IIEC Exhibit 3.0

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	**:**	
	:	**Docket No. 07-0566**
Proposed general increase in electric rates	**:**	

Corrected Direct Testimony and Exhibits of

David L. Stowe

On behalf of

Illinois Industrial Energy Consumers

February 11, 2008
Project 8883

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

STATE OF ILLINOIS

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COMMONWEALTH EDISON COMPANY	**:**	
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Corrected Direct Testimony of David L. Stowe

Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is David L. Stowe. My business address is 1215 Fern Ridge Parkway, Suite 208; St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This is summarized in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Illinois Industrial Energy Consumers ("IIEC"). The IIEC is an ad hoc group of industrial customers eligible to take power and energy or delivery service from Commonwealth Edison Company ("ComEd" or "Company").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to describe my review of the Company's cost of service study ("COSS"), and to recommend specific improvements that would make it useful for determining rates in this case.

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A The Company's COSS, while structurally and functionally similar to those filed in previous cases, contains serious flaws that make it fundamentally unreliable. In my testimony I outline the principles of a proper COSS and show how the Company's COSS falls short of these principles. Those flaws are as follows: (1) the Company's COSS cannot identify or separate primary and secondary costs; (2) it does not recognize the costs imposed by safety and reliability standards such as the National Electrical Safety Code ("NESC"); (3) it improperly allocates costs to customers taking service at voltages above 69 kilovolts ("kV"); and (4) it contains errors that affect the factors used to distribute costs to customer classes.

I will explain the modifications I made to the Company's COSS to realign it with proper cost-causation principles, and compare the results of my modified COSS with those of the Company's COSS.

Cost of Service Overview

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A COSS?

A After determining the total company cost of service or revenue requirement and the responsibility of various groups of customers for those costs, a COSS is used to allocate the revenue requirement or cost responsibility among the customer classes. A COSS compares the cost that each customer class imposes on the system to the

revenues each class contributes. For example, when a customer class produces the same rate of return as the total system rate of return, it is paying revenue to the utility just sufficient to cover the costs incurred in serving that class. If a class produces a below-average rate of return, it may be concluded that the revenues provided by the class are insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but is also paying part of the cost attributable to other classes who produce a below system average rate of return. The class COSS is important because, when properly conducted, it shows the cost to serve each rate class, as well as the rate of return from each class under current and proposed rates.

Q PLEASE DESCRIBE THE PROPER FUNDAMENTALS OF A COSS.

A Cost of service is a basic and fundamental concept in the ratemaking process. In all cost of service studies, certain fundamental principles should be recognized and implemented. Of primary importance is the cost-causation principle, *i.e.,* attributing costs to those customers or classes that caused them to be incurred.

The first step in the process is to distinguish costs according to major functions, such as production, transmission, distribution, and customer service. Many analysts also create sub-functions, such as primary and secondary voltage distribution lines, services, line transformer costs, *etc*., allowing them to segregate costs more precisely. The process of functionalization is important because it allows the analyst to aggregate *costs associated with specific functions,* and to assign them to the customer classes that benefit from those functions.

For example, consider a customer that owns or rents the transformer serving its facility, and that has agreed to have their usage metered on the primary, or higher voltage, side of that transformer. Such customers (referred to as "Primary customers") are somewhat unique in that they benefit from the utility's primary distribution system, sub-transmission and transmission systems, customer service functions, etc., but do not use or receive any benefit whatsoever from the secondary distribution system. The cost analyst, in recognition of the fact that such customers exist on his system, will define separate primary and secondary distribution functions, thereby eliminating the possibility that the Primary customers could be allocated secondary system costs.

The second step in a COSS is to classify[1] the functionalized costs based on *cost-causation* principles. Specifically, this cost classification is based on whether costs vary with the quantity of energy consumed, the peak electrical demand required by the system, the number of customers served, or some combination of these.

Energy-related costs are usage driven; that is, they vary in direct proportion as customers use more or less energy. Demand-related costs are incurred specifically to meet the customers' anticipated peak demand. Finally, customer-related costs are more closely related to the number of customers served than to the quantity of energy consumed or the electrical demands placed upon the system.

The third step in the COSS process is to assign or allocate the functionalized and classified costs to each class of customer, using factors that comport with the causes identified in the previous step. This step often relies upon supplemental studies of class loads, line losses, average meter costs, number of customers per class, *etc*., which are used to calculate the allocation ratios or factors.

[1]This step is called "classification of *costs."* All cost of service studies also include the classification of *customers* via a somewhat different mechanism.

For example, primary distribution substation costs, which are generally incurred to meet the combined demand of all the primary and secondary customers, would be distributed to the primary and secondary customer classes using allocation factors derived from each class's peak demand. However, secondary distribution costs, since they are not incurred to serve the Primary customers, should be distributed to only the Secondary customers[2] using allocation factors derived from the peak demand of classes using secondary (< 4 kV) distribution facilities.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost-causation, appropriate price signals, conservation, and revenue stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A To the extent practical, when rates are based on cost, each customer or class pays what it costs the utility to serve them, no more and no less. If rates are *not* based on cost of service, then some customers or classes contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

[2]Secondary customers are those taking service at secondary voltages, which ComEd defines as voltages below 4,000 volts (4 kV).

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the rate-setting step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When rates are designed so that energy, demand, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility about the need for new investment.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on costs do customers receive an accurate and appropriate price signal with which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the impact on a utility's earnings due to changes in customer use patterns will be minimized. Rates that are set at the level of costs result in revenue changes that mirror cost changes. Thus, from the utility's perspective, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of overall power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to know what will affect their rates or why. They may lose the ability to translate expected utility-wide cost changes (such as expected increases in overall revenue requirements) into changes in their own rates. This situation introduces additional uncertainty and reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power cost.

ComEd's Cost of Service Study

Q HAVE YOU REVIEWED COMED'S COSS FILED IN THIS CASE?

A Yes, it is presented by ComEd witness, Alan C. Heintz, in ComEd Exhibit 13.1.

Q HAVE YOU FOUND PROBLEMS IN COMED'S COSS?

A Yes, I have.

Q PLEASE EXPLAIN THE PROBLEMS YOU FOUND IN THE COMPANY'S COSS.

A The Company has presented essentially the same COSS as that approved by the Commission for certain limited uses in the utility's previous rate case. ComEd's witness Heintz writes:

> The basic structure and functioning of the study presented in this proceeding is not different from ComEd's embedded cost of service studies as filed in Docket Nos. 99-0177, 01-0423, and 05-0597…

The Company implies that its proposed COSS is reasonable and proper based largely on the notion that it is sufficient that the study is structurally and

functionally similar to those approved in past cases.[3] However, close inspection of the Company's COSS reveals that the basic premises upon which the structural and functional workings of the COSS operate are invalid.

The Company's COSS contains several serious flaws that fly in the face of cost-causation principles. Among the most egregious, the Company's COSS:

1. Assigns over $88 million; incurred to install, operate, and maintain equipment used to provide service at secondary voltages, to Commercial and Industrial customers taking service at primary voltages.

2. Distributes additional millions of dollars of customer-related plant and O&M costs to the classes on the basis of demand.

3. Assigns nearly $5.5 million; incurred to install, operate, and maintain equipment operating below 69 kV, to customers taking service at or above 69 kV.

4. Ignores these errors by claiming the proposed COSS "…is reasonable and properly allocates costs among ComEd's customer classes…," yet providing neither verifiable data nor testimony to support this claim.

Given the Commission's statutory obligation to render a proper rate determination, it has every right to expect cost analysts presenting testimony to develop the best and most accurate COSS possible. In my opinion, this means that greater emphasis must be placed on aligning the COSS with cost-causation principles. Cost analysts cannot use past approval of a study's "structure and functioning" as a substitute for making the COSS better. This is especially true in this case, as unbundled delivery service rates are still relatively new (eight years), and since 1999, the Commission has not fully accepted ComEd's COSS for all ratemaking purposes.

[3]Please see IIEC witness Stephens' testimony for a brief description of how the Commission used ComEd's COSS in the past cases cited.

Results of ComEd's COSS

Q HAVE YOU REVIEWED THE RESULTS OF COMED'S COSS?

A Yes, I reviewed the results of the Company's embedded COSS for the test year ending December 31, 2006, updated for proposed known and measurable adjustments through September 30, 2007.

Q WHAT ARE THE RESULTS OF THE COMPANY'S COSS?

A The results of the Company's COSS are shown in Table 1.

TABLE 1

Results of ComEd's COSS

Line	Rate Class	RORB	RORB Index
1	Single Family Without Space Heat	6.2%	92
2	Multi Family Without Space Heat	3.0%	44
3	Single Family With Space Heat	7.6%	113
4	Multi Family With Space Heat	5.0%	74
5	Watt-Hour	9.9%	146
6	Small Load	8.7%	129
7	Medium Load	8.8%	131
8	Large Load	8.8%	130
9	Very Large Load	9.3%	137
10	Extra Large Load	(3.5%)	(51)
11	High Voltage Up to 10 MW	(5.5%)	(82)
12	High Voltage Over 10 MW	(6.6%)	(97)
13	Fixture-Included Lighting	10.4%	154
14	Dusk to Dawn Lighting	7.8%	116
15	General Lighting	7.9%	117
16	Railroad	(2.4%)	(35)
	Total	6.8%	100

Q WHAT DOES THE RORB INDEX COLUMN SHOW?

A That column shows each class' return on rate base ("RORB") indexed relative to the Company's total RORB. If a class' RORB Index is 100, this indicates that the RORB for that class is equal to the total Company RORB of 7.0%. RORB Index values below 100 indicate that the associated class' RORB is less than the total Company RORB, and index values above 100 indicate a class RORB greater than the total Company RORB.

The results in Table 1 show that, overall, the revenue recovered through the existing rates is adequate to meet the Company's expenses plus provide a 7.0% RORB. However, the results also suggest that the revenue recovered from individual classes varies widely, some being less than the cost of service and others being significantly above the cost of service.

These results, of course, are premised on ComEd's COSS model (*viz*., a spreadsheet based program that performs the calculations needed to derive the results shown in Table 1), and are entirely dependent on the inputs and assumptions that go into the model. Obviously, the results are only as accurate and valid as the assumptions and inputs upon which the COSS model is built.

In my testimony, I present evidence that shows that certain assumptions and inputs underlying ComEd's COSS contain serious flaws. I will also show that the Company's results cannot possibly be accurate because of those flawed inputs and assumptions.

ComEd Flaw No. 1: No Recognition of Primary and Secondary Voltage Differences

Q PLEASE DESCRIBE THE FIRST FLAW THAT YOU FOUND IN THE COMPANY'S COSS?

A The Company's COSS identifies and distinguishes the costs of service at only two voltage levels: (1) at and above 69 kV or "High Voltage" ("HV"), and (2) below 69 kV or "Distribution." That single cost distinction, however, does not recognize either the cost of service impact of the voltage at which service is taken, or the fact that ComEd has primary customers in the Distribution group.

