SURVEY OF APPROACHES TO DISTRIBUTION COST ALLOCATION BY VOLTAGE

for

Commonwealth Edison Company

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Survey Report

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Executive Summary

The Illinois Commerce Commission ("ICC" or "Commission") recently directed Commonwealth Edison Company ("ComEd") to investigate how other utilities allocate costs for primary and secondary voltage facilities ("primary/secondary") that provide retail service to electric utility customers.[1] In its Order concluding ComEd's 2010 rate case in Docket No. 10-0467 ("Order") the Commission further directed ComEd to confer with the ICC Staff ("Staff") in developing the approach to this investigation and in reviewing the results.

ComEd asked Christensen Associates Energy Consulting ("CA Energy Consulting") to undertake a survey of electric utilities to acquire the relevant information, including participating utilities' cost-of-service ("COS") studies, where available.

Costing Issues Investigated in the Survey

In response to the Order, and with input from the ICC Staff, the survey undertook to investigate several aspects of primary/secondary cost allocation. These included: 1) the incidence of such cost splitting, including whether primary distribution system costs are further segmented relative to what was provided in ComEd's primary/secondary analysis; 2) the reflection of voltage cost differences in retail tariffs; 3) the types of allocators used to yield costs by rate class; 4) the handling of costs that might be directly assigned to customers and the costing and pricing of special service requests by customers; 5) the treatment of costs in FERC account 364 (poles, towers and fixtures); 6) geographically-based costing; 7) the recognition of single-phase and three-phase service in COS; and 8) the degree to which cost separation between primary and secondary voltage generates controversy in regulatory proceedings.

Information on these topics can be used to inform future regulatory proceedings in Illinois and may offer information on costing approaches for other topics under review as directed by the ICC in ComEd's 2010 rate case.

Survey Approach

CA Energy Consulting solicited opinion from a diverse group of investor-owned utilities selected on the basis of size, as represented by number of customers and service territory density, measured by the number of customers per transmission-mile. A group of 120 utilities for which recent data are available was divided into nine "bins" based on two criteria: the number of customers served; and the density of customers in the service

[1] ICC Order for Docket No. 10-0467, May 24, 2011.

territory (measured by the number of customers per transmission mile). A survey size of 16 utilities was chosen as being sufficiently diverse, as well as appropriate for the nature of the questions under research. A disproportionate share of the sample was drawn from the groups of utilities most similar to the group to which ComEd belongs.

The survey administrators succeeded in acquiring responses for 16 utilities, matching closely the target diversity of the design. In particular, two utilities categorized in the same bin as ComEd provided responses. Respondents were geographically diverse as well, drawn primarily from the Midwest and Eastern United States although one Pacific Coast utility participated as well. Additionally CA Energy Consulting secured a survey from Ameren Illinois, the other large utility in the Illinois Commerce Commission's jurisdiction.

Survey Results

The survey's major findings are:

- Almost all utilities segment distribution costs between primary and secondary service facilities, and have done so for a decade or more. The trend, initiated in the 1970's, appears to have been predominantly utility-driven.
- Tariffs recognize this primary/secondary differentiation implicitly because energy delivery for the majority of customers in a class is often at a single voltage. Adjustments in charges related to transformer ownership assist in this differentiation. Some utilities formally distinguish prices by voltage, especially in rates for large load customers.
- The boundary line between primary and secondary voltage facilities varies across utilities, but is in the range of 2.4 to 4 kV. ComEd's lower bound of primary voltage is 4 kV, similar to that of other utilities.[2] Two respondents reported having two segments to their primary voltages, but neither split primary costs into segments for cost allocation purposes.
- The issue of single-phase vs. three-phase service is not investigated closely in most jurisdictions. Many utilities do not keep track of this factor for COS purposes.
- Direct assignment of costs to customers is common but does not amount to a significant share of overall costs.
- Similarly, utilities are flexible in the treatment of special customer needs. They typically recover full costs of special equipment and services from the customer requesting the special service. In COS practices are varied, chiefly due to the relative insignificance of the amounts involved.
- COS allocators of distribution charges follow NARUC guidelines but allocator usage varies fairly widely across utilities. Some allocate according to demand only, while others split distribution into demand and customer portions, using familiar, established methods (minimum system or zero intercept). Demand-related costs at the primary service level are allocated by a mix of coincident peak

[2] In the case of ComEd, the use of "4kV" refers to their 4.16 kV primary system operations.

(CP) and noncoincident peak (NCP) allocators. At the secondary level, NCP predominates, with use of both a "class NCP" and a "sum-of-the-customers" NCP. ComEd's use of CP allocators for electric service provided by primary voltage facilities is shared by several utilities, but not all.

- The costing practices of the surveyed utilities do not appear to generate controversy in regulatory proceedings. Few respondents reported methodology disputes of any consequence. Additionally, respondents' costing practices appear to be consistent with NARUC principles. All respondents reported this perception, and the allocators and primary/secondary splitting procedures reported can be found in the NARUC Cost of Service manual.[3]

<u>Conclusions</u>

The survey reveals that distribution cost allocation with respect to voltage is widespread and uses a variety of practices while remaining within the principles articulated by NARUC in its well known Cost of Service Manual. Additionally, it appears that ComEd's costing practices are well within the range of those reported in the survey. Specifically, the Company's practices of using CP allocators at the primary voltage level and NCP allocators at the secondary voltage level are consistent with practices elsewhere.

The methods that the surveyed utilities use to develop the data that underpin allocators are not uniform. A particular issue in ComEd's 2010 rate case pertained to FERC account 364, poles, towers and fixtures. Methods include the extension to account 364 totals of allocators applied to other FERC accounts, and the use of actual pole data to develop shares. However, direct use of recent data (as opposed to surveys, which tended to be of uncertain vintage) and the explicit treatment of shared poles are not widespread.

Regarding the extent to which single-phase and three-phase service information is used, most utilities do not appear to study the incidence of such wires. Costing to reflect such departures is typically not done (other than for meter costs and sometimes service drops).

The survey also investigates COS methods relating to direct assignment of costs for actual equipment and the treatment of requests for special service. Survey respondents uniformly charged customers for the full costs of special arrangements. However, the accounting treatment of revenues and costs is not consistent and usually does not involve recognition at the class level.

The survey also inquires into the incidence of geographic cost differentiation. Just one utility in our survey develops cost information by distribution costing area and their methods do not involve the use of embedded cost, but instead use marginal cost.

Lastly, costing practices surrounding the demarcation of primary and secondary voltages does not appear to be generating regular methodological disputes in regulatory proceedings.

[3] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992

1 Introduction & Background

1.1 Regulatory Context

In ComEd’s 2010 rate case, Commonwealth Edison Company was directed by the Illinois Commerce Commission to work with ICC Staff to analyze other utilities’ cost of service studies to determine how other utilities allocate cost for primary and secondary voltage facilities that provide retail service to electric utility customers.

This inquiry came about in part as a response to intervenors’ and Staff’s concerns regarding ComEd’s distribution cost allocation methods and in part because the Commission wanted more extensive evidence of practices elsewhere.

In response to the Order, ComEd selected Christensen Associates Energy Consulting to conduct a survey of electric utilities on the topic of the methodology regarding separation and allocation of costs to secondary and primary voltage levels. CA Energy Consulting drafted a survey, obtained input on the survey from ComEd and Staff, and contacted a diverse set of utilities selected with the intent of identifying a broad range of industry practices.

The survey is just one component of CA Energy Consulting’s research for ComEd growing out of the Order. Other research includes conducting sampling and direct observation to check the allocation methodology contained in ComEd's Primary/Secondary Cost Study; developing a statistically valid sample of circuits; identifying and deleting 4 kV distribution costs assigned to the Railroad customers; and undertaking a study of the assets serving the Extra Large Load Customer class, including whether Rider NS – Nonstandard Service and Facilities (Rider NS) costs and revenues are properly handled in ComEd's cost-of-service study.

1.2 Cost Allocation Issues

The rate case proceedings in Docket 10-0467 included testimony on several aspects of distribution cost allocation resulting from ComEd’s primary/secondary analysis. A number of intervenors representing customers at the primary service level questioned ComEd’s allocation of costs, chiefly stating that costs had been allocated to the primary voltage level that they felt belonged at the secondary voltage level, sometimes because ComEd, in their opinion, had failed to use sufficiently detailed allocation methods to arrive at an accurate allocation methodology. These intervenors included the Illinois Industrial Energy Consumers (IIEC), the Coalition to Request Equitable Allocation of Costs Together (REACT), the Chicago Transit Authority (CTA), and the Northeast Illinois Regional Commuter Railroad Corporation d/b/a Metra Corporation (METRA).[4]

More specifically, they questioned ComEd’s methods or results on the following issues:

[4] The Commercial Group also appeared as an intervenor, but did not object to ComEd’s allocation approach.

- Pole costs: how should pole costs be allocated between primary and secondary voltage and, in particular, what should be done regarding “shared poles” which carry both primary and secondary voltage lines?
- Single-phase vs. three-phase service: how detailed does analysis of the relationship between phase and voltage level of service need to be?
- Customer size: should separate analysis of the Extra Large Load class’s costs be undertaken?

In addition, the Staff took issue with ComEd’s documentation supporting a range of allocation rules. While recognizing that ComEd had investigated other utilities’ tariffs regarding segmentation by voltage, the Staff wanted information regarding the cost allocation practices that underlie those tariffs. As well, the Staff wanted more extensive sampling of ComEd service territory assets to support its engineering estimates in FERC Accounts 364, 365, and 366. A survey of other utilities’ asset sampling practices, they reasoned, might provide guidance on information to obtain in direct sampling of assets.

Subsequent to project initiation, ComEd and Staff suggested that the survey consider a broader range of topics, including:

- Separation of distribution cost and FERC accounts into primary and secondary voltages. Working definitions of primary and secondary. Further separation of primary into separate voltage levels.
- Recognition of single-phase and three-phase service in cost allocation.
- Geographical differentiation: cost differentiation between urban and rural service areas.
- Cost assignments in cost of service, and related analyses that develop inputs to cost of service, where certain costs are known on a specific customer basis.
- Treatment of non-standard equipment in cost of service.
- Tariff recognition of voltage.
- Types of allocators used to assign distribution costs to rate classes (e.g., coincident peak and non-coincident peak allocators).
- Treatment of pole costs, focusing on poles that share primary and secondary lines.
- Tendency for distribution cost allocation issues of interest in the survey to generate regulatory dispute.

CA Energy Consulting developed questions to inquire into each of these issues.

1.3 Report Structure

This report sets out the survey approach in Section 2 and describes the issues investigated in the survey. Section 3 presents the survey results, while Section 4 provides conclusions based on the results, and then makes recommendations as to how the results should influence ComEd’s own cost allocation by voltage level. An appendix provides the survey document.

2 Survey Approach

2.1 Survey Design and Sampling

The survey set out to acquire information from utilities with a variety of characteristics, in order to maximize the likelihood that a broad range of industry practices in distribution cost allocation would be identified. CA Energy Consulting used FERC Form 1 data from 2010 to classify 120 investor-owned utilities according to their size and the density of their service territory. Number of customers served as a proxy for size and customers per mile of transmission line represented density.[5]

CA Energy Consulting subdivided the population into nine groups or "bins" based on combinations of size and density of service territory, selecting boundaries to meet two criteria. The first criterion involved setting boundaries such that the bin containing ComEd would consist of utilities fairly similar to the Company's characteristics. The second criterion was to make the remaining bins fairly similar in numbers of utilities. The utility size categories selected are: 1) less than 500 thousand customers, 2) 500 thousand to 2 million, 3) and over 2 million. The density categories are: A) under 250 customers per transmission-mile, B) 250 to 1,000, and C) over 1,000. The outcome of this segmentation appears in Table 1 below.

Table 1
Population of Utilities Eligible for Survey

	Density Category			
Size Category	A. under 250	B. 250 to 1,000	C. Over 1,000	Total
1. under 500k	32	21	9	62
2. 500k to 2m	18	20	9	47
3. Over 2m	1	7	3	11
Total	51	48	21	120

ComEd, with 3.8 million customers and 1,406 customers per transmission mile, resides in the bin containing the utilities with the largest number of customers and densest service territories. (The table labels bins by the convention (row number, column letter), with the bin containing ComEd designated (3,C)). Bins in the same row or column as ComEd's contain relatively small numbers of utilities as a result of the first criterion. Other bins contain larger numbers of utilities.

ComEd had previously acquired tariff sheets for 35 utilities to examine the degree to which utilities differentiate rates by voltage. CA Energy Consulting determined that a smaller survey would likely acquire a sufficient diversity of opinions on costing methods, permit fairly detailed questions, and be cost effective. Following review by ComEd and the Staff reviewers, CA Energy Consulting determined to strive for a sample of 17

[5] A better representation of density might have used miles of distribution line rather than transmission line. Unfortunately, the FERC Form 1 data do not provide such totals as readily as transmission line mileage. Constructing such an index would have involved a large effort that would not necessarily have provided any material difference to the analysis.

utilities, with segmentation based on proximity to ComEd's bin and diversity sufficient to cover all bins. The target sample appears in Table 2, below.

Table 2
Target Sample Size of Survey

	Density Category			
Size Category	A. under 250	B. 250 to 1,000	C. Over 1,000	Total
1. under 500k	3	1	1	5
2. 500k to 2m	1	2	3	6
3. Over 2m	1	3	2	6
Total	5	6	6	17

In developing the sample, CA Energy Consulting sought to contact all of the utilities in the bin that includes ComEd bin (3,C), a significant number in the nearby bins {(2,C), (3,B) and (2,B)}, and at least one utility in each of the other bins. CA Energy Consulting solicited three responses from bin (1,A) because it has more utilities than the other bins, because Ameren Illinois (a significant utility in the ICC's jurisdiction) is in that bin, and because it includes a utility, Mississippi Power, with an authority on cost of service, who had the potential to provide extra insight on the survey topics.[6]

CA Energy Consulting prepared a survey to administer by telephone in July 2011, covering the topics agreed upon by ComEd and the Staff reviewers. That survey appears in the appendix of this report. CA Energy Consulting anticipated soliciting responses in telephone interviews, and sent the surveys to contacted utilities in advance of the scheduled calls. Utilities largely preferred to return written responses, which usually produced more systematic responses and shortened the telephone interviews considerably. In a few cases, respondents were not available for telephone interviews but did respond to follow-up emailed questions, where needed.

Ultimately CA Energy Consulting solicited 19 responses and dispatched 18 surveys via email, having received no response from just one utility. Of the 18 surveys sent, just two were refused subsequently. Refusals were due to time constraints and lack of on-site expertise during the survey window. By the end of the survey period, respondents had completed and returned 16 surveys. CA Energy Consulting conducted telephone interviews with 13 respondents. Emails clarified questions for two more utilities. Survey solicitation was successful in that most bin targets were attained. The single setback was the failure to induce the one utility in bin (3,A), to participate. Table 3 summarizes completed responses.

[6] Mr. Larry Vogt of Mississippi Power is the author of a book about pricing and cost of service: Laurence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies*, CRC Press, Dec. 2009.

Table 3
Completed Surveys

	Density Category			
Size Category	A. under 250	B. 250 to 1,000	C. Over 1,000	Total
1. under 500k	3	1	1	5
2. 500k to 2m	1	2	3	6
3. Over 2m	0	3	2	5
Total	4	6	6	16

2.2 Survey Topics

The survey explored a range of cost allocation practices that utilities apply to the challenge of spreading distribution costs across voltages. The challenge arises from the complexity of service arrangements that utilities adopt to fit the circumstances in their service territories. Complications arise from customer diversity, proximity of customers to lines of varying voltages, the variety of voltage levels within the main levels of primary and secondary service, the use of underground and overhead connections and the presence of both single- and three-phase service. The subsections below summarize the topics and issues surrounding them.

2.2.1 Primary/secondary differentiation and primary level segmentation

CA Energy Consulting first asked respondents whether they differentiated distribution costs between primary and secondary voltages, and if so, for how long they had been doing so. Additionally, at the behest of Staff, the survey inquired as to the stimulus for introducing the practice, whether it was internal, due to regulatory influence, or arising from some other source.

2.2.2 Tariff specificity regarding voltage

ComEd surveyed a number of utilities in 2010 regarding the degree to which they recognize voltage in their tariff sheets. The survey included this question in its review in order to be able to compare pricing practices with costing approach for each surveyed utility.

2.2.3 Geographic diversity, urban-rural differentiation

ComEd and its customers face very different circumstances in the central business district of the City of Chicago when compared with suburban or agricultural areas of its service territory. Geographical segmentation in tariff design is rare. An exception lies in service territories that are the result of corporate mergers, where service territories within one state may remain distinct despite having been brought under one corporate entity. An example of this practice can be found at AEP Ohio, which has two service territories in Ohio – Ohio Power and Columbus Southern Power – each with its own tariff sheets.

An instance of geographical segmentation not related to corporate merger can be found in Pacific Gas & Electric’s tariff sheets. For example, their E-1 Residential tariff is an inclining block product whose blocks are defined as a percentage of a baseline quantity, expressed in kWh per day. Customers are segmented by 1) basic or all-electric service; and 2) by “baseline territory”, of which there are ten. The baseline territories are defined by location and elevation, indicating that climate is a significant driver in baseline determination. The baseline is also defined for each of two seasons.

From the customer perspective, those in dense urban areas can bridle at geographically uniform costing methods. Thus, the issue merits inclusion in the survey.

2.2.4 Allocators to rate class used in COS

While the Staff is familiar with standard cost allocation practices for distribution assets and costs, it wanted to have the survey inquire into the actual allocators used by the survey respondents for various cost components. That is, the Staff wanted to know in what circumstances the participating utilities use coincident peak and non-coincident peak allocators for the various components of their distribution system.

2.2.5 Treatment of single-phase vs. three-phase service

Typically, single-phase service is found at the secondary level while three-phase service is found at the primary level. However, ComEd’s service territory is not segmented sharply along these lines. The Staff were interested in learning to what extent utilities keep track of this segmentation and, more importantly, make provision for it in their cost allocation practices.

2.2.6 Direct assignment of customer-specific standard cost

An additional issue of interest for the survey involves the way utilities handle cases in which costs are known on a customer-specific basis. This inquiry has two components. First, standard costs can sometimes be assigned directly in cost of service to customers because the assets are clearly associated with service to a specific customer or well identified set of customers. To what extent do utilities in these circumstances actually assign those costs directly to customers?

2.2.7 Customer-specific charges for non-standard equipment

The second component regarding the handling of costs on a customer-specific basis involves cases when customers have special needs that result in non-standard equipment being installed by the utility. The concern is the extent to which utilities directly charge customers for such equipment and related services, what form the charges take, and then how the utility handles the cost and revenue impacts in cost allocation.

2.2.8 Treatment of poles

Staff maintains that direct observation of assets in the field could improve the accuracy of ComEd’s engineering estimates. Regarding FERC account 364, ComEd stated it “does not have data readily available” to determine the exact number of poles in its system with primary and secondary voltage facilities, and thus to allocate costs by voltage based on direct evidence. As a result, the survey was designed to elicit information on how other utilities conduct cost allocation of poles by primary and secondary voltage facilities. One aspect of this costing issue arises from the fact that typically a significant subset of poles carries both primary and secondary voltage facilities. Cost allocation thus involves deciding how much direct observation of pole and related information to undertake, and how to treat these “shared poles” for cost purposes.

2.2.9 Degree of regulatory controversy

ComEd and Staff also wanted to learn about whether cost allocation by voltage was a source of ongoing debate during regulatory proceedings elsewhere, because that might provide guidance as to the degree of scrutiny that Illinois should be giving the topic. Additionally, a related consideration is whether any aspect of a respondent’s methodology raises concerns about compatibility with NARUC’s standard distribution cost allocation approach(es) or, alternatively, is within the canon of standard practice.

2.3 Survey Respondents

Our requests to participate in the survey were met largely with prompt and thorough response. In some utilities, more than one costing analyst provided detailed responses to our inquiries. Table 4 lists the utilities participating, by bin.

Table 4
Survey Respondents

	Density Category			
Size Category	A. under 250	B. 250 to 1,000	C. Over 1,000	Total
1. under 500k	Ameren Illinois Company Cleco Power LLC Mississippi Power Company	Delmarva Power & Light Company	The United Illuminating Company	5
2. 500k to 2m	Oklahoma Gas and Electric Company	Kansas City Power & Light Company Xcel Energy (NSP)	Baltimore Gas and Electric Company PECO Energy Company Potomac Electric Power Company - MD	6
3. Over 2m	none	Duke Energy Carolinas, LLC Pacific Gas & Electric Company Dominion Virginia Power	Consolidated Edison Company of New York, Inc. Public Service Electric and Gas Company	5
Total	4	6	6	16

3 Survey Results

3.1 Major findings

This section reports respondents’ views on the topics set out in Section 2. Since the topics are varied, a summary of the findings in advance of the reported detail is provided below.

- Almost all utilities segment distribution costs between primary and secondary voltage, and have done so for a decade or more. Methods for doing so vary with respect to account and subaccount detail, the extent to which data from geographic information systems (“GIS”) are used, and the degree to which special studies or field surveys are pursued to acquire data. The trend, initiated in the 1970's, appears to have been utility-driven predominantly.

- Tariffs recognize this primary/secondary differentiation implicitly because energy delivery for the majority of customers in a class is often at a single voltage. Adjustments in charges related to transformer ownership assist in this differentiation. Some utilities formally distinguish prices by voltage, especially in rates for large load customers.
- The boundary line between primary and secondary voltage service varies across utilities, but is in the range of 2.4 to 4 kV. ComEd's lower bound of primary voltage level is 4 kV, similar to that of other utilities. Two respondents reported having two segments to their primary voltages, but neither split primary costs into segments for cost allocation purposes.
- The issue of single-phase vs. three-phase service is not investigated closely in most jurisdictions. Many utilities do not keep track of this factor for COS purposes other than for meters and, sometimes, service drops.
- Direct assignment of costs to customers is common but does not amount to a significant share of overall costs.
- Poles which carry both primary and secondary distribution facilities are sometimes split to primary and secondary with various methods, and sometimes simply assigned to primary.
- Similarly, utilities are flexible in the treatment of special customer needs. They typically recover full costs of special equipment and services from the customer. COS practices are varied, chiefly due to the relative insignificance of the amounts involved.
- COS allocators of distribution charