Training course

CUSTOMER SERVICE METERING AND BILLING

Tariff designing and principle of calculating tariff

The objective of this training course is to learn the methods of designing tariff, principles of calculating tariff for specific customer category and learn how to manage the customer's information system.

The material of the part I and II, prepared by IED, can be a basic of 2 – 2.5 day-long intensive training course. It will be accompanied by presentations in MS PowerPoints. This textbook was compiled and adapted from different sources as a manual hand-out for Customer services personnel of EDC. Some practical exercises are included for each session.

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Chapter I – Electricity pricing and tariff

1. Electricity costs

The cost of supplying electricity has three main components:

(a) A component related to the supply capacity provided to meet the power demand, i.e., a component to cover mainly the capital charges on generating plant and transmission and distribution equipment. This component also covers some of the operation and maintenance costs, as well as all administration costs and other overheads, related to the size of the system, i.e. to its capacity.

(b) A component related to the quantity of energy generated, i.e., to cover the costs of fuel on a thermal system, the balance of operation and maintenance costs, and losses in the system; in the case of a hydroelectric system most, if not all, of the cost of water storage is related to energy.

(c) A component related to consumer services, i.e., to cover the costs of service connection, metering and billing, DSM costs.

Components (a) and (c) are termed the **fixed costs** and (b) is termed the **variable, running and operating cost.**

Other classification could be used :

(a) Capital costs : depreciation, financial charges, taxes, and work in progress charges.
(b) O&M costs which include labour cost, cost of material and services, operation cost, maintenance cost.
(c) Fuel costs : fuel price at the border, transportation, taxes on fuel, and other[1]
(d) Customer service costs (connecting cost, customer service, metering and billing).

Example on coverage of electricity costs

A. Coverage of investment costs

1. Construction
  1.1 Direct costs
    Site preparation
    Civil works
    Material, equipment & manpower
  1.2 Indirect costs
    Design, engineering & supervision
    Provisional equipment & operation
    Worksite & administrative expenses

[1] Fuel cost usually included in O&M costs, but for analytical purpose, it is more relevant to separate this fuel cost from O&M cost, as it can represent more than 50% of O&M costs.

1.3 Owner's costs
- General administration
- Pre-operation
- R&D (plant specific)
- Spare parts
- Site selection, licensing & public relations
- Taxes (local/regional, plant specific)

2. Other overnight capital costs
- Major refurbishment
- Decommissioning
- Others

3. Contingency (share of base cost when specified)

B. Coverage of O&M costs
- Operation
- Maintenance (material, manpower, services)
- Engineering support staff
- Administration
- General expenses of central services
- Taxes & duties (plant specific)
- Insurance (plant specific)
- Major refurbishment
- Operating waste disposal
- Others

C. Coverage of fuel costs (Thermal)
- Fuel price at the border or domestic mine
- Transportation to the power plant
- Taxes on fuel
- Others

D. Coverage of customer services
- Cost of service connections
- Cost of metering and billing
- Cost of electricity lost
- DSM

There are many factors which influences the electricity costs : the electricity demand patterns, technical and non-technical losses, the power factor, quality of supply, environmental requirements….

Electricity tariff should file the costs of servicing the various consumer classes based on embedded (average) cost and marginal cost methods. The estimates of embedded and marginal costs, particularly the marginal cost estimates, are important benchmarks in determining whether the tariffs reflect the economic costs of servicing its customers.

Usually, regulatory bodies require these costs to be determined by customer classes and/or voltage levels and compare the tariffs with these estimates of costs by category and/or voltage. A detail tariff structure could be based on :

- Voltage level.
- Geographical area.
- Seasonal and time-of-use.
- Income level.
- Economic activity.

Objectives of electricity tariff are :

(a) Efficient allocation of resources : the tariff regime should promote efficiency in the sector, both in terms of:
- ❖ allocative efficiency: the tariff should reflect underlying marginal costs of electricity provision, allowing producers and consumers to allocate resources efficiently in response to tariff price signals. For example, with electricity prices reflecting marginal costs, consumers face the correct incentive when considering extra electricity consumption or an investment in energy efficiency;
- ❖ productive efficiency: the cost of electricity provision should be the lowest possible consistent with the required quality of service, reflecting efficient investment and operation. Market discipline can ensure efficient provision in generation and supply where effective competition can be developed. However, regulatory controls will be necessary until effective competition in generation and supply is established and to ensure efficient provision in transmission and distribution which are natural monopolies;

(b) Social equity and fairness : fair burden distribution among the customers, assurance of equal access to electricity for low income people by a subsidy to the minimal level by:
- ❖ preserving a degree of cross-subsidy: to support low income customers and to maintain the uniform national tariff at least for the present (currently, MEA and PEA apply the same tariff throughout the country, although it is more expensive to supply customers in areas of low load density than in areas of high load density). In due course, we understand that the uniform national tariff will be phased-out;
- ❖ appropriately balancing the interests of the utilities and their customers: there is some concern that the present tariff setting mechanism may have unduly insulated the utilities from the consequences of the economic crisis;
- ❖ ensuring a level playing field between utilities and competing suppliers (initially, we understand only small power producers (SPPs) will compete to supply final customers);

(c) Cost recovery: the tariff regime should allow the utilities sufficient revenue to finance an efficient investment programme and to cover efficiently incurred operation costs, including an appropriate return commensurate with the risks of their business;

(d) Simplicity: the tariff regime should be understood by customers. Large customers are sophisticated users and should be able to understand and respond to more complex price signals than small customers;

(e) Stability: the tariff regime should be relatively stable to give producers and consumers confidence to make investment decisions based on the tariff price signals; and

(f) Ease of implementation: the tariff regime should ensure any transaction costs associated with implementation are exceeded by benefits. In particular, metering costs mean that complex tariff structures may not be appropriate for low volume customers.
(g) It discourages wasteful consumption.

2. Marginal cost pricing and average cost pricing

The costs of supply and/or distribution of energy can be calculated by two alternative methods, the embedded cost method and the marginal cost method.

Marginal cost pricing is deduced from the theory that the marginal value of any resource and its market price should be equal; and in the case of electricity is more particularly expressed in the form that the price of a unit of electricity, be it energy (say, 1 kWh) or the rate at which energy is consumed (say, 1 kW) should be equal to the marginal cost of supplying that unit of electricity.

Marginal cost pricing of electricity is concerned with only future costs to the economy, and how changes in future requirements of electricity, both power and energy, may affect such costs. Costs already incurred or to which the supply authority is already committed (known as "sunk" costs) are not considered in strict marginal cost pricing.

The marginal cost of electricity, like the total costs, has capacity-related, energy-related and consumer-related components; of these the first two may also be dependent on the time of day, the season, the power factor, the voltage of supply and the supply reliability provided.

Total, Average, and Marginal Costs

Associated with the basic inputs of labor and capital are the notions of variable and fixed costs. ***Fixed costs*** are fixed during some period. Although a cost might be fixed during a short period, such as a month, it could vary during a longer period, such as a year. We define the ***short run*** as a period during which there are *some* fixed costs. Further, we can define the following terms whereby technology describes how L and K are combined to produce *Q:*

Time	Cost	Technology
very short run	**all** costs are fixed	fixed
shortrun	**some** costs are fixed	fixed
long run	**no** costs are fixed	fixed
very long run	**no** costs are fixed	**not fixed**

Also, variable costs are those costs that vary in the short run with changes in output. Although some forms of labor, once hired, are fixed in the short run and some forms of capital are rented under agreements that depend on output, we will assume that labor is variable and capital is fixed in the short run.

Total Cost (*TC*) is the sum of ***Variable Cost*** (VC, e.g., the wage bill) and ***Fixed Cost*** (FC, e.g., the cost of renting capital). We represent this as :

$$TC = w * L + r * K = VC + FC \qquad (2.2)$$

Average *cost* *(AC)* is total cost divided by the quantity produced (Q):

$$AC = TC / Q = VC / Q + FC / Q = A\ VC + AFC (2.3)$$

where
VC / Q is Average Variable Cost (A VC)
FC / Q is Average Fixed Cost (AFC)

An example of these cost terms can be found in Table 1 and in Figures 1a and 1b. Also, ***Marginal Cost*** (MC) is equal to the change in total cost with a unit change in quantity, Q (discussed below).
In determining how to allocate variable inputs, it is important to know the cost of producing a particular unit of output. The cost of producing a *particular* unit is its *marginal cost.* The marginal cost of producing the first unit includes all of the fixed costs and *some* of the variable costs. Therefore, marginal cost can be different in the *short run,* where some costs are fixed (i.e., *short-run marginal cost),* and in the *long run*, where no costs are fixed (i.e., *long-run marginal cost).*

Quantity	Total cost	Fixed cost	Variable cost	Average cost	Average fixed cost	Average variable cost	Marginal cost
Q	TC	FC	VC	AC	AFC	AVC	MC
100	7 250	5 000	2 250	73	50	22,5	22,7
200	10 000	5 000	5 000	50	25	25,0	27,5
300	13 250	5 000	8 250	44	17	27,5	32,5
400	17 000	5 000	12 000	43	13	30,0	37,5
500	21 250	5 000	16 250	43	10	32,5	42,5
600	26 000	5 000	21 000	43	8	35,0	47,5
700	31 250	5 000	26 250	45	7	37,5	52,5
800	37 000	5 000	32 000	46	6	40,0	57,5
900	43 250	5 000	38 250	48	6	42,5	62,5

Table 1. Total, Average, and Marginal Cost

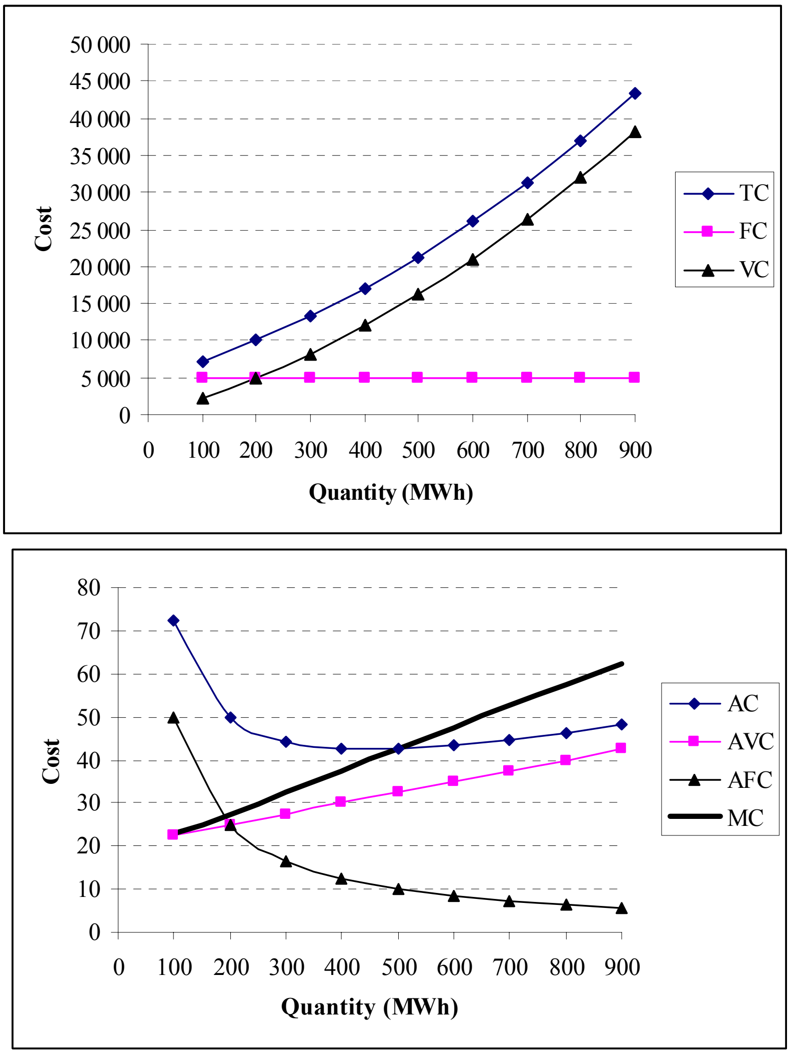


Figure 1. (a) Total, variable, and fixed costs. (b) Average and marginal costs.

