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# Statistical Evaluation of the O&M Cost Performance of the Ameren Illinois Utilities

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# Executive Summary

On June 5, 2009 Ameren Corporation filed for a rate increase for its three utilities in Illinois: AmerenCILCO, AmerenCIPS, and AmerenIP. The Illinois Citizens Utility Board (CUB) and The People of the State of Illinois have retained Power System Engineering, Inc. (PSE), to evaluate the recent electric cost performance of the Ameren Illinois Utilities (AIU) and provide benchmarking of these expenses in relation to other sampled electric utilities.

This report offers a statistical perspective on the evaluation of the recent non-purchased power electric operation and maintenance (O&M) cost performance of AIU. O&M expenses comprise the majority of costs over which current management can exercise a large amount of immediate control. Thus, AIU's recent performance in this cost area is of considerable importance in the context of the current rate proceeding. In addition, in consideration of the recent economic climate, examining utility expenses takes on even greater importance.

This report uses econometric benchmarking techniques to evaluate the performance of AIU in containing O&M expenses relative to a sample comprising of 115 U.S. investor-owned electric utilities. Benchmarking's role in energy utility regulation has grown. In 2009, Florida Power & Light and Oklahoma Gas & Electric, for example, have sponsored benchmarking studies to display superior cost performance relative to the industry. The Ontario Energy Board now requires annual cost benchmarking updates of all power distributors operating in Ontario, Canada, and allowed rate escalation is partially determined by benchmarking scores. AIU itself sponsored benchmarking testimony in this proceeding regarding its administrative and general expenses. In the early 2000's, Ameren Corporation's Missouri utility, AmerenUE, filed benchmarking testimony defending the cost performance of its Missouri electric operations. The AmerenUE report used econometric benchmarking techniques similar to the approach found in this report.

In this research, actual incurred costs of the three Ameren Illinois electric utilities are compared to model-generated expected costs for the three years of 2005, 2006, and 2007. Two O&M subcategories were examined: distribution and customer care (D&CC), and administrative and general (A&G) expenses.[1] During this timeframe, AIU's actual costs have consistently been above the model's expected costs for each Illinois utility in both of the examined O&M subcategories.

AIU's annual average 2005-2007 D&CC expenses have been 14.8 percent[2] above the model's prediction. This can be interpreted to signify that expenses have been 14.8 percent above what an *average* performing utility would be expected to spend, given Ameren's specific operating conditions. If a top quartile standard is preferred, AIU's 2005-2007 D&CC expenses are approximately 35.0 percent above this standard. The 2005-2007 A&G expenses even further exceed the model's prediction. Expenses have been 27.2 percent above expected spending for an average performing utility and about 48.6 percent above a top quartile performance standard.

These 2005-2007 performance results are then combined with AIU's proposed statement of operating income, Ameren Exhibit 2.1-2.3, to determine the estimated inefficient O&M spending amounts implicit in AIU's proposal.[3] According to this evaluation, estimated D&CC inefficiencies amount to $96.7 million for AIU's proposed 2008 test year spending levels, assuming an average performance standard. If a top quartile standard is used, estimated D&CC inefficiencies amount to $132.3 million for AIU. A&G expense inefficiencies are estimated at $61.8 million for AIU's proposed 2008 test year spending levels, assuming an average performance standard. Using a top quartile standard, A&G inefficiencies are estimated at $83.9 million.

A brief introduction to this benchmarking report is found in the first section. Section 2 follows with a description of the benchmarking methods popular in North American utility regulation. Sections 3 and 4 explain the models for each cost category, the variables that were found to significantly impact these costs, and AIU's rankings and performance. Section 5 offers a discussion on estimating cost inefficiency amounts implicit within AIU's 2008 proposed test

[1] Customer care expenses include the FERC Form 1 O&M subcategories of customer service and information, customer accounts, and sales.

[2] All benchmarking percentages are presented in logarithmic form. Continuous growth rates are calculated by the equation, $C_1 = C_0 * e^r$, here r equals the reported percentages, $C_1$ equals the actual cost, and $C_0$ equals the expected value of cost.

[3] The terms "inefficient" and "inefficiencies" are used throughout this report and are defined by the author as expenditures that exceed a given standard. In this report, the two standards of comparison are average and top quartile.

year spending levels. The Appendix contains technical details of the econometric models, followed by a Bibliography of resources used in this study.

# 1 Introduction

On June 5, 2009, Ameren Corp. filed an application to increase the electric and gas delivery rates paid by AIU ratepayers. The amount of the requested increase is $226 million, $181 million of which is proposed to increase electric rates. This electric rate increase is divided amongst the three Ameren utilities operating in Illinois: Central Illinois Light Co. (AmerenCILCO), Central Illinois Public Service Co. (AmerenCIPS), and Illinois Power (AmerenIP), with requested electric rate increases of $28 million, $51 million, and $102 million, respectively. Collectively, these utilities comprise Ameren Illinois Utilities, or AIU.

In the context of this request for increased rates, the Illinois Citizens Utility Board (CUB) and The People of the State of Illinois have retained Power System Engineering, Inc. (PSE) to evaluate the cost efficiency of AIU. Founded in 1974, PSE is a full-service consulting firm serving the electric utility industry with offices in Wisconsin, Indiana, Minnesota, and Ohio. In addition to our benchmarking services, PSE has expertise in the areas of DSM, load forecasting, T&D system planning and design, communications equipment, smart grid technologies, rate design, and cost of service studies.

According to FERC Form 1, the 2007 non-purchased electric O&M expenses of AIU were just over $450 million. Approximately half of these costs were attributed to AmerenIP, one-third to AmerenCIPS, and the remainder to AmerenCILCO's electric operations.

O&M expenses can be further disaggregated into three subcategories: A&G, D&CC, and other expenses. Figure 1-1 presents the relative proportions of these three subcategories for AIU.

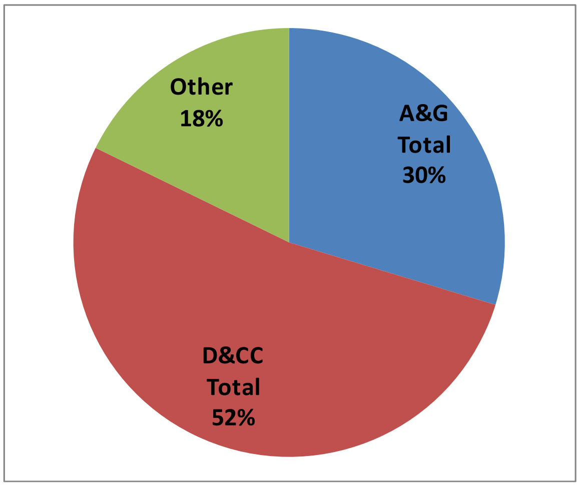


**Figure 1-1 2007 AIU O&M Expenses**

As demonstrated in Figure 1-1, the majority of O&M expenses for AIU are categorized as A&G and D&CC expenses. The appropriate level of these two cost categories is therefore a main focus in the current rate case. Absent market forces to provide the impetus for efficient operation, regulators must provide diligent oversight of expenses in determining their just and reasonable levels.[4]

Benchmarking allows a statistical comparison of performance to a utility's peers. In a competitive market setting, a firm may be forced into bankruptcy if its unit costs are higher than its competitors, assuming a homogenous product. In a regulatory environment, benchmarking reveals cost performance relative to the industry. If rewards and punishments correspond to benchmarking scores[5], benchmarking can promote competition, while maintaining the natural monopoly benefits inherent in power distribution technology.

This report offers an evaluation of the recent non-purchased power electric O&M cost performance of AIU. Two areas will be examined: A&G expenses and D&CC expenses. Non-

[4] Benchmarking is a relatively inexpensive way for regulators to examine spending levels. Benchmarking can provide strong evidence for utility performance in a number of areas including cost, reliability, DSM programs, and line losses.

