Conceptual framework of Tenaga Nasional Berhad (TNB) cost of service (COS) model

WNRA Zainudin1, WWM Ishak2 and NA Sulaiman3
1, 2 Faculty of Science and Technology, Universiti Sains Islam Malaysia, 71800 Nilai, Negeri Sembilan, Malaysia
3 Department of Accountancy, Faculty of Business and Accountancy, University of Malaya, 50603 Kuala Lumpur, Malaysia
Email: rahini@usim.edu.my

Abstract. One of Malaysia Electricity Supply Industry (MESI) objectives is to ensure Tenaga Nasional Berhad (TNB) economic viability based on a fair economic electricity pricing. In meeting such objective, a framework that investigates the effect of cost of service (COS) on revenue is in great need. This paper attempts to present a conceptual framework that illustrate the distribution of the COS among TNB’s various cost centres which are subsequently redistributed in varying quantities among all of its customer categories. A deep understanding on the concepts will ensure optimal allocation of COS elements between different sub activities of energy production processes can be achieved. However, this optimal allocation needs to be achieved with respect to the imposed TNB revenue constraint. Therefore, the methodology used for this conceptual approach is being modelled into four steps. Firstly, TNB revenue requirement is being examined to ensure the conceptual framework addressed the requirement properly. Secondly, the revenue requirement is unbundled between three major cost centres or business units consist of generation, transmission and distribution and the cost is classified based on demand, energy and customers related charges. Finally, the classified costs are being allocated to different customer categories i.e. Household, Commercial, and Industrial. In summary, this paper proposed a conceptual framework on the cost of specific services that TNB currently charging its customers and served as potential input into the process of developing revised electricity tariff rates. On that purpose, the finding of this COS study finds cost to serve customer varies with the voltage level that customer connected to, the timing and the magnitude of customer demand on the system. This COS conceptual framework could potentially be integrated into a particular tariff structure and serve as a useful tool for TNB.

1. Introduction of the study
In July 2015, the Parliament approved the Bill to amend the Electricity Supply Act 1990 (Act 447). The purpose of this amendment is to enhance the governance of the electricity supply industry in ensuring better sector efficiency, reliability and safety in the industry. Among the key points of the Electricity Supply Act (Amendment) 2015 are the set up of the Electricity Industry Fund, the ring fencing of Single Buyer (SB) and Grid System Operator (GSO), the separation of licensed activities and requirement for licensees to submit business plan [1]. Some countries decided to have separate
system operation from potentially all competitive parts of the electricity value chain i.e. generation, wholesale and retail. However, this option requires major changes to existing industry structure and may result in significant risks for the safe and reliable operation of the power system if not properly enacted.

As an alternative, other countries therefore opted for the option of ring fencing the system operator by introducing certain changes and safeguards in order to ensure that the system operator acts in transparent and non-discriminatory manner and to avoid cross-subsidies between the system operator and other parts of vertically integrated utility. Organisational unbundling are chosen for Peninsular Malaysia as it provides most of the benefits to the system with lower cost and level complexity compared to legal unbundling or ownership unbundling practices. It is important that unbundling mechanism fulfilled the transparency criterion that is the process documentations need to be well defined, endorsed and published. For non-discriminatory criteria, the unbundling mechanism need to have access to fair and equal information, decisions taken need to be perceived and there is a clear cost separation.

It is now becoming mandatory for the Electrical utilities to gradually reduce the cross subsidy and move the tariffs in a state towards the COS. Traditionally, tariffs for domestic and agricultural customers have been heavily subsidised either by state or cross subsidisation from other consumer categories, primarily the consumer using electricity at high voltages [2]. A basic principle that has been widely accepted in electricity sector regulation is that the tariffs for various categories of customers should be practical and equal to the costs imposed by that category of customers on the system. This is what currently understood in COS. The estimation of COS on each category of customers enable the calculation of cross subsidy. The obligation to reduce cross subsidy comes from the legal, policy and regulatory framework of the power sector. In relation to this, this study attempts to find the best possible methodology that can be used by TNB to adopt COS in their tariff design. Using COS study, utility could seek to allocate all the cost to each of the customer classes it serves. The costs can also be used as an input to tariff design or to determine cross subsidy. The determination of COS for each of customer categories require disaggregating the utility’s costs into functions, services and categories.