If average variable cost is constant, marginal cost is level. If productive capacity becomes constrained, marginal cost rises, For example, the cost of producing a MWh changes as more MWh are produced. Marginal cost can decrease as more electricity is produced, it can be level until capacity is constrained, and it can become very high when full capacity is reached (and diesel generators are started). Although marginal cost is associated with units of output, we will assume continuous changes in cost such that marginal cost (MC) can be represented as the first derivative of total cost with respect to quantity :

$$MC = dTC / dQ \qquad (2.4)$$

where d is an instantaneous change in the variable

<u>*Comparison of Marginal Cost and Average Cost Pricing*</u>

The rationale for *marginal cost pricing* in the context of electricity is that it signals, or should signal, to consumers the true economic cost, i.e., the cost to society, of supplying additional demand, and conversely the true economic saving resulting from reduced demand. If additional demand is priced below the marginal cost of meeting it, consumers are encouraged to waste electricity, which is a national resource, while if it is priced much above the marginal cost the resource may be under-used. Pricing at marginal cost creates the correct balance between waste and under-use, i.e., maximizes economic efficiency.

In contrast, electricity prices based on *the average costs* of supplying consumers reflect "sunk" costs and presume that additional future demand will cost, or reduced demand will save, the same as in the past. Quite apart from the effects of inflation the costs of providing the same facilities will vary with time, for example, as a result of technical progress or economies of scale, and future costs will be quite different. Furthermore, any over- or under-investment in the past will be reflected in prices based on average costs which respectively overstate or understate the cost of additional demand (for example, during peak-load periods).

Typically this method uses the projections of costs based on historical accounting costs that have been incurred for servicing the category. Thus the revenues derived from tariffs can be closely matched with the costs of service derived from this method.

Analysis of Marginal Costs

Several methods of calculating marginal costs have evolved over the past few years, ranging from:
(a) rough estimates of unit-capacity cost (e.g. per kW) of peak load generating plant and transmission and distribution equipment, and of specific fuel cost (e.g. per kWh); to
(b) rigorous analysis of all components of cost under different system operating conditions.

(see "Guidelines for marginal cost analysis of power systems", World Bank - Energy Department paper N° 18, June 1984, for further information).

Long run marginal cost and short run marginal cost

Strict long run marginal cost is defines as the incremental cost of all adjustment in the system expansion plan and the system operation attributable to an increase in demand that is sustained into the future.

Short-run marginal cost (SRMC) estimates an increase in the rate of utilisation of existing plants and equipments. It excludes fixed costs and fixed operating cost.
Long run marginal cost (LRMC) is calculated under the assumption that the increase in the output is accomplished by a appropriate increase and adaptation of plant capacity.

LRMC = marginal capacity cost + marginal operating cost.

Example of "Framework for calculation of LRMC"

Step 1 : Load forecasting
Construction of load curves and duration curves, based on historic hourly load curves and taking into account consumption trends for each category of customers.
Step 2 : Optimal expansion plans for power system.

The optimal generation expansion plans are developed to find least cost combinations of power system over long period (base plan and incremental plan).

Step 3 : Total cost and total incremental cost, incremental capacity cost

Present values of total cost for different cases are calculated. Total cost includes : investment cost, fuel costs, O&M fixed and variable costs, import and purchase costs. Capacity cost includes Investment cost and O&M fixed cost.

Total incremental cost is a difference between total cost of incremental plan and of base plan. Incremental capacity cost is a difference between capacity cost of incremental plan and of base plan

Step 4 : Total marginal cost and marginal capacity cost

Total marginal cost per kWh is calculated by dividing the present value of total incremental cost by the total incremented energy over the expansion period.

Application of marginal cost pricing in practice

Marginal cost based tariff schemes (First best pricing rule) require that the cost and demand function of the utility are fully known at present and in the future. A survey by the World Bank of over 60 developing countries shows that in 1987, electricity tariff were not based on the marginal costs of supplying electricity in 80% of survey sample. Because the government in developing countries have to combine other social and economic objectives in tariff system.

The majority of utilities employ average cost pricing (average system cost).

Second best pricing rule (know as Baumol-Bradford rule) : the objective is to determine the prices and quantities of good i and j so as to maximise the net social benefit with a guarantee of predetermined level of profit for the producer.

$$\frac{\dfrac{P_1 - MC_1}{P_1}}{\dfrac{P_2 - MC_2}{P_2}} = \frac{\dfrac{1}{e_1} + \dfrac{1}{e_{12}}}{\dfrac{1}{e_2} + \dfrac{1}{e_{12}}}$$

If the cross price elasticity of demand $e_{ij} = 0$, the rule can be expressed as :

$$\frac{\dfrac{P_1 - MC_1}{P_1}}{\dfrac{P_2 - MC_2}{P_2}} = \frac{\dfrac{1}{e_1}}{\dfrac{1}{e_2}}$$

The i and j can be interpreted as electricity consumption by two different consumer groups i and j in the same period or consumption of the same group in two periods. The price adjustment should be smaller for customers with large elasticity to price changes (more sensitive), and larger for customers with small elasticity (less sensitive).

Practical limitations of adopting this rule are :

- lack of elasticity coefficient estimations

- large number of customers and periods are involved.

Example on Calculation of Electricity tariff impact on a factory's production cost

Consider a factory that can choose from the 3 different tariff schedules shown in the table. The factory operates 20 days per month, and its total cost consist of only labor and electricity which are shown in tables below. The factory has two possibilities to operate : day shift from 8h00 to 22h00, or night shift from 22h00 to 10h00.
Calculate the factory total monthly operating cost for each of the 3 tariffs and propose a most cost-effective for the factory.

Tariff (€/MWh)				
One single tariff	Multi tariff		Time-of-day tariff	
	Consumption MWh/month	€/MWh	Period	€/MWh
80	0-10	65	22:00 – 08:00	35
	10-15	75	08:00 – 12:00	85
	Over 15	95	12:00 – 18:00	78
			18:00 – 22:00	90

The factory has 2 x 100 kW machines each operating for 8 hours/day resulting in the following total daily load profile for the factory

Time	Power load (kW), day shift	Time	Power load (kW), night shift
08:00 – 12:00	200	22:00 – 02:00	200
12:00 – 14:00	2	02:00 – 04:00	2
14:00 – 18:00	200	04:00 – 08:00	200
18:00 – 20:00	2	08:00 – 10:00	2
20:00 – 08:00	1	10:00 – 22:00	1

Change in working time will involve higher labor cost as given in the table below.

Time shift	Labor cost
Day time	8000 €/month
Night time	9400 €/month

Solution :

1) One tariff

Total, €/month	**2592,0**

2) Multi tariff

First block 10 MWh	650
Second block 5 MWh	375
Last block	1653,0
Total, €/month	**2678,0**

3) Time-of-day tariff

		A) Day time shift		*B) Night time shift*	
Time	*Tariff, €/MWh*	*Elect. cons, kWh*	*Cost, €*	*Elect. cons, kWh*	*Cost, €*
0:00	35	1	0,035	200	7,000
1:00	35	1	0,035	200	7,000
2:00	35	1	0,035	2	0,070
3:00	35	1	0,035	2	0,070
4:00	35	1	0,035	200	7,000
5:00	35	1	0,035	200	7,000
6:00	35	1	0,035	200	7,000
7:00	35	1	0,035	200	7,000
8:00	85	200	17,000	2	0,170
9:00	85	200	17,000	2	0,170
10:00	85	200	17,000	1	0,085
11:00	85	200	17,000	1	0,085
12:00	78	2	0,156	1	0,078
13:00	78	2	0,156	1	0,078
14:00	78	200	15,600	1	0,078
15:00	78	200	15,600	1	0,078
16:00	78	200	15,600	1	0,078
17:00	78	200	15,600	1	0,078
18:00	90	2	0,180	1	0,090
19:00	90	2	0,180	1	0,090
20:00	90	1	0,090	1	0,090
21:00	90	1	0,090	1	0,090
22:00	35	1	0,035	200	7,000
23:00	35	1	0,035	200	7,000
Total per day		**1620**	**131,602**	**1620**	**57,478**
Total per month (20 days)		**32400**	**2632,04**	**32400**	**1149,56**

Total cost

	Day shift			Night shift		
	One tariff	Multi tariff	TOD tariff	One tariff	Multi tariff	TOD tariff
Labor cost, €	8000,0	8000,0	8000,0	9400,0	9400,0	9400,0
Elect. cost, €	2592,0	2678,0	2632,0	2592,0	2678,0	1149,6
Total cost, €	*10592,0*	10678,0	10632,0	11992,0	12078,0	*10549,6*

If the factory choose to operate at day time, the most cost – effective tariff is one single tariff. But if it choose to operate at night time, the most economic tariff could be time-of-day tariff.

3. Electricity tariff on energy charge and on demand charge

The power utilities usually establish a tariff system based on three criteria :

1) Electricity consumption, in kWh
2) Active power demand, in kW.
3) Apparent power demand, in kVA.

A brief explanation of the nature of each of the above tariff is provided in the next section.

1) Tariff based on electricity consumption:

The electricity cost to the customer depend directly to it electricity consumed, in kWh. However, a customer have to pay an amount minimum fixed because the even when the customer do not use any kWh, the connection to the network represent certain expenses that the utility have to recover. The delivered service of electricity is paid progressively as the consumption increases, and it allow to apply a decreasing tariff. For example, the tariff for small customers can commence from 8 cents/kWh for the first 10,000 kWh and then comes to 4 cents/kWh for the rest. The same principle can be applied to intermediate and large customers.

2) Tariff based on active power demand :

The cost of electricity supply depends not only the quantity of electricity in kWh, but also on active power demand, in kW.

