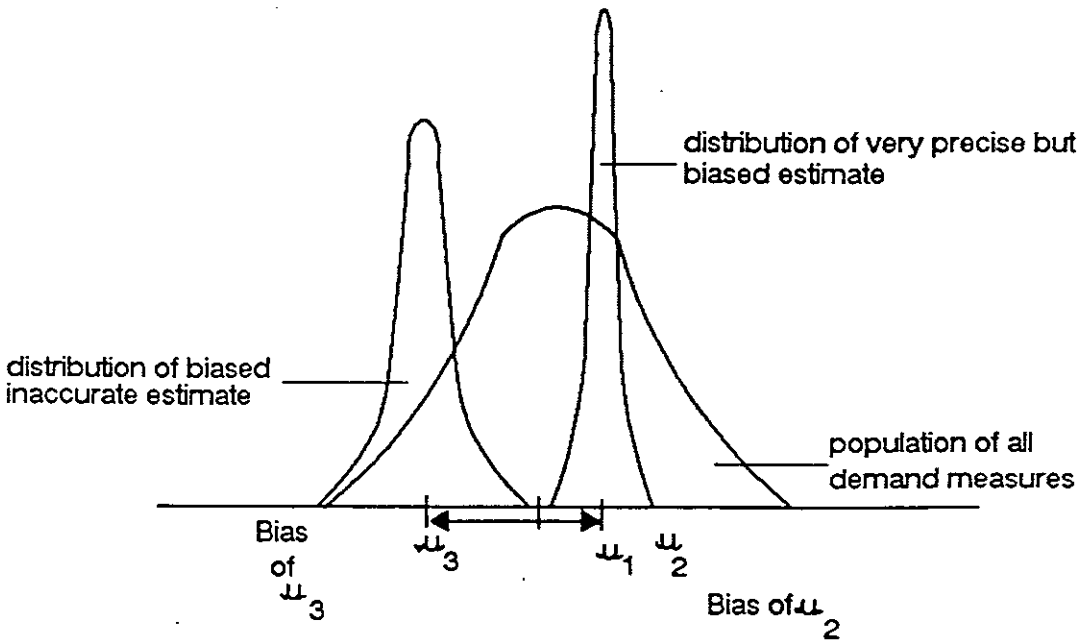
D. Form of Estimator

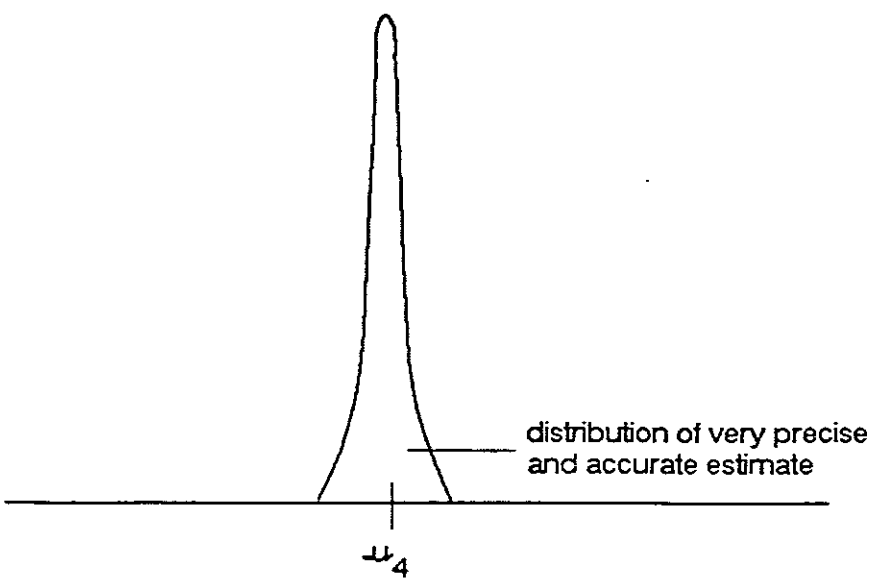
Prior to 1979, the mean per unit technique was used almost exclusively to estimate class demands from sample results. Since 1979 sampling statisticians familiar with the characteristics of load data and the problems of measuring it have developed applications of statistical theory to the estimation of demands at single hours and a combination of a number of hours. Due to the increased concern about the quality of load data collected through studies and the concern of reducing sampling cost, these developments were disseminated quite widely and many utilities started using the ratio and regression estimators. Recently, much research has been done demonstrating that the ratio estimator is better than the mean per unit estimator and many companies have changed to the ratio statistic.