In response to the Department of Energy's Data Request Nos. DOE 1.14 and 1.15, which asked the Company to identify the voltage levels of lines included in the COSS' rate base line item "Distribution Lines," the Company said:

> "...This rate base includes distribution lines at voltages of below 69 kV. *ComEd does not have information to further identify the voltages of the distribution lines.*" [Emphasis added]

In other words, ComEd asserts that it does not have data identifying the specific voltages of the Distribution (< 69 kV) lines underlying the Distribution Lines cost component of its study. This is surprising since ComEd's operations require a thorough knowledge of the voltages at which *all* its lines and electrical equipment operate. The Company even publishes a definition of the primary and secondary distribution systems wherein it lists the voltages of each.[4] I've summarized that list in Table 2.

[4]Commonwealth Edison Company GENERAL TERMS AND CONDITIONS, primary Distribution System, 1st Revised Sheet No. 528, and secondary Service Voltage; Sheet Nos. 535 through 537, "Rate Book," available online at http://www.exeloncorp.com.

TABLE 2

Company's Primary and Secondary Voltage Levels

Primary Distribution Voltages below 69 kV

4 kV
12 kV
34.5 kV

Secondary Distribution Voltages

Residential	**Non-Res 600 kW**
120/240 V	120/240 V
120/208 V	120/208 V
	480 V
	2.4 kV

Non-Res 600 kW to 4.5 MW	**Non-Res over 4.5 MW**
277/480 V minimum	2.16/3.74 kV minimum

In its GENERAL TERMS AND CONDITIONS, the Company recognizes that it provides service at multiple primary and secondary voltages, and that the secondary voltages are associated with customer peak loads. In light of this, ComEd's claim not to have the information necessary to identify costs by voltage level of its distribution rate base below 69 kV is surprising. To the extent this lack of data reflects a choice by ComEd or Mr. Heintz not to differentiate, for purposes of its COSS, the voltages at which customers are served, such a decision by cost experts is puzzling. The consequence of that data deficiency (or decision) is that although customers taking service at various distribution voltages use different portions of the < 69 kV system, the Company's COSS treats each as though it uses all distribution facilities.

Without the ability to identify the costs associated with its primary and secondary distribution systems, there is no way the Company can model its COSS to adhere to cost-causation principles.

Q WHAT DO YOU MEAN?

A Table 2 shows that the Company's secondary system operates at 3,740 volts or less. It is from this secondary system that the vast majority (over 99.8%) of the Company's customers take service. Because of this, the Company incurs billions of dollars in distribution plant and O&M costs to step the voltage down to secondary levels, and distribute that electricity to Secondary customers. Approximately 0.2% of customers, however, do not take service from the secondary system. Instead, they either purchase and maintain their own transformer and secondary system or rent the equipment from the Company.

If, as the Company has stated, it cannot identify the plant and O&M costs associated with its secondary system, and if it truly cannot separate those costs from the primary system costs, then it cannot prevent subsidization of secondary system costs by primary customers. This is a fundamental shortcoming, one that is central to ComEd's COSS.

If the Company wishes to develop a proper COSS, it is imperative that it "…further identify the voltages of the distribution lines." It cannot simply ignore the issue and pretend that voltage level has no effect on cost.

Q HOW DOES VOLTAGE LEVEL AFFECT COST?

A In general electricity is less costly to deliver at high voltage than at low voltage. This may be easier to understand though an analogy. Consider a delivery system that uses a hose instead of wire to deliver water instead of electricity. In this illustration, the pressure of the water is analogous to voltage, and the quantity of water (in gallons) flowing thru the hose is analogous to electrical amperage. The combination of the two, the quantity delivered per minute, hour, etc. is analogous to demand.

Suppose that you wanted to deliver 10,000 gallons of water very quickly (one minute) into an empty tank. If the water pressure was very low, (*e.g.*, 1 pound per square inch, or "psi"), the 10,000 gallons could only be delivered in the time allotted if the hose were extremely large, perhaps twenty feet or more in diameter. Such a large hose would very difficult to find and also very expensive.

However, if the water pressure were increased to 10 psi, the same 10,000 gallons could be delivered in a minute through a much smaller, and less expensive, hose. If the water pressure were increased even more to 1,000 psi, the necessary hose may only need to be a few inches in diameter, and would certainly be much less costly. In each instance, the total amount of water delivered is a function of the size of the hose and the pressure of the water out of the hose.

This analogy works quite well in explaining the flow of electricity through a wire as well. A customer's peak electrical demand is a measure of electrical power given in units of watts (W), kilowatts (kW), or megawatts (MW), etc. In its simplest form, the electrical power required to meet a customer's peak demand is the product of the electrical current (in amperes) and the voltage at which the current is delivered.[5] Mathematically, this is:

$$Power = volts \times current$$

This equation can be used to show that a secondary customer, taking service at 480 volts and having a peak demand of 1 MW (1,000,000 W), i.e., a large customer, would require

[5]For simplicity, this assumes single-phase service. Calculations for three-phase service are slightly more complicated.

$$1{,}000{,}000\ W = 480\ volts \times current$$

or:

$$current = \frac{1{,}000{,}000\ W}{480\ volts} = 2{,}083.33\ amperes$$

Thus, the customer requires a distribution system capable of delivering over two thousand amperes of electrical current. Such a system would require extremely large conductors, and would be extremely expensive.

On the other hand, if the same customer took service at a primary voltage, say 12 kV, the utility would need wires capable of carrying only:

$$current = \frac{1{,}000{,}000\ W}{12{,}000\ volts} = 83.33\ amperes$$

This is a much more reasonable electrical current, one that could be easily distributed by readily available, and much less costly, conductors. Serving large demands at higher voltage is more economical for both customers and the utility. This is why all of the customers in the Company's Very Large Load and Extra Large Load classes take service at primary voltages. It also explains the architecture of ComEd's system, which moves electricity at the high voltage to the extent possible.

Q THE COMPANY CLAIMS IT CANNOT IDENTIFY THE VOLTAGE OF DISTRIBUTION LINES BELOW 69 KV. HOW CAN YOU CLAIM THAT VERY LARGE LOAD AND EXTRA LARGE LOAD CUSTOMERS TAKE SERVICE AT PRIMARY VOLTAGES?

A ComEd has provided evidence that confirms my statement. In addition, such service arrangements are consistent with my experience, and also are common practice in the industry.

Q WHAT EVIDENCE HAS COMED PROVIDED?

A In its response to Data Request No. IIEC 1.08, the Company provided a document titled *2006 ComEd Distribution System Loss Factors* ("the 2006 Loss Study"). This document describes the Company's most recent study of distribution losses associated with its customer classes. The document is important because it identifies the distribution components – by voltage level – that electricity must pass through to serve the various customer classes. The particular customer groupings used in the 2006 Loss Study perfectly match the rate classes identified in the COSS.

With the detailed information provided in the 2006 Loss Study, I was able to identify the percentage of load for each class that passes through the individual primary and secondary components.

I have reproduced the pertinent data from the 2006 Loss Study in IIEC Exhibit 3.1.

Q WHAT DOES THIS EXHIBIT SHOW?

A IIEC Exhibit 3.1 shows the percentage of class load that passes through various parts of the Company's primary and secondary systems. Perhaps the easiest way to understand the exhibit is to walk through the data for one individual customer class.

I have excerpted the data pertaining to Single Family w/o Space Heating (SF) customers from IIEC Exhibit 3.1 and show it in Table 3.

TABLE 3

Percentage of Load Passing Through Various System Components – Single Family Without Space Heating Class

Line	Description	SF
1	HV ESS	---
2	138-69 kV TSS	4%
3	138-34 kV TSS	17%
4	34 kV Lines	17%
5	34-12 kV Dist Cntr	13%
6	34-4 kV Dist Cntr	4%
7	34 kV ESS	---
8	138/69-12 kV TDC	83%
9	12 kV Lines	5%
10	12 kV Feeder	78%
11	12-4 kV Dist Cntr	5%
12	12 kV ESS	---
13	4 kV Feeder	9%
14	AC Ntwrk Feeder	---
15	AC Ntwrk Xfrmr	---
16	AC Ntwrk Sec	---
17	Line Xfrmr	100%
18	480 V DryType Xfrmr	---
19	Sec/Service	95%
20	Transmission	100%

Line 20 of Table 3 shows that 100% of the SF class load passes through the transmission system. This is logical since it is the link between generation and distribution. Similarly, line 8 shows that 83% of the SF load passes through a "138/69-12 kV TDC" (*i.e.*, a transmission and distribution center). The remaining 17% passes through a "138-34 kV TSS" (*i.e.*, a transmission service station), and then "34 kV Lines" as shown in lines 3 and 4. These two lines confirm that 100% of the SF class load is delivered over the primary distribution system. Using Table 3, we can track the flow of electrical current from the transmission system through primary feeders and lines, and even through the transformers and secondary system.

Perhaps the most important information for our purposes is found in lines 15 and 17 where the Company provides the percentage of class load passing through its network and line transformers. This is the key indicator that a class takes service at secondary voltages. Line 17 shows that 100% of the SF class load passes through line transformers. The SF class receives its entire load from the secondary distribution system. Hence, all members of this class utilize both the primary and secondary parts of the distribution system.

Q ARE THERE CUSTOMER CLASSES THAT TAKE ONLY A PORTION OF THEIR LOAD FROM THE SECONDARY SYSTEM?

A Yes. In Table 4, I have excerpted the data from IIEC Exhibit 3.1 for Medium and Large Load customers. Lines 15 and 17 for the Medium Load 100 kW - 400 kW (ML), and Large Load 400 kW – 1 MW (LL) classes show that the percentage of load passing through a Line or AC Network Transformer, and therefore being defined as secondary, is 85% and 62%, respectively.

TABLE 4

Percentage of Load Passing Through Various System Components – Medium Load and Large Load Classes

Line	Description	ML 100 - 400 kW	LL 400 - 1 MW
1	HV ESS	---	---
2	138-69 kV TSS	4%	4%
3	138-34 kV TSS	20%	20%
4	34 kV Lines	20%	20%
5	34-12 kV Dist Cntr	10%	6%
6	34-4 kV Dist Cntr	5%	1%
7	34 kV ESS	5%	13%
8	138/69-12 kV TDC	---	80%
9	12 kV Lines	8%	11%
10	12 kV Feeder	67%	64%
11	12-4 kV Dist Cntr	3%	---
12	12 kV ESS	10%	25%
13	4 kV Feeder	8%	1%
14	AC Ntwrk Feeder	5%	5%
15	AC Ntwrk Xfrmr	5%	5%
16	AC Ntwrk Sec	5%	5%
17	Line Xfrmr	80%	57%
18	480 V DryTypeXfrmr	---	---
19	Sec/Service	---	---
20	Transmission	100%	100%

Q WERE YOU ABLE TO DETERMINE THE PERCENTAGE OF CLASS LOAD THAT PASSED THROUGH PRIMARY AND SECONDARY DISTRIBUTION COMPONENTS FOR EACH CUSTOMER CLASS USING THIS SAME TECHNIQUE?

A Yes, I was. The results are shown in Table 5.

