Benchmarking Electric Distribution Utilities in the Philippines

Larry Blank, Doug Gegax & Benjamin Widner
Department of Economics & International Business
& Center for Public Utilities, New Mexico State University
P.O. Box 3127, Las Cruces, New Mexico 88003, USA
E-mail: bwidner@nmsu.edu

Received: August 2, 2011 Accepted: September 27, 2011 Published: March 1, 2012
doi:10.5539/ass.v8n3p3 URL: http://dx.doi.org/10.5539/ass.v8n3p3

Abstract

A new law in 2001 granted flexibility for the Philippines Energy Regulatory Commission to implement alternative forms of regulation for distribution utilities as a complement to traditional cost-based regulation. We estimate a cost benchmark model from Philippines' data of distribution utilities to explore "yardstick competition" as an alternative under which the regulated firms may be rewarded or punished based on their performance relative to their peers. Our model is based on technical and institutional considerations. System energy loss reduction is treated as an output and we find that such efforts by cooperatives have a lower impact on cost than privately-owned utilities. This result is probably due to the non-technical nature of network energy losses in areas served by cooperatives. Although geography appears to affect costs, we fail to find evidence of higher costs in the politically tense area known as the Autonomous Region of Muslim Mindanao.

Keywords: Utility regulation, Benchmarking, Alternative regulation, Yardstick competition

1. Introduction

The Philippines' Electric Power Industry Reform Act of 2001 (hereafter, "the Act") created the Energy Regulatory Commission (ERC) with authority and responsibilities never before held by predecessor regulatory agencies. The overall objectives of the Act are to increase the efficiency of the Philippines electric industry and strengthen the regulatory processes that govern the industry.

The structure of the electric power industry in the Philippines includes an upstream National Power Corporation (NPC) and a National Transmission Corporation (Transco), both of which are currently owned by the government. (Note 1) NPC controls the dominant share of power production in the nation through direct ownership of generation plants and long-term contracts with independent power producers (IPPs). Transco owns and controls the backbone transmission grid throughout most of the nation which allows for the sale and delivery of NPC and IPP power to electric distribution utilities (DUs). Each DU then delivers electricity to the end-use retail customers within its monopoly franchise area. With a few minor exceptions, the DUs are delivery and retail sales operations and do not own power generation facilities. The Philippines is a nation with thousands of islands but the majority of the DUs are connected to one of three Transco backbone grids. Of the 139 DUs in the nation, 19 are privately-owned companies and 120 are electric cooperatives. Figure 1 provides an example of the geography and service areas for 16 DUs in the Philippines.

<Insert Figure 1 here>

Among the many mandates placed on the ERC and the electric industry, the Act required ERC approval of unbundled rates; that is, separate rate elements for each of the functional service components of the industry: generation, transmission, distribution, and supply. (Note 2) Shortly after its inception, the ERC, released a pro-forma model for unbundling and ordered the filing of unbundled cost-of-service rates by all 139 distribution utilities (DUs). Because of an expedited time schedule mandated by the Act to process so many rate cases, the ERC did not have time to consider alternatives to traditional cost-of-service regulation and instead focused on the new mandate of unbundling the costs. These rate cases, however, provide the source of the data used in the development of the cost benchmark model herein. (Note 3)

The Act did grant flexibility to the newly formed ERC to implement alternative forms of regulation as a substitute to traditional cost-of-service regulation. Indeed, ERC has adopted new rules for price-cap regulation of the state-owned Transco, known as the "Transmission Wheeling Rate Guidelines" (TWRG), and the agency also adopted the "Distribution Wheeling Rate Guidelines" (DWRG) as an optional form of revenue-cap regulation for privately-owned DUs. (Note 4) Whereas the TWRG was mandatory for Transco, the DWRG is an optional form of alternative regulation for the DUs. Although the DWRG has been available since early 2005, few DUs have opted into the alternative regulatory regime and the scheme is not an option for the 120 electric cooperatives (ECs).

Herein we explore the possible development of an alternative regime known as "yardstick regulation" or "yardstick competition" which may be suitable for both private DUs and ECs and is arguably much easier to administer than the DWRG mentioned above. Moreover, yardstick regulation could serve as a regulatory mechanism that streamlines the traditional cost-of-service regulatory process. This is particularly important for a jurisdiction like the Philippines where a very large number of utilities (over 140) are regulated by a single agency. In particular, the benchmark model allows the agency to "flag" high-cost companies thereby limiting the number of in-depth audits that the regulatory agency must perform.

2. Motivation for Benchmarking

Under traditional cost-of-service regulation, also known as rate-of-return regulation when applied to privately-owned utilities, prices are set as to recover prudently-incurred expenses, including depreciation expense to return the investments made on physical plant and equipment required to produce safe and reliable service. During a cost-of-service rate case, the regulator ultimately determines a new set of prices under which the firm will operate. These prices remain in effect until such time that another next rate case is initiated. The regulator must approve the level of annual expenses and the monetary stock value of plant and equipment on which the firm is allowed depreciation expense. In total, these elements of the total allowed cost of providing service are then essentially divided by output measures in order to determine the new set of prices. During the process, costs are reviewed and those costs that have been imprudently incurred are disallowed and, therefore, are not allowed to be recovered through the new set of regulated prices. (Note 5) Finally, at some future date, if costs and/or revenues have changed significantly, a new rate case may be initiated.

Critics of the cost-of-service scheme have argued that such regulation offers little incentive for firms to minimize cost. This argument is as follows. First, because regulated prices track actual firm costs, there is little profit incentive for the firm to reduce costs; indeed, the firm may have an incentive to inflate costs and/or overcapitalize. Second, prudence reviews by the regulator rarely result in significant reductions in the costs the firm is allowed to recover through regulated prices. This failure of prudence reviews to flag inflated costs is due to the fact that the regulator is unlikely to know what the appropriate level of cost should be. That is, under traditional cost-of-service regulation, there is no ideal benchmark against which to compare the regulated firm's actual reported costs against its peer utilities.

Proponents of traditional cost-of-service regulation counter with the observation that regulated prices do not continuously adjust to changes in cost. Rather, regulated prices remain fixed between rate cases and the period of time between such cases can lag for many years. Because of the fixed prices owed to "regulatory lag," cost-cutting measures by the firm will result in above-normal profits; therefore, the firm does in fact have an incentive to minimize costs. Critics reply that as the next rate case nears, utilities (operating under the knowledge that the next set of regulated prices will essentially track costs that exist just prior to the rate case) will once again have an incentive to inflate costs and may well not reduce costs to efficient levels (Vogelsang, 1983). (Note 6) Bailey and Coleman (1971) show, however, that as the time between rate cases increases, the utility has less of an incentive to inflate costs and overcapitalize.

The debate on whether or not the utility has an incentive to minimize costs is complicated by the following fact: While the regulator requires full information on the firm's actual demand and costs from the test year, without duplicating the firm's management, the regulatory agency can only obtain such information from the firm itself. There are at least three difficulties here: (1) the firm must also adjust the historical test-year information for "known and measurable changes" so that the adjusted data will most likely represent conditions under which the firm will operate moving forward; (2) the regulatory agency must determine if the costs incurred by the firm are prudent; and, (3) the firm may have an incentive to distort the information given to the regulator. Recognizing that the firm may have an incentive to misrepresent its costs when it has an information advantage, Baron and Myerson (1982) explore optimum regulatory strategies. A major challenge inherent in these regulatory strategies is for the regulator to induce the firm to not misrepresent its costs and for the regulatory to determine whether or not these costs are prudent. The latter challenge is particularly problematic (even if the firm does not misrepresent its costs) because, as mentioned above, the regulator may not know what the appropriate level of cost should be.

An alternative approach is for the regulatory agency to obtain a benchmark against which to compare the regulated firm's actual reported costs. A regulatory regime which takes this approach is "yardstick regulation." Yardstick regulation involves comparing the performance of a firm with that of a peer group of other firms within the same industry. Through these comparisons, the regulator is essentially aiming to simulate a competitive environment under which the regulated firms may be rewarded or punished based on their performance relative to their peer group. In modeling peer-group costs, it is crucial to allow for all factors that may cause individual firm costs to vary.

Yardstick regulation can also be used in conjunction with other regulatory schemes such as traditional cost-of-service regulation and price-cap regulation. By using yardstick regulation in conjunction with other regulatory mechanisms, the benchmark costs can serve as the informational basis for a more effective regulatory hybrid because it reduces the informational asymmetries between firms and regulators regarding cost. In the case of the Philippines, yardstick regulation could be used in conjunction with the optional Distribution Wheeling Rate Guidelines (DWRG) for regulation of privately-owned distribution utilities and could be applied to electric cooperatives. Moreover, yardstick regulation can be used in the Philippines to streamline the cost-of-service regulatory process itself and can serve as a cost-minimization mechanism; both of which help satisfy the overall objective of the Act to increase the efficiency of the Philippines electric industry.

Under yardstick regulation, for any given firm, the regulator uses the costs of comparable firms to infer the given firm's attainable – indeed desirable – cost level. A key challenge facing yardstick regulation is in determining what firms are to be included in the "peer group" and how to account for any differences that may exist between members of the group. Shleifer (1985) shows that the use of costs of comparable firms is best illustrated in the case of "identical firms" producing a homogeneous good. Shleifer states that:

> [b]y relating the utility's price to the costs of firms identical to it, the regulator can force firms serving different markets to effectively compete. If a firm reduces costs when its twin firms do not, it profits; if it fails to reduce costs when other firms do, it incurs a loss. To use this scheme, the regulator does not need to know the cost reduction technology; the accounting data suffice to achieve efficiency. (p. 320)

Of course this best-case illustration is complicated by the real-world fact that a utility has its own unique service territory and the characteristics of service territories across utilities will differ; that is, utilities within any chosen peer group will not be identical. However, Shleifer goes on to show that even in the case of heterogeneous firms, yardstick regulation is likely to be very useful as long as the heterogeneity is accounted for correctly. In such a situation, the regulator can avoid the problem of no identical firms if the characteristics that make firms differ are observable to the regulator and if the regulator corrects for this heterogeneity. According to Shleifer, "[t]his correction amounts to a regression of costs on characteristics that determine diversity." (p. 324)

Many researchers have successfully applied Shleifer's correction methodology for the purpose of benchmarking the performance of distribution utilities. For example, Filippini & Wild (1999) use a panel of 45 Swiss electric distribution utilities and follow Shleifer's suggestion to estimate a multivariate average-cost function that could be employed by the regulatory commission to benchmark distribution-network access prices. Their estimation results also indicate the existence of significant economies of scale the degree to which most Swiss utilities have not been able to fully exploit. Ida and Kuwahara (2004) estimate a multivariate translog cost function and apply the results to yardstick regulation by introducing two kinds of cost-comparison coefficients – one for the exogenous service territory effects (as suggested by Shleifer) and one for economies of scale and scope effects. Controlling for the network characteristics of Swedish distribution utilities, Kumbhakar and Hjalmarsson (1998) estimate dual production and cost functions and apply yardstick regulation to the comparisons of privately- versus publicly- owned utilities. Their results show that the privately-owned utilities are relatively more efficient.

As described in detail in the next two sections, we deviate from these above earlier works with respect to the choice of output variables to include in our model. Specifically, a large number of previous works have treated kilowatt hours (kWh) of electrical energy as a key output for distribution utilities. (Note 7) Estache, et.al., 2004, p.274, for example, justify their inclusion of kWh as an output based on the fact that it is frequently used in the literature: "Hence following the specialized literature, we use an electricity distribution model that includes three outputs (the number of final customers, the total energy supplied to final customers, and the service area)." The inclusion of kWh, however, runs counter to the actual outputs produced, and the nature of costs faced, by DUs. Distribution utilities are delivery firms who do not produce their own power and simply flow through their wholesale power procurement costs to their end-use retail customers without a markup. Unlike generators of power, DU delivery costs are not sensitive to kWh of energy. Such energy-related costs are characteristics of generation entities, are sensitive to the production of kWh and are primarily comprised of fuel costs.

We have chosen output variables that more closely capture the network characteristics that vary from one distribution utility to the next. These include: number of customers, a joint output variable for network circuit kilometers and system peak demand, and system loss factor. We also incorporate model design to capture geographic and institutional differences between the DUs.

Yardstick regulation may serve as a useful alternative form of regulation in the Philippines. Because of the heterogeneity of electric distribution, we follow Shleifer's suggestion to estimate a multivariate cost function in order to benchmark prices for distribution service. We estimate a cost benchmark model by regressing actual costs on observable characteristics that determine diversity. This model is derived from actual data of 115 electric distribution utilities in the Philippines. (Note 8)

3. The Nature of a Distribution Network

An electric distribution utility is a delivery company with one or more points of receipt (points where the company receives power produced by generation plants) and multiple delivery points (end-use customers). To ensure system reliability, the network capacity must be sized to meet maximum demand (peak demand) regardless of when that peak occurs and the network must be routed throughout the company's service territory to accommodate actual end-use customer locations. The costs associated with the capacity required to meet peak demand are referred to as demand-related costs. Finally, each end-use customer requires a dedicated connection to the distribution network, a meter, and service account; the costs associated with such connection are referred to as customer-related costs. Distribution costs are demand-related and customer-related in nature. Again, distribution network costs do not have an energy-related component.

As the network extends from the points of receipt toward end-use customer locations, the network is stepped-down both in terms of voltage level as well as in terms of capacity (measured in kilowatt "kW" demand). Individual routes branch out to serve fewer and fewer customers until a dedicated connection tap is sized to serve the maximum instantaneous demand (measured in kW) of a single customer. Upstream network facilities must be sized to accommodate total system peak demand whereas downstream facilities are sized to meet maximum demand of those particular customers connected to the facilities. Based on this network description, it should be clear that distribution costs vary with customers' instantaneous demand on the network, the overall length of the network, and the number of customers.

Suppose we were to rearrange the network end-to-end with the large demand-capacity facilities first, middle demand-capacity facilities next, and lowest demand-capacity facilities last – all connected with length of wires equal to "total circuit kilometers." We would then have a network that approximates the shape of a cone or pyramid with a "base area" equal to system peak demand (Peak kW) and the length or "height" of the network "cone" equal to total circuit kilometers (CKM). The "size" or volume of the cone is (1/3*Base Area*Height) or (1/3*Peak kW*CKM). Arguably, this composite measure is superior to treating Peak kW and CKM as two separate and distinct outputs as has been done by previous authors. The output provided by the company is the delivery network as a whole where Peak kW and CKM are joint outputs. (Note 9) Treating these as two separate outputs masks the network reality that you cannot have one without the other.

Number of customers is a network characteristic that is independent of Peak kW and CKM and should be treated as a stand-alone output. As mentioned above, there are customer-related costs such as dedicated connections, meters, and service accounts (e.g., billing costs).

Distribution system loss is the difference between the amount of energy entering the distribution network and the amount of energy metered (billed) at the end-use customer location. System losses occur due to both technical and non-technical reasons. Technical losses are due to energy which is naturally dissipated in any electrical network due to resistance. (Note 10) Technical losses vary between networks based on the technical characteristics of the network such as voltage level, number of voltage transformations, and length of the circuits. Technical losses may be reduced through additional network equipment investment and additional maintenance expenditures. Non-technical losses can occur due to two reasons: energy theft (pilferage) in the form of illegal taps on the distribution network; and free, non-metered connections provided by the distribution utility. The first form of non-technical losses can be reduced through anti-theft and prosecution expenditures. The latter form of non-technical losses, on the other hand, is not a problem that can be solved by additional expenditures. (Note 11) These are losses driven by cultural or institutional reasons.

The regulatory response to system losses in the Philippines has been to impose system loss caps that prohibit the pass-through of purchased power costs related to kWh losses in excess of the caps. The original caps, established in a somewhat arbitrary fashion, were set at 9% for private utilities and 14% for electric cooperatives. The Act, however, empowered the ERC to implement company-specific caps based on technical characteristics. For the purposes of cost benchmarking, we recognize that a DU must incur costs to reduce system losses and to maintain lower system losses. Such costs include equipment investment, maintenance expense, and anti-theft activity costs. A utility should not be penalized for higher costs due to such expenditures if system losses are commensurate with cost levels. The large variation in system losses across DUs in the Philippines suggests another output dimension beyond the network size and number of customers. The output in this case is one minus the system loss factor; thereby making it a positive output measure.

Before leaving this section on the nature of distribution costs we would like to comment on an output measure used by previous authors in studying distribution utility costs. What should be clear from the network description given above is that the amount of energy, measured in terms of kilo-watt hours (kWh), does not drive distribution costs. (Note 12) Other authors have used kWh as a regressor in similar studies finding high correlation between distribution costs and kWh. Appealing to such correlation and including kWh as a key variable, however, is not supported by cost-causation principles. Although kWh may serve as a proxy for Peak kW in academic cost research, it should be avoided in real-world benchmarking because the above true drivers of distribution costs are directly observable and easily measured.

4. The Data, Variable Definitions, and Empirical Model

Our data come from 115 electric distribution utilities in the Philippines during the year 2000. Our dependent variable, total cost, is defined as the sum of annual distribution-related expenses, customer service accounts expenses, plus administrative and general expenses. We have not included purchased power costs and transmission costs which are not part of the production vector of distribution utilities and are treated as a one-for-one, pass-through cost for the utilities to their end-use retail customers. (Note 13) For each observed DU, we obtained the system peak demand measured in kW, the network total circuit kilometers, the number of customers, and the system loss factor. Some descriptive statistics for each of these variables are found in Table 1.

<Insert Table 1 here>

In addition to these variables, recall that the composition of distribution utilities in the Philippines includes both privately-owned companies (11 in our sample) and electric cooperatives (104 in our sample). (Note 14) The governance and incentive structures tend to differ between these two types of utilities. To control for these possible institutional differences, we include a "Type" dummy variable that is used as a "slope shifter" to allow for a slope change on the system one-loss variable. (Note 15) As revealed in Table 1, system loss factors vary considerably, ranging from less than 6% to nearly 30%. The higher system loss levels tend to be found in the electric cooperatives and a large portion of these losses tend to be non-technical in nature. There are a variety of possible explanations for this phenomenon. One of which may be the dominant presence of certain rebel groups in many areas served by cooperatives. One of these rebel groups is a communist organization known as the New People's Army (NPA). (Note 16) The NPA is known to take monies from legitimate businesses in exchange for "security" and failure of a company to pay often times results in destruction of that business property. If the business is an electric distribution company, it may be natural for the NPA to collect a portion of security payments in the form of non-metered electrical connections to the utility's network which would cause losses to increase. Furthermore, other government and non-government officials may receive "free" connections from the electric cooperative.

Although we cannot perfectly account for the variation of this institutional loss behavior from one utility to the next, when such behavior does occur, it is typically found in the territories served by electric cooperatives. This form of non-technical loss is different than "traditional theft," which is prevalent across all types of utilities and can be controlled through anti-theft expenditures. Rather, the non-technical loss described here is institutional in nature and related to NPA "security services." The costs of this security is borne by the distribution utility and passed on to all retail customers as total costs are divided by total *metered* consumption. DUs themselves should not be penalized for such engrained institutional factors in their service territory that are outside their control; that is, such factors need to be accounted for within the specification of the benchmark model.

The basic (unrestricted) OLS empirical model to be estimated is as follows:

$$\text{Total Cost} = \alpha + \beta_1 \text{(1-Loss)} + \beta_2 \text{(TypeLoss)} + \beta_3 \text{(Customers)} + \beta_4 \text{(Cone)} + \beta_5 \text{(Mcone)} + \varepsilon$$

where (1-Loss) is one minus the system loss factor; TypeLoss is the product of the dummy variable Type and the continuous variable (1-Loss), where Type equals one if the firm is a cooperative and equals 0 otherwise (thus TypeLoss allows for a slope change on the variable (1-Loss); Customers is the number of customers served by the DU; Cone is 1/3 Peak kW times CKM; CKM is total circuit-kilometers of distribution wire; and, Mcone is the product of the dummay variable MD and the continuous variable Cone, where MD is a geographic dummy variable which equals one if the distribution utility is located in the southern region of the Philippines known as Mindanao and equals 0 otherwise (thus Mcone allows for a slope change on the variable Cone).

5. Estimated Benchmark Model

We would expect the intercept in our model to equal zero because if all our independent variables are zero, cost should be zero. Rather than imposing a zero intercept restriction in our model, *a priori*, we first estimate the model to test this hypothesis. Table 2 reports the unrestricted version of the model. As expected, we fail to reject the null hypothesis that the intercept is zero (t-statistic is -0.74). Note that all independent variables are statistically significant with the expected sign. We now refine our model by restricting the intercept to zero.

<Insert Table 2 here>

Table 3 reports the results for the restricted OLS version. The estimated parameter for one minus loss ("One-Loss") is positive and significant suggesting that system loss reduction is costly (as expected). Interestingly, the parameter estimate for our slope-shift variable "TypeLoss" indicates that electric cooperatives on average do not necessarily require more costs to reduce system losses. This suggests that variation in system losses in those service areas may be driven more by the non-technical institutional characteristics faced by the cooperatives such as non-metered service taps (as discussed above).

<Insert Table 3 here>

Both number of customers and our joint output measure "Cone" perform well and, as expected, the parameter estimates are positive. The Mindanao slope shift variable for Cone (Mcone) is positive and statistically significant suggesting that geographic conditions in that southern region of the Philippines may lead to higher investment and/or operation & maintenance costs. Please note that Mindanao receives some attention by the international news media for its relatively large population of people of Islamic faith and historical political tensions between the Muslim people and the Christian-dominated national government. The highest concentration of Muslims are in a sub-region of Mindanao known as the Autonomous Region of Muslim Mindanao (ARMM). The question becomes, therefore, is the significance of Mcone due to characteristics of the entire Island of Mindanao itself, or is it due to political tensions in sub-regions of Mindanao.

Using a sub-region dummy allows us to test whether the higher costs in Mindanao are driven by the specific DUs that are either within or border the ARMM sub-region of Mindanao or whether the higher Mindanao costs are a greater phenomenon of the entire Island of Mindanao itself. In our sample, there are 16 DUs with service territories that are either within the ARMM or are adjacent to that sub-region of Mindanao. We then created two more slope-shift dummy variables, MM*cone and MM*cust, to test whether the parameter estimate on either Cone or number of customers should be higher in that sub-region (MM equals one if the DU is in the ARMM sub-region or borders that sub-region, otherwise MM equals zero). Tables 4 and 5 report our results. We fail to find any significant relationship between these variables and total costs suggesting that the tendency for higher costs in Mindanao is a wider regional phenomenon and not driven by the distribution utilities found in the ARMM sub-region.

<Insert Table 4 here>

<Insert Table 5 here>

We also must report the presence of two clear outliers within our data sample. The largest DU in the Philippines is the Manila Electric Company (MERALCO) with over 3.5 million customers and over 12,000 circuit kilometers. The smallest DU is Siasi Electric Cooperative with less than 1,600 customers and only 61 circuit kilometers. The difference between each of these companies and the next closest utility in size is considerable. When we remove these two observations from the sample our results do not change dramatically as reported in Table 6.

<Insert Table 6 here>

The only notable changes in our results are the increase in the parameter estimate for Cone and the decrease in the parameter estimate for Mcone. All parameter estimates remain statistically significant and the Adjusted R^2 value has only fallen slightly to 0.934 (from 0.997).

6. The "Flagging" Methodology

A benchmark regulatory system should penalize abnormally high cost utilities (perhaps first through a detailed financial audit) but also reward those companies flagged as low cost performers. The estimated benchmark cost model, summarized in Table 2, describes a peer cost model that accounts for the key heterogeneity factors across firms within the peer group. In order to "flag" high- and low- cost firms we employ the standard assumption required to perform both the standard t-tests as well as the flagging process itself. (Note 17) That is, we assume that for fixed levels of the independent variables there exists a hypothetical population of firms with varying levels of total cost. For each fixed level of independent variables there exists a distribution of cost values that is normally distributed with an expected value, or mean, equal to the corresponding fitted value. Table 7 shows the total number of firms who had cost levels that are either abnormally low or abnormally high. As should be expected, a larger number of firms are flagged when the two suspected outliers (large and small) are removed from model estimation. In either case, however, a relatively small number of firms are flagged with only 2.6% of the total firms flagged as "high-cost" with the suspected outliers in the model and just 5.3% flagged as "high-cost" when the suspected outliers are removed from the model.

The regulatory agency could utilize the model in a variety of ways. One method would be to order a thorough financial and operational audit of the few firms that are flagged as high cost. Under traditional cost of service regulation, such an audit should be performed each time there is a general rate case. With over 140 firms to regulate, however, performing a thorough audit each time there is a rate case demands considerable time and resources. On the other hand, the benchmark model allows the regulatory agency to be far more selective in deciding where extra scrutiny is deserved. When a thorough audit seems justified based on the benchmark model, the audit may reveal special circumstances for the distribution utility explaining the high cost nature of the firm or, alternatively, the audit may expose excesses and unnecessary costs that could be denied by the regulatory agency.

<Insert Table 7 here>

Arguably, the "low-cost" firms identified by the benchmark model should be rewarded for such performance. A variety of reward mechanisms could be implemented such as allowing higher returns (with or without profit-sharing) in the case of a privately-owned utility, or simply higher management compensation in the case of an electric cooperative.

7. Conclusions

Benchmark regulation appears to be a promising modification for the traditional regulatory activity of the Energy Regulatory Commission in the Philippines. With over 140 companies to regulate, this is good news in that benchmarking can augment the limited resources of the agency. Our model appears to perform very well in terms of goodness-of-fit and in terms of the independent utility characteristic (output) variables selected: one minus system loss factor, number of customers, the joint output measure for network length and capacity "Cone." Future research could include additional focus on the determinants of system loss factors and the interplay with costs. As indicated, certain geographic or cultural characteristics faced by some distribution utilities may make system loss factor reduction cost prohibitive (e.g., expenditures on the margin will not eliminate non-metered connections by certain customers).

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Notes

Note 1. The Act called for the privatization of the government controlled operations but has since not come to fruition.

Note 2. "Supply" is the wording used in the Act. Supply refers to retail customer services such as meter reading, billing, response to customer complaints, etc. Generation refers to the physical production of electricity, transmission refers to the physical transportation of electricity through high-voltage wires, and distribution refers to the physical delivery of electricity through low-voltage wires.

Note 3. The authors wish to thank the staff of the ERC for their help in compiling these data.

Note 4. In regulatory economics parlance, the TWRG is a type of price cap regulation and the DWRG is a form of revenue cap regulation. In its simplest form, price-cap regulation sets the maximum prices that companies can charge for their services and, in general, the companies can sell services at prices equal to or less than the maximum. This then creates an incentive for companies to cut cost in order to increase profit. While the goal of price-cap regulation is to minimize costs, the goal of revenue-cap regulation is to shield the utility from quantity risk and, therefore, attempts to eliminate utility disincentives from investing in conservation measures and/or simply attempts to break the relationship between fixed-cost recovery and kilowatt-hour sales (and for distribution utilities the vast majority of costs are fixed). Under revenue-cap regulation, the flow of revenue to cover cost of service remains fixed while prices are allowed to adjust to changes in kilowatt-hour sales.

Note 5. Such a review is referred to as a prudence review.

Note 6. The period just before the rate case (typically the last calendar year) in which the reported costs actually occurred is referred to as the historical "test year."

Note 7. Jamasb and Pollitt, 2003, p. 1615, report that 12 out of the 20 benchmarking studies of electric distribution utilities they surveyed included units of energy sold (kWh) as an output measure.

Note 8. Our sample is limited by missing observations on some of the variables for 24 of the 139 DUs.

Note 9. The fact that Peak kW and CKM are joint outputs also leads to multicollinearity problems in econometric modeling when the two are treated as separate independent variables when actually they are not independent.

Note 10. This dissipation is owed to some electrical energy being converted to heat due to resistance. Loss factors measure the percent of total energy going into a distribution network that is dissipated.

Note 11. Here we are ignoring the possibility of side-payments to the customers receiving "free" service from the utility.

Note 12. In contrast to distribution costs, fuel used in power generation is a good example of a cost caused by energy (kWh) consumption by customers.

Note 13. The distribution utilities in the Philippines do not generate their own power which comes from a mix of independent power producers and the National Power Corporation, and transmitted via a transmission grid owned and controlled by the National Transmission Company.

Note 14. Our sample includes one DU owned and controlled by a local government entity. We treat this DU as an electric cooperative.

Note 15. This control variable is also justified by the findings of Dan Berry, 1994, whose formal investigation of investor-owned utilities and electric cooperatives in the United States finds that electric cooperatives produce their outputs less efficiently than investor-owned utilities.

Note 16. The U.S. Department of State designated the New People's Army as a terrorist organization in 2002. Federal Register: August 9, 2002 (Volume 67, Number 154).

Note 17. After a visually inspecting the scatter-plots of the residual values on each of the independent variables we detected no serious indications that this normality assumption was violated. We also checked our constant variance assumption by conducting a series of Goldfeld-Quandt tests for each of the independent variables (omitting the middle observations accounting for one-fifth of the total sample size) and at a level of significance (no less than 10% from the F table) we rejected the null hypothesis that there exists heteroscedasticity.

Table 1. Descriptive Statistics

Variable	No. Obs.	Mean	Std Dev	Min	Max
Total Cost (Pesos)	115	141,277,872	816,989,390	2,579,728	8,759,356,388
System Losses (%)	115	15.35	5.29	29.95	5.29
One-Loss (%)	115	84.65	5.29	70.05	94.71
Cone (kW*ckm)	115	164,255,288	1,587,337,903	27,000	17,032,837,333
Circuit km	115	1,761	1,528	61	12,304
Peak kW	115	55,914	386,658	383	4,153,000
No. Customers	115	74,255	333,299	1,597	3,598,473

Table 2. Results for Unrestricted OLS

Dependent Variable: Total Cost		
Ind. Var.	Parameter Est.	t-statistic
Intercept	-47,543,054	-0.74
One - Loss	1,390,834	1.9
Type*Loss	-1,132,810	-6.78
Customers	1,722	11.63
Cone	0.146	4.73
Mcone	0.905	4.93
No. Obs.	115	
Adjusted R-sq	0.997	

Table 3. Results for Restricted OLS (no interest)

Dependent Variable: Total Cost		
Ind. Var.	Parameter Est.	t-statistic
One - Loss	868,768	4.78
Type*Loss	-1,165,731	-7.26
Customers	1,702	11.71
Cone	0.15	4.96
Mcone	0.923	5.08
Adjusted R-sq	0.997	

Table 4. Results for Restricted OLS (no interest)
Muslim Mindanao Slope Test for Cone

Dependent Variable: Total Cost

Ind. Var.	Parameter Est.	t-statistic
One - Loss	944,249	4.65
Type*Loss	-1,276,005	-7.19
Customers	1,880	12.02
Cone	0.113	3.46
MMcone	0.515	0.58
Adjusted R-sq	0.997	

Table 5. Results for Restricted OLS (no interest)
Muslim Mindanao Slope Test for # Customers

Dependent Variable: Total Cost

Ind. Var.	Parameter Est.	t-statistic
One - Loss	945,818	4.65
Type*Loss	-1,279,934	-7.23
Customers	1,882	12.04
Cone	0.112	3.44
MMcust	148.4	0.51
Adjusted R-sq	0.997	

Table 6. Results for Restricted OLS (no interest)
Large and Small Outliers Removed

Dependent Variable: Total Cost

Ind. Var.	Parameter Est.	t-statistic
One - Loss	911,303	6.5
Type*Loss	-1,013,551	-8.13
Customers	1,019	7.39
Cone	1.19	9.84
Mcone	0.448	2.99
Adjusted R-sq	0.934	

Table 7. Number of Low-Cost and High-Cost Performers

Low-Cost Firms

	Probability that a firm with same characteristics should have higher cost.			
Probability	99%	97.50%	95%	90%
No. Firms with outliers in model. (N=115)	3	1	3	0
No. Firms without outliers in model (N=113)	4	2	3	2

High-Cost Firms

	Probability that a firm with same characteristics should have lower cost.			
Probability	90%	95%	97.50%	99%
No. Firms with outliers in model. (N=115)	1	0	0	2
No. Firms without outliers in model (N=113)	4	1	0	1

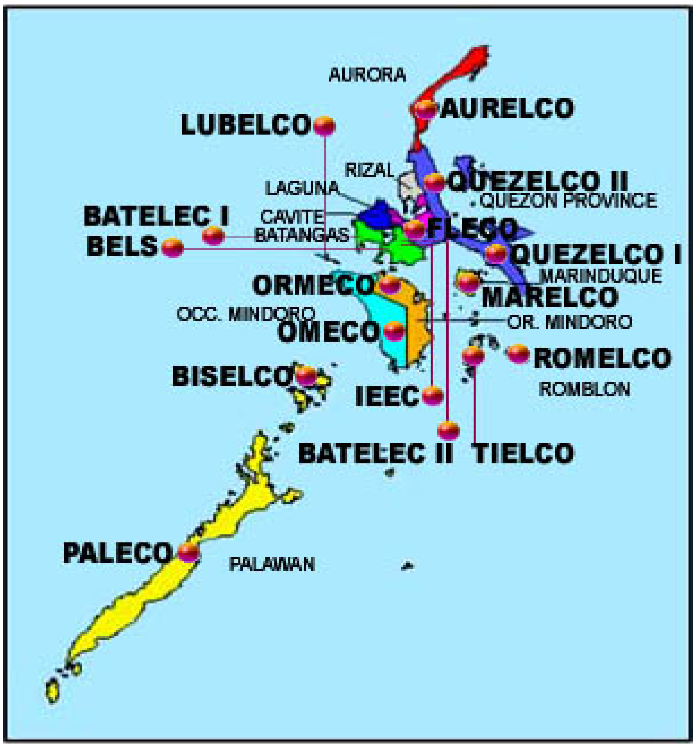

Figure 1. Sample geography and distribution utilities ("Region 4")

Source: ERC Website at http://www.erc.gov.ph/