[5] This is the case in the province of Ontario, where benchmarking scores directly impact allowed annual rate escalation.

purchased power O&M cost is the major component of base rate cost, over which current management can exercise a large amount of control. A statistical framework for evaluation of these pertinent costs is presented in this report.

# 1.1 Benchmarking Defined

Statistical, or performance, benchmarking is growing in the regulatory arena. Florida Power & Light and Oklahoma Gas & Electric, for example, both filed benchmarking studies this year examining their O&M cost performance. Additionally, the Ontario Energy Board is now using O&M benchmarking results to partially determine allowed annual rate escalation for the power distributors operating in Ontario, Canada. AIU filed benchmarking testimony in the current rate case evaluating its A&G expenses. In 2003, an Ameren Co. subsidiary, AmerenUE, filed econometric benchmarking testimony to provide evidence of superior cost performance in its Missouri electric utility operations.[6]

Benchmarking allows regulators to compare performance across utilities and jurisdictions. Regulators can use benchmarking when regulating electric reliability, determining appropriate cost or salary levels, evaluating energy efficiency attainment and goals, and in the escalation provisions of multi-year rate or revenue caps. Utility managers can use benchmarking to determine overall performance within the industry, pinpoint areas where improvements can be made, set challenging yet achievable goals, and identify best practices.

Statistical cost theory states that cost equals input price multiplied by input quantity. Input quantity is driven by the output level and external operating conditions faced by a utility combined with management decisions given those constraints. Similarly, input prices are a function of external business conditions combined with management decisions involving the procurement of inputs at given prices. A performance cost benchmarking study evaluates management decisions involving input quantities and prices given the external conditions and constraints faced by utility management.

Performance cost benchmarking enables a comparison to be constructed relating a utility's actual costs to a customized expectation of those costs. Good cost performers will have actual costs

[6] These are only examples of recent benchmarking studies and not an exhaustive list.

below the expected amounts, whereas poor performers will have actual costs above the expected amounts.

$$Performance = \frac{Costs^{Actual}}{Costs^{Expected}} \qquad [1]$$

Equation 1 shows performance to be a function of two terms. Actual costs are reported directly from the utility, whereas expected (benchmark) costs must be estimated. The research challenge is to calculate expected costs in a fair and accurate way, accounting for the specific advantages and disadvantages inherent in the operating circumstances of each utility.

# 2 Benchmarking Approaches

The two most popular benchmarking methods in North American regulation are the peer group and econometric approaches. This section summarizes the fundamentals of these approaches and discusses the strengths and weaknesses of each.

## 2.1 Peer Group Approach

When using the peer group approach, the analyst calculates the ratio of the relevant statistic being measured (e.g., A&G cost) to a measure of output (e.g., number of customers). This ratio is compared to the mean metric of a group of firms sharing similar business and operating conditions to the company being investigated. This group is called a peer group. The peer group average serves as an estimate for the expected unit cost of the investigated utility. If a firm's unit cost ratio is below the peer group average, they are classified as an above average performer, and vice versa.

$$Performance = \frac{A\&G\,Unit\,Cost^{Actual}}{A\&G\,Unit\,Cost^{Peer\,Group\;Average}} \qquad [2]$$

The appeal of the peer group approach is the simplicity of the calculations. Simplicity is enhanced if the denominator contains only one driver rather than a multi-output index. The researcher need only divide the chosen variables, determine peer groupings of similarly situated firms, and compare each utility to their peer group average. This is the approach testified to by Mr. Ronald J. Amen on behalf of AIU in regards to the A&G expenses of the utility.[7]

A compromise in accuracy, however, accompanies this technique. In the power distribution industry, there are numerous variables that impact cost. (Sections 3 and 4 discuss statistically significant evidence of electric O&M cost being influenced by multiple variables.) The peer group benchmarking approach does not explicitly adjust for this reality. Adjustments for differing operating conditions rest solely upon the selection of an appropriate peer group.

[7] Ameren Exhibit 5.0E

Peer group selection must be done with extreme caution as this is the method used to correct for the heterogeneous operating conditions faced by each power distributor. If peer groups include members with dissimilar circumstances or too few members, results can be skewed and therefore be misleading and inaccurate.

There is a lack of suitable peers to AIU to perform a valid peer group benchmarking study. It is impossible to find a large enough number of parallel utilities (similar input prices, lack of generation assets, similar proportions of underground line, scale, gas operations, etc.). Given this fact, PSE turned to the econometric benchmarking approach, which enables simultaneous adjustment for numerous factors impacting electric utility O&M expenses.

## 2.2 Econometric Approach

The econometric approach to benchmarking allows the researcher to fashion an appropriate target (or benchmark) for an examined metric. Econometric benchmarking calculates a prediction of cost customized for the specific operating conditions encountered by each utility. This model prediction is interpreted as the expected costs of a utility with identical characteristics and “average” performance. This benchmark can be compared to the target company’s actual costs to determine performance, as shown below in Equation 3.

$$Performance = \frac{A\&G\,Cost^{Actual}}{A\&G\;Cost^{Model\;\;Prediction}} \qquad [3]$$

This equation can be manipulated to reveal two items of interest. The first is an estimate of the percentage by which a utility’s costs are above or below the model prediction.[8] The second is an estimate of the cost savings or excesses consequential to the judged performance level.[9]

The model prediction of the appropriate cost level is attained by choosing a functional form, based on economic theory, and using regression analysis to estimate the parameters embedded within this functional form. This approach not only allows for multiple, simultaneous consideration of cost drivers, but also permits statistical testing of these variables and an estimate

[8] Percentage equals the natural log of actual cost divided by model-predicted cost.
[9] Cost excesses equal actual cost subtracted from model-predicted cost.

of their respective impact on the estimation of predicted cost. A simplified functional form is offered below in Equation 4.

$$\text{Predicted } Cost = a + b * No.of\ Customers + c * Percent\ undergrounding \qquad [4]$$

If the researcher postulates that power distribution O&M costs are only linearly influenced by the number of customers and the percent of lines underground, Equation 4 would be the functional form. The coefficient "*a*" is the intercept term: its interpretation is that it costs money to be in business even if output is zero. The coefficient "*b*" signifies the marginal cost of adding a customer, and the coefficient "*c*" shows the marginal cost of increasing the proportion of undergrounding.[10]

The researcher would then collect a data sample and use regression analysis to estimate these parameter values. The signs of the estimates would need to conform to theory, and hypothesis testing would be conducted to assure the researcher that these variables are indeed statistically significant cost drivers. The values of *a*, *b*, and *c* serve as "weights" to determine the magnitude of the impact of each variable on cost.

Equation 4, although simplified, shows the superiority of the econometric benchmarking approach because it permits the consideration of multiple variables. While a researcher would typically ignore a significant cost driver such as undergrounding using the peer group approach, he can now, using the econometric benchmarking approach, test the significance of this variable and incorporate it into his analysis.

To contrast the econometric approach with the use of unit cost peer grouping, Equation 5 presents the implicit functional form of the peer group method.

$$Predicted\ Cost = b * No.of\ Customers \qquad [5]$$

[10] Underground lines will typically lower O&M cost, yet raise total costs (O&M plus capital costs). Additionally, they will typically increase the reliability level (e.g., SAIDI, SAIFI, CAIDI) of the power system and the aesthetic appearance of neighborhoods.

In Equation 5, the coefficient *b* is determined by the peer group average of cost divided by the number of customers. As one can see by the differences between Equations 4 and 5, the intercept and undergrounding term are being omitted by the peer group approach.

Econometric benchmarking is further enhanced by the inclusion of additional variables. Estimation is also improved by taking the natural log of each variable. This transforms the parameter estimates from marginal cost to cost elasticity estimates. Cost elasticity measures the *percentage* change in cost relative to a *percentage* change in the cost driver. For example, with this transformation, the interpretation of *b* in Equation 4 is: if customers increase by 10 percent then cost is predicted to increase by *b* times 10 percent. If *b* equals 0.5, then a 10 percent increase in customers is estimated to increase cost by 5 percent.