Ratio and regression estimation use auxiliary data on the billing records for sample customers and the entire rate class to increase the precision of the estimate. When the auxiliary data is billed KWH, the estimation process resembles an application of estimating the load factor rather than the demand itself. In general, the higher the correlation between the auxiliary variable and the demand to be estimated, the greater the increase in precision. Ratio expansion uses energy in the statistical expansion from sample to rate class while mean per unit estimation employs number of customers. While the ratio estimator is technically biased, the degree of bias is extremely small for samples of even moderate size. (In statistical theory, bias refers to the difference between the expected value of the estimate and the true value being estimated.) The form of statistical estimation does not have to be the same in all rate classes. Figure A-2 is a comparison of the distribution of the population demand measures and the distributions of various estimators and shows the bias of these various estimators.

FIGURE A-2

DISTRIBUTION OF CUSTOMER DEMANDS AND OF THREE ESTIMATORS OF CLASS DEMAND





μ_1 = mean of the population of demand measures

μ_2 = mean of precise but biased estimator of μ_1

μ_3 = mean of biased and imprecise estimator of μ_1

μ_4 = mean of precise, unbiased (if $\mu_4 = \mu_1$) estimator of μ_1

E. Selection of the Sample

The sample is selected from a frame or non-duplicative listing of all members (possible sampling units) of the rate class. Unfortunately, in utility research the frame is changing constantly. The dynamic nature of the frame is a concern because the frame from which we sample and consequently collect data is not the same frame about which we will make inferences. The magnitude of this problem can be reduced somewhat by using meter location (address) for the sampling unit as opposed to the customer's name. Since the frame used for sampling will not be representative of the rate class after a period of time due to new customers entering and old customers leaving, new samples should be selected every one or two years or some method should be developed to deal with entries and exits.

F. Selection of the Equipment

The implementation of a load study involves the using of metering, recording, and translation equipment. Currently, rotating disc and solid state meters are available; both of these types of meters may be modified to transmit pulses to a storage device such as a recorder. There are two types of recorders in general use: magnetic tape and solid state. In the magnetic tape recorder the pulses are recorded on a tape which is replaced monthly; a translation machine in a central office converts the data into a form readable by a computer. In addition, the translator checks the data for errors, inconsistencies, and outages or malfunctioning of the recorder.

In the solid state recorder the pulses transmitted by the meter are stored in a memory system which retains the latest thirty or more days of data. The data stored in the solid state recorder can be retrieved by the utility through a telephone line, a power line carrier system or a portable reader which is transported to the meter site to copy the data from the memory of the solid state recorder into its memory. The data which has been retrieved by one of the three methods will also be put through a translator. Since solid state recorders can be used with rotating disc meters, a number of metering and recording equipment options are available.

II. DATA COLLECTION

The success of a load study will require good organization and sufficient training of the field personnel to minimize non-response bias, equipment failure and other measurement problems.

A. Installation of Recorders

To reduce the potential bias from non-response, the importance of installing a recorder on each selected premise should be communicated to the employees installing the meters. Studies have shown that there is a difference, often significant, between the people who refuse and those who participate. Written procedures should be developed to deal with problems, such as different meter installations and customer refusals, and the likely impact of these problems. The employees installing recorders should have to explain in detail why they can't use the selected customer. The alternate should be provided only after review determines that the original selection cannot be used. Customers should not be offered a choice regarding participation; participation should be assumed except in extreme cases. A brochure on why load research is needed with load curves illustrating how the data is used is helpful for developing good customer relations and very low refusal rates.