Active power demand is the average value of power load absorbed by a customer during an given time interval, generally 15 minutes. Active power load (or demand) plays an important role in tariff system because it is directly related to the cost of installed equipment to supply the electricity (post of transformer, distribution lines,…)

Consider an example : two factories A and B with different load curves profiles, supplied by two transformers Ta and Tb

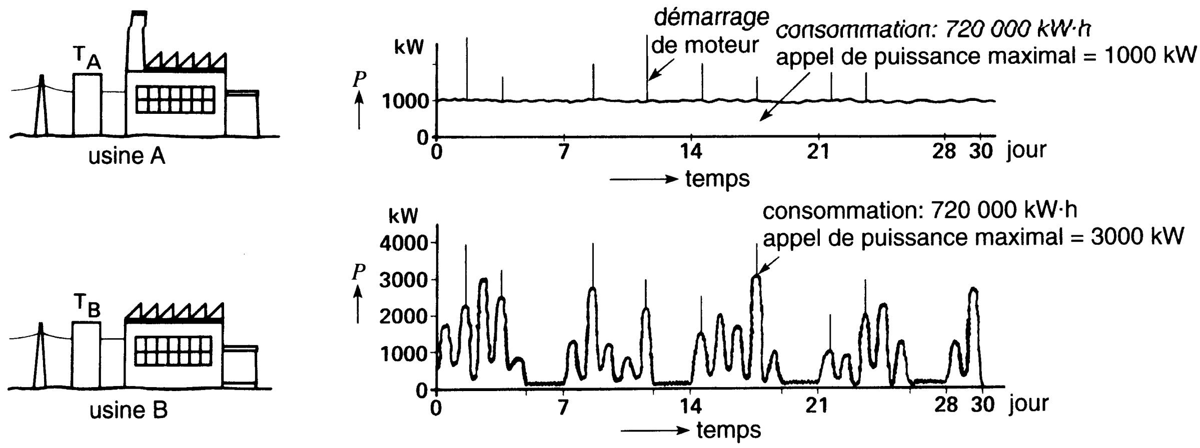


Figure 2.

The factory A has a stable power load profile during the whole period with maximum at 1000 kW and consumes each month (720h) a quantity of :

1000 kW x 720 h = 720 000 kWh

The factory B consumes the same quantity of electricity but under different profile. It does not work during the week-end, its load varies from 0 to 3000 kW during weekdays and can attain 4000 kW in very short time when big motors start.

The capacity of the transformer in kVA and the electric line that supplies electricity to the factory B should be largely superior compared to those who supply electricity to the factory A. The supplier of electricity should make an investment more important to supply electricity to the factory B. Therefore, it is naturally that the factory B should pay its electricity at higher price.

3) Power demand indicator

To measure the power demand of customers, the supplier installs power meter. In order to record a maximal load, the power meter has two needles-indicators : the first needle, its deflection is proportional to the average value of load during 15 minutes, pushes an second needle-indicator of the maximum. When the load decreases, the first needle goes down to zero but the second needle rests in the position of the maximum power load. Each month, meter reader will note the value of the second needle and put it at zero level.

Recorded time interval is usually fixed between 15 minutes and 30 minutes. In certain case of large customer, the interval may be up to 60 minutes.

For a customer, this power demand is usually fixed in advance in supply contract. If this fixed value has been exceeded during an period (month), the customer have to pay an expensive fine. It is therefore in interest of the customer to avoid exceed this value. To control the situation, the large customer can use a *load stabilisator* who disconnects non-essential load-charge from the network when total load approaches the maximal value and connects again the load when peak is over, in order to keep the customer load relatively stable and reduce the power demand subscription cost.

Example :

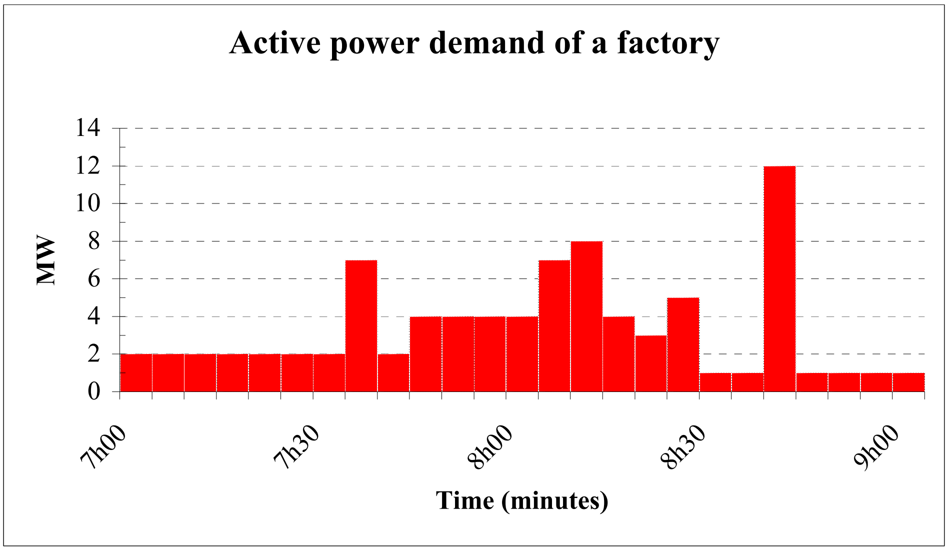


Figure 3. Active power demand of a factory

The figure 3 represents load curve of a factory between 7h00 and 9h00. The power meter records the power demand each 30 minutes. At 7h00, the first needle indicates 2 MW and the second needle indicates 3 MW. Calculate the meter reading at hours :

a) 7h30; b) 8h00 c) 8h30 d) 9h00

<u>Solution</u> :

a) As shown in the figure 3, the power demand between 7h00 and 7h30 is 2 MW. As a result, at 7h30, the first needle indicates 2 MW and the second indicates 3 MW
b) The average demand Pd between 7h30 and 8h00 is given by :

   Pd = (7MW x 5 min + 2 MW x 5 min + 4 MW x 20 min) / 30 min = 4.17 MW

   During this interval of time, the first needle goes up gradually from 3 MW (at 7h30) to 4.17 MW (at 8h00) pushing the second needle to 4.17 MW. So at 8h00, both needles indicate 4.17 MW

c) The average demand Pd between 8h00 and 8h30 is

   Pd = (7x5 + 8x5 + 4x5 + 3x5 + 5x5 + 1x5)/30 = 4.67

   At 8h30, both needles indicate 4.67 MW

d) The average demand Pd between 8h30 and 9h00 is given by :

   Pd = (1x5 + 12x5 + 1x20)/30 = 2.83 MW

   During this period, the first needle goes down to 2.83 MW but the second needle rests at 4.67 which is a maximal value recorded.

4) Tariff based on apparent power demand

Many equipments of AC such as induction motors or electronic converters consume not only active power but also reactive power. They have power factor much less than 100%. The power factor measure the relation between active power and apparent power.

We have seen that a customer has to pay an extra when its load exceed subscribed active power. Now we give another example on why customer has to pay more expensive when its power factor is too low.

Two factories A & B consume the same amount of electricity per month and have the same maximum active power demand. The power factor (PF) of the factory A is 100% and 50% for the second. (figure 4)

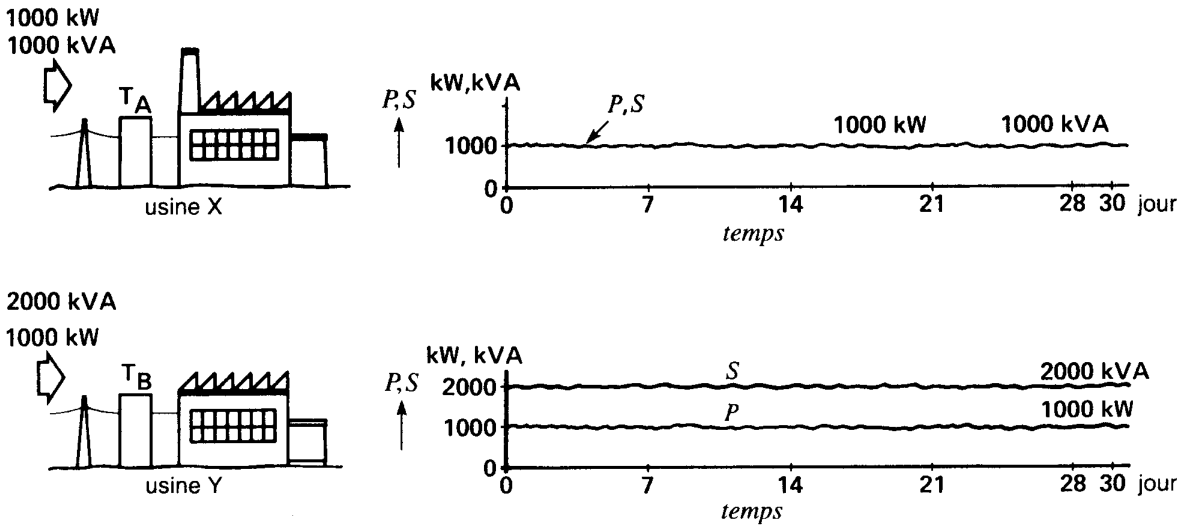


Figure 4 : Apparent power demand and active power demand

The electricity consumed and active power demand are the same for both factories : energy meter and power meter indicate the same value at the end of month. However, they use different apparent power. The apparent power supplied to the factory A is :

S = P/ PF = 1000 / 1 = 1000 kVA

For the second factory B,

S = P/PF = 1000 / 0.5 = 2000 kVA

As the current supported by a line is proportional to the apparent power, the factory B draws a current two time the current requested by the factory A.

Consequently, the line section supplied to the factory B should be doubled compared to the line section to the factory A. In addition, the capacity in kVA of the network connected to the factory B should be two time more than to the factory A.

Electricity company who supplies the electricity to the factory B have to invest more capital to its supply network. It is logic that the factory B pays more for it consumption, even that electricity consumption in kWh for both factory are the same. That is why power utility imposes a special tariff on the customers with low power factor.

To measure the power factor, it uses an indicator of maximal apparent power. Its function principle is likely to that of indicator of active power. The difference is only that maximal apparent power is recorded each 15 second interval.

In practice, large customers have to pays an extra if their PF is lower than 90%. In the invert case, the customers have an interest to install reactive compensations to correct their PF.

4. Electricity tariff based on customer categories

The proposed schedule of charges has been determined with the objective of unbundling costs and reflecting them appropriately in the tariff structure. The current schedule of charges, usually has the following tariff components:

- Energy charges in €/kWh for all categories (including optional metered tariff for Agricultural and Irrigation)
- Demand charges (for a few categories) in €/kVA/month or €/kW/month
- Fixed charges in €/month for certain consumer categories
- Monthly minimum charges.
- Over-drawal charges for certain categories.
- Flat rate tariffs in €/annum
- Social tariff
- Interruptible tariff
- Fuel adjustment tariff and DSM adjustment tariff.

Energy charges
These charges are per kwh of energy consumed. The energy charges include recovery of both variable and a large proportion of fixed costs, but generally do not reflect the true marginal costs of production. Most of the fixed costs are also covered in this charge, the extent of which varies between categories.