After the functional form is chosen, industry data is collected. The econometric approach enables a large sample since utilities with vastly differing operating conditions can be included. Contrary to the peer group approach, since the econometric method adjusts for numerous conditions, a sample with varied operating conditions actually enhances the evaluation.

The downside of the econometric approach, however, is the need for regression analysis. This increases the complexity of the calculation procedures and limits the transparency of the approach and results.

# 3 Evaluation of Electric Delivery and Customer Care Expenses

This section provides the results of the electric distribution and customer care (D&CC) cost performance of each Ameren Illinois utility. The administrative and general cost performance results will be presented in Section 4. We begin with a discussion of each variable comprising the econometric model. Section 3.2 describes the data sample. The econometric model is displayed in Table 3-2 of Section 3.3. The AIU performance results of D&CC expenses are presented in the last section.

## 3.1 Model Variables

Numerous external circumstances influence the level of distribution and customer care costs incurred by a power distributor. A sound benchmarking approach incorporates these exogenous items in the evaluation process. This report has accounted for eight such cost drivers: retail customers, retail deliveries, wage level, percent undergrounding, percent service area that is forested, amount of generation, quantity of gas distribution customers, and a trend variable.

### 3.1.1 Definition of Cost

Cost data has been collected via a commercially available data vendor, SNL Energy. SNL Energy gathers and processes the publically available FERC Form 1s that have been filed by each utility in the sample. Cost data can be found on Form 1 pages 320-323, Operation and Maintenance Expenses, and are calculated by summing the subcategory O&M expenses of distribution, customer service and information, customer accounts, and sales. The FERC Form 1 account numbers comprising the D&CC definition of cost are 580-598, 901-905, 907-913, and 916.

The sample includes data from 1994-2007. For each year, cost was divided by that year's Gross Domestic Product Price Index (GDPPI) as reported by the U.S. Bureau of Economic Analysis (BEA). This allows cost to be stated in real (inflation adjusted) rather than nominal terms.

### 3.1.2 Number of Customers and Delivery Volume

Connecting customers to the grid and reliably meeting the power demands imposed by those customers comprise the primary “outputs” of an electric distribution company. In meeting its obligation to fulfill these output requirements, a utility will necessarily incur expenses. However, the expenses do not rise uniformly with output since power distribution technology involves increasing economies of scale for a significant portion of the sample space. In economic terms, the cost elasticity of output is not equal to one for all distributors.

The magnitude of different outputs varies. The number of customers, for example, asserts a larger influence on O&M cost than retail deliveries. While both have a significant impact, the cost elasticity of customers is greater than that of volume.

This benchmarking report defines the number of customers and deliveries as output variables. The impacts on cost of each of these outputs are quantified and weighted using econometric analysis. Within the estimation process, the availability of scale economies is recognized, allowing for a fair comparison between distributors with differing scales and output compositions.

Data for retail customers and volumes was gathered and processed by SNL Energy via page 300 on the FERC Form 1 before 1997. In the late 1990s and into the early part of this century, parts of the country engaged in a restructuring of their electric industries to enable retail competition. Retail customer and volume data for the post-restructuring years was gathered from EIA-861 forms, allowing inclusion of all unbundled deliveries. It should be noted that the EIA-861 is not yet available for 2008, leading to an end-year of 2007 for this analysis. Extending the research to include data from 2008 will be feasible when EIA-861 data becomes available.

### 3.1.3 Input Prices

A utility’s outputs and operating conditions primarily drive the input quantities (i.e., labor, materials, and services), yet cost is also directly impacted by the price of employing these inputs. Management has partial control over salary levels, although external business conditions also play a significant part. The developed econometric model provides an adjustment for the business conditions of the utility by looking at wage rates provided by the U.S. Bureau of Labor Statistics BLS for areas within the service territory of each utility.

Adjusting the cost model for external wage rates within each service territory allows us to isolate the management decisions from those circumstances beyond management's control. In this way, we can compare a utility serving a high wage area (e.g., Commonwealth Edison) to a utility serving a lower wage area.

This data was entered from the BLS website under the section for Occupational Employment Statistics, which contains a listing of cities and occupational salaries. PSE staff gathered this data by mapping each utility to appropriate areas provided by the "May 2008 Metropolitan and Non-Metropolitan Area Occupational Employment and Wage Estimates."

### 3.1.4 Operating Condition Variables

Characteristics other than output and input price levels can significantly impact utility costs. Heterogeneous operating conditions contribute to explainable variations in distribution unit costs. The econometric model for D&CC expenses identified four such variables: amount of generation, number of natural gas customers, underground line percentage, and percent of service territory forested. The coefficient estimates provide the weights given to each of these variables, allowing for an "apples to apples" comparison of utilities with different external circumstances. All parameter estimates have signs that correspond to theory, are plausible in magnitude, and are statistically significant based on t-statistic hypothesis tests.

*DEGREE OF GENERATION*

The presence of power generation at a utility offers the opportunity to capture scope economies for its power distribution functions, permitting a more seamless path for the transfer of electricity from primary sources to customer end use. We would expect the impact of a higher degree of self-generation to manifest in lower distribution costs. Thus, the anticipated parameter estimate is negative. As shown in Table 3-2, this is the finding of the econometric analysis, and this result has a high degree of statistical significance.

Data was gathered using PSE's subscription to SNL Energy, which processed FERC Form 1 data. Data on the net generation of each sampled utility can be found on page 401 of the FERC Form 1. Line 9 offers the megawatt-hours of annual power generation for the reporting company.

*NUMBER OF NATURAL GAS CUSTOMERS*

Similar to the self-generation of electricity, the presence of natural gas operations allows economies of scope to lower electric distribution and customer care expenses. Costs can be shared between the gas and electric departments, allowing for each department to lower its unit costs compared to what they would be if each were operating independently. As with the generation variable, we anticipate the parameter estimate to be negative. As seen in Section 3.3, this is the finding of the econometric analysis, and this result has a high degree of statistical significance.

Data for the variable on the number of natural gas customers was gathered by SNL Energy. Raw sources are from annual reports filed by utilities to their state regulators, most of which follow the FERC Form 2 template, and from EIA-176 forms.

*UNDERGROUND LINE PERCENTAGE*

The prevalence of system undergrounding has a conflicting effect on overall utility cost. Installing power lines underground increases capital investment, and thus the rate base, relative to overhead lines. At the same time, annual O&M costs experience a reduction as the proportion of underground lines increases.[11] This is due to lower occurrences of damage from environmental factors (e.g., trees, animals, wind).

This variable also serves as a proxy for customer density as urban areas tend to have a higher proportion of underground lines compared to rural areas. In the context of an O&M evaluation, the parameter is expected to have a negative sign. Section 3.3 shows that this is the finding of the econometric analysis, and this result has a high degree of statistical significance.

[11] Recent research by the author has also revealed a significant impact on system reliability resulting from underground lines. Benefit cost tests of underground investments should incorporate the benefit of reductions in O&M and increases in system reliability. Additionally, utilities engaging in the expansion of underground lines should include a forecast of the annual O&M savings expected to result from this investment.

Data for this variable was gathered using PSE's subscription to SNL Energy, which processed FERC Form 1 data. Data on the plant in service of each sampled utility can be found on pages 204-207 of the FERC Form 1. End of year totals found on lines 66 "Underground Conduit" and 67 "Underground Conductors and Devices" were divided by line 75 "Total Distribution Plant" to measure the degree of undergrounding in each utility distribution system.

*PERCENT OF SERVICE TERRITORY FORESTED*

A system surrounded by a high proportion of trees forces the utility to increase tree trimming and line maintenance efforts. Additionally, service outages become more prevalent as the percentage of forestation increases, causing restoration expenses to be more common. We would expect the parameter estimate on the percent forested variable to be positive. This is the finding of the econometric analysis presented in Table 3-2, and this result has a high degree of statistical significance.