TABLE 5

Percentage of Class Load Carried Over ComEd's Primary and Secondary Systems

Line	Customer Class	% Primary	% Secondary
1	Single Family Without Space Heat	100%	100%
2	Multi Family Without Space Heat	100%	100%
3	Single Family With Space Heat	100%	100%
4	Multi Family With Space Heat	100%	100%
5	Watt-Hour	100%	100%
6	Small Load (< 100 kW)	100%	100%
7	Medium Load (100 - 400 kW)	100%	85%
8	Large Load (400 kW - 1 MW)	100%	62%
9	Very Large Load (1 - 10 MW)	100%	0%
10	Extra Large Load (> 10 MW)	100%	0%
11	High Voltage Up to 10 MW	0%	0%
12	High Voltage Over 10 MW*	0%	0%
13	Fixture-Included Lighting	100%	100%
14	Dusk to Dawn Lighting	100%	100%
15	General Lighting	100%	100%
16	Railroad	100%	0%

*The High Voltage class costs are not part of the primary or secondary system, but are identified separately.

Q PLEASE DISCUSS THE RESULTS.

A Table 5 shows that many customer classes are served entirely from the secondary system. These are the Single Family w/o Space Heating, Multi Family w/o Space Heating, Single Family w/ Space Heating, Multi Family w/ Space Heating, Watt-Hour, Small Load, and the three Lighting classes.

Table 5 also shows that a number of classes are served entirely from the primary distribution system, with no involvement of secondary facilities. These are the Very Large Load (1 - 10 MW), Extra Large Load (>10 MW), and the Railroad classes. Finally, two classes take service at both primary and secondary voltages.

These are the Medium Load (100 kW - 400 kW class), and the Large Load (400 kW - 1 MW) classes.

Q DOES THE COMPANY'S COSS ALLOCATE SECONDARY COSTS TO CUSTOMERS WHO DO NOT USE SECONDARY FACILITIES??

A Yes, it does. The Company's COSS combines secondary and primary plant and O&M costs. It then allocates the combined costs (over $3.8 billion in rate base and nearly $500 million in expenses) to all customer classes based on their respective class peak demand. By doing so, the Company's COSS grossly overstates the rate base and expenses incurred to serve primary classes, and consequently understates the RORB from them.

Q IS THE COMPANY'S COSS CAPABLE OF SEPARATING THE COST OF SECONDARY EQUIPMENT FROM THAT OF PRIMARY EQUIPMENT?

A No. The Company's COSS, in the form provided in discovery, has neither the structure nor the functionality to separate primary and secondary costs.

Q HAVE YOU MODIFIED THE COMPANY'S COSS TO ACCOMPLISH THIS SEPARATION?

A Yes, I have. My changes are generally formatting in nature and allow for the separation of primary and secondary costs.

Q PLEASE DESCRIBE YOUR MODIFICATIONS.

A The Company's COSS is an electronic spreadsheet consisting of multiple worksheets wherein the various steps of the COSS are completed. In the "Functions" worksheet,

I inserted an additional column so that I could separate costs by primary and secondary distribution functions. I entered primary and secondary percentages for the major distribution facilities accounts -- FERC Accounts 364 (Poles, Towers and Fixtures), 365 (Overhead Conductors and Devices), 366 (Underground Conduit), and 367 (Underground Conductors and Devices). Then I modified the formulae in the appropriate cells so that they determined the functionalized (primary or secondary) costs using the appropriate FERC account percentages.

Many costs could not be associated with a specific FERC account, and could not be separated using FERC account percentages described above. However, these were clearly costs incurred in the operation and maintenance of both primary and secondary equipment [e.g., costs in Accounts 389 through 399 (General Plant)]. I separated these costs into primary and secondary components using the ratio of primary to secondary costs in the identified FERC accounts.

Q HOW WERE YOU ABLE TO DETERMINE THE PRIMARY AND SECONDARY PERCENTAGES THAT YOU SPECIFIED IN THE HEADER?

A I developed the primary and secondary percentages from data acquired in the Company's data room in Springfield, IL. I have attached a copy of this data as IIEC Exhibit 3.2.

IIEC Exhibit 3.2 is a list of overhead and underground wires (describing wire type, total number of feet, and total cost), purchased from 2002 through 2006. From the description, I determined if the conductor was of a type typically used on the primary system, the secondary system, or both.

The results are shown in Table 6.

TABLE 6

Percentage of Primary and Secondary Wire Purchased by ComEd in the Last Five Years

Underground	
% Secondary	**49.3%**
% Primary	**50.7%**
Overhead	
% Secondary	**24.5%**
% Primary	**75.5%**

Q WHAT PERCENTAGES DID YOU USE IN YOUR MODIFIED COSS?

A For the costs in FERC Accounts 364 and 365, I specified 75% primary and 25% secondary. For Accounts 366 and 367, I specified 50% primary and 50% secondary. I used the primary and secondary percentages for Overhead Conductors as a proxy for poles, and those of Underground Conductors as a proxy for Conduit. While this is a reasonable approach, if (despite its claimed lack of data) the Company can document the actual primary and secondary percentages, it would be reasonable to use the Company's percentages rather than mine.

The most important capability of the modified COSS is that it allocates primary and secondary costs separately. This eliminates the problem of unfairly allocating secondary costs to Primary customers and the resulting subsidies.

Q WHAT EFFECT DOES YOUR MODIFICATIONS HAVE ON THE RESULTS OF THE COSS?

A I've summarized the results from the modified COSS in Table 7.

TABLE 7

Modified COSS With Primary and Secondary Voltage Separation

Line	Rate Class	RORB	RORB Index
1	Single Family Without Space Heat	4.9%	73
2	Multi Family Without Space Heat	1.9%	28
3	Single Family With Space Heat	5.9%	88
4	Multi Family With Space Heat	3.5%	51
5	Watt-Hour	8.2%	122
6	Small Load	7.0%	104
7	Medium Load	8.1%	119
8	Large Load	9.9%	147
9	Very Large Load	18.5%	274
10	Extra Large Load	(0.3%)	(4)
11	High Voltage Up to 10 MW	1.0%	15
12	High Voltage Over 10 MW	(4.6%)	(69)
13	Fixture-Included Lighting	10.2%	151
14	Dusk to Dawn Lighting	5.8%	86
15	General Lighting	6.3%	93
16	Railroad	1.3%	20
	Total	6.8%	100

Q HOW DO THESE RESULTS COMPARE TO THE COMPANY'S COSS?

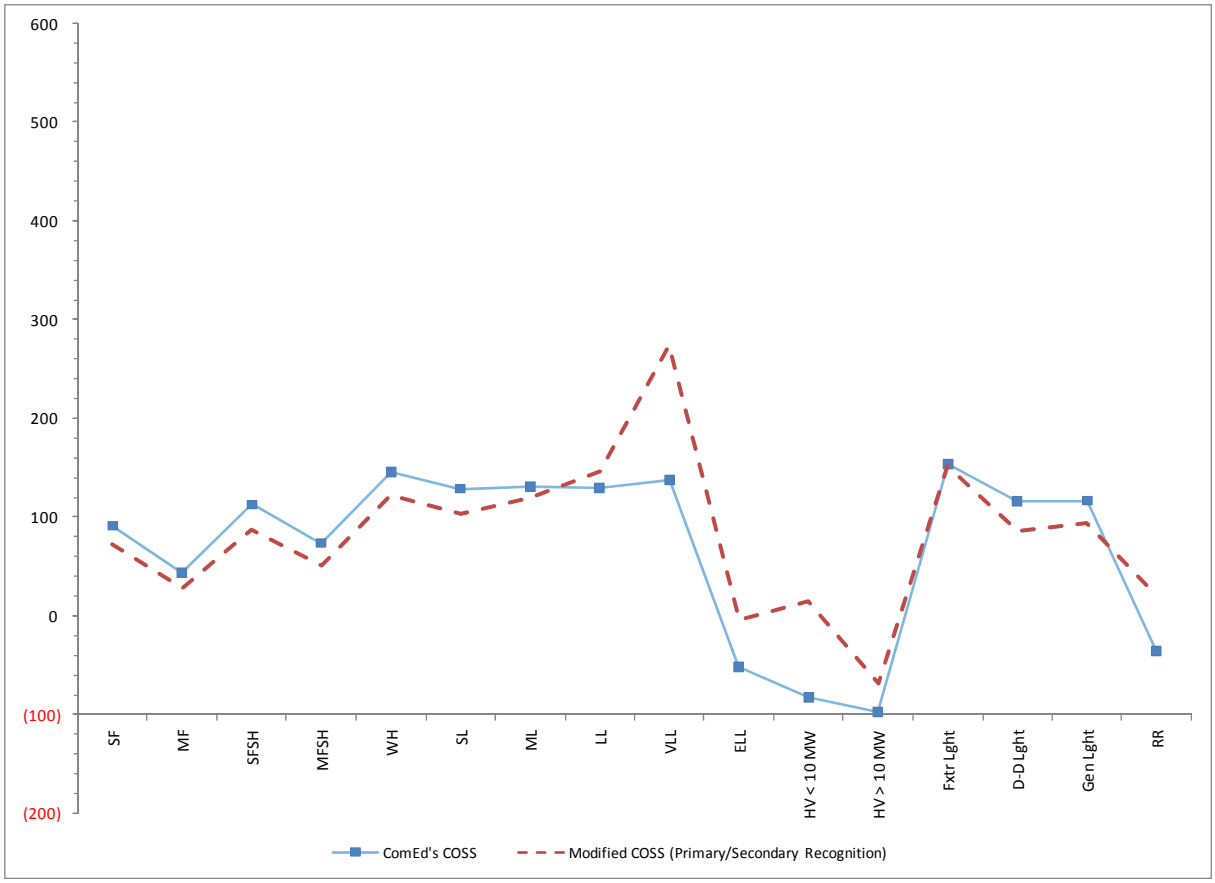
A I created a graph illustrating the RORB, by rate class, for the Company's COSS and the modified COSS. I have included that graph as Figure 1.

By separately allocating primary and secondary costs, the modified COSS eliminates the subsidization of secondary costs by Primary customers. With

secondary plant and O&M costs now properly allocated to classes taking service at secondary voltages, the RORB for those classes decreased.

Correspondingly, the RORB increased for classes where some or all of the customers took service at primary voltages. This, of course, was expected since these classes no longer shared the cost of nearly $89 million in secondary plant and O&M costs.

Figure 1: Index of Return at Present Rates



Q PLEASE SUMMARIZE THE MODIFICATIONS YOU MADE TO THE COMPANY'S COSS TO FUNCTIONALIZE AND ALLOCATE COSTS BETWEEN PRIMARY AND SECONDARY CLASSES.

A I made the following modifications to the Company's COSS:

1. I added a column and modified the formulae on the "Functions" tab of the COSS so that it will calculate secondary, as well as primary, costs.

2. I entered primary and secondary percentages for FERC Accounts 364, 365, 366, and 367. The percentages were as follows: Accounts 364 and 365 were 75% primary/25% secondary and Account 366 and 367 were 50% primary/50% secondary.

3. I determined the percentage of each class's load that passes through the secondary distribution system, and used it as a proxy for the percentage of distribution costs that should be allocated to each class.

4. I modified the "Allocation" and "Allocation Factors" portions of the COSS to allow for the allocation of secondary distribution costs separately from primary distribution costs.

ComEd Flaw No. 2: No Recognition of the Distribution System Components that Do Not Vary With Demand

Q PLEASE DESCRIBE THE SECOND MAJOR FLAW YOU FOUND IN THE COMPANY'S COSS?

A In its development of the COSS, the Company ignored that fact that there are delivery service costs directly attributable to electrical industry mandated safety and reliability requirements for distribution facilities that do not vary with customer demand. Accordingly, those costs should not be allocated on the same basis as demand-related distribution system costs.

Q IS THIS A NEW COST OF SERVICE CONCEPT?

A No. IIEC has previously presented this cost of service study criticism in more theoretical terms. There is a minimum cost incurred by the Company to install the distribution system that does not vary with customer demand. This minimum cost – generally called the minimum distribution system ("MDS") cost – is incurred whenever the Company extends its primary and secondary distribution system, or replaces a component on those systems.

The cost of the MDS is the cost of the distribution system the Company must build simply to provide service to its customers regardless of the electrical demand of those customers. Since the cost of the MDS is unrelated to demand but is directly related to the number of customers, it is properly classified as a customer cost and distributed to the classes proportionate to the number of customers in each class.

Q HAS THE COMMISSION ADDRESSED THE ISSUE OF AN MDS IN PAST CASES?

A Yes, but as noted, previous presentations of the concept were heavily policy-oriented and theoretical, without sufficient evidentiary support to persuade the Commission. In previous orders, the Commission has ruled that a utility's distribution system is "designed in an integrated manner to deliver electricity to customers in quantities to *meet all customer demands* and individual components of the system cannot be identified for purposes of connecting customers only."[6]

[6] Illinois Commerce Commission's Final Order in Docket No. 00-0802 [Emphasis added].

Company witness Alan Heintz, in a prior case, referenced the fact that the Commission has rejected past MDS presentations and concluded:

> "This issue has been **fully analyzed** by the Commission in the above-noted … dockets and no new information has been brought before the Commission that is likely to change its conclusion as expressed in the orders in those dockets."[7] [Emphasis added]

Q IF THE COMMISSION HAS REJECTED MDS PRESENTATIONS IN PAST CASES, WHY RAISE THE ISSUE AGAIN?

A The cost of service distortions resulting from the misallocation of these costs are significant. In addition, the Commission has indicated a willingness to consider the merits of the MDS approach in the last ComEd DST case.[8] The Commission has also expressed the reasonable expectation that arguments and evidence proposing MDS methods be sound and compelling. Its past rejection of traditional MDS methods indicates that the Commission has, thus far, found them to be neither.

However, I believe there is information about the MDS that the Commission has not previously received or considered. In this section of my testimony, I will present that information and demonstrate the following:

1. Utilities design their electric distribution systems to comply with many criteria, not just customer demand. Among these, safety and reliability are paramount.

2. Since the Company cannot extend its distribution system unless it conforms, at a minimum, to the industry mandated safety and reliability standards, these standards establish the MDS.

3. The total cost of the distribution system components specified by the standards does not vary with customer demand. However, it varies in direct proportion to the number of customers.

4. The costs associated with the MDS are identifiable and quantifiable, and the methods used to identify and quantify them are clear and straightforward. A cost

[7] Rebuttal testimony of Alan C. Heintz, Docket No. ICC-05-0597.
[8] Order, July 26, 2006, ICC Dkt. No. 05-0597 at 165

analyst with access to the requisite utilities' records can compute the MDS costs in a reasonable and dependable fashion.[9]

Q WOULD YOU AGREE THAT CUSTOMER ELECTRICAL DEMAND IS AN IMPORTANT CRITERION WHEN DESIGNING A DISTRIBUTION SYSTEM?

A Yes, I would. Distribution engineers rely on load forecasts and load flow studies to identify and design distribution system upgrades or to project load growth, and peak demand is a vital component of these forecasts and studies. Further, some (but not all) segments of the delivery system will vary with expected demand. However, when developing a COSS, focusing strictly on design criteria can become something of a smokescreen that obscures the more important issue.

Q PLEASE EXPLAIN WHAT YOU MEAN.

A As I suggested previously, perhaps the fundamental premise of a proper COSS is the concept of *cost-causation.* As I have already discussed in my testimony, cost-causation is, in many cases, directly related to electrical parameters like voltage level or peak demand. This is particularly true when planning for maximum conditions or "worst case" scenarios. However, there are factors besides voltage level and peak demand that can significantly affect cost. A properly conducted COSS must consider all cost causing factors.

When distribution engineers *design* the enhancement, upgrade, or extension of an electric system, they must be constantly aware of the operating parameters of the system. Yet, it is in the construction of the distribution system that the *true cause*

[9] I performed exactly this type of study on multiple occasions in my previous employment with Aquila, Inc. See Appendix A for more information.

of many distribution costs is clearly seen. Surprisingly, that cause is *not* always demand.

An illustration helps make this issue clear. Consider a customer who intends to build a home on a new lot, one that does not already have electrical service. This customer is cost and energy conscious and thus chooses to use as many energy efficiency techniques and appliances as they can. After considerable research and consultation with experts, the customer calls the utility and informs it that they will require service capable of providing a maximum peak demand of 2,000 watts (2 kW).[10]

During the installation of the primary and secondary distribution extension to the customer's home, the customer notices that the linemen are using conductors, poles, cross-arms, and components identical to those serving the much larger, and less efficient, home down the street. After more investigation, the customer learns that the distribution extension to their home is capable of carrying far greater demand than their home was designed to use. When they inform the utility of this 'error,' the utility explains that it cannot install wires smaller than a certain size or hang them below a certain height. In short, there are specified minimum standards that the utility must meet that are wholly unrelated to the new home's reduced demand.

This illustration demonstrates that although utilities design and install distribution equipment to satisfy their customers' need for electricity, there are factors other than electrical demand that force them to incur costs. Safety and reliability are as critical to every phase of design and construction as demand. It is less obvious, however, that as one reviews the cost of the distribution system nearest the customer (that portion from the primary radial lines through the line transformers and secondary

[10]This is about two-thirds of the peak demand of a typical residential customer.

system), the cost incurred to comply with safety and reliability standards begins to outweigh the cost of meeting electrical demand. ComEd produces a manual titled "Install New Services for Residential Customers" containing numerous checklists and review sheets to expedite the installation of new services to customers. Tellingly, nowhere on those checklists or review sheets is there any mention of the customer's electrical demand.

Nearly every major primary and secondary distribution component (FERC Accounts 364 through 367) must conform to standards set forth in the National Electrical Safety Code[11] ("NESC" or "Code"). In conforming to the Code, the Company incurs costs in direct proportion to the number of poles, cross-arms, feet of wire installed, etc.

If the demand of existing customers increases, the cost of meeting the NESC standards remain fixed. In other words, the cost of meeting the Code for a customer with a peak demand of 3 kW, is exactly the same as that for a customer with a peak of 40 kW, 100 kW, or even 1 MW.[12] Conversely, whenever an *extension* of the primary and/or secondary system is constructed, the Company must conform to the minimum standards and will incur additional minimum system costs. Given that the principal reason to extend the distribution system is to serve additional customers, it is only reasonable to conclude that the costs associated with the MDS vary in direct proportion to the number of customers.

[11]In the case of Conduit (FERC Account 366), the National Electric Code ("NEC") is the governing standard.

[12]The NESC specifies clearances of lines by voltage level. Thus, lines at higher voltages may require taller poles and longer cross-arms.

Conceptually, distribution components that *only just* conform to standards such as the NESC[13] comprise the MDS.

Q HAS THE ILLINOIS COMMERCE COMMISSION ADOPTED THE NESC STANDARDS IN THE ADMINISTRATIVE CODE?

A Yes. Title 83 of the Illinois Administrative Code, Part 305, Subsection 305.20b) states:

> "The Illinois Commerce Commission *adopts as its rules the following portions of the National Electrical Safety Code C2-200* (2002 edition, approved June 4, 2001, published by the Institute of Electrical and Electronics Engineers, Inc., 3 Park Avenue, New York NY 10016-5997)…" [Emphasis added]

Q WHAT IS THE PURPOSE OF THE NESC?

A Section 1, Part 010, of the NESC states:

> "The purpose of these rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and their associated equipment. They contain *minimum provisions considered necessary* for the safety of employees and the public. They are not intended as a design specification or an instruction manual." [Emphasis added]

Q IS IT POSSIBLE THAT SOME OF THE COMPANY'S EXISTING DISTRIBUTION SYSTEM COMPONENTS WERE DESIGNED AND INSTALLED PRIOR TO THE NESC – THAT THEY ARE, IN EFFECT, "GRANDFATHERED," AND NOT COVERED BY THE NESC?

A It is possible, but unlikely. Congress authorized the National Bureau of Standards ("NBS") to study hazards of electrical practice in 1913. In 1915, the NBS published

[13] While I limit my discussion to the NESC, there are other standards to which the Company must comply.

Circular No. 34 titled "Proposed NESC," and published the very first edition of the NESC as NBS handbooks in 1920.[14] Except in extremely rare cases, it is unlikely that there are lines, poles, and equipment that pre-date these standards. Even in those extreme cases, though, the costs of the components certainly will be depreciated by now, and have no bearing on the COSS.

Capacity of MDS Components

Q DOES THE NESC ALSO ESTABLISH STANDARDS FOR THE ELECTRICAL DEMAND EACH COMPONENT MUST BE CAPABLE OF CARRYING?

A Not directly. To my knowledge, the only situation where the NESC covers something like this is in the case of ground wires where the NESC sets the "short time ampacity adequate for a fault current."[15] Yet even here, the underlying issue is one of safety and reliability, rather than customer demand.

With that said, it is important to understand that a distribution system, constructed to *only just* conform to the NESC, is capable of carrying the demand of many of the customers on the system.

Q PLEASE EXPLAIN WHAT YOU MEAN.

A Consider a length of overhead conductor that extends to a customer's meter. This segment is the "service drop" or "service" (see Diagram in Appendix B).

[14]The Institute of Electrical and Electronic Engineers ("IEEE") was designated as Administrative Secretariat for the NESC (replacing NBS) in 1972 and continues in that role today.

[15]Section 9, Subsection 93.C., Ampacity and Strength.

The NESC requires that each energized conductor of a typical[16] service drop be at least a #6 American Wire Gauge ("AWG").[17] The NESC does not base this requirement on the electrical capacity of the conductor or on the expected demand of the customer. Rather, the standard addresses safety and reliability issues associated with the line – how much physical load from wind, ice, tree branches, etc. the line can handle without breaking.

An insulated #6 ACSR service conductor is capable of carrying about 85 amperes of electrical current, and for the majority of customers will operate near 120 volts. A conductor of this size and type could serve a demand of 10.2 kW,[18] or roughly three to four times the *peak*[19] load of the Company's average residential customer. Considering that the service drop consists of two 'hot' conductors and a ground, and that both hot conductors must be at least #6 AWG, most service drops will be capable of providing six to eight times the peak demand of the typical residential customer. Stated another way, a customer's demand would have to be at least six to eight times that of a typical residential customer before its level of demand created any difference in the cost of the service.

If the Company designed and installed services simply to meet customer demand, there would be no reason to install services capable of providing six to eight times that anticipated demand. Utilities would be free to install smaller and less expensive service drops and, in most cases, likely would.

[16]It is common practice for utilities to use an aluminum conductor strengthened with steel cable reinforcement ("ACSR") and covered in insulting rubber for this segment.
[17]Section 263E, Table 263-1; 2002 NESC.
[18]85 amps x 120 volts = 10,200 watts or 10.2 kW.
[19]Using 1 kW as the avg. residential demand, and a load factor of nearly 30%, I've estimated a peak demand of approximately 3 kW per Residential customer.

Q SINCE THE MINIMUM CONDUCTOR SIZE SPECIFIED BY THE NESC IS CAPABLE OF SERVING SUCH A HIGH DEMAND, SHOULD THE COST OF THE MDS BE CLASSIFIED AS DEMAND?

A No. Again, the question is not one of wire capacity, but of *cost-causation*. The Commission has adopted, and enforces compliance with, the NESC standards. The NESC requires that conductors be a minimum size. Under these constraints, a utility that intends to extend service to an additional customer must incur the cost of a conductor that conforms, at a minimum, to the NESC. The *cause* of this minimum cost is the NESC.

To a cost analyst, the classic indications of a customer-related cost are: (1) constant regardless of customer's electrical demand except in the extreme; (2) incurred specifically to meet NESC standards; and (3) directly proportional to the number of customers. All three describe service drop costs which is why service drops are classified as customer-related even though they are capable of carrying considerable demand.

Q CAN YOU PROVIDE AN EXAMPLE OF A DISTRIBUTION COST THAT MAY BE CLASSIFIED AS BOTH CUSTOMER- AND DEMAND-RELATED?

A Yes, I can. Costs in FERC Account 365 (Overhead Conductors) may be classified as both customer- and demand-related. To illustrate why this is so, I will build from what I have just explained about services.

Consider the segment of the *secondary system* that stretches from the customer's property line, attaching to a pole or two[20] until it reaches the transformer (see Appendix B). Secondary conductors physically connect to services, and require

[20]Incidentally, these poles could be considered as part of the secondary distribution system.

no special equipment in the transition except, perhaps, a few cable connectors and an anchor point on a pole. The only difference between a secondary and a service is that a secondary *may* serve two or more customers, whereas each service drop connects to a single customer.[21]

Since they are generally identical to service drops, a secondary that *only just* conforms to the NESC is capable of meeting the peak demand of approximately six to eight customers.

Clearly, a portion of secondary conductor costs are customer-related, and for many of the same reasons that services are customer-related. However, since secondary conductors may serve multiple customers simultaneously, the combined peak demand of those customers may require a conductor larger than the NESC minimum. In such cases, a portion of secondary costs is demand-related as well.

Q ARE THERE OTHER EXAMPLES OF COSTS THAT INCLUDE BOTH CUSTOMER AND DEMAND COMPONENTS?

A Yes, there are. It may seem that the cost of *primary conductors*, which carry the demands of dozens and even hundreds of customers simultaneously, are incurred solely to meet the demand of those customers. And certainly, the combined customer demand has a greater influence on the costs of primary distribution systems than it has on secondary distribution systems or service drops. Yet, it is incorrect to assume that there is no customer-related cost in the primary distribution system.

Just as was the case with secondary conductors, the NESC requires that the typical primary conductor have a diameter no less than #6 AWG. Primary conductors are not usually insulated which allows them to dissipate heat more efficiently and, as

[21]In cases where only one customer is served by a secondary line, the secondary becomes the service drop at the customer's property line.

a result, can carry more electrical current than an insulated secondary or service drop of the same size. A #6 ACSR bare conductor is capable of carrying about 105 amperes of electrical current. On a typical primary distribution system, the conductor would carry that current at voltages greater than 12,400 volts.

The power carrying capacity of this line is estimated to be:

(105 amps) x (7,160 volts) = 751,800 volt-amperes or 752 kVA[22]

If a power factor of 95% is assumed, the total capacity of the line will be approximately:

(752 kVA) * .95 = .714 MW or 714 kW

This is equivalent to the peak demand of over 235 residential customers.[23] Thus, a primary conductor that *'only just'* conforms to the NESC standards, may have the electrical capacity to serve some, but not all, of the combined customer demand of the subdivision it serves.

Whenever the Company extends a primary radial line to serve a load less than 714 kW it will, nonetheless, incur the cost to conform to the NESC standards. It is reasonable to assume that there will be situations where the NESC is the principal cause of the cost of the primary line, and customer demand will have no influence whatsoever. However, the Company has stated that a typical distribution circuit serves approximately 800 to 1,000 customers. Obviously, the combined demand of those customers will surpass the capabilities of the minimum conductor specified by

[22]Distribution voltages are generally stated as the voltage between one phase conductor and another. This is called the line-to-line, or simply the "line" voltage. However, when discussing a single primary radial, we are concerned with the line-to-ground voltage which is calculated by dividing the line voltage by the square root of 3, or 1.732.

[23]In a presentation by the Company's Distribution Delivery Operations, the Company stated that it has approximately 5,300 distribution circuits, with approximately 800 to 1,000 customers on a circuit.

the Code. It *is reasonable, therefore, to classify the cost of surpassing the standards as demand-related and the cost of conforming to the NESC as customer-related.*

Q WHAT OTHER COSTS COULD BE CLASSIFIED AS BOTH CUSTOMER- AND DEMAND-RELATED?

A The NESC specifies minimum clearances between conductors and the ground surface (not electrical ground conductor), and between conductors and other conductors or equipment. In doing so, it establishes the minimum height of poles the Company can install. The NESC requires that electrical conductors be kept high enough off the ground to allow people and vehicles to pass safely below them, and spaced widely enough to prevent arcing and/or interference. These are safety and reliability issues where the electrical demand of the customer has no bearing whatsoever. Thus, just as was the case with distribution conductors, the total cost of distribution poles contains a portion incurred simply to comply with the minimum standards of the NESC.

Q HOW HAS THE COMPANY CLASSIFIED AND ALLOCATED THE COST OF DISTRIBUTION CONDUCTORS AND POLES IN ITS COSS?

A The Company has classified the costs of distribution conductors (both primary and secondary) and the cost of distribution poles as solely demand-related, and has allocated them to the customers based on class demand.

Q DO YOU AGREE WITH THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DISTRIBUTION CONDUCTORS AND POLES?

A No. Using demand allocation factors to distribute costs that are not incurred to meet demand and do not vary with demand, but instead are incurred in direct proportion to the number of customers, is a blatant error that violates basic cost-causation principles. In addition, the Company's demand allocation percentages for the Large Load, Very Large Load, and Extra Large Load classes are 9.2%, 14.9%, and 3.3%, respectively. In contrast to this, the customer allocation percentages for the Large Load, Very Large Load, and Extra Large Load classes are 0.11%, 0.05%, and 0.001%, respectively.

If a proper MDS study were to be performed, it is reasonable to expect that much of the primary system would be classified as customer-related. The net result is that a COSS that accounted for the presence of the MDS would allocate significantly fewer primary distribution costs to the Large Load, Very Large Load, and Extra Large Load classes.

Instead, the Company's COSS ignores the cause of these costs, allocating and recovering them as though they were incurred only to meet its customers' electrical demand. Not only does this violate basic cost-causation principles and lay the groundwork for improper rate design, it is inconsistent with the way the Company allocates distribution costs in its day-to-day practice.

Q WHAT DO YOU MEAN?

A ComEd has rules on file with the Commission that allow it, in particular circumstances, to distribute the costs of distribution components on a basis other than demand.

Q UNDER WHAT CIRCUMSTANCES CAN THE COMPANY DO THIS?

A When ComEd extends the distribution system to serve a customer or group of customers, it will do so at no charge up to: (1) the cost of a single-phase overhead system of 250 feet (per customer); or (2) the estimated annual delivery services revenue per customer. If the costs exceed the larger of these two, the Company's tariffs state:

> "The cost of extensions in excess of the amount as determined under item (A) in paragraph 1 of the Free Extensions section and any resulting deposits, ***shall be allocated among customers based on their respective share of the length of the line extension.*** Deposits will be refundable based on changed circumstances or shared use for a period of ten years from the date the line extension is placed in service."[24] [Emphasis added]

According to the Company's tariff, "excess" costs of a distribution system extension can be allocated to specific customers, based on each customer's share "of the length of the line extension," and recovered through refundable customer deposits, rental agreements, or customer purchases.[25] Obviously, the Company accepts that line extension costs are incurred and should be distributed in a way that is reflective of the number of customers, not demand.

Q IF THE 'EXCESS' COST OF THESE EXTENSIONS IS ALLOCATED AND RECOVERED AS YOU HAVE DESCRIBED, HOW ARE THE COSTS OF THE FIRST 250 FEET OF EXTENSION ALLOCATED AND RECOVERED?

A Base extension costs (those equivalent to the first 250 feet of overhead extension per applicant) are accumulated in FERC Accounts 364 through 368. These accumulated costs contain both customer-related costs incurred to conform to the NESC and,

[24]ComEd Rider No. 2, *Electric Line Extensions*, pg. 62.1, Sub-paragraph (2). Rider Nos. 2 and 6 mentioned in the next footnote were in place during the test year, but are not current.

[25]ComEd Rider Nos. 2, 6, and DE.

potentially, demand-related costs incurred to enhance the extensions load carrying capability beyond that provided by the MDS. However, as I explained above, the Company's COSS treats these costs as if no MDS exists, and allocates them entirely on the basis of demand.

Q IS THERE A BETTER WAY OF ALLOCATING BASE EXTENSION COSTS?

A Yes. Base extension costs should be allocated in a manner that reflects their cause. The best way to allocate them is to separate the cost of conforming to the NESC from the total, and to distribute that portion of costs to the classes using a customer allocator. The remainder should be distributed using a demand allocator.

Q WHAT PROBLEMS ARISE FROM ALLOCATING COSTS USING THE WRONG FACTOR?

A The most obvious problem is that the rates will no longer be based on cost-causation, and therefore will suffer the deficiencies inherent in that misallocation, which were discussed earlier in my testimony (*viz*., inequity, inappropriate price signals, detriments to conservation, and revenue instability).

Effect of MDS Methods on Rates

Q HOW DOES THE USE OF MDS METHODS AFFECT THE CUSTOMER RATES IN THIS CASE?

A In general, using MDS methods provide analysts a closer look at the cause of certain costs, allowing them to better align rates with cost-causation principles. MDS methods generally result in a smaller allocation of distribution costs to classes with

fewer customers (e.g., Large Industrial companies), and a larger allocation of distribution costs to classes with more customers (e.g., Residential customers).

Q DOES THE USE OF MDS METHODS RESULT IN AN UNFAIR ALLOCATION OF COSTS?

A No. Since these methods adhere to cost-causation principles, their use allocates costs to customer classes that cause the Company to incur them. In short, accounting for the cost of meeting minimum safety and reliability standards results in a better COSS than those that deny the MDS exists.

Q WOULD THE USE OF MDS METHODS RESULT IN A DOUBLE ALLOCATION OF DEMAND COSTS TO LOW LOAD FACTOR CUSTOMERS?

A No. The accumulation of costs in multiple FERC accounts, as well as the process of cost classification, separate and distinguish costs from each other *preventing* the double allocation of costs to customers. This occurs regardless of the use of minimum distribution methods. When costs are classified as customer- or demand-related, they are isolated from each other. Furthermore, all costs, whether classified as customer- or demand-related, are distributed to the classes only once.

Q IS THE MDS A RECOGNIZED APPROACH?

A Yes. The MDS approach is presented in the National Association of Regulatory Utility Commissioners *Electrical Utility Cost Allocation Manual*,[26] ("NARUC manual") and has been used in a number of states.

[26]Chapter 6, Section II, pgs. 90-96.

Methods for Determining MDS Cost

Q HOW ARE THE COSTS OF CONFORMING TO THE MINIMUM STANDARDS CALCULATED?

A This is precisely what the MDS techniques were developed to determine, and it is not surprising that they are given names such as *minimum system* and *minimum or zero intercept*. Every method compares the replacement cost of each major component (i.e., poles, overhead conductors, etc.) to the replacement cost of each component if it were of the minimum size to only just conform to the NESC or other applicable safety and reliability standard.

Q HOW DO THESE TECHNIQUES DIFFER FROM EACH OTHER?

A While all the methods attempt to calculate the cost of the MDS, they differ in how they go about it. The zero intercept methods calculate the cost of the minimum sized components using *theoretical* components, whereas the minimum system methods use *actual* components available on the market.

Q YOU USE THE PLURAL FORM OF THE WORD 'METHODS' WHEN SPEAKING OF EITHER THE ZERO INTERCEPT OR THE MINIMUM SYSTEM. ARE THERE VARIATIONS EVEN WITHIN THESE METHODS?

A Yes. I am aware of two variations of the minimum system method, and two variations of the zero intercept method.

Q WHAT ARE THE VARIATIONS OF THE MINIMUM SYSTEM METHOD?

A One variation relies on distribution components that the Company *normally purchases or has in inventory*. If, for example, the Company were to calculate the

minimum system costs for Account 364 (Poles) using this variation, for example, it would use the shortest pole in its inventory – provided it conformed to the NESC -- even if a smaller and/or less expensive pole were available on the market.

For example, if a company only purchased utility poles that were 30 feet or more in length, it would define the minimum length of pole as 30 feet, even though 25-foot poles are readily available on the market.

The second variation of the minimum system method relies on components that are available on the market, regardless of *whether the company uses such components or not*. Using this method, the company mentioned above would define the minimum length of pole as 25 feet, even though it does not purchase poles of that length.[27]

The advantage to both methods is that they use data that is readily available to the analyst. They provide a way to quickly estimate minimum system costs, and allow the cost analyst to do more than arbitrarily classify some, all, or none of the distribution costs to demand- or customer-related.

Q WHAT ARE THE VARIATIONS ON THE ZERO INTERCEPT METHOD?

A The zero intercept methods attempt to calculate the cost of the minimum system that either: (1) only just conforms to the NESC standards; or (2) has reduced the demand cost to zero. Both are theoretical values calculated using statistical methods. However, the zero intercept methods are considered by many analysts to be the most accurate methods to use in estimating the customer portion of distribution costs.[28]

[27]Obviously, poles are only one example of MDS components, but they illustrate the concept.

[28]National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual ("NARUC Manual"), Chapter 6, Section II.B., page 92.

Q IS THERE A PREFERRED MDS METHOD?

A If the options are: (1) to perform a minimum distribution study that calculates the customer and demand percentages, or (2) to directly assign certain distribution accounts entirely to demand, as was done by the Company in this case, then the preferred method would be to perform a study.

The evidence that a MDS exists and that its cost is a significant percentage of the total distribution cost is simply too clear and compelling to ignore. However, by classifying the cost of poles, conductors, transformers, and conduit the way it has, the Company ignores the evidence. It would be far better to perform a minimum distribution study so that the COSS can truly reflect cost-causation principles and provide better information upon which to design the Company's rates.

In a perfect world, where the necessary data were available and time was allowed for a thorough study, the preferred method would be to perform the *minimum system* study using commercially available components that *only just* conform to the NESC. If a component of the precise size is not commercially available – as may well happen in the case of FERC Account 364 (Poles) – it would be preferable to use the zero intercept technique to determine the cost of the *theoretical* component that only just conforms to the NESC.

Q IS THE COMPANY'S COSS CAPABLE OF ALLOCATING MDS COSTS TO CUSTOMER CLASSES PROPERLY?

A No. The Company's COSS, in the form provided in discovery, does not allow for the allocation of MDS costs.

Q HAVE YOU PERFORMED A PRECISE ANALYSIS OF COMED'S DISTRIBUTION COSTS USING YOUR PREFERRED METHOD?

A No. The discovery process in this case did not afford the necessary information and time for me to conduct a complete study. In the absence of a precise MDS study, I have estimated customer and demand percentages that are reasonable for the Company.

Q HAVE YOU MODIFIED THE COMPANY'S COSS TO ALLOCATE CUSTOMER- AND DEMAND- RELATED COSTS BASED ON MDS PRINCIPLES?

A Yes, I have. My changes are generally formatting in nature and allow for the separation of primary and secondary costs.

Q PLEASE DESCRIBE YOUR MODIFICATIONS.

A Using steps similar to those taken to separate primary and secondary costs, I modified the structure and functionality of the Company's COSS to allow for the proper allocation of MDS costs. I created new columns and a second header wherein the estimated percentage of customer- and demand- related costs for FERC Accounts 364 through 367 were entered. I also modified the formulae to calculate costs using the customer- and demand- related percentages from the new header.

Q WHAT CUSTOMER AND DEMAND PERCENTAGES DID YOU ENTER IN THE HEADER?

A The following customer and demand percentages were used: (1) for FERC Account 364 (Poles), I used 60% for the Demand percentage, and 40% customer, (2) for FERC Account 365 (Overhead Wires), 60% demand and 40% customer, (3) for

FERC Account 366 (Conduit), 25% demand and 75% customer, and (4) for FERC Account 367 (Underground Conductor), 20% demand and 80% customer.

Q WHAT DID YOU RELY UPON TO DETERMINE THESE PERCENTAGES?

A. As I have discussed previous, the MDS is the system that only just conforms to safety and reliability standards such as the NESC. These standards apply equally to nearly every electric utility in the nation, and it is reasonable to assume that the standards required by the NESC in one territory are exactly the same as those required in every other service territory. Based upon this fact, and coupled with my experience in performing MDS studies on utilities operating in Missouri, Kansas, Colorado, and Montana, I chose customer and demand percentages that were within the range of those determined for other utilities with urban operations, suburban operations, and rural operations similar to those within the ComEd territories.

While this is a reasonable approach, if the Company can document the actual customer and demand percentages, it would be reasonable to use the Company's percentages rather than mine.

Q WHAT EFFECT DO YOUR MODIFICATIONS HAVE ON THE RESULTS OF THE COSS?

A I've summarized the results from the modified COSS in Table 8.

TABLE 8

Results of Modified COSS With Primary/Secondary Recognition and MDS

Line	Rate Class	RORB	RORB Index
1	Single Family Without Space Heat	2.7%	40
2	Multi Family Without Space Heat	(3.5%)	(52)
3	Single Family With Space Heat	8.8%	131
4	Multi Family With Space Heat	2.1%	31
5	Watt-Hour	(0.2%)	(3)
6	Small Load	12.1%	179
7	Medium Load	19.9%	294
8	Large Load	22.5%	333
9	Very Large Load	32.7%	483
10	Extra Large Load	5.2%	76
11	High Voltage Up to 10 MW	1.0%	15
12	High Voltage Over 10 MW	(4.6%)	(69)
13	Fixture-Included Lighting	10.8%	159
14	Dusk to Dawn Lighting	17.9%	264
15	General Lighting	9.4%	139
16	Railroad	8.4%	124
	Total	6.8%	100

Q HOW DO THESE RESULTS COMPARE TO THE COMPANY'S COSS?

A I created a graph illustrating the RORB, by rate class, for the Company's COSS and the modified COSS. I have included that graph as Figure 2.

Figure 2: Index of Return at Present Rates

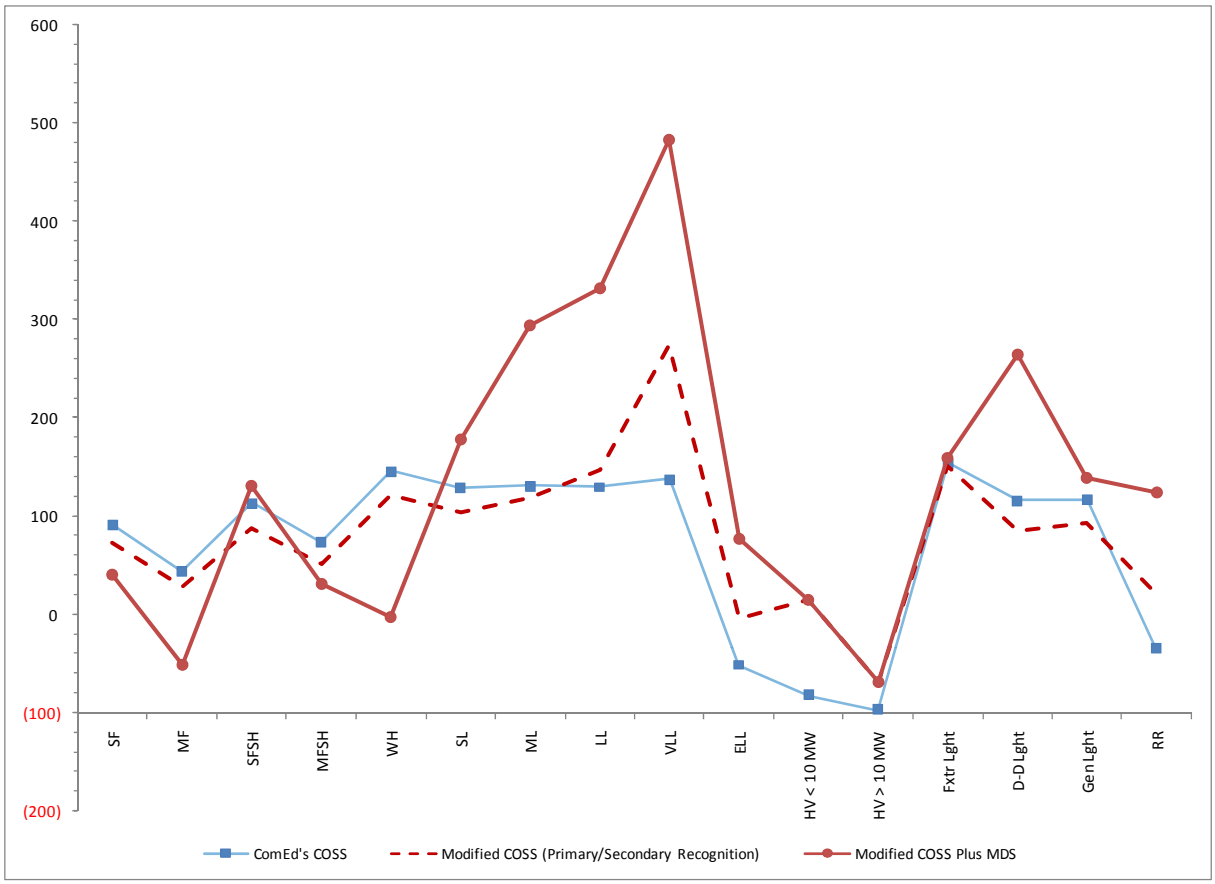


Figure 2 indicates the cumulative effect of changes to the COSS to (1) separate primary and secondary costs, and (2) apply customer and demand percentages for the MDS. The modified COSS results are also reflected in IIEC Exhibit 3.3.