Demand Charges
Demand charges are designed to enable the utility to meet at least a part of its fixed cost obligations. Usually demand charges are applicable to MT & HT categories. However, imposition of demand charges requires meters capable of measuring maximum demand. Apart from the HT categories having demand meters, only some the MT Industrial category consumers have such meters. Hence utility can propose an optional tariff with a demand charge component based on contracted demand in place of the fixed charges based on connected load. The cost of installing such a meter does not justify the benefit for all categories and also for relevant categories, replacement with such electronic meters requires substantial effort and time.

Fixed charges
It recognises the need for collection of fixed charges from those categories consumers who are not subjected to demand charges. It usually has considered the introduction of fixed charges for other categories having a single part tariff. However, it believes that the fixed charges incident on a category should be linked to the variability in revenues from the category and not to the cost structures of the customer alone. In future, when better information is available on the variability in consumption profiles of the categories across time of the day and months of the year, the utility can consider introduction of fixed charges for these categories to address the variability in revenues and costs.

Monthly minimum charges
These charges are currently made applicable in respect of certain tariff categories, to ensure certain minimum amount from the consumer, when the consumer does not consume a minimum level of energy. It can be applied a minimum charge for Demand for categories

having a two-part tariff. This is necessary to protect utility's fixed charge revenues from variations beyond an operations range.

Demand Over-drawal charges

These charges are essential as they protect the utility from under-contracting of load by consumers. The penalties on over-drawl would help the utility pay for any surcharge incident on it for overdrawal by its consumers.

Flat rate tariffs

Flat rate charges are applicable to the un-metered consumers. These charges are based on the estimated capacity, and location of the consumer and not the actual level of energy consumed. It recognises that having charges based on estimated capacity and independent of actual usage is an inefficient method of tariff design. The absence of any metering infrastructure is the primary impediment in introducing metered tariffs on a universal basis for the consumers of this category.

Social tariff

Social tariff is elaborated in accordance with government policy to ensure electricity supply to some social low-income categories who are not able to pays electricity at normal tariff. Because electricity supply is considered as government policy in this case, the government should pays the difference between social tariff and normal tariff from its compensation funds.

Interruptible tariff

This tariff is designed to provide capacity saving to utilities. Participating customers are proposed a reduced demand charge if they agreed to be interrupted by the utility for a specific period of time. Customers may also be allowed to choose the frequency of interruption, maximum duration, and the amount of load to be disconnected.

Often, utilities also offer incentive to customers allowing demand interruption. Such incentive are designed on the cost-effective basic (net avoided cost by the utility from interrupting the customer load).

Fuel adjustment and DSM adjustment charge, Power purchase adjustment charges

Few utilities practice this tariff. Fuel adjustment tariff mostly elaborated for the power systems depending heavily on thermal power plants using import fuels. To avoid that this international price fluctuation affect largely utilities, fuel adjustment clause enabled utility to automatically recover higher fuel prices from the customers.

In addition, The costs of DSM programs (cost of program, lost margins, shareholder incentives, applicable taxes) and the administrative costs of doing DSM are recovered through the tariffs via the surcharge DSM adjustment tariff.

The utility has to procure power and fuel from different sources and the cost are subject to fluctuations over wide range. The utility therefore should be insulated against such fluctuations by being provided the option of periodical adjustments in the tariff. The utility could include a base tariff and revisions in fuel and power purchase costs would be added or deducted in the tariff from time to time.

Example of load shape objectives and DSM programs

The expected change in load shapes are the key basic to evaluate the potential benefits of any DSM program. The following illustrations, (Gellings C.W.& Chamberling J.H. "DSM:concepts andmethods", The Fairmont press GA, 1988), give some basic load shape objectives in designing DSM programs.

a) Peak clipping : direct load control of customer appliances – efficient lighting lamps.
b) Valley filling : involves building of off-peak load - promotion of programmable water heating.
c) Load shifting : accumulate heating system, storage coolness.
d) Strategic conservation : combination use of efficient devices.
e) Strategic load growth : when utility has surplus capacity – expansion of rural electrification program.
f) Flexible load shape : considering system reliability as a variable in utility planning, changes in reliability and load shapes could be affected through different DSM programs. Variation in interruptible load is one of the options.

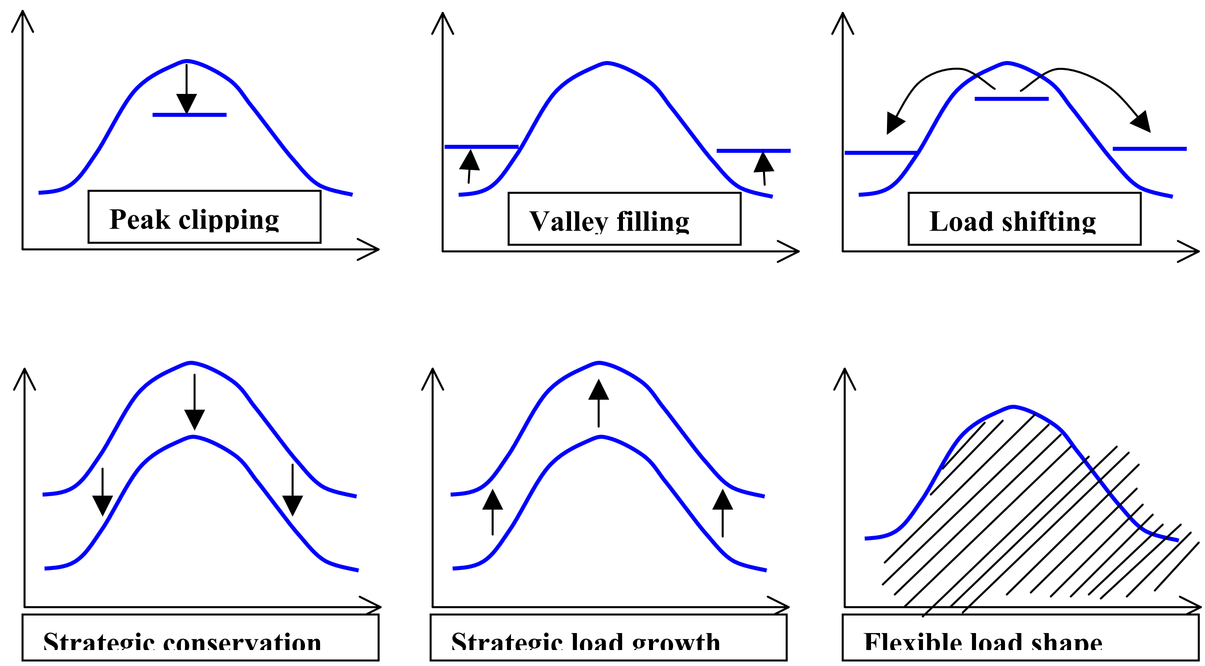


Table : Example from real tariff categories and tariff elements (X = applied), MECO

Sche-dule	**Customer**	**Comment**	**Custom. Charge**	**Demand Charge (*)**	**Energy Charge**	**Power Factor Charge**
R	Residential		X		X	
G	General Service Non-Demand	≤ 5,000 kWh/month and ≤ 25 kW	X		X	
J	General Service Demand	> 5,000 kWh/month or > 25 kW	X	X	X	X if < 0.85
H (K)	Commercial Cooking, Heating, Air-conditioning, Refrigeration	Referred to as Schedule K if the demand is metered (usually if ≥ 25 kW)	X	X	X	
P	Large Power		X	X	X	X if < 0.85
F	Public Street Lighting			X (**)	X	
E	Employees (***) and social categories	Incl. retirees and Board members	X		X	

(*) The demand charge ($ per kW per month) for the schedules J, K and P is related to the maximum load. The billed maximum load is calculated from the metered maximum average load during any 15-minute period of the billing month and the greatest maximum, or a percentage thereof, observed in the preceding eleven months. The higher value is selected.

(**) Fixture charge depending on the type and wattage of lamps.

(***) Rates are 2/3 of residential rates up to 825 kWh/month. Energy usage above 825 kWh billed at full residential energy charge.

5. Seasonal and time-of-day tariff

A tariff incorporating peak and off-peak energy charges (seasonal and time-of day tariff) is more effective than a maximum-demand tariff because it gives clearer signals to consumers of the higher marginal costs of supply during peak-load periods: a consumer charged under a peak and off-peak energy tariff knows that every kWh taken during peak-load periods will cost him more than during off-peak periods, whereas if he were charged under a maximum demand tariff there would be no incentive for him to reduce his consumption during peak-load periods. This advantage of time-of-day tariffs is of particular importance where there is a long daily plateau of high load.

Seasonal and day-of-time tariff incorporating different energy rates during peak and off-peak periods would necessitate separate peak and off-peak metering equipment including time switches, and the extra cost of such metering again could be justified only in the case of the larger industrial and commercial consumers. For the vast majority of consumers, i.e. domestic and smaller industrial and commercial consumers, the proportions of their total consumptions during peak and off-peak periods can be estimated, and a common energy rate set, by weighting it in those proportions, to ensure that the marginal costs are recovered taking one period with another.

The seasonal demand fluctuations which affect the system, placing it under severe stress at certain times of the year. The necessity for system management at times of such peak demand expectedly escalates the operational expenses and increases the marginal cost of supply. Similar differences exist for cost of power supplied during different parts of the day. Various studies have highlighted the need for seasonally differentiated prices. The price differential for different times of the day may not be feasible for all consumers since this would require installation of superior quality meters. The idea can be tried for bulk consumers.

Demand is one of the most critical decision variables in the exercise of economic costing. The structure and size of the market is reflected in the demand. Information on market pattern helps the management in planning its resources in optimum manner. Differentiated tariffs needs examination due to its positive role in effecting operational efficiency. The feasibility of geographically differentiated and time differentiated tariffs can be examined in an effort to create an atmosphere of internal competitiveness in the monopoly organisation. This will, however, be subject to availability of technical resources with the utility. The differentiation, however, should be such that the consumer may not feel confused about the tariff rates applicable to his consumption of electricity. There should not be a state of total uncertainty about the rates since it may create an adverse reaction from the consumers.

An example with EDF tariff system

the structural evolution of the power production plants EDF allow to determine several steps in its marginal production cost. Between the cost of kWh produced from a nuclear power plant on base load and the cost of kWh from a gas turbine on peak load, there is a graduation which justifies a multi seasonal and time-of-day tariff system.

EDF distinguishes four seasonal periods and three day-off-time periods :

a) *Seasonal periods :*

- winter : December, January, February
- semi-season : March, November
- summer : April, May, June, September, October
- July and August

b) *Time-of-day periods :*
- peak : four hours per day from Monday to Friday, not including holidays, during winter period. From 9h00 to 11h00 and 18h00 to 20h00;
- off-peak : six hours per day from Monday to Friday, plus whole days of Saturdays, Sundays, and holidays, and whole month of July and August;
- base : all other hours;

Table 2 : EDF tariff structure (Source : Percebois J., p. 270)

Tariff depending Voltage

Universal tariff (*)
(23 m customers)

Tariff 'Green'
1) MV (150000 customers)

2) HT (400 customers)

3) Very High Tension
(50 customers)

Tariff structure depending Power

	Possible option	Seasonal hours
Tariff 'Blue' from 3 – 36 kVA	- Option Base - Option Peak hours - Option EJP**	1 2 2
Tariff 'Yellow' from 36 – 250 kVA	- Option Base - Option EJP	4 4
Tariff 'Green' Green A5 : 250 – 10000 kW Green A8 : 3000 – 10000 kW	- Option Base - Option EJP - Option Base -Option EJP	5 4 8 6
Tariff 'Green B' 10 – 40 MW	- Option Base - Option EJP	8 6
Tariff 'Green C' >40 MW	- Option Base - Option EJP	8 6

Country	Residential	Commercial	Industrial
Brunei Darussalam	2.88 - 14.42	2.88 - 11.54	2.88 - 11.54
Cambodia	9.17 - 17.03	15.72 - 17.03	12.58 - 15.72
Indonesia	1.69 - 4.60	2.77 - 5.65	1.71 - 4.38
Lao PDR	0.55 - 3.8	4.18 - 5.22	3.51
Malaysia	5.53 - 8.94	2.63 - 10.52	2.63 - 10.52
Myanmar	8.14	8.14	8.14
Philippines	3.15 - 10.71	3.68 - 9.85	3.35 - 10.84
Singapore	9.23	4.42 - 7.18	4.16 - 6.69
Thailand	3.41 - 7.47	2.94 - 7.47	2.94 - 7.13
Vietnam	2.92 - 8.17	4.24 - 13.96	2.83 - 13.96

Figure : Basic Electricity Tariff in the ASEAN Countries.
(Note : ranges per kWh, as of 24 September 2003 (In US cents/kWh).
Source : ASEAN Centre for Energy

General overview of the survey results

inra

Prices /kWh in EUROcents	Residential prices (electricity + consumers taxes + VAT)			Non Residential prices (electricity + consumers taxes)			
	Band 1 X <= 2 MWh	Band 2 2 < X <= 7 MWh	Band 3 X > 7 MWh	Band 4 X <= 0.1 GWh	Band 5 0.1 GWh < X <= 1 GWh	Band 6 1 GWh < X <= 9 GWh	Band 7 9 GWh < X <= 50 GWh
Austria	16.97	15.10	13.26	12.46	9.91	8.10	
Belgium	17.78	13.79	11.07	13.17	10.95	7.05	5.10
Czech Republic	12.93	10.10	7.27	9.78	7.26	5.40	4.64
Denmark	31.59	22.44	20.46	17.33	16.26	14.07	13.51
France	15.32	11.63	10.33	9.11	7.69	6.04	3.99
Germany	19.27	15.80	13.29	12.95	8.67	6.55	4.98
Greece	7.93	6.54	6.42	8.87	7.13	6.14	5.01
Hungary	10.14	8.12	7.20	9.07	8.23	6.56	5.96
Ireland	16.62	11.33	8.29	16.57	11.60		
Italy	10.40	15.61	18.40	12.89	11.37	9.30	7.19
Luxembourg	18.24	11.85	9.58	12.87	11.13	8.38	7.39
Netherlands	25.12	18.45	16.04	11.39	8.66	6.33	
Portugal	14.21	12.86	8.84	10.27	8.03	7.12	5.29
Spain	14.39	10.94	8.39	10.37	7.69	5.95	4.72
Sweden	14.18	10.50	7.67	6.68	4.89	4.04	3.26
Switzerland	25.20	14.90	11.82	14.96	12.44	10.33	9.79
UK		10.38	8.53	8.75			

Due to the fact that in **Italy** 96% of residential consumers falling in **band 2** have subscribed a 3 kW contract, Italian price in this band has been calculated using a 3 kW contract tariff

The residential prices, in UK, do not take into account pre-payment customers

The average per band is calculated as follows :
  tariff survey : arithmetic average of the prices
  field survey : arithmetic average of all observations in the band

Prices include transport & distribution costs and other (fixed charges)

Residential prices include consumers taxes and VAT
Non Residential prices include consumers taxes

Tariff survey
Field survey
No survey
Too few observations

Figure : Electricity prices in Europe in 2002.(Source : European Electricity Price Observatory)

6. Tariff regulation

The pricing mechanism in a regulatory framework has been traditionally based on several techniques. The role of regulation is to encourage enough investment to meet customer demand and to compensate utility with a reasonable rate of return by setting adequate tariff structure. There are several ways to achieve this goal. We present two basic regulatory forms for determining appropriate level of revenues for power utility : **Rate of return regulation (RoR)** and **Performance based regulation (PBR).**

6.1. Rate of return regulation (RoR)

also known as "cost-of service" or "cost plus pricing". The regulation involves in two step procedures. The first step concerns with i) identifying allowed cost and investment, and ii) setting an allowed rate of return so that the utility will have an appropriate level of earning on its investment. During this step, tariffs are set based on a test period (accounting period) , and remain in effect until the next step. The second step, tariff structure, involves with setting tariff for different customer categories and product that permits the utility to recover the revenue required to earn its allowed rate of return. The procedure of this regulation usually follows :

1) Complaint by one side (utility or regulatory body) that current tariffs are too low or too high because the allowed RoR is wrong.
2) Preparation and presentation accounting details by both sides. Negotiation takes place and the regulator determines the appropriated level of expenses and sets the allowed rate of return.
3) Tariff are adjusted to yield the new RoR allowed by the regulator.

The following equation summarizes the process of determining the RoR :

$$RR = Ed + Eo\&m + T + (RB \times RoR)$$

Where,

RR = the total annual revenue requirement of the utility
Ed = annual depreciation expense
Eo&m = annual operation & maintenance (O&M) expense
T = annual taxes paid by the utility
RB = the rate base (required investment) of the utility = the value of the allowed investment.
RoR = the allowed rate of return on investment (debt and equity).

Underlying idea is that it enables a utility to collect all its prudently incurred expenses, in addition to a regulated return on prudent investment. This provides an incentive to the utility for efficient behaviour or a penalty for inefficient practices.

Advantages	**Disadvantages**
1. Interest of consumer is safeguarded since their viewpoints are incorporated at the stage of tariff change	1. The cost of regulatory process for tariff fixation under this strategy is comparatively higher and

and non-economical goals benefiting the consumer are easily met.	procedure is quite time consuming.
2. The cost having been fixed on basis of performance for the test year remains unchanged for the period prescribed under the tariff order. The utility has, therefore, to resort to imaginative planning in order to offset the changes in external operational environment and also to devise short-term cost minimisation strategy for the tariff period.	2. In case the RoR exceeds the cost of capital, then the utility may resort to non-essential investments in plant development activities. In the opposite situation where RoR is less than the cost of capital, the utility may be discouraged to invest in such activities despite genuine requirement.
3. The system lends itself easily for monitoring and control by the regulatory agency by assigning a clear direction of progress.	3. In the long run this strategy does not leave much incentives for the utility to resort to cost minimization.

6.2. Performance based regulation (PBR)

This form of regulation strengths the financial incentives to lower rates or lower costs and improves performance compared with traditional RoR regulation. PBR establishes a formula that sets utility's revenues or tariffs during a regulatory period of several years, and after that period, a complete revision of costs and investments takes place. and a new revenue or tariff formula is establish for the next regulatory period.

The design and application process include a set of tasks:

1) Determine a benchmarking cost level (benchmarking cost analysis) and revenue requirement for the utility at the beginning period.
2) Set scaling factor (scaling adjustment) for whole subsequent period. These adjustments takes into consideration all variations and changes that might modify the utility benchmarking (efficient) cost.
3) Establish a set of objective criteria to be meet (quality, reliability, social, environment …) and control mechanisms.

The most typical forms of PBR are : Scaling factor, Revenue cap, Price cap.

6.2.1. Scaling factor :

This regulation method permits the sharing of risks and rewards between the utility and consumers. Therefore scaling factor is an earning-loss sharing mechanisms between the utility and its customers. Under this form, scaling factor would adjust prices in current rate so that the allowed rate of return RoR at the new price would be :

$$RoR = RoR_t + k*(RoR_1 – RoR_t)$$

where :
k is a constant (scaling factor) between 0 and 1
RoR_t is the realized rate of return at the tariffs set in the previous rate case in year t
RoR_1 is the target rate of return

If k=1, tariffs are always adjusted to give the firm a rate of return RoR = RoR_1 . If rate case were frequent, the utility would neither benefit from being efficient, nor be damaged from being inefficient. If k=0, all gains from increase in efficiency and all losses from increase in costs affect the utility alone. If k = 0.5, it would indicate that all unexpected benefits and losses are shared between the utility and its customers.

6.2.2 Revenue Cap :

Under this regulation, the utility's allowed revenues are set during a regulatory period of several years. The revenues allowed during the first year is adjusted in subsequent years according to a predetermined set of economic indices and factors. Subject to this cap, the utility is permitted to increase its profits by reducing its costs. The revenue cap form usually is presented as :

$RR = (RR_{-1} + CGA \times ACC) \times (i - X) \pm Z$

where
RR_{-1} is utility revenue in previous year
CGA is Consumer Growth Adjustment factor in (€/customer)
ACC is Annual Change in customer
i is retail price index or inflation index in percentage.
X is measure of productivity of the utility in percentage
Z is external changes unrelated to inflation or productivity and represents any incremental cost that are not subject to the cap.

Revenue caps create incentives to minimize sales to reduce costs. It can be considered open to energy saving programs.

6.2.3 Price Cap :

Under this regulation, maximum prices for utility services are set for several years. Maximum prices allowed during the first year are adjusted according to a predetermined set of economic indices and factors in the common form as :

$P = P_{-1} \times (i - X) \pm Z$

where
P_{-1} is cap of price to a category of customers for the previous year.

Price caps create incentives to maximize sales.

Advantages	**Disadvantages**
The advantages of the system are more or less the same as in case of RoR method with the clear benefit of an in built system of incentives and penalties which reduces the necessity for repeated filing of tariff at	1. The method cannot be successful unless the baseline data is prepared with complete accuracy and the possibility of subsequent undue advantage to the utility due to such inaccuracy is ruled out. This is essential because the regulatory mechanism in this methodology is less rigid.
	2. There is less opportunity for public participation under this strategy as the number of hearings is less than the RoR method.

repeated filing of tariff at short intervals before the regulatory authority and thereby leading to savings in administrative expenses involved in the exercise.	3. The careful designing of the system is essential in order to ensure that the utility does not reduce the quality of services offered in its attempt to achieve rewards in other areas on basis of achievement on other parameters. For devising the system a very careful understanding of inter-dependence of various sub-processes within the system is essential.

Some Problems with Incentive Regulation

Concerns with PBR regulation include the following:

1 . Quality of service degradation. Because the regulated firm is the only provider of services, most customers will continue to buy at the regulated tariff even if quality suffers from cutting costs. A practical implication is that regulators must set standards for quality, monitor utility performance, and penalize poor quality.

2. Concerns over excessive or low profits cause a convergence with ROR regulation. As the time between rate cases increases, the utility captures more benefits from any productivity - improving initiatives. Unfortunately, several factors, including considerations to set equitable rates, unforeseen events that influence utility costs, and asymmetric information problems, could increase the rate case frequency, making incentive regulation more closely resemble traditional (ROR) regulation.

3. Shift of costs toward the most captive customers. The utility has incentive to shift costs from the unregulated to the regulated lines of business, because under incentive regulation, regulators are relieved of the need to monitor costs. Further, if the PBR plan allows pricing flexibility, it will likely lead to an increase in relative rates for customer classes that have the fewest alternatives.

7. Billing calculation and practical exercises

Following table gives a detail tariff of a distribution company.

General tariff – small customers The monthly tariff, *tariff G*, is applied for customers with maximal power demand less than 100 kW. Its structure is following : - 11.67$ for subscription fee - 13.69$/kW for each kW exceeding 40 kW - 7.41 c/kWh for first 11,700 kWh - 3.74 c/kWh for the next kWh Minimal charge amount is 35.01 $
General tariff – intermediate customers The monthly tariff, *tariff M*, is applied for customers with power demand more than 100 kW. Its structure is following : - 11.97 $/kW of maximal power demand during the month - 3.72 c/kWh for the first 210,000 kWh - 2.42 c/kWh for the next kWh Minimal subscribed power demand is 100 kW. The maximal power demand is the highest value of the following values, but can not less than subscribed power demand : - Maximal active power demand (real) - 90% of maximal apparent power demand in kVA
Residential tariff The monthly residential tariff, *tariff D*, is applied for residential customers. - 39 c/day for subscription fee - 4.74 c/kWh for the first 30 kWh per day - 5.97 c/kWh for the next kWh
General tariff – large customers The monthly tariff, *tariff L*, is applied for customer with power demand more than 5000 kW. - 10.95 $/kW of maximal power demand during the month - 2.42 c/kWh Minimal subscribed power demand is 5000 kW. The maximal recorded power demand is the highest value of the following values, but can not less than the subscribed power demand : - Maximal recorded active power demand (real) - 95% of maximal apparent power demand in kVA

Exercise 1 : billing calculation for a residential customer

A residential customer uses 950 kWh in June. Calculate the bill for this customer, base on the presented tariff.

a) Monthly subscription fee is : 30 days x 39 c/day = 11.7 $
b) The first 30kWh/day during 30 days costs :
   30 kWh x 30 days = 900 kWh x 4.74 c = 42.66 $
c) The rest of electricity consumed at : (950 kWh – 900 kWh) x 5.97 c = 2.99 $

d) Total of bill = 57.35 $

Average electricity price is 5735 / 950 = 6.04 c/kWh

Exercise 2 : billing calculation for a intermediate customer

A factory has been classified into the category of intermediate customer. It runs 7 days per week, night and day and uses 260,000 kWh. Maximal power demand is 400 kW. Calculate its monthly bill.

a) 400 kW x 11.97 $/kW	= 4,788 $
b) 210,000 kWh x 3.72 c/kWh	= 7,812 $
c) (260,000 kWh – 210,000 kWh) x 2.42 c/kWh	= 1,210 $
d) Total	=13,810 $

Note that average electricity price is 13,180/ 260,000 = 5.31 c/kWh

For a comparison, consider another factory which consumes the same amount of electricity 260,000 kWh/month, but its maximal recorded demand is 2000 kW :

a) 2,000 kW x 11.97 $/kW	=23,940 $
b) 210,000 kWh x 3.72 c/kWh	= 7,812 $
c) (260,000 kWh – 210,000 kWh) x 2.42 c/kWh	= 1,210 $
d) Total	=32,762 $

Its average electricity price is 32,762/260,000 = 12.6 c/kWh. It shows that high power demand imposes a double electricity cost for the second factory. It is therefore in the interest of the second factory to install a power stabilisator to reduce its peak demand by cutting off non-essential load.

Exercise 3 : billing calculation for a large customer

A factory consumes 11,628,000 kWh/month. This factory has two meters : the first meter indicated a real active power demand of 16,000 kW, and the second meter recorded a real apparent power demand of 20,000 kVA. Subscribed power demand is 18,000 kW. Calculate the bill.

As Factory's subscribed power demand is more than 5000 kW, the factory comes under tariff L.

95% of the maximal apparent power demand is 0.95 x 20,000 = 19,000 kW
This demand is higher than the maximal active power demand (16,000) and its subscribed demand (18,000), so this is considered as maximal recorded power demand and used to calculate the bill

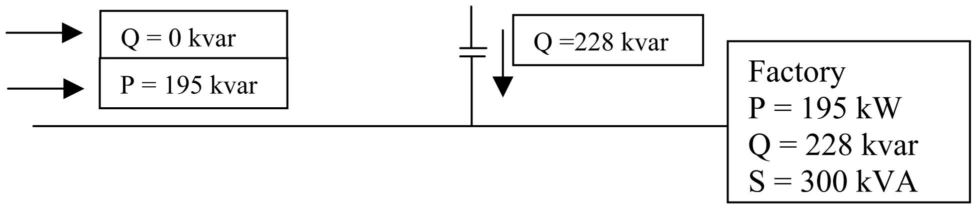
a) 19,000 kW x 10.95 $/kW	=208,050 $
b) 11,628,000 kWh x 2.42 c/kWh	=281,396 $
c) Total	=489,446 $

In fact, the power factor of the factory at peak demand is 16,000 kW / 20,000 kVA = 0.8 or 80%. It is thus in the interest of the factory to install a group of capactors to reduces its apparent power demand. We will consider this correction of power factor in the next exercise.

Exercise 4 : Correction of power factor (PF) for a customer

A factory consumes an apparent power of 300 kVA at a power factor of 65%. Calculate the capacity in kvar of capacitors to be installed at the entry of the factory to correct the PF to a) 100%; b) 90%.

a) Apparent power demand of the factory is : S = 300 kVA
   Active power demand of the factory is P = S x PF = 300 x 0.65 = 195 kW
   Reactive power demand of the factory is $Q = \sqrt{(S^2 - P^2)} = \sqrt{(300^2 - 195^2)} = 228$ kvar.
   If we want to correct the PF to 100%, we need to compensate all reactive power demand of the factory. The capacity of the capacitors should be 228 kvar. Figure below gives power flow of the network after the installation of capacitors.



b) The active power demand of the factory is always P = 195 kW, as its mechanical and thermal demand do not change. If PF should be correct to be 90%, the apparent power demand from the network should be
   S = P /PF = 195 / 0.9 = 216.7 kVA
   Reactive power demand from network is $Q = \sqrt{(S^2 - P^2)} = \sqrt{(216.7^2 - 195^2)} = 95$ kvar
   Given that reactive power demand of the factory is always 228 kvar and that the network should supply only 95 kvar, the difference should be supplied by capacitor. The capacity of the installed capacitors is 228kvar – 95 kvar = 133 kvar.

We can note that if PF required correction from 100% to 90%, the capacity and the cost of capacitors would be reduce up to 42%.

Exercise 5 :
A wattmeter for residential use has a precision of 0.7%. What is the possible maximal error for a household that consumes 800 kWh? (5.6 kWh)

Exercise 6
Three capacitors of 100µF, 600 V are connected in triangle to three-phase line of 600 V, 50 Hz, What is capacity of the group in kvar?

($Xc = 1/(2\pi fC)$; where Xc is Ohms, F is frequency in hertz, C is capacitance of condenser in farads; $Qc = E^2/Xc$).

Exercise 7

From the data presented in the table, Estimate the annual consumption of the country in 2005.

Customer category	Total number of customers	Total annual consumption, GWh	Monthly consumption kWh/customer
Industry	619	1130	152 000
Commercial	14 880	1022	5 720
Residential	117 800	1186	839
These data for the year 1997. We estimate that annual consumption increases 2%/year.			

8. A modern tariff restructuring process

The objectives of a modern electricity tariff restructure are:

- ❖ to have a tariff that genuinely reflects the economic costs and to promote efficient use of electricity, in particular to encourage less consumption during the peak period of the power system, which will help reduce generation and distribution costs in the long run;
- ❖ to secure the financial status of power utility, which will enable future expansion of its operations;
- ❖ to provide fairness for all power consumer categories by reducing cross subsidization from one category to another; and
- ❖ to achieve a mechanism of the electricity tariff adjustment that is flexible and automatic, corresponding with changing fuel prices in the competitive market.

This process involves commonly the steps which are briefly describes hereafter :

1. Set up criteria and collect data :

   - Marginal costs : can be divided into several level : generation, transmission, distribution and retailing
   - Power load patterns and load forecasting
   - Revenue requirement and financial criteria
   - Social criteria : uniform and differentiated tariffs, subsidy and cross-subsidy

2. Analysis of the current electricity tariff structure :

   - Bulk tariff structure
   - Retail tariff structure
   - Current automatic adjustment mechanism

3. Proposal of a new electricity tariff structure :

   - Objectives of tariff restructuring
   - Investment plans and operating efficiency
   - Tariff regulation
   - Marginal cost proposed tariffs
   - Revenue and financial forecast

- Detail tariff structure : bulk supply tariff, retail tariff, automatic adjustment mechanism
- Impact on customers

Annex A : Example on Thailand Electricity tariff study (exerted from "Review of Electric power tariff", NEPO)

A1. Policy objectives and constraints

A1.1 Policy objectives
The review of electricity tariff is undertaken against the background of :
- Current economic activity
- Consequent concerns which have been raised about current tariff
- Future development of power sector

The central policy question is : how tariffs might have been affected in the current economic and social conditions.

A1.2 Tariff objectives
Against this background, the objectives of tariff study should be clear (see the above section)

A1.3. Key constraints
The tariff regime should be robust to medium term sector restructure and ownership change (separation of generation and transmission, split of distribution companies, development of power market, retail competition)

To accommodate short term change (unbundled transmission and distribution charges)

To avoid changes that could provide grounds for legal challenge and compensation claims (on existing tariff adjustment mechanism).

Accordingly, tariff design involves judgements about the appropriate trade-offs among the objectives and constraints.

A2. Investments and operating efficiency review

In this section, the study summaries the current generation, transmission and distribution investment and operating efficiency.

A2.1. Review of demand forecast
The demand forecast underlies the investment and operation plans. The review should help to determine the questions : load forecast methodology is sound? It provides a sensible basis for long term investment planning?

A2.2. Review of investment plans
These investment plans include Generation investment plan, Transmission investment plan, Distribution investment plan

A2.3. Review of operating efficiency
This section discusses Generation and transmission operating efficiency, distribution efficiency. The review includes :

Productivity indicators,
Efficiency indicators (fuel efficiency, Heat rate, …)
Operational efficiency (number of O&M employees /MWh or km, losses…)
Reliability performance (forced outage rate, unserved energy, SAIFI, SAIDI[2]…)

A3. Financial performance criteria.

The financial criteria are used to define acceptable financial performance and to determine the allowed revenue that the utilities may recover through tariffs.

Ratio	Criteria
Self-Financing Ratio	Minimum 25%
Debt Service Cover Ratio	Minimum 1.3 for EGAT Minimum 1.5 for MEA and PEA
Debt/Equity Ratio	Maximum 1.5 : 1.0
(Short and Medium Term Debt)/Total Long Term Debt	Maximum 15%

These ratios are defined as follows:

(a) **self-financing ratio** (SFR) is the ratio of funds generated from internal sources over the average three-year capital expenditure, where;

(i) funds from internal sources comprise:

- *net cash income* for the year, including both operating and non-operating income, after deduction of provisions for major repairs, bonus, remittance to Ministry of Finance and interest;
- less *loan repayments* and provision for bullet repayments of bonds;
- plus reduction (less increase) in *non-cash working capital*;

(ii) capital expenditure is the average over three years (the year, the previous year and the following year[3]);

[2] SAIF (System Average Interruption Frequency), CAID (Customer Average Interruption Duration) et SAID (System Average Interruption Duration)

$$\text{SAIF} = \frac{\text{Total number of customer interruptions}}{\text{Number of customers served during the year}}$$

$$\text{CAID} = \frac{\text{Total customer interruption duration}}{\text{Total number of customer interruptions}}$$

$$\text{SAID} = \text{SAIF x CAID}$$

[3] SFR will clearly be based on projections of capital expenditure for the current year and following year.

(b) **debt service cover ratio** (DSCR) is the ratio of net cash income, *before interest*, over debt service requirements for the year;

(c) **debt/equity ratio** is the ratio of long-term debt over total equity;

(d) **(short and medium term debt)/total long-term debt** is the ratio of all debt maturing less than five years from the date on which it was issued over total long-term debt.

With these financial criteria and given the background economic conditions, the policy objectives and review of investment and operating efficiency, the study should able to recommend appropriate base allowed revenues and corresponding average base tariffs.

A4. Marginal costs

As discussed above, a common approach is to reflect the net present value of the incremental costs resulting from a sustained increment in demand over a number of future years. LRMC in power sector comprise *: marginal capacity costs*, *marginal energy costs* and *marginal customer-related costs*.

Common assumption : voltage levels (230 kV, 115/69 kV, MV, and LV), price level (1998 price level), inflation (5% for local and 3%/y for foreign inflation), discounted rate (7%), exchange rate (utilities' assumption).

A4.1. Generation marginal costs

EGAT uses PROSCREEN II model to estimate the annualised marginal cost, and its split between marginal capacity cost and marginal energy cost. To allocate these costs over the hours in the year, in the case of :

Marginal capacity cost, based on estimates of the daily profile of LOLP;
Marginal energy cost, based on estimates of the daily profile of marginal energy cost.

The tariffs do not contain regional variation in energy costs.

Load curve is divided into 2 periods for simplicity : Peak period from 9h00 – 22h00 of the working days, and off-peak period.

A4.2. Transmission marginal costs

Transmission marginal cost include : marginal capacity costs, marginal transmission losses and marginal connection and customer service costs.

For marginal capacity cost :

- ❖ Identify the new demand at each voltage level in the future years, and optimal incremental costs required to meet this new demand;
- ❖ For each voltage level, to discount the incremental costs and the incremental demand in each year to produce a resent value; then derive the LRAIC.

A4.3. Distribution marginal costs

The methodology to calculate these costs are similar to that of trnamission.

A4.4. Customer-related supply costs

Marginal customer-related cost comprise :

- Distribution connection costs (annuitised capital and installation costs, O&M costs assumed to be 2% of capital cost each year);
- Customer service (meter reading, billing and collection MRBC) costs;

Both of these costs are largely fixed annual costs which depend on the type of connection and meter.

For connection costs, annual connection costs for an assumed representative type of connection for each customer class are estimated annuitising over an average asset life of 15 years at 7% real discount rate.

Marginal MRBC cost are the increase in MRBC cost divided by the increase in the number of customers. This cost may appear to be negative if cost reduction due to efficiency gains exceed cost increases due to increase in customer numbers (i.e. costs decrease with increase in customer number. Thailand used average cost as a proxy for marginal customer service costs and assumed that marginal MRBC costs are half average costs.

A5. Marginal cost based tariffs

There is number of issues related to tariff design : coverage, extent of uniform national tariffs, metering and power factor. In general terms, tariff restructuring sought to minimise changes to the tariff structure and should be ready for any restructuring (de)regulation in the future.

A5.1. Tariff coverage

all customers should have right to be supplied under one of the published tariffs. Tariffs cover all electricity supply costs with the exception of connection costs of new customers which would be recovered by a separate connection charge.

A5.2. Extent of uniform national tariffs

Policy guidance is that the present uniform national tariffs should continue for all customer categories. However, in long term, tariffs should vary regionally to reflect regional differences in the cost of supply.

To maintain the uniform national tariff, there needs to be some cross-subsidy both within a tariff category and potentially between tariff categories.

A5.3. Metering

Ideally all customers should have metering which recorded energy in all periods where was significant cost variation, and which recorded capacity usage.

For larger customer, the practice is to measure both energy and capacity usage. For smaller customers, international practice is to employ an energy only meter with some time-of-day rates. Capacity costs for this category are recovered through energy charges, as installation of demand metering or current limiters would not be cost-effective.

A5.4. Power factor

Power factor charge should be based on power factor study. The study proposes to intoduce power factor charge/kVar/month for each lagging kVar below 0.875 for bulk supply tariff and below 0.9 for retail tariff. Power factor rebates should not be offered for power factor within the target range, as this may create an overcompensation problem in long run.

A5.5. Recommended tariff system

Based upon the examination of marginal costs and all above principles, a set of marginal costs based tariffs was proposed (before scaling to meet financial requirements) for :

- Bulk supply tariff (depend on Time period and voltage) :
    - Generation costs
    - Transmission costs
    - Transmission losses
    - Connection fee
- Retail tariff
    - Progressive block structure for residential customers.
    - For general service and specific business : demand charges in the peak period, energy charge, monthly service charge and power factor charge.
- Transmission use of system charges
- Distribution use of system charges

A6. Tariff adjustment mechanism (F_t)

The main objective for the tariff adjustment mechanism is to maintain sufficient stability to the utilities financial position; to encourage efficiency improvement and energy conservation; to provide transparency and fairness to consumers.

A6.1. Introduction

The Automatic Adjustment Mechanism (F_t), which is added to the base tariffs to form the tariffs actually charged to customers. The base tariffs were established in 1991. Since then, there have been certain changes in the structure of base tariffs, but the intention has been to maintain the same average level in nominal terms. Meanwhile, Ft has generally increased over time and has determined the escalation in electricity tariffs since 1991.

A6.2. Description of Ft

The automatic adjustment mechanism that is applied to retail tariffs - **retail F_t** - is defined by an algebraic formula which is set out below. Retail F_t is a money amount per kWh which is applied to the energy charge for all customer classes (but not to any demand charges). It is calculated for every month, but is used to establish actual tariff levels for a future four month period, in order to provide reasonable tariff stability for consumers. Retail F_t accounts for about 20% of the average retail tariff, although, since it is a flat rate addition to energy charges, the proportion varies by customer category and by load factor.

The formula for retail F_t is as follows:

$$F_t = FAC_{t-1} + MAC_t + AF_{t-1} + DC - MR_{t-1} + DT_t + DD_t + DR_t$$

Where:

(e) FAC_{t-1} is the Fuel Adjustment Charge in respect of month t-1. The effect of the Fuel Adjustment charge is to allow fuel cost pass-through. The formula is set out below;

(f) MAC_t is the monthly adjustment charge for uncontrollable costs. It contains provision for the pass-through of:

(i) Land and Property Taxes.

(ii) Demand Side Management costs; and

(iii) since the beginning of 1999[4], exchange rate losses on foreign debt;

VAT, another uncontrollable cost, was taken out of F_t in 1997, since when it has been separately itemised on customer bills;

(g) AF_{t-1} is the Accumulated Energy Adjustment Charge in month t-1. The purpose of the Accumulated Energy Adjustment Charge is to correct for the fact that retail tariffs are fixed for four months whereas F_t varies monthly;

(h) DC is the Discrepancy Charge. This corrects for the lag in the application of the adjustment factors, which means that the volumes to which the adjustment factors FAC, MAC, AF and MR apply are different from the volumes on which they were incurred;

(i) MR_{t-1} is a factor to correct for differences between actual average unit revenue and planned average unit revenue: this would normally occur if there is a mis-estimation in customer mix. However, if the planned revenue is revised, such as when the tariffs were reviewed in April 1998, it is this term (in the overall Ft formula) which has been used to reflect the change in planned revenues. The specific formula for MR_{t-1} is set out below; and

[4] Previously, foreign exchange losses on foreign debt were taken account of through revisions to the MR element of the F_t formula. The planned average unit revenue was multiplied by an index that reflected the baht/dollar exchange rate and the weighting of foreign denominated costs. The index was calculated as (1-the weighting of foreign denominated costs) + (weighting of foreign denominated costs in total costs x actual baht/dollar exchange rate/27). The baht/dollar exchange rate immediately before the depreciation was 25.80 - the utilities were expected to absorb a small amount of the exchange rate loss. The new treatment allows pass-through of "actual exchange rate losses" rather than an estimate.

(j) DT_t, DD_t and DR_t are factors to correct for variances of actual inflation from the forecast figures used to set the planned purchase price, and are applied to the original estimates of transmission, distribution and supply operating costs respectively.

FAC_{t-1}, the Fuel Adjustment Charge, is calculated according to the formula:

$$FAC_{t-1} = AFC_{t-1} - BFC_{t-1}$$

Where:

(k) AFC_{t-1} is the Actual Fuel Cost incurred per unit of kWh of energy sold to final customers, calculated according to the formula:

$$AFC_{t-1} = (\Sigma_i (P_{it-1} \times Q_{it-1}))/S_{At-1}$$

where:

(i) P_{it-1} is the actual price of resource i in Month t-1. There are the following different resources: heavy fuel oil; diesel oil; natural gas; and energy purchased from IPPs, SPPs, Lao Republic and Malaysia. Note that lignite is excluded;

(ii) Q_{it-1} is the actual quantity of resource i consumed in Month t-1;

(iii) S_{At-1} is the actual end-use energy sold in month t-1

(l) BFT_{t-1} is the Base Fuel cost per unit of energy forecast to be sold in Power Development Plan 90-03 (PDP90-03). PDP90-03 was written in 1990, and contains forecasts of annual demand for the period 1990-2005. Standard monthly load profiles are then applied to the forecast annual demand to create a demand forecast for the month in question.