Forestation data was attained from the website of the U.S. Forest Service. This data allows estimates to be made on the relative prevalence of forestation for each electric utility included in the sample. Estimates were made by taking the amount of forested land area divided by the total non-water land area of each county in the service territory of the utility.

### 3.1.5 Trend Variable

A trend variable is extremely revealing in studying expected utility costs. This variable incorporates the annual trend in technological change in the power distribution industry, along with the trend in the differences in industry input prices relative to the trend in the U.S. GDPPI. The interpretation of this variable is that utility cost typically increases by the percentage change in GDPPI plus the parameter estimate on the trend variable, ceteris paribus. Theory also states that unit costs, from which prices are based, should rise by GDPPI plus the trend estimate minus the realization of scale economies, assuming efficient production.

This report's findings reveal that the U.S. power distribution industry has experienced a trend with a negative parameter estimate. Table 3-2 shows that the parameter estimate for D&CC expenses is -0.0116. This implies that, given constant output and operating conditions, D&CC costs have been increasing by the annual change in GDPPI minus 1.16 percent. For a utility experiencing modest growth, we would expect unit costs to rise by GDPPI minus 1.16 percent minus increased productivity due to realized scale economies.[12]

$$\Delta Cost = \Delta GDPPI - 1.16\% - increased\ productivity + \Delta output \qquad [6]$$

$$\Delta Unit\ Cost = \Delta GDPPI - 1.16\% - increased\ productivity \qquad [7]$$

An important test for utility managers, regulators, and consumer advocates is to measure whether costs are rising according to Equation 6, and prices are increasing according to Equation 7. If not, this is evidence that a utility is either increasing or decreasing its cost efficiency and performance. These equations can be used to determine appropriate escalation of costs for forward test year revenue requirements and in multi-year rate and revenue caps (e.g., revenue decoupling).

Section 5 draws upon these findings in assessing how AIU's cost performance has changed from the 2005-2007 period to the 2008 test year costs proposed by AIU. Costs increasing beyond what is predicted in Equation 6 evidences worsening cost efficiency. Costs increasing less than predicted evidences improving cost efficiency.

## 3.2 Sample

The sample selected in this study consists of 115 investor-owned utilities (IOUs) spanning the period of 1994-2007, including the three utilities of AIU. This sample comprises those IOUs that had plausible data for all examined variables over this timeframe. The dataset was an "unbalanced panel" as some annual observations were excluded for specific utilities, primarily due to missing data. The final sample includes 1,451 observations. Such a large sample enabled the robust estimates discussed in the next section. Table 3-1 presents the utilities included in the sample.

[12] This discussion assumes the efficiency level of the utility remains constant. Costs can increase or decrease due to changes in overall cost efficiency over time. For a utility with poor cost efficiency we would expect to have lower cost escalation than predicted by the trend variable due to cost savings resulting from increased efficiency.

**Table 3-1 U.S. Electric Investor-Owned Utility Benchmarking Sample**

Alabama Power Company
ALLETE (Minnesota Power)
Appalachian Power Company
Arizona Public Service Company
Atlantic City Electric Company
Avista Corporation
Baltimore Gas and Electric Company
Bangor Hydro Electric Company
Black Hills Power, Inc.
Carolina Power & Light Company
Central Hudson Gas & Electric Corp
Central Illinois Light Company (AmerenCILCO)*
Central Illinois Public Service Co (AmerenCIPS)*
Central Maine Power Company
Central Vermont Public Service Corporation
Cleco Power LLC
Cleveland Electric Illuminating Company
Columbus Southern Power Company
Commonwealth Edison Company
Connecticut Light and Power Company
Consolidated Edison Company of New York, Inc.
Consumers Energy Company
Dayton Power and Light Company
Delmarva Power & Light Company
Detroit Edison Company
Duke Energy Carolinas, LLC
Duke Energy Indiana, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Edison Sault Electric Company
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, L.L.C.
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Florida Power & Light Company
Florida Power Corporation
Georgia Power Company
Green Mountain Power Corporation
Gulf Power Company
Hawaii Electric Light Company, Inc.
Hawaiian Electric Company, Inc.
Idaho Power Co.
Illinois Power Company (AmerenIP)*
Indiana Michigan Power Company
Indianapolis Power & Light Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas and Electric Company
Kentucky Power Company
Kentucky Utilities Company
Kingsport Power Company
Louisville Gas and Electric Company
Madison Gas and Electric Company
Maine Public Service Company
Massachusetts Electric Company
Maui Electric Company, Limited
Metropolitan Edison Company
Mississippi Power Company
Monongahela Power Company
Mt. Carmel Public Utility Company
Narragansett Electric Company
Nevada Power Company
New York State Electric & Gas Corp
Niagara Mohawk Power Corporation
Northern Indiana Public Service Co.
Northern States Power Company MN
Northern States Power Company WI
NSTAR Electric Company
Ohio Edison Company
Ohio Power Company
Oklahoma Gas and Electric Company
Orange and Rockland Utilities, Inc.
Otter Tail Corporation
Pacific Gas and Electric Company
PacifiCorp
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power Company
Portland General Electric Company
Potomac Edison Company
Potomac Electric Power Company
PPL Electric Utilities Corporation
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Company of Oklahoma
Public Service Electric and Gas Company
Puget Sound Energy, Inc.
Rochester Gas and Electric Corp
San Diego Gas & Electric Co.
Sierra Pacific Power Company
South Carolina Electric & Gas Co.
Southern California Edison Co.
Southern Indiana Gas and Electric Company, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
Superior Water, Light and Power Company
Tampa Electric Company
Toledo Edison Company
Tucson Electric Power Company
Union Electric Company
United Illuminating Company
Upper Peninsula Power Company
Virginia Electric and Power Company
West Penn Power Company
Westar Energy (KPL)
Western Massachusetts Electric Company
Wheeling Power Co
Wisconsin Electric Power Company
Wisconsin Power and Light Company
Wisconsin Public Service Corp

* Ameren Illinois Utilities

## 3.3 Parameter Estimates

D&CC coefficient estimates are presented in Table 3-2. Variables include a constant term, number of customers, retail deliveries, wage level, net generation, percent undergrounding, number of gas customers, percent service territory forested, and a time trend variable. There are additional "interaction" terms that allow for a more flexible functional form. This is in following the translog cost function that is popular in cost theory research.[13] These interaction terms can be ignored if one is interested in the cost response to each variable at the *mean* of the sampled data.

[13] See the Appendix for the functional form of the translog specification used in this report.

**Table 3-2 D&CC Econometric Parameter Estimates**

**Dependent Variable: Distribution & Customer Care O&M cost divided by U.S. GDPPI (Logged)**

**Independent Variables (Logged):**

Number of customers (N)
Retail volumes (V)
D&CC wage level (WL)
Net Generation (G)
Percentage undergrounding (UG)
Number of gas customers (YNG)
Percent forested (F)

| | Variable | Parameter Value | T-stat | P-value |
|---|---|---|---|---|
| First Order Terms | | | | |
| | Constant | 7.1063 | 903.1693 | 0.0000 |
| | N | 0.9387 | 54.7403 | 0.0000 |
| | V | 0.0500 | 3.5275 | 0.0004 |
| | WL | 1.7368 | 8.4791 | 0.0000 |
| | G | -0.0238 | -7.2457 | 0.0000 |
| | UG | -0.0465 | -5.5248 | 0.0000 |
| | YNG | -0.0065 | -2.9481 | 0.0032 |
| | F | 0.0373 | 6.2763 | 0.0000 |
| | Trend | -0.0116 | -15.9631 | 0.0000 |
| Second Order Terms | | | | |
| | N*N | 0.3379 | 10.4956 | 0.0000 |
| | V*V | 0.3207 | 11.5259 | 0.0000 |
| | N*V | -0.6622 | -11.5120 | 0.0000 |
| | WL*WL | 21.5998 | 11.8215 | 0.0000 |
| | N*WL | 1.6753 | 2.5404 | 0.0112 |
| | V*WL | -2.6602 | -4.1561 | 0.0000 |

Parameter estimates measure the actual cost elasticity of the given explanatory variable. This means that as the explanatory variable is increased by 1 percent, real cost increases by the parameter estimate times 1 percent. For example, the parameter estimate on retail customers (N) is 0.9387. It follows that if the number of customers increase by 2 percent and all other variables remain constant, we would expect cost to increase by 0.9387 times 2 percent, or 1.8774 percent.[14]

The adjusted $R^2$ of the model equals 0.980. This is a test of how well the model "fits" the observed data. It can be interpreted as the percentage of the observed variation that is captured by the model. In this case, 98.0% of the variation in D&CC cost is accounted for by the model.