B. Duration of Study

Data should be collected for at least twelve consecutive months to provide the data required by cost studies in today's ratemaking and costing environment. Also, the data should be collected during the same time period for all rate classes. Because the rate class population is constantly changing, meters should be reset on a new sample of customers every one or two years or some method (such as a "birthing" strata) should be used to account for customers entering or leaving the population. Note, account number changes usually do not mean the premise left the population.

C. Demographic Data

It is often important to obtain demographic and appliance saturation data on the load research sample to enhance the use of the load data for many other applications.

III. ESTIMATION OF LOADS

In this phase of the study computer programs are used to estimate statistically the demands of interest for each rate class sampled. Even though a specific estimator (i.e., mean per unit or ratio) was used during the design phase, this earlier decision does not preclude the use of other estimators in the estimation phase. One may use any estimator provided one does not switch to another estimator after the value is calculated. Sound judgment should be used in the selection of the estimator. The particular formulas used in the estimation process must reflect the design of the sample and whether the estimate is for one hour or a combination of a number of hours. Confidence intervals and the relative precision should be calculated for a specified level of confidence.

IV. USE OF DATA

A. Historic Test Year Coincident with Load Study

Coincident and class noncoincident demands for sampled rate classes would have been estimated statistically for all hours of interest for the cost study in the load estimation phase. In addition, demands should be calculated for all 100% time-recorded classes and the lighting classes. The sum of the coincident demands for all classes for any hour adjusted for losses will not equal the demand the utility generated in that hour. This is because of sampling and nonsampling errors.

When the historic test year is coincident with the year the load data was collected, the cost analyst can use the demands as estimated and calculated but usually an adjustment is made to the demands so that they sum to the actual demand of the utility in that hour. Sampling statisticians prefer that no adjustment be made because of the uncertainty as to whether the adjusted demands by class represent more accurately the class's proportion of the total demand than the statistically estimated demands. Some cost analysts have adjusted the estimated demands proportionately of only those classes that are not 100% time-recorded. This procedure, however, ignores the size of the sampling error of the various estimates and the measurement errors present in 100% time-recorded classes.

B. Projected Test Year or Historic Test Year Not Coincident with the Load Study

When the test year is not coincident with a time period when load research data was collected, the most recent load data must be used to develop projected demands for

the test year. The preferred method for projecting coincident demands is to calculate monthly ratios of each class's estimated or calculated coincident demand to its actual KWH sales from the load data. These ratios are then applied to the class's projected test period KWH sales to derive the projected monthly coincident demands.

Similarly, it is recommended that class annual noncoincident demand should be derived by applying the annual class load factor calculated from the most recent load study to the projected annual KWH sales. The use of an annual load factor in contrast to a monthly load factor in the derivation of the class noncoincident class peak demand may, however, result in a larger deviation between the historic and projected coincidence factors. Thus, it is advisable to check the relationship of the projected class noncoincident demands and the projected coincident demands for the same month to that for the same demands estimated in the most recent load studies. The cost analyst may want to explore whether the use of other load relationships will yield projected noncoincident demands whose coincidence with system peak in the same month is more similar. If indicated, different load relationships can be used for different classes.

An example of data collected in a load study is shown in Table A-1.

TABLE A-1
LOAD STUDY DEMAND DATA[1]

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
								Load Factor	
Rate Class	Average Number of Customers	MWH (Output to Line)	Average Demand MW (2) ÷ 8784[2]	Coincident Demand MW Winter	Coincident Demand MW Summer	Class Noncoincid. Demand (MW)	Coincidence Factor [4] ÷ [6]	Coincident Demand [3] ÷ [4]	Non-coincid. Demand [Class] [3] ÷ [6]
Residential	328,480	4,234,145	482	1208	938	1208	1.00	39.9%	39.9%
General Service Non Demand	37,975	642,751	73	119	149	166	.72	61.3	44.0
General Service Demand	5,517	2,368,914	270	338	399	469	.72	80.0	57.6
General Service Large Demand	121	2,696,647	307	322	357	382	.84	95.3	80.4
Street and Outdoor Lighting	142	103,928	12	3	0	22	.14	400.0	54.5
Total Company	372,235	10,046,386	1144	1990	1843			57.5	

[1] At generation level

[2] 8784 hours in a leap year

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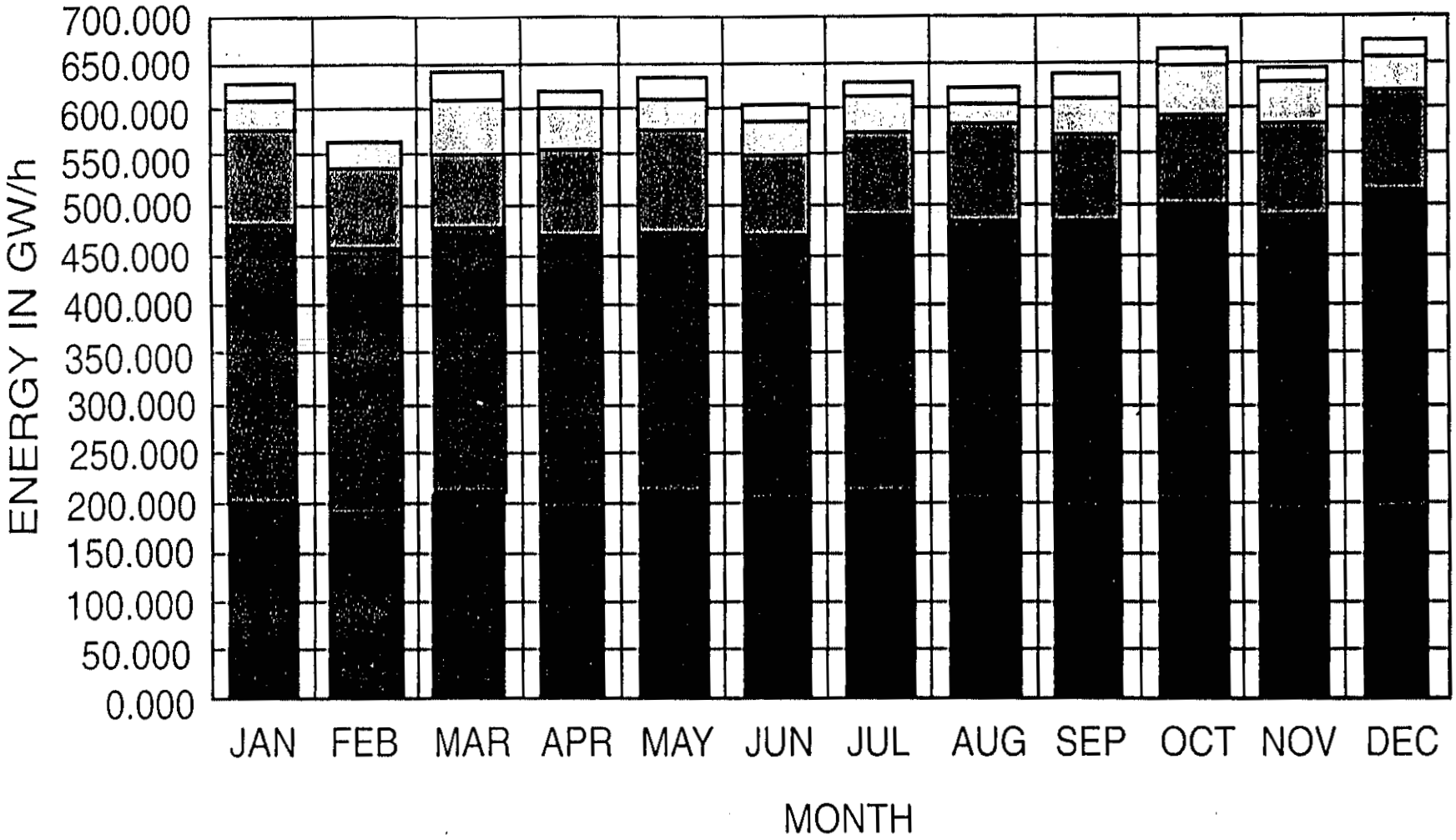
APPENDIX II