It has also been proven in economic theory that tariffs reflecting a COS to the customer category are able to provide economic signals for an optimum use of electricity and investment. This COS can either be determined using an embedded cost or marginal cost approach basis. The embedded cost based uses the historical accounting information and ensure all prudent cost are being allocated. However, this approach does not provide any economic signal to the consumers. While the marginal cost based uses the future costs to determine the tariffs and provide economic signal for the efficient investment and optimum uses of electricity. However, this approach does not ensure adjustment for the recovery of the actual cost [2].

2. Conceptual Framework of Cost of Service (COS) Model

There are several key requirements in an electric COS Model. It is designed to fulfil the best practice of COS studies where it need to have a structural and systematic framework to carry out cost functionalization, classification and allocation. In addition, it also addresses Malaysia’s unique context which are IBR regime and Single Buyer Model. Hence, detailed understanding of how customers use electricity in Malaysia are needed to develop a robust COS platform. The two primary types of COS are embedded COS and marginal COS. The majority of jurisdiction use embedded COS based on actual book data and class load for cost allocation while the marginal COS is used based on the forward looking incremental costs of serving customers. Both type of COS are used for development of time-of-use pricing, demand-side management and energy efficiency evaluation. As for TNB, they primarily using embedded COS although marginal COS may serve as basis for TOU tariff. Figure 1 illustrates the conceptual framework of the COS model. Detailed discussion on the framework is discussed in the later sections.
Figure 1: Conceptual Framework of COS Model.

For the purpose of this study, the conceptual approach also is being modelled using the following mathematical approach. Firstly, a utility’s revenue requirement is being represented based on the total amount of revenue need to be collected from all customers and it is used to pay all costs of doing business including a reasonable return. As mentioned before, TNB must produce sufficient revenue through its charge rate to cover its revenue requirements also known as costs. In order to calculate the revenue requirement, the general formulation is as follow:

\[ t = (WACC_t(r) \times AB_t) + OPEX_t + D_t + T_t + Efficiency\ carryover\ amount \]  

\[ t = Revenue\ Requirement \]

WACC = Weighted Average Cost of Capital

r = Return

OPEX = Operating Expenses

D = Depreciation

T = Taxes

\[ t = Test\ year \]

Secondly, the revenue requirement will be unbundled between the three major business units or functions that are Generation, Transmission and Distribution. Let \( \{A_i\}_{i=1}^{n_A} \) be the principal functions involved in the functional unbundling process, i.e. Distribution (\( A_1 \)), Transmission (\( A_2 \)) and Generation (\( A_3 \)). All these principal activities \( A_{i,1\leq i \leq 3} \) required sub-activities; \( \{a(i,j)\}_{j=1}^{n_{a_i}} \) that will incur respective costs in a chosen period of time. Therefore, the cost for each principal activity, \( C_{A_i} \) can be deduced as,

\[ C_{A_i} = \sum_{j=1}^{n_{a_i}} C_{a(i,j)} \]  

As a result, the total COS, \( C \) used to recover the revenue requirement, over a relevant period of time can be expressed as;

\[ C = \sum_{i=1}^{n_A} C_{A_i} = \sum_{i=1}^{n_A} \sum_{j=1}^{n_{a_i}} C_{a(i,j)} \]  

3
Once the revenue requirement has been established and the functional services are being unbundled, the next process is cost classification. As a basis for allocating costs to individual classifications, the revenue requirement is being classified based on specific cost components within each functional area such as system demand component, energy consumptions component and the customers related charge component. Finally, these classified costs are being allocated to customer classes based on the customer class usage characteristic such as Domestic, Commercial and Industrial.

Let, \( \{K_i\}_{i=1}^{nK} \) be the principal consumers involved in consumption of the generated energy, i.e. Households, Commercial and Industries. Then, let assume that each of the sub-activities in principal activities could be classified into one of the following class cost; \( \{S_k\}_{k=1}^{nS} \) such as demand related cost, energy related cost and providing customer related cost. For each consumer group, \( K_i \) we further assume that we have devised a function,

\[
 f_{K_i}(S_k, a_{(i,j)}) = P(K_i, S_k, a_{(i,j)}), \quad 0 < P(K_i, S_k, a_{(i,j)}) < 1 \quad (4)
\]

Thus,

\[
 \sum_{K=1}^{nK} P(K_i, S_k, a_{(i,j)}) = 1 \quad (5)
\]

Where it is represent the fractional contribution of services, \( S_k \) to activity, \( A_i \) for each consumer group, \( K_i \).

2.1 Establishment of Revenue Requirement

The first component in COS is an examination of revenue requirements for TNB. To remain financially sound, TNB must produce sufficient revenue through its rate. This is important to cover its revenue requirements which is also known as costs. The annual revenue requirement is also used as a basis for subsequent phases in the framework. The establishment of the annual revenue requirement is done by determining the total revenue that TNB need to collect for the services provided to serve its customers, maintaining its debt service obligations, investing in its system and providing additional funds required to governing bodies as appropriate. Study by [3] suggests that examination on revenue requirement can be done by comparing the projected income earned from revenue at existing electric rate against the expenses expected to be incurred in serving customers during the same period. This means that the annual revenue requirement is equal to the annual COS. Hence, the annual revenue requirement is used as a basis for the COS analysis based on numerous assumptions.

The setting of revenue requirement can substantially affect the profitability of the utility as well as the costs of ratepayers. One of the basic method for setting revenue requirement is rate of return methodology which also known as cost plus or COS regulation [4]. Other than determining revenue, the revenue requirement is also used to determine cost components for the TNB. Therefore, the key elements in the cost of rate of return methodology include operating expenses, taxes and depreciation. The operating expenses relate to operating and maintaining the utility plant and providing the utility services [5]. These key elements are also being used to calculate the revenue requirement to ensure a fair rate of return on utilised assets.

Meanwhile, in an analysis done by [6], in order to determine a utility’s annual revenue requirement, a financial model is being developed to provide an estimation of financial results for a five-year period. Within the model, projections were made on operating revenues, operation and maintenance expenses, depreciation expense and interest or taxes expenses for each fiscal year. These projections are based on certain assumption. Besides that, they also projected the number of customers by class, total energy sale by customer class and energy requirements, rate of revenues based on the existing
rate, other operating revenues, operation and maintenance expenses, purchased power expenses, plant in service and rate base, debt service and net income.

In summary, COS is defined as the amount of revenue by a regulated energy company such as TNB must collect from the rates being charged to their consumers so that the cost of doing business can be recovered. These costs include operating and maintenance expenses, depreciation expense, taxes and a reasonable rate of return on investment. Other than that, COS analysis also provides a basis for the distribution of TNB’s costs across its rate classes and guideline for assigning cost responsibility to each classification. This is important to avoid unjustifiable price discrimination. Additionally, mismatching the tariff rates and the costs underlying those tariffs can cause several issues such as inadequate revenue recovery, increased risk and higher costs of capital, inefficient behaviours and non-optimal investments in long lasting durables.

2.2 Functional Unbundling
The second component in COS is performing functional unbundling. Various revenue requirement components are unbundled by functional utility service. Previous study done by [6] stated that the electric service utility provided to its customer is sold as a bundled product that involves the provision of multiple functional services. Thus, utility need to unbundle the cost which will facilitates implementation of separated pricing of individual services. In analysing the functional services the utility provides to the customers, thirteen specific services are identified including Power Supply, Transmission Delivery, Distribution Delivery, and Customer. Subsequently, each component of the revenue requirement is assigned to one or more of the unbundled functional services. In order to unbundle the costs by functions and services, the TNB’s revenue requirement could potentially be divided into three major business units or functions which is Generation, Transmission and Distribution.

In another study done by [7], they explained that the functional unbundling process involves categorising the revenue requirement on the basis of utility function and service. The costs are unbundled into Production and Transmission, Distribution and Customer functions. For the purpose of the study, costs for production and transmission are collectively referred to as the “Cost of Power”. Likewise, the revenue requirement also could be functionalized using rate base component rather than expense components. In addition, [8] mentioned that revenue requirements can also be allocated to functional cost categories that correspond to the services provided such as energy, distribution, customer service, subsidy for Utility Discount Program (UDP) customers and credit for net wholesale power revenue. Along with, it also functionalized operating cost of revenue requirements by separating it into network and non-network component. In short, the unbundling function process is generally depended on the policy and structure of the utilities itself.

2.3 Classifying Cost
The third component, as a basis for allocating costs to individual classifications, TNB is proposed to classify the revenue requirement based on the specific cost components within each functional area. These components and the type of costs assigned to each functions include system demand component, energy consumptions component and the customers related charge component. Preliminary study undertaken by [3] stated that demand component is the costs incurred to provide an electric system capable of meeting the total combined demands of customers, the portion of purchased power and generations, operating and maintenance expenses, capital expenditures and other costs which are generally fixed and do not vary materially with the amount of electricity consumed or which cannot be designated specifically as a customer or energy cost. While, energy consumptions component is the costs that vary substantially or directly with the amount of energy purchased or generated and the cost are expected to vary with electricity consumption. Finally, the customer related component is the costs directly related to the number, type and size of customers such as customer accounting, billing, cost of meters and services or other equipment to provide service.
In other words, classification is the process of separating the functionalized costs into classifications based on what the costs are sensitive to. The primary cost classification categories include demand related cost (kW), energy related cost (kWh) and customer related cost. Therefore, previous study done by [2] showed that each functions have its own related costs. For example, the generation function has incurred energy and demand related cost. This is because, power purchase cost generally have two elements that are fixed and variable costs. The fixed or demand costs include costs associated with the plant capacity. Meanwhile, fuel costs are treated as variable or energy related costs. For the transmission function, it is designed to handle certain peak demand and the costs are fixed or can be treated as demand related. Finally, the distribution functions are used to provide various services to the end user such as metering and billing. Hence, the costs can be classified into demand related and customer related. There are no set of prescribed rules for functionalities and classification on these costs since they are mainly depend on the experience and judgement of the utility in classifying these costs in the best possible manner.

2.4 Allocation Cost
The allocation costs are developed among customer classes to reflect the relative impact on each rate class. In a study carried out by [6] the allocated annual revenue requirement by service classification are allocated into14 customer classes such as Residential Sale, Water Well Sales, Small Power, Large Power and Industrial Power. As for TNB, the classified costs are allocated by customer classes based on customer class usage characteristic. These classes are Domestic, Commercial and Industrial customers. In a study of allocation of customer classification by [3], there are various factors to be considered in allocating the Electric Division revenue requirement to individual customer classification. These allocation factors need to reflect an accepted ratemaking principle. Therefore, amongst the allocation factors used are demand allocations which relate to the peak demands and coincident peak (CP) demands by customer class which reflect the maximum monthly and annual demands on the system. In addition, coincident and non-coincident demand (NCD) is typically calculated by considering one, four or twelve month time periods. However, the method used to allocate the costs depends on a utility function and specified demand cost items.

Allocation also refers to the process of assigning the functionalized and classified revenue requirement to different jurisdictions and customer rate classes. This is because, different customer groups use the system differently. Hence, the costs can be allocated by using several cost drivers such as energy (kWh), generation and transmission capacity using coincident peak, distribution using non-coincident peak, customer service, metering and billing. Once the customer class categories have been designated, particular functionalized and classified costs are allocated among the rate classes based on an allocation method that considered to be most consistent with cost causation. This particular allocation method also known as allocation factor. It is based on a set of percentages that sum to hundred percent.

For demand related cost allocation method, system peak responsibility for example twelve month coincident peak (12CP) is typically used for allocation of transmission demand related cost. While, the non-coincident demand (NCD) is typically used for the allocation of distribution demand related cost. This method is consistent with the accepted approach to general distribution demand allocation. However, allocation of generation demand related cost normally used Average-Excess Demand (AED).

In contrast, the generation energy related cost allocation method is using kWh of Energy at customer’s meters and generation plants as its estimation. This allocation method should take into account the fact that different rate classes have different contributions to line losses. For example, residential and small commercial customers contribute significantly more to losses compared to the large high voltage customers. Finally, customer related cost allocation method is using a relative number of customer or relative weighted number of customers where the weightage is based on class-average meter cost, billing cost and service line. A suitable allocation method should be reflect an actual planning and operating characteristics of the utility’s system, cost causation and stable result.
3. Conclusion

This paper attempts to present a conceptual framework on the COS model. The framework begins by defining the revenue requirement to be based on the total amount of revenue need to be collected from all customers and to be used to pay all costs of doing business including a reasonable return. Then, the revenue requirement is being unbundled into three major business units or functions that are Generation, Transmission and Distribution. Once the revenue requirement has been established and the functional services are being unbundled, the next process is cost classification. As a basis for allocating costs to individual classifications, the revenue requirement is being classified based on specific cost components within each functional area such as system demand component, energy consumptions component and the customers related charge component. Finally, these classified costs are being allocated to customer classes based on the customer class usage characteristic such as Domestic, Commercial and Industrial. In summary, this paper provides a conceptual framework on the cost of specific services that TNB currently charging its customers and served as potential input into the process of developing revised electricity tariff rates. For future study, the differences in the partition of allocation in domestic, commercial and industrial customers should be explored further.

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