## 3.4 D&CC Evaluation Results

AIU's D&CC cost performance is evaluated relative to their ranking among the 115 utilities in the sample and by a comparison of AIU's actual costs to the prediction of the model. The difference in the actual to expected cost is the most likely estimate of excess cost. A three-year average of latest available performance scores is taken to smooth out annual fluctuations.

[14] Again, assuming the utility is at the average number of customers for the sample. With the flexibility of the translog cost function, utilities deviating from the mean might have different cost elasticities.

### 3.4.1 Rankings

Out of the 115 IOUs included in the sample, all three of the AIU companies were in the bottom half of the rankings according to the econometric model. AmerenCILCO was ranked **76th**, AmerenIP **80th**, and AmerenCIPS **94th**. Figure 3-1 shows the rankings of each Ameren utility relative to the sample.

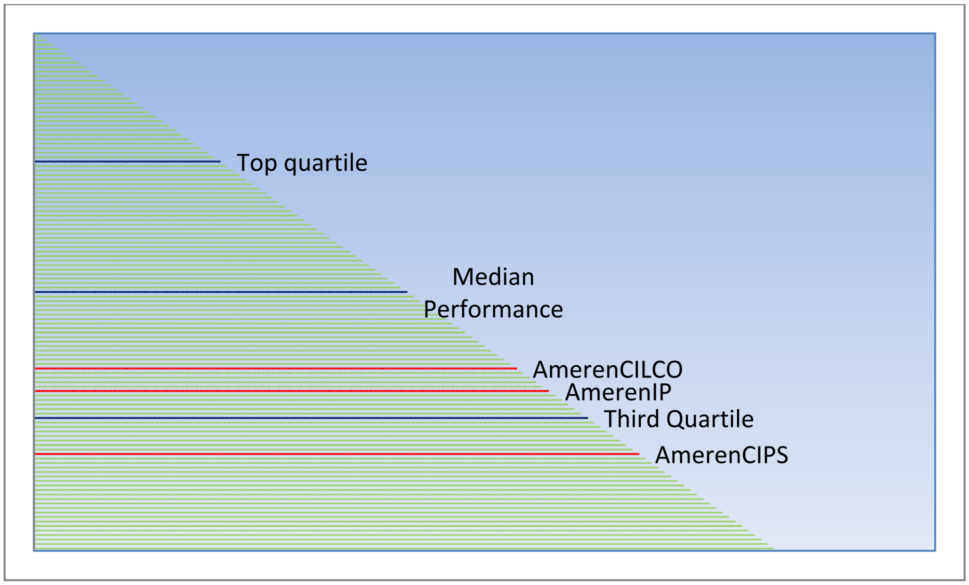


**Figure 3-1 AIU Ranking by D&CC Cost**

### 3.4.2 Comparison of Actual Cost to Expected Cost

Perhaps a more revealing comparison is AIU's D&CC O&M actual costs compared to the prediction of the econometric model. Recall that this model accounts for a number of variables found to be statistically significant cost drivers of D&CC expenses. The model prediction is interpreted as the expected level of costs for an *average* performing utility, given the circumstances faced by AIU.

For the most recent three-year period of available data, 2005-2007, AmerenCILCO's actual costs are **11.5 percent above**, AmerenIP's costs are **12.4 percent above**, and AmerenCIPS' costs are **20.1 percent above** the model's prediction. An interpretation of these percentages is that costs would need to be reduced by these amounts in order for each utility to be at the industry norm in terms of performance.

It is debatable what an appropriate standard should be. Perhaps an average standard is acceptable in defining reasonable cost levels. However, some might argue that the bar should be set with a higher standard. For example, attaining a top quartile standard might be a reasonable prospect. If a top quartile performance level were the expectation, AmerenCILCO's costs would need to be reduced by **31.7 percent**, AmerenIP's by **32.6 percent**, and AmerenCIPS' by **40.3 percent**.

Table 3-3 displays these results and translates these percentages into costs. The table displays the amount of reductions that would have needed to be made in order for AIU to attain an average or top quartile performance.

**Table 3-3 D&CC Cost Performance Evaluation**

| Utility | Rank[1] | 2005-2007 average actual costs | 2005-2007 average predicted costs | Percent actual over predicted[2] | Annual cost reductions required to reach *average* performance | Annual cost reductions required to attain *top quartile* performance |
|---|---|---|---|---|---|---|
| AmerenCILCO | 76 of 115 | $34,079,000 | $30,376,867 | 11.5% | $3,702,133 | $9,258,216 |
| AmerenIP | 80 of 115 | $106,364,666 | $93,960,402 | 12.4% | $12,404,264 | $29,590,098 |
| AmerenCIPS | 94 of 115 | $72,626,666 | $59,402,253 | 20.1% | $13,224,413 | $24,089,386 |
| **Total AIU** | | **$213,070,332** | **$183,739,522** | **14.8%** | **$29,330,810** | **$62,937,701** |

Notes:

1. Evaluation is based on 3-year (2005-2007) average O&M costs.
2. Calculated logarithmically. Recall that continuous growth rates are calculated by $C_1 = C_0 * e^r$

# 4 Evaluation of Electric A&G Expenses

This section provides the results of the administrative and general (A&G) cost performance of each Ameren Illinois utility. It begins with a discussion of the variables comprising the econometric model. Section 4.2 describes the data sample, and Section 4.3 displays the econometric model. The AIU performance results of A&G expenses are presented in the last section.

## 4.1 Model Variables

Numerous external circumstances influence the level of administrative and general costs incurred by a power distributor. A sound benchmarking approach incorporates these exogenous items in the evaluation process. This report has accounted for five such cost drivers: retail customers, net generation, wage level, percent undergrounding, and a trend variable.

### 4.1.1 Definition of Cost

Cost data has been collected via a commercially available data vendor, SNL Energy, which gathers and processes publically available FERC Form 1s previously filed by each utility in the sample. Cost data can be found on pages 320-323, Operation and Maintenance Expenses, and are calculated by subtracting employee pensions and benefits (FERC account 926) from the subcategory O&M expenses of administrative and general expenses. Pensions and benefits are subtracted from the definition of cost because these costs are highly variable and partially dependent on external market conditions. The FERC Form 1 account numbers comprising the definition of A&G cost are 920-925, 927-929, 930.1, 930.2, and 931.

The sample includes data from 1994-2007. For each year, cost was divided by that year's GDPPI as reported by the U.S. Bureau of Economic Analysis (BEA). This allows cost to be stated in real rather than nominal terms.

### 4.1.2 Number of Customers and Net Generation

In benchmarking A&G expenses, "output" is defined as the number of retail customers and the amount of net generation. The impacts on cost of each of these outputs are quantified and weighted using econometric analysis. Within the estimation process, the availability of scale economies is recognized, allowing for a fair comparison between distributors with differing scales and output compositions.