MR_{t-1}, the correction factor for the variance between the actual average price and the planned average price (usually due to any mis-forecast of customer mix), is calculated using the formula:

$$MR_{t-1} = \Sigma_k [(P_{Akt-1} - P_{pk}) \times S_{Akt-1}]/S_{At-1}$$

Where:

(m) P_{Akt-1} is the actual average unit revenue of utility k in month t-1;

(n) P_{pk} is the planned average unit revenue for utility k for the year. Note that when the tariffs were reviewed in April 1998 the values of P_{pk} were increased for EGAT and MEA. As a result, P_{pk} exceeded P_{Akt-1}, and hence MR_{t-1} was negative and F_t increased;

(o) S_{Akt-1} is the actual energy sold of utility k in month t-1; and

(p) S_{At-1} is the actual end-use energy sold in month t-1.

There is no algebraic expression for the automatic adjustment mechanism that is applied to the base BST - wholesale $\mathbf{F_t}$ - in the same way as there is for the retail F_t. Instead, it is derived by allocating to EGAT its "share" of retail F_t as follows:

(q) the Fuel Adjustment charge;

(r) the share relating to EGAT's uncontrollable costs;

(s) the inflation adjustment to transmission operating costs; and

(t) the amounts due to EGAT in respect of the application of the correction factors.

Chapter II – SOFTWARE TOOLS FOR ASSISTING WITH MANAGEMENT AND MAINTENANCE OF MINI ELECTRIC GRIDS AND PHOTOVOLTAIC KITS SYSTEMS

1. ISSUES

Nowadays, the new challenges of decentralized rural electrification are organizational and financial issues. Il results from the durability of the projects and the affirmation of the proposed schemes as alternatives to a conventional electrification in rural area.

In a commercial context where system management is furthermore dedicated to the local private operators, an urgent need is required to understand the following factors :

1- To the management of non-conventional customer (often not able to read and write, living in rural areas, earning an irregular income, …), in a context where exploitation results are very sensible to bill collection rate;

2- To the necessity of regular technical controls and preventive equipment maintenance, the exploitation results depend on the good operation of the equipment and therefore the regular analysis of :

- Technical reports on the generator and of the distribution grid
- Load curves, allowing to an adjustment of the supply corresponding to the demand

3- Furthermore, in the **leasing schemes** which are widely adopted, the remuneration for the manager is indexed to a set of performance indicators, related at the same time to the technical performance and to quality of service. This supposes the regular update and exact definition by the concessionaire a set of indicators which fixes the remuneration for the services of the manager.

4- In monopole context in the pass of the national power utilities, **the concerned national/ local operators** do not have operational experiences of the electric grid. The system and the important control operations related to this kind of schemes require an automatic processing of data. However, this processing need to be considered in the specific context of each project and the particular environment of each operator.

2. THE DEVELOPMENT OF SOLUTIONS : A PARTICIPATIVE APPROACH

The development of the solutions rests on three strong components :

1. The design
2. The development of the software package
3. The operational testing.

Phase I: Modeling of the Information system.

Since twenty years ago, the **MERISE methodology**, developed in France, largely proved reliable as systemic analysis, particularly in the Business data processing, in France and in Europe. It is used as a basis for the design and the development of an information system computerized, preliminary to the installation of a database.

In the context of the Decentralized Rural Electrification, this method has the merit to be participative, with the association of actors in different critical phases. The initial modeling process comprises three steps : Development of a master scheme, Preliminary study and Detailed study. These initial steps focus on specifying the general framework, on definition of the various information systems, mainly in term of objectives and constraints : modeling orientations, organizational issues (including the definition of the working stations), material and software selection, total planning of the development and budgetary frameworks.

As noted, the model tool should show the adaptability to the context of Decentralized Rural Electrification. At the same time, in term of customer management and specific technological considerations, it has to integrate two following functionalities:

- A capacity of taking into account the management of the customers and preventive maintenance of the equipment.

- A capacity to facilitate the measurement of the performances of the private operator and the calculation of its remuneration.

<u>Phase II: Development of the software package</u>

In this phase of development, it is a question of participation of concerned actors with the data processing tool in its design phase : private companies in charge of the exploitation and / or maintenance, regulatory body, national rural electrification agencies, ministry of energy, users association, etc, to collect their reactions and commentaries on the results of phase I.

Several working meetings to be organized with these various actors in order to validate the preliminary studies, particularly with regard to the Organizational Information system: management and organization, resources and assignment.

The programming of the database is done under the relational database management system ACCESS. Integrated into the MERISE methodology, this stage of production/validation of the software is an essential phase of the process.

ACCESS is selected because of several criteria:

- **The cost.** ACCESS is delivered with Microsoft Office, which includes the software widely used, like Word and Excel, often delivered with a computer. This choice avoids an extra cost for operator/user to buy new software;
- **Flexibility and user-friendliness.** With ACCESS, it is possible to develop convivial user-software interfaces. In the context of developing countries, this criteria is important to ensure its integration.

This phase will thus lead to the release of the software package (program writing, creation of the files and the databases, development tests), and to its start-up (planning of installation, creation and loading of the basic information, training of the users, checking of the correct operation of the software, installation progressive of the new organization).

Phase III: Test of the software package

Tests of the software package in normal operation conditions to be then carried out with the customers, to integrate the reactions of the users and to define the operational methods of maintenance of the software package.

MRGESTION ©

A software tool for assisting with management and maintenance of mini electric grids

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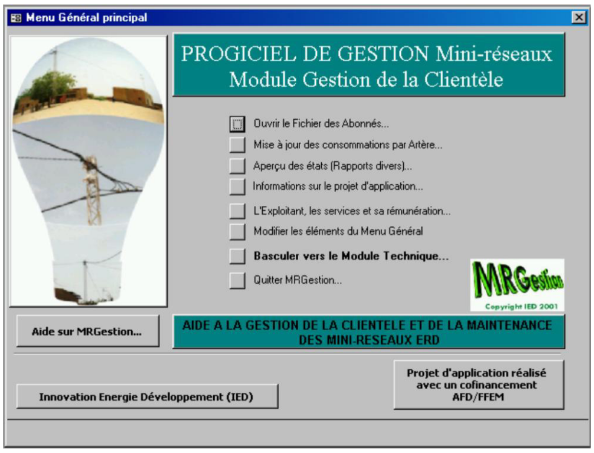
The solution MRGestion©

In the relation between Contractor/ manager, the software MRGestion ©, developed by IED, brings a solution to three components :

1. Assist the customer management of mini grids : Customer records, billing, payment record, analysis of collection rate, etc.
2. Assist the management of technical control (generators life time, operation time, fuel and lubrification oil consumption, etc.) and equipment maintenance (check-lists, breakdown, repairs, etc.) ;
3. Performance indication of the Operator (collection rate, number of customers, energy billed and consumed, specific consumption, grid efficiency, etc.) and regular determination for operator’s remuneration.



MRGestion© is a relational database, which allows the user to manage the customer services of mini grids, follow the technical control and the maintenance of production and distribution equipments.

MRGestion© in addition, can determine the remuneration amount of the Operator, from a set of performance indicators.

<u>*OUTPUTS OF THE MODULE « CUSTOMER MANAGEMENT »*</u>

- **Customer records**
- **Regular listing of invoices and customer bill**
- **List of non- paid bill**
- **Billing records of a customer**
- **Analysis of collection rate**

OUTPUTS OF THE « TECHNICAL » MODULE

- **Regular operational records of the generator**
- **Regular operational records of the distribution grid**
- **Regular technical report, production indicators, load curves**
- **Saturation rate of different feeders**

CALCULATION OF THE REMUNERATION FOR THE MANAGER BY MRGESTION©

- **Remuneration of manager :** amount of remuneration by period (month, …), based on performance indicators.

DATA INPUT AND COLLECTION : THE FORMS OF MRGESTION©

- **Subscription form**
- **Extension / renewal form**
- **Generating operation**
- **Check-list of the generators**
- **Report of the breakdowns/ repairs for the generators**
- **Routine report on grid line**
- **Records of “typical day” for load curves**
- **Report of the breakdowns/ repairs for the grid**

PVGESTION ©

A software tool for assisting with customer management and Photovoltaic kits maintenance

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Data base structure of "PVGestion"

PVGestion is a software tool that assists in customer management, follows customer payments and keeps a track on the maintenance aspects. It is developed in ACCESS database, a widely accessible software, with a user-friendly interface and requires no pre IT knowledge to use it.

This brochure presents the structure of this database **PVGestion.**

The database of ***PVGestion*** *is built in the form of tables that are inter- linked. The tables are constructed in such a way allowing for easy printing of client information, management analysis and differing monitoring documents. Several forms make the interface easier for the user.*

PRESENTATION OF TABLES

- **Donor and Project manager :** information on the donor and the Project manager
- **Customer :** information on the customers (references, locality, region, coordinates GPS, closest town, accessibility type , customer status (name or occupation, etc.)
- **Order :** order(s) put forward by the customer to the Operator;
- **Details of the order :** specific information on the order including the order reference, the product reference, quantities and prices, subsidies if any;
- **Employees :** list of agents of the Operator with their references, coordinates, name, etc.
- **Information on the Operator :** information on the operator, including the address and the TVA rate for products;
- **Maintenance :** records of maintenance operation carried out for each customer, comprising the operation reference, the customer reference, reported breakdown type, date, status of different component and type of maintenance operation carried out ;
- **Project responsible :** Information on the organization responsible for the project;
- **Payment Mode:** list of different payment modes : «cash» or « credit » ;
- **Payments :** detailing in the case of credit payment, different payments made by customer. It permits to have a chronological situation of debts ;
- **Products :** list of products (types of kits) available from the Operator;

REPORT PRESENTATION

The database **PVGestion** can produce the following reports :

- **Sale document :** specified in tender file, this document is the sale contract between the Operator and each customer. It includes the Operator ID, Seller ID, Customer ID, information on the order with total price, payment mode in case of credit payment.
- **Sale status per agent :** This report allows to summarize all sales made by each agent of the Operator. It can serve to analyze the « sale strength» within the Operator team;

- **Maintenance report per customer :** Report which allows to summarize different maintenance operations carried out per customer;

- **Update list of customers/ kit type :** a report, describing in the tender files as a commitment of the Operator. In fact, at the end of each month the Operator has to provide to the project manager an updated list of customers and installed systems. This list should include the ID number of each module and a certificate of factory measure;
- **Maintenance by region :** status of the maintenance operations grouped by area (region).

PRESENTATION OF FORMS

All tables are linked to an end-user interface called a form. These forms allow for easy data entry and printing of the various reports.
The main **« Switchboard »** form is designed to be user-friendly, allowing the user to integrate or display different data on customers (orders, maintenance operations, etc.), modify or display information on the Operator (ID, coordinates, record the technical and commercial agents, etc.), and view all reports before printing.
The form "**Order by Customer",** accessible from the Switchboard, allows to constitute the Customer file, described in the contract, and to enter into following forms :

1. **Order :** detail of different elements of the active customer's order ;
2. **View of the Sale document :** can obtain a view of the contractual document « Sale document » and to print;
3. **Payments :** permits to follow payments by each customer in case of payment by credit ;
4. **Maintenance file :** permits to record and follow different operations of maintenance carried out for the active customer.