LOAD PATTERNS
(Monthly & Daily)_

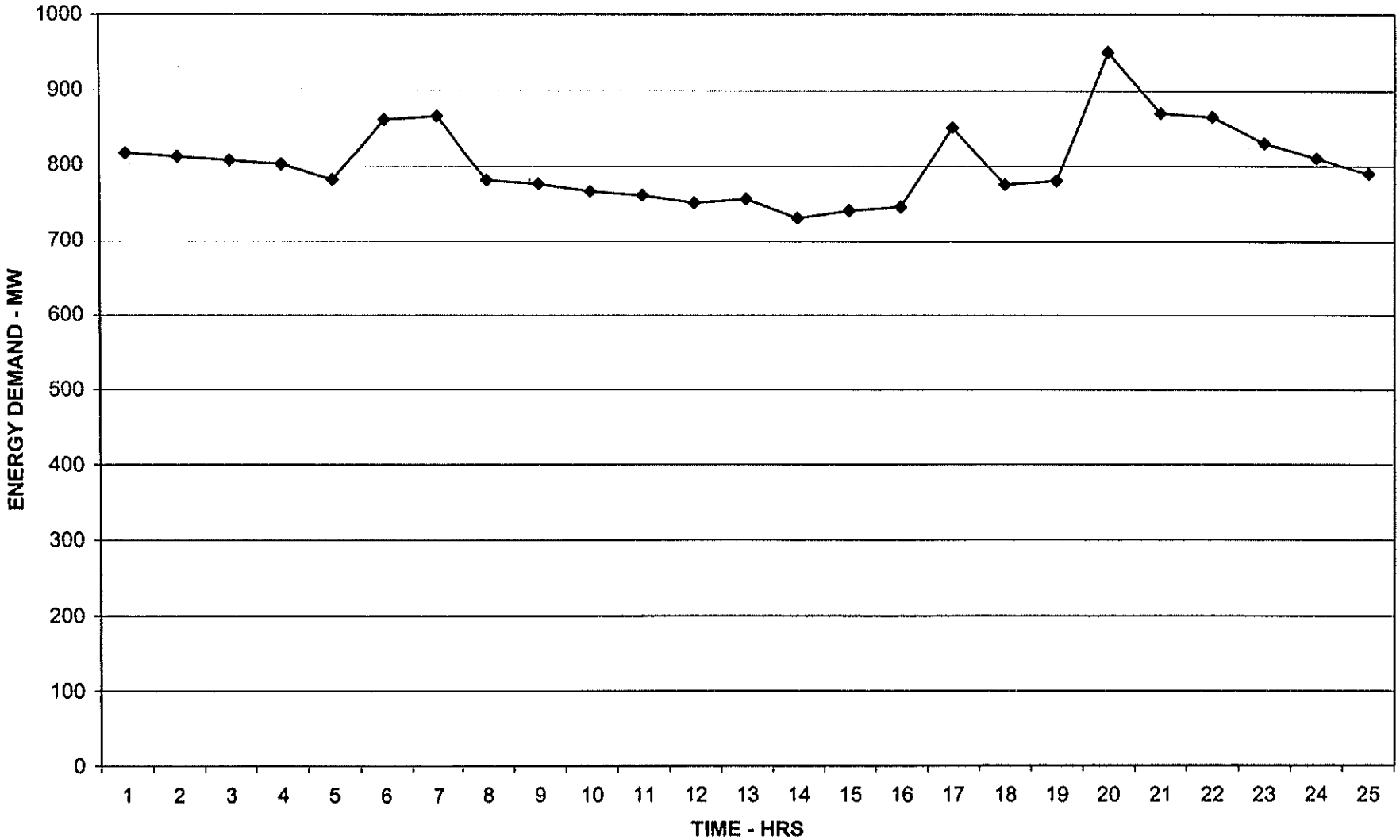
MONTHLY ENERGY CONSUMPTION — 1997



VOLTA RIVER AUTHORITY

56

VRA - HOURLY LOAD CURVE (FRIDAY, JULY 9, 1999)



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