Net generation was previously defined as a business condition variable for the D&CC model. The difference for the A&G model is that reported A&G expenses cover the generation activities of utilities. No allocation is made between A&G incurred due to distribution and generation functions. Given this, generation is not a variable offering scope economies for A&G, but rather a driver of these costs. As with the number of customers, we would anticipate a positive parameter estimate. As seen in Section 4.3, this is the finding of the econometric analysis, and this result has a high degree of statistical significance.

An important finding of the A&G model is the vast scale economies available within this category of utility cost. The cost elasticity of customers at the mean is estimated to be 0.662 and the generation elasticity at 0.195. If a vertically integrated utility were to expand customers and generation uniformly by 10 percent, we would expect A&G costs to only rise by about 8.57 percent. In the context of benchmarking AIU, this report looked at each Illinois utility separately, assuming it was a standalone utility. This treatment was favorable to AIU as the consolidation of Ameren Services can take advantage of these scale economies without it being reflected in the cost prediction of the model.

Data for retail customers was gathered and processed by SNL Energy via page 300 on the FERC Form 1 before 1997. Retail customer data for the post-restructuring years was gathered from EIA-861 forms, which include all unbundled deliveries. It should be noted that the EIA-861 is not yet available for 2008, leading to an end-year of 2007 for this analysis. Extending the research to incorporate 2008 data will become feasible when EIA-861 data becomes available.

Data for the generation variable was gathered using PSE’s subscription to SNL Energy, which processed FERC Form 1 data. Data on the net generation of each sampled utility can be found on page 401 of the FERC Form 1. Line 9 offers the megawatt-hours of annual net power generation for the reporting company.

### 4.1.3 Input Prices

A utility's outputs and operating conditions primarily drive the input quantities (i.e., labor, materials, and services), yet cost is also directly impacted by the price of employing these inputs. Management has partial control over salary levels, although external business conditions also play a significant part. The developed econometric model provides an adjustment for the business conditions of the utility by looking at wage rates provided by the BLS for areas within the service territory of each utility.

Adjusting the cost model for the external wage rates within each service territory allows us to isolate the management decisions from those circumstances beyond management's control. In this way, we can compare a utility serving a high wage area (e.g., Commonwealth Edison) to a utility serving a lower wage area.

This data was entered from the BLS website under the section for Occupational Employment Statistics. This section contains a listing of cities and occupational salaries. PSE staff gathered this data by mapping each utility to appropriate areas provided by the "May 2008 Metropolitan and Non-Metropolitan Area Occupational Employment and Wage Estimates".

### 4.1.4 Operating Condition Variables

Characteristics other than output and input price levels can significantly impact utility costs. Heterogeneous operating conditions contribute to explainable variations in unit costs. The econometric model for A&G expenses identified one such variable. The parameter estimate has a sign that corresponds to theory, is plausible in magnitude, and is statistically significant based on t-statistic hypothesis tests.

*UNDERGROUND PERCENTAGE*

The prevalence of system undergrounding has a conflicting effect on overall utility cost. Installing power lines underground increases capital investment, and thus the rate base, relative to overhead lines. But, at the same time, annual O&M costs experience a reduction as the proportion of underground lines increase.[15] This is due to lower occurrences of damage from environmental factors (e.g., trees, animals, wind). In the context of A&G costs, smaller

[15] See footnote 11.

maintenance crews and lower levels of restoration coordination are necessary with a system that contains more underground lines.

This variable also serves as a proxy for customer density, as urban areas tend to have a higher proportion of underground lines compared to rural areas. This offers additional cost savings to A&G expenses. In the context of an O&M evaluation, this parameter is expected to have a negative sign. As seen in Section 4.3, this is the finding of the econometric analysis, and this result has a high degree of statistical significance.

Data for this variable was gathered using PSE's subscription to SNL Energy who processed FERC Form 1 data. Data on the plant in service of each sampled utility can be found on pages 204-207 of the FERC Form 1. End of year totals found on lines 66 "Underground Conduit" and 67 "Underground Conductors and Devices" was divided by line 75 "Total Distribution Plant" to measure the degree of undergrounding in each utility distribution system.

### 4.1.5 Trend Variable

A trend variable is extremely revealing in studying expected utility costs. This variable incorporates the annual trend in technological change in the A&G expenses of electric utilities, along with the trend in the differences in industry input prices relative to the trend in the U.S. GDPPI. The interpretation of this variable is that cost typically increases by the percentage change in GDPPI plus the parameter estimate on the trend variable, ceteris paribus. Theory also states that unit costs, from which prices are based, should rise by GDPPI plus the trend estimate minus the realization of scale economies, assuming efficient production.

This report's finding from 1994-2007 is that the U.S. power utility industry has experienced a trend with a negative parameter estimate on A&G expenses. As seen in Section 4.3, the estimate is -0.0011. However, hypothesis tests reveal that we cannot reject the hypothesis that this variable has zero impact on cost. Using the most likely value of the trend (-0.0011), according to Equation 8 and 9, we see what A&G costs and unit costs should be rising by.

$$\Delta Cost = \Delta GDPPI - 0.11\% - increased\ productivity + \Delta output \quad [8]$$

$$\Delta Unit\ Cost = \Delta GDPPI - 0.11\% - increased\ productivity \quad [9]$$

An important test for utility managers, regulators, and consumer advocates is to measure whether costs are rising according to Equation 8, and prices increasing according to Equation 9. If not, this is evidence that a utility is either increasing or decreasing its cost efficiency and performance. These equations can be used to help determine appropriate escalation of costs for forward test year revenue requirements and in multi-year price and revenue caps (e.g., revenue decoupling).

Section 5 draws upon these findings in assessing how AIU's cost performance has changed from the 2005-2007 period to the 2008 test year costs proposed by AIU. Costs increasing beyond what is predicted in Equation 8 evidences worsening cost efficiency. Costs increasing less than predicted evidences improving cost efficiency.

## 4.2 Sample

The sample consists of 115 utilities spanning the period of 1994-2007. In addition to the three AIU companies, this sample comprises those investor-owned utilities that had plausible data for all examined variables over this timeframe. The dataset was an "unbalanced panel," as some annual observations were excluded for specific utilities, primarily due to missing data. After this process, the sample includes 1,451 observations. Such a large sample enabled the robust estimates discussed in the next section. See Table 3-1 for a list of the sampled utilities.

## 4.3 Parameter Estimates

A&G coefficient estimates are presented in Table 4-1. Variables include a constant term, number of customers, net generation, wage level, percent undergrounding, and a time trend variable. There are additional "interaction" terms that allow for a more flexible functional form. This is in following the translog cost function that is popular in cost theory research.[16] These interaction terms can be ignored if one is interested in the cost response to each variable at the *mean* of the sampled data.

[16] See Appendix for the full functional form.

**Table 4-1 A&G Econometric Parameter Estimates**

**Dependent Variable: Administrative and General O&M cost divided by U.S. GDPPI (Logged)**

**Independent Variables (Logged):**
Number of customers (N)
Net Generation (G)
A&G Wage Level (WL)
Percentage Undergrounding (UG)

| | Variable | Parameter Value | T-stat | P-value |
|---|---|---|---|---|
| First Order Terms | | | | |
| | Constant | 6.8180 | 733.4390 | 0.0000 |
| | N | 0.6618 | 45.1672 | 0.0000 |
| | G | 0.1955 | 35.8486 | 0.0000 |
| | WL | 2.4438 | 10.0792 | 0.0000 |
| | UG | -0.0277 | -2.9887 | 0.0028 |
| | Trend | -0.0011 | -1.1585 | 0.2469 |
| Second Order Terms | | | | |
| | N*N | 0.0349 | 6.7176 | 0.0000 |
| | G*G | 0.0207 | 15.5140 | 0.0000 |
| | N*G | -0.0639 | -14.6185 | 0.0000 |
| | WL*WL | -7.9529 | -3.8538 | 0.0001 |
| | N*WL | -0.1466 | -0.7450 | 0.4564 |
| | G*WL | 0.0835 | 0.9136 | 0.3611 |

Parameter estimates measure the actual cost elasticity of the given explanatory variable. This means that as the explanatory variable is increased by 1 percent, real cost increases by the parameter estimate times 1 percent. For example, the parameter estimate on retail customers is 0.662. This means that if the number of customers increases by 2 percent and all other variables remain constant, we would expect cost to increase by 0.662 times 2 percent, or 1.324 percent.[17]

The adjusted $R^2$ of the model equals 0.957. This is a test of how well the model “fits” the observed data. It can be interpreted as the percentage of the observed variation that is captured by the model. In this case, 95.7% of the variation in A&G cost is accounted for by the model.

[17] Again, assuming the utility is at the average number of customers for the sample. With the flexibility of the translog cost function, utilities deviating from the mean might have different cost elasticities.

## 4.4 Evaluation Results

AIU's A&G cost performance is evaluated relative to their ranking amongst the 115 utilities in the sample and by a comparison of Ameren's actual costs to the prediction of the model. The difference in the actual to expected cost is the most likely estimate of excess cost. A three-year average of cost is taken to smooth out annual fluctuations.

### 4.4.1 Rankings in Comparison to Sample

Out of the 115 U.S. IOU power utilities included in the sample, all three of the AIU utilities were in the bottom half of the rankings according to the econometric model presented in Section 4.3. AmerenCILCO was ranked **105th**, AmerenIP **95th**, and AmerenCIPS **85th** in the sample. Figure 4-1 shows the rankings of the each Ameren utility relative to the sample.

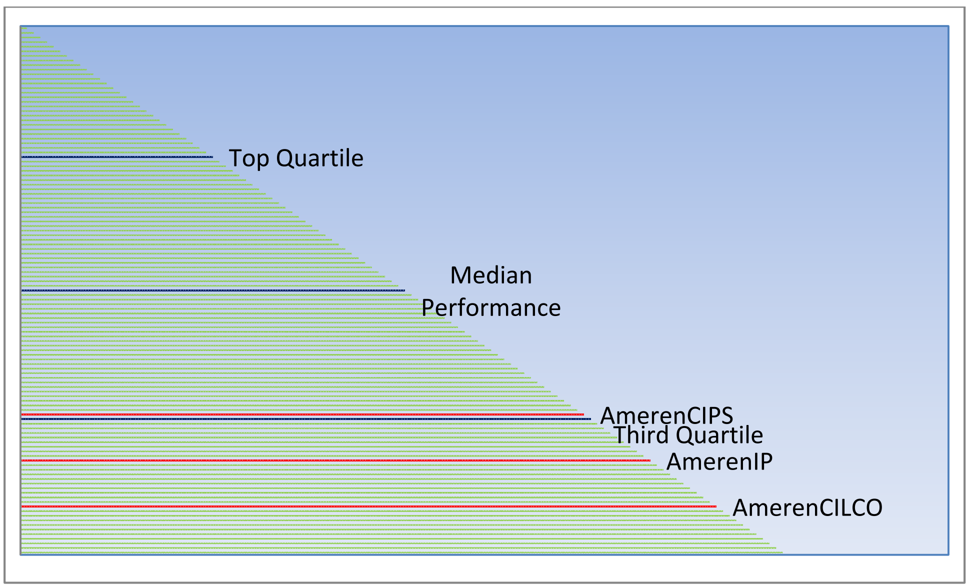


**Figure 4-1 AIU Ranking by A&G Cost**

### 4.4.2 Comparison of Actual Cost to Expected Cost

Perhaps a more revealing comparison is AIU's A&G actual costs compared to the prediction of the econometric model. Recall this model accounts for a number of variables found to be statistically significant cost drivers of A&G expenses. The model prediction is interpreted as the expected level of costs for an *average* performing utility given the circumstances faced by AIU.

For the most recent three-year period of available data (2005-2007), AmerenCILCO's actual costs are **42.3 percent above**, AmerenIP's costs are **27.1 percent above**, and AmerenCIPS's costs are **16.9 percent above** the model's prediction. An interpretation of these percentages is that costs would need to be reduced by these amounts in order for each utility to be at the industry norm in terms of performance.

It is debatable what an appropriate standard should be. Perhaps an average standard is acceptable in defining reasonable cost levels. However, some might argue that the bar should be set with a higher standard. For example, attaining a top quartile standard might be reasonable. If a top quartile performance level were the expectation, then Central Illinois Lights' costs would need to be reduced by **63.8 percent**, Illinois Power's by **48.6 percent**, and Central Illinois Public Service Company's by **38.4 percent**.

Table 4-2 displays these results and translates these percentages into costs. The table displays the amount of cost reductions that would have needed to be made in order for AIU to attain an average or top quartile performance.

**Table 4-2 A&G Cost Performance Evaluation**

| Utility | Rank[1] | 2005-2007 average actual costs | 2005-2007 average predicted costs | Percent actual over predicted[2] | Annual cost reductions required to reach *average* performance | Annual cost reductions required to attain *top quartile* performance |
|---|---|---|---|---|---|---|
| AmerenCILCO | 105 of 115 | $23,763,333 | $15,566,852 | 42.3% | $8,196,481 | $11,208,022 |
| AmerenIP | 95 of 115 | $59,025,666 | $45,013,947 | 27.1% | $14,011,719 | $22,720,053 |
| AmerenCIPS | 85 of 115 | $30,512,666 | $25,768,218 | 16.9% | $4,744,448 | $9,729,530 |
| **Total AIU** | | **$113,301,665** | **$86,349,016** | **27.2%** | **$26,952,649** | **$43,657,605** |

Notes:

1. Evaluation is based on 3-year (2005-2007) average O&M costs less pension and benefits.
2. Calculated logarithmically. Recall that continuous growth rates are calculated by $C_1 = C_0 * e^r$

# 5 Application to Proposed 2008 Test Year Costs

It is relevant in the context of the current proceeding to estimate the cost efficiency level of AIU inherent in the proposed 2008 test year spending levels. To do this, we need to assess the changes in cost performance from the 2005-2007 period to 2008. The following process shows PSE's estimate of the change in cost efficiency from the benchmarked period (2005-2007) to 2008. This change is then added to the 2005-2007 evaluation to determine the cost excesses contained in AIU's proposed 2008 test year expenses.

As shown in Sections 3.1 and 4.1, the econometric model offers an estimate of the annual growth in each cost category. Equations 6 and 8 reveal that the expected rise in cost equals the percentage change in GDPPI plus the trend variable plus the percentage change in output. From the 2005-2007 average period to 2008, GDPPI rose by 5.03%. During this same time, the number of customers for AIU increased by about 3%.[18] These two components put upward pressure on costs to the tune of about 8 percent. However, this pressure is partially offset by expected increases in productivity, as shown in the parameter estimate of the trend variable.[19]

Table 5-1 and Table 5-2 show the expense increases of AIU from the 2005-2007 period to 2008 along with the expected increases a typical utility would experience. These tables also display the added inefficiency in the 2008 proposed spending levels calculated by taking the difference between AIU's cost increases and those of a typical utility.

[18] This is estimated since EIA-861 data is not yet available. A more rapid estimate benefits AIU's efficiency estimate.

[19] This is a conservative estimate for AIU since it ignores productivity gains available by increased scale economies due to output growth.

**Table 5-1 Comparison of Actual to Expected D&CC Cost Increases from 2005-2007 to 2008**

| | D&CC Expenses ($000) | | | | |
|---|---|---|---|---|---|
| | AIU Proposed | 2005-2007 AIU Average | Percentage Change | **Model Expected Cost Change[1]** | **Increased Inefficiency** |
| AmerenCILCO | $45,812 | $34,079 | 29.6% | 5.7% | **23.9%** |
| AmerenIP | $150,682 | $106,365 | 34.8% | 5.7% | **29.1%** |
| AmerenCIPS | $94,759 | $72,627 | 26.6% | 5.7% | **20.9%** |

Note:

1. Calculated by taking the percentage change in GDPPI (5.03%) adding the trend variable (-1.16%) for two years and adding customer growth (~3%) between 2005-2007 and 2008.

**Table 5-2 Comparison of Actual to Expected A&G Cost Increases from 2005-2007 to 2008**

| | A&G Expenses ($000) | | | | |
|---|---|---|---|---|---|
| | AIU Proposed | 2005-2007 AIU Average | Percentage Change | **Model Expected Cost Change[1]** | **Increased Inefficiency** |
| AmerenCILCO | $31,186 | $32,715 | -4.8% | 7.8% | **-12.6%** |
| AmerenIP | $93,618 | $65,610 | 35.5% | 7.8% | **27.7%** |
| AmerenCIPS | $51,125 | $40,338 | 23.7% | 7.8% | **15.9%** |

Note:

1. Calculated by taking the percentage change in GDPPI (5.03%) adding the trend variable (-0.11%) for two years and adding customer growth (~3%) between 2005-2007 and 2008.

By combining estimates of AIU’s performance for the 2005-2007 period with estimates of the cost inefficiencies added since that time, we can calculate the inefficiencies implicit in the proposed test year spending amounts. Table 5-3 and Table 5-4 present the estimated inefficiencies of AIU for D&CC and A&G expenses for an average and top quartile standard. If an average performance standard is implemented, Table 5-3 estimates D&CC excess costs implicit in the proposed test year equal $13.6 million, $51.2 million, $31.8 million for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively. Using a top quartile standard, excess D&CC expenses equal $19.5 million, $69.4 million, $43.3 million for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

**Table 5-3 Estimated D&CC Cost Inefficiency in AIU's Proposed Test Year Expenses**

| | Proposed Expenses ($000) | Estimated 2005-2007 Inefficiency: Average Standard | Estimated 2005-2007 Inefficiency: Top Quartile Standard | Added Inefficiency Since 2005-2007 | Estimated inefficiency in proposed test year spending: Average Standard | Estimated inefficiency in proposed test year spending: Top Quartile Standard | Estimated Excess Costs ($000)[1]: Average Standard | Estimated Excess Costs ($000)[1]: Top Quartile Standard |
|---|---|---|---|---|---|---|---|---|
| | **[A]** | **[B]** | **[C]** | **[D]** | **E=B+D** | **F=C+D** | **A-A/exp(E)** | **A-A/exp(F)** |
| AmerenCILCO | $45,812 | 11.5% | 31.7% | 23.9% | 35.4% | 55.6% | **$13,650** | **$19,533** |
| AmerenIP | $150,682 | 12.4% | 32.6% | 29.1% | 41.5% | 61.7% | **$51,200** | **$69,396** |
| AmerenCIPS | $94,759 | 20.1% | 40.3% | 20.9% | 41.0% | 61.2% | **$31,866** | **$43,369** |
| **AIU total** | **$291,253** | | | | | | **$96,716** | **$132,298** |

Note:

1. Calculated logarithmically by taking proposed costs and subtracting by the expected costs implicit in inefficiency scores.

**Table 5-4 Estimated A&G Cost Inefficiency in AIU's Proposed Test Year Expenses**

| | Proposed Expenses ($000) | Estimated 2005-2007 Inefficiency: Average Standard | Estimated 2005-2007 Inefficiency: Top Quartile Standard | Added Inefficiency Since 2005-2007 | Estimated inefficiency in proposed test year spending: Average Standard | Estimated inefficiency in proposed test year spending: Top Quartile Standard | Estimated Excess Costs ($000)[1]: Average Standard | Estimated Excess Costs ($000)[1]: Top Quartile Standard |
|---|---|---|---|---|---|---|---|---|
| | **[A]** | **[B]** | **[C]** | **[D]** | **E=B+D** | **F=C+D** | **A-A/exp(E)** | **A-A/exp(F)** |
| AmerenCILCO | $31,186 | 42.3% | 63.8% | -12.6% | 29.7% | 51.2% | **$8,014** | **$12,497** |
| AmerenIP | $93,618 | 27.1% | 48.6% | 27.7% | 54.8% | 76.3% | **$39,518** | **$49,984** |
| AmerenCIPS | $51,125 | 16.9% | 38.4% | 15.9% | 32.8% | 54.3% | **$14,292** | **$21,418** |
| **AIU total** | **$175,929** | | | | | | **$61,825** | **$83,899** |

Note:

1. Calculated logarithmically by taking proposed costs and subtracting by the expected costs implicit in inefficiency scores.

If an average performance standard is implemented, Table 5-4 estimates A&G excess costs implicit in the proposed test year equal $8 million, $39.5 million, $14.3 million for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively. Using a top quartile standard, excess A&G expenses equal $12.5 million, $50.0 million, $21.4 million for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

# Appendix

This section discusses the functional form of the two econometric models developed for this report. Both models conform to the translog cost function, which is popular in the scholarly production economics literature.

# Functional Form and Estimation

A functional form is based on economic theory and the researcher's beliefs about the relationship between certain variables. On the left-hand side of the equation lies the dependent variable, which the researcher is attempting to predict (in this case, real cost). On the right-hand side lie independent variables, which the researcher believes impact the dependent variable.

The functional forms of each of the models are given below. Abbreviations for explanatory variables can be found in Table 3-2.

**<u>D&CC Model</u>**

$$\begin{aligned}\ln\left(\frac{D\,\&\,CC\,Cost_{i,t}}{GDPPI_t}\right) = {} & \beta_0 + \beta_1 \ln(N_{i,t}) + \beta_2 \ln(N_{i,t}) * \ln(N_{i,t}) + \beta_3 \ln(V_{i,t}) + \beta_4 \ln(V_{i,t})\ln(V_{i,t}) \\ & + \beta_5 \ln(N_{i,t})\ln(V_{i,t}) + \beta_6 \ln(WL_i^{D\&CC}) + \beta_7 \ln(WL_i^{D\&CC})\ln(WL_i^{D\&CC}) \\ & + \beta_8 \ln(N_{i,t})\ln(WL_i^{D\&CC}) + \beta_9 \ln(V_{i,t})\ln(WL_i^{D\&CC}) + \beta_{10} \ln(G_{i,t}) \\ & + \beta_{11} \ln(UG_{i,t}) + \beta_{12} \ln(YNG_{i,t}) + \beta_{13} \ln(F_i) + \beta_{14} Trend_t. + \varepsilon_{i,t}.\end{aligned}$$

**<u>A&G Model</u>**

$$\begin{aligned}\ln\left(\frac{A\,\&\,G\,Cost_{i,t}}{GDPPI_t}\right) = {} & \beta_0 + \beta_1 \ln(N_{i,t}) + \beta_2 \ln(N_{i,t}) * \ln(N_{i,t}) + \beta_3 \ln(G_{i,t}) + \beta_4 \ln(G_{i,t})\ln(G_{i,t}) \\ & + \beta_5 \ln(N_{i,t})\ln(G_{i,t}) + \beta_6 \ln(WL_i^{A\&G}) + \beta_7 \ln(WL_i^{A\&G})\ln(WL_i^{A\&G}) \\ & + \beta_8 \ln(N_{i,t})\ln(WL_i^{A\&G}) + \beta_9 \ln(G_{i,t})\ln(WL_i^{A\&G}) + \beta_{10} \ln(UG_{i,t}) \\ & + \beta_{14} Trend_t. + \varepsilon_{i,t}.\end{aligned}$$

The above models were estimated using EViews 6.0 econometric software[20]. EViews allows for a panel-specific estimation procedure accounting for the unbalanced nature of the dataset employed.

[20] Quantitative Micro Software, LLC

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