Q ARE THERE COSS TECHNIQUES THAT COULD BE USED, ABSENT A MDS, THAT CAN BETTER ALIGN THE COSS WITH COST-CAUSATION PRINCIPLES?

A Yes, there are. One method is to determine costs with such specificity that they can be directly assigned to the customer classes. MDS methods estimate the percentage of costs necessary to conform to the minimum standards. The ability to directly assign costs with specificity would reduce the need for estimates.

The obvious problem is that the analysis required to identify costs with such specificity is far more time consuming and costly than simply performing the MDS study.

Another possible alternative is to identify the costs of serving customers at multiple primary voltage levels. This is similar to what I described earlier in my testimony, except in this case, the voltage levels in question would not simply be primary and secondary. If the costs of serving customers through each the primary distribution voltage levels (34 kV, 12 kV, and 4 kV) could be identified and if those costs could be directly assigned to the customers taking service at each voltage level, then the inequity that the MDS methods address would be drastically reduced. While the primary/secondary correction I make in this case is a significant improvement to ComEd's COSS, it does not accomplish what this greater voltage differentiation, or what implementation of an MDS approach would.

ComEd Flaw No. 3: Distribution Costs Allocated to High Voltage Customers

Q WHAT OTHER FLAWS EXIST IN THE COMPANY'S COSS?

A The Company's COSS improperly allocates primary and secondary distribution lines, substation costs, and O&M expenses to the High Voltage (HV) class. Specifically, the HV class consists of customers served at 69 kV and above, whereas the distribution classes take service below 69 kV.

In its 2006 Loss Study (IIEC Exhibit 3.1), the Company indicates that 100% of the load for the HV >= 69 kV class passes through High Voltage Energy Service Stations (HV ESS). Based on this evidence, the allocation to HV voltage level customers of primary and secondary costs below 69 kV is unjustified.

If there are HV customers that take a portion of their demand requirements at otherwise lower voltages, then there should be a separate rate to identify and recover these costs.

Q WERE YOU ABLE TO CORRECT THIS ERROR IN THE MODIFIED COSS?

A Yes. The modification I previously made to the COSS to allow me to separate the cost of the primary system and secondary system also allowed me to reduce the primary and secondary costs allocated to the HV class to zero. Eliminating the assignment of primary and secondary costs to the HV class results in a $5,466,770 reduction in cost to this class.

Q WHAT OTHER PROBLEMS HAVE YOU IDENTIFIED IN THE COMPANY'S COSS?

A. As part of its standard filing requirements (Section 285.5025), the Company provided monthly class billing data in Schedule E-4: Billing Units. This schedule includes monthly peak demand values for most of ComEd's commercial and industrial customer classes. This data is a fundamental and critical component in determining the rates charged to the classes to recover the required revenue. It is equally as important that the cost analyst be able to follow the progression from billing demand data to the demand values used in the COSS to develop revenue allocation factors.

The demand values for the coincident peak ("CP") do not match those provided in Schedule E-4. I collected the billing demand used by the commercial and industrial classes during the test year, and compared them to the CP values used in the Company's COSS. The results of this comparison are shown in Table 9.

TABLE 9

Comparison of Billing Demand and COSS Demand

Description	Small Load	Medium Load	Large Load	Very Large Load	Extra Large Load	High Voltage	High Voltage	Railroads
	0-100 kW	101-400 kW	401-1000 kW	1-10 MW	> 10 MW	< 10 MW	> 10 MW	
Coincident Peak	44.5%	23.7%	9.2%	22.5%	32.8%	(9.0%)	13.3%	46.6%
Non-Coincident Peak	28.3%	7.7%	4.7%	18.6%	24.4%	1.4%	996.6%	3.0%

Table 9 compares demand values used in the Company's COSS to the billing demand for each class. Positive percentage differences indicate that the billing demand for the class is larger than the CP values used in the Company's COSS. Negative percentage values indicate the COSS demand values are greater than the billing demand.

Table 9 shows that the Company's COSS CP allocator for the HV < 10 MW class is 9% greater than the billing demand. This is clearly an error, since it indicates the HV < 10 MW class's maximum demand at any time during the year was 9% less than its demand during the system peak hour.

Until these differences are corrected or explained, the Company's COSS should not be relied upon as a basis for setting rates.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of David L. Stowe

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A David L. Stowe. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the Kansas State University's College of Electrical and Computer Engineering in 1987, with a Bachelor of Science degree in Electrical Engineering. Following my graduation, I worked with the Kansas Corporation Commission (KCC) as a Utilities Engineer. My responsibilities included the review and engineering analysis of utility filings, investigations of compliance with the Commission's Orders and State laws, and filing and defending testimony regarding those finds. In addition, I served as Geographic Information Systems Coordinator as the KCC digitized and automated its utility facilities and territory maps from the original velum sheets.

In April of 1993, I accepted a position with the Missouri Public Service Commission where, again in the capacity of a Utilities Engineer, focused primarily on depreciation, jurisdictional allocations, and production cost modeling. My employment with the Commission also allowed me to complete the requirements for

Professional Engineer registration. I acquired my certificate for Professional Engineering registration in 1996.

From October 1995 until January 2002, I developed my expertise in computer engineering and communications; first acting as a Unix System Administrator and Oracle DBA with Kansas City Power and Light, and later offering both hardware and software consulting services to corporations with enterprise-wide application requirements with Digital Equipment Corporation and Compaq. During this time, I was also the president and owner of a company that installed analog and digital communication systems in cellular phone towers.

In January of 2002, I joined the Analytic Services Department of Aquila, Inc. as a Senior Regulatory Analyst where I was primarily responsible for developing and maintaining cost of service models for each of Aquila's electrical territories. In addition, I was solely responsible for completing associated engineering studies to determine the primary and secondary portions of each subsidiaries' distribution systems, calculating the zero intercept values for the subsidiaries' poles, conductors, conduits, and transformers, performing customer impact analyses, and assisting in rate design.

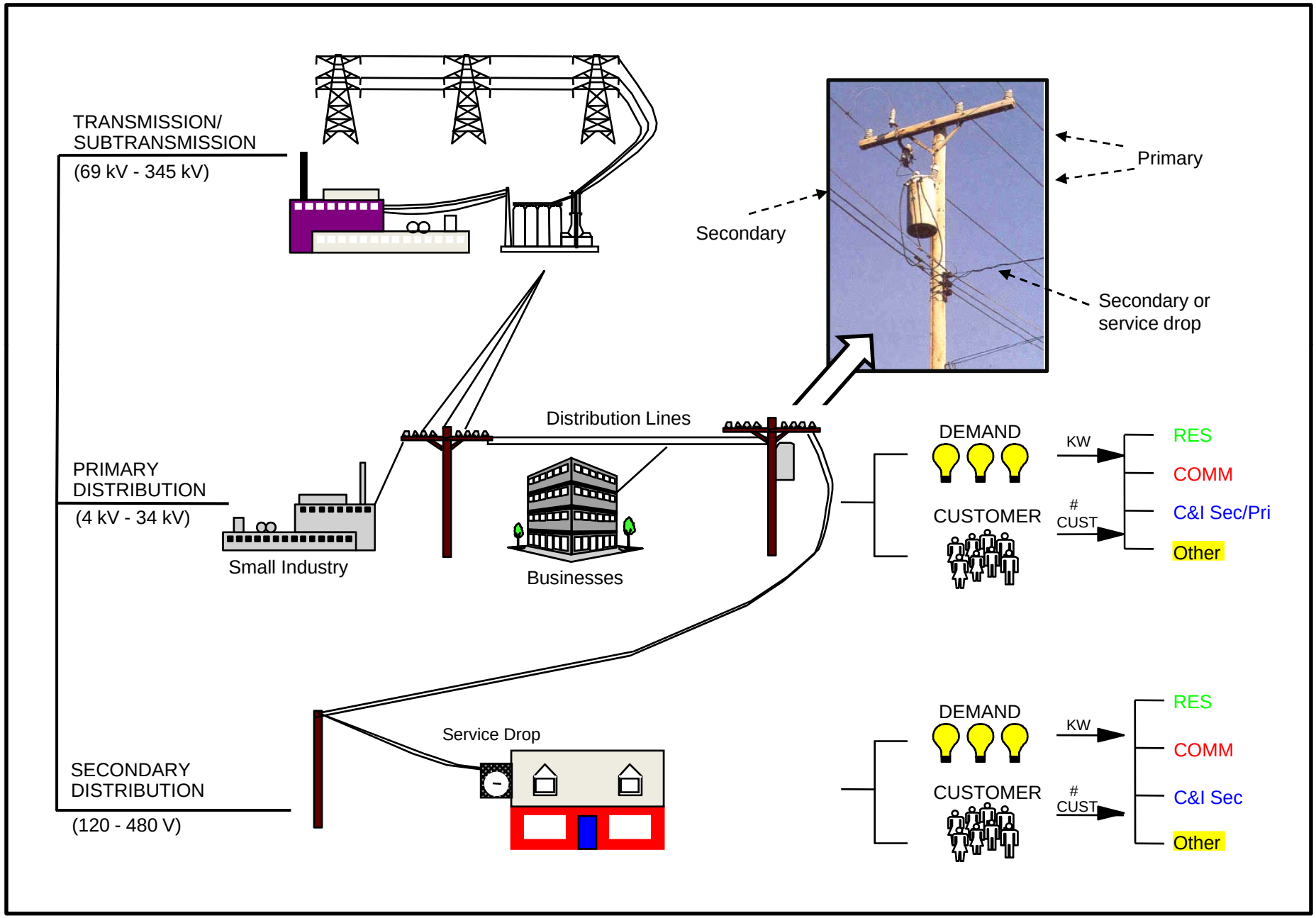
In October of 2007, I joined Brubaker & Associates, Inc. as a consultant. Since that time, I have assisted on cost of service, revenue requirement, and tariff issues in Montana, Wyoming, and New York.

I have testified before the State Commissions of Kansas, Missouri, and Colorado.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

TRANSMISSION AND DELIVERY OF ELECTRICITY

Appendix B



Commonwealth Edison Company
Docket No. 07-0566

ComEd's 2006 Loss Factors - Percent of Class Load Through Elements.

Line	Description	SF	100-400 kW	400kW-1MW	1-10 MW	>10 MW	HV >= 69 kV	RR	D-D Lighting	Gen Lighting
1	HV ESS						100%			
2	138-69 kV TSS	4%	4%	4%	4%	4%		5%	4%	4%
3	138-34 kV TSS	17%	20%	20%	25%	25%		3%	17%	17%
4	34 kV Lines	17%	20%	20%	25%	25%		3%	17%	17%
5	34-12 kV Dist Cntr	13%	10%	6%				3%	13%	13%
6	34-4 kV Dist Cntr	4%	5%	1%					4%	4%
7	34 kV ESS		5%	13%	25%	25%				
8	138/69-12 kV TDC	83%	0%	80%	75%	75%		97%	83%	83%
9	12 kV Lines	5%	8%	11%	35%	35%		85%	10%	10%
10	12 kV Feeder	78%	67%	64%	40%	40%		12%	71%	71%
11	12-4 kV Dist Cntr	5%	3%						5%	5%
12	12 kV ESS		10%	25%	75%	75%				
13	4 kV Feeder	9%	8%	1%					9%	9%
14	AC Ntwrk Feeder		5%	5%					2%	2%
15	AC Ntwrk Xfrmr		5%	5%					2%	2%
16	AC Ntwrk Sec		5%	5%					2%	2%
17	Line Xfrmr	100%	80%	57%					98%	98%
18	480 V DryType Xfrmr	0%								
19	Sec/Service	95%							90%	90%
20	Transmission	100%	100%	100%	100%	100%	100%	100%	100%	100%
21	% Secondary	100%	85%	63%	0%	0%	0%	0%	100%	100%
22	% Primary	0%	15%	37%	100%	100%	100%	100%	0%	0%

Commonwealth Edison Company
Docket No. 07-0566

Underground			2002	2003	2004	2005	2006	5 Yr. Tot
			Ft	Ft	Ft	Ft	Ft	Ft
Cable	Aluminum	600V URD 4/0	5,976,634	6,116,641	6,717,566	6,602,129	5,334,187	30,747,157
Cable	Aluminum	15kV #2 1/C	723,775	1,584,662	3,040,155	2,330,290	3,246,128	10,925,010
Cable	Aluminum	15kV 3/0 1/C	2,690,414	2,108,265	2,071,683	2,342,986	2,779,961	11,993,309
Cable	Aluminum	15kV 750 kCMIL	747,018	397,312	525,246	446,995	758,564	2,875,135
Cable	Aluminum	15kV 3/0 3/C	887,294	424,643	547,177	511,175	693,366	3,063,655
Cable	Aluminum	15kV #2 3/C	448,193	441,584	661,773	499,364	681,196	2,732,110
		Primary Total	5,496,694	4,956,466	6,846,034	6,130,810	8,159,215	31,589,219
		Grand Total	11,473,328	11,073,107	13,563,600	12,732,939	13,493,402	62,336,376
Underground Cable		Secondary	52.09%	55.24%	49.53%	51.85%	39.53%	**49.32%**
Underground Cable		Primary	47.91%	44.76%	50.47%	48.15%	60.47%	**50.68%**

Overhead			2002	2003	2004	2005	2006	5 Yr. Tot
			Ft	Ft	Ft	Ft	Ft	Ft
Wire	Aluminum	Svc Drop	757,280	1,001,926	978,761	1,014,140	974,619	4,726,726
Wire	Aluminum	Svc Drop	525,758	635,311	626,585	680,718	695,305	3,163,677
		Secondary Total	1,283,038	1,637,237	1,605,346	1,694,858	1,669,924	7,890,403
Wire	Aluminum	Bare 477 kCMIL	1,633,202	1,855,843	1,943,648	1,900,509	2,964,920	10,298,122
Wire	Aluminum	Bare 1/0	1,820,285	1,353,130	1,892,085	1,777,060	1,710,250	8,552,810
Wire	Aluminum	Bare 4/0	45,875	251,100	263,595	605,765	732,193	1,898,528
Wire	Copper	Wthr Resist	628,737	508,268	564,225	803,753	1,039,390	3,544,373
		Primary Total	4,128,099	3,968,341	4,663,553	5,087,087	6,446,753	24,293,833
		Grand Total	5,411,137	5,605,578	6,268,899	6,781,945	8,116,677	32,184,236
Overhead Wire		Secondary	23.71%	29.21%	25.61%	24.99%	20.57%	**24.52%**
Overhead Wire		Primary	76.29%	70.79%	74.39%	75.01%	79.43%	**75.48%**

Commonwealth Edison Company
Docket No. 07-0566

Modified COSS Summary Including
Primary and Secondary Recognition and MDS

Description		Total ICC	Single Family w/o Space Heat	Multi Family w/o Space Heat	Single Family w/Space Heat	Multi Family w/Space Heat	Watt-Hour	Small Load 0-100 kw	Medium Load 101-400 kw
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Modified COSS									
Total O & M Expenses		793,192,491	384,857,072	146,437,487	7,506,568	26,140,366	15,041,072	77,100,436	36,102,766
Total Depreciation Expense		356,649,463	175,144,528	53,324,263	3,822,008	10,765,086	5,194,222	36,271,801	22,349,446
Total Taxes Other than Income (Ex.Illinois Electric Dist. Tax)		43,223,482	21,024,998	7,272,105	430,825	1,362,906	718,866	4,366,446	2,318,492
Total Operating Expenses		1,193,065,436	581,026,598	207,033,855	11,759,400	38,268,358	20,954,160	117,738,683	60,770,704
Total Rate Base		7,056,804,483	3,437,833,920	1,040,165,642	74,340,205	208,626,431	100,340,808	705,340,551	450,033,990
Target Rate of Return & Income Taxes Gross Up (%)		11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%
Total Return & Income Taxes		835,525,651	407,039,536	123,155,612	8,801,880	24,701,369	11,880,352	83,512,321	53,284,024
Subtotal Cost of Service		2,028,591,087	988,066,134	330,189,467	20,561,281	62,969,728	32,834,512	201,251,005	114,054,728
Revenue Adjustment Factor	0.99871								
TOTAL COST OF SERVICE (Revenue-Related Distributed)		**2,025,981,874**	**986,795,264**	**329,764,771**	**20,534,834**	**62,888,735**	**32,792,280**	**200,992,152**	**113,908,029**
ComEd COSS									
Total O & M Expenses		793,192,491	337,328,920	113,791,000	7,832,368	23,505,764	11,714,491	85,492,841	53,405,854
Total Depreciation Expense		356,649,463	142,259,146	31,836,663	3,945,697	8,879,290	3,009,293	40,832,045	33,209,958
Total Taxes Other than Income (Ex.Illinois Electric Dist. Tax)		43,223,482	17,490,926	4,865,971	453,051	1,165,724	473,776	4,966,224	3,584,775
Total Operating Expenses		1,193,065,436	497,078,992	150,493,634	12,231,117	33,550,778	15,197,559	131,291,110	90,200,586
Total Rate Base		7,058,403,092	2,727,868,375	560,412,362	78,472,384	168,811,228	51,488,224	821,736,954	700,870,505
Target Rate of Return & Income Taxes Gross Up (%)		11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%
Total Return & Income Taxes		835,714,926	322,979,616	66,352,824	9,291,130	19,987,249	6,096,206	97,293,655	82,983,068
Subtotal Cost of Service		2,028,780,362	820,058,608	216,846,458	21,522,247	53,538,027	21,293,765	228,584,765	173,183,654
Revenue Adjustment Factor	0.99871								
TOTAL COST OF SERVICE (Revenue-Related Distributed)		**2,026,170,905**	**819,003,832**	**216,567,546**	**21,494,565**	**53,469,165**	**21,266,377**	**228,290,755**	**172,960,902**

Commonwealth Edison Company
Docket No. 07-0566

Modified COSS Summary Including
Primary and Secondary Recognition and MDS

Description	Large Load 401-1000 kw	Very Large Load Over 1,000-10,000 kw	Extra Large Load Over 10,000 kW	High Voltage Up to 10,000 kW	High Voltage Over 10,000 kW	Fixt. Incl. Ltg	Dusk to Dawn	General Lighting incl. Traffic Signals	Railroads
	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Modified COSS									
Total O & M Expenses	30,124,680	44,383,370	7,735,317	903,125	3,127,996	10,606,012	1,545,201	258,400	1,322,624
Total Depreciation Expense	16,724,819	19,982,199	4,130,589	424,947	1,654,118	5,016,962	1,024,790	119,628	700,055
Total Taxes Other than Income (Ex.Illinois Electric Dist. Tax)	1,816,345	2,440,903	470,272	52,771	195,350	559,084	100,370	14,015	79,735
Total Operating Expenses	48,665,843	66,806,472	12,336,179	1,380,843	4,977,464	16,182,058	2,670,362	392,043	2,102,414
Total Rate Base	339,615,228	423,618,131	90,367,838	9,502,949	37,517,211	102,606,375	19,376,659	2,329,084	15,189,460
Target Rate of Return & Income Taxes Gross Up (%)	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%
Total Return & Income Taxes	40,210,443	50,156,387	10,699,552	1,125,149	4,442,038	12,148,595	2,294,196	275,764	1,798,432
Subtotal Cost of Service	88,876,286	116,962,858	23,035,731	2,505,993	9,419,502	28,330,653	4,964,558	667,806	3,900,846
Revenue Adjustment Factor									
TOTAL COST OF SERVICE (Revenue-Related Distributed)	**88,761,972**	**116,812,418**	**23,006,102**	**2,502,769**	**9,407,386**	**28,294,213**	**4,958,173**	**666,947**	**3,895,829**
ComEd COSS									
Total O & M Expenses	46,166,558	77,304,853	14,931,871	1,665,963	4,133,682	10,729,797	2,265,281	271,605	2,651,641
Total Depreciation Expense	27,443,186	44,484,306	9,485,545	869,089	2,236,484	5,086,492	1,448,503	125,663	1,498,103
Total Taxes Other than Income (Ex.Illinois Electric Dist. Tax)	3,004,346	4,933,135	1,015,028	102,966	261,337	567,970	152,446	14,936	170,870
Total Operating Expenses	76,614,090	126,722,294	25,432,445	2,638,018	6,631,503	16,384,259	3,866,230	412,204	4,320,615
Total Rate Base	577,211,962	930,728,352	201,207,378	19,408,867	50,559,324	104,338,900	29,594,684	2,504,043	33,189,550
Target Rate of Return & Income Taxes Gross Up (%)	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%	11.84%
Total Return & Income Taxes	68,341,896	110,198,237	23,822,954	2,298,010	5,986,224	12,353,726	3,504,011	296,479	3,929,643
Subtotal Cost of Service	144,955,987	236,920,531	49,255,399	4,936,028	12,617,727	28,737,985	7,370,241	708,683	8,250,257
Revenue Adjustment Factor									
TOTAL COST OF SERVICE (Revenue-Related Distributed)	**144,769,542**	**236,615,799**	**49,192,045**	**4,929,679**	**12,601,498**	**28,701,022**	**7,360,761**	**707,772**	**8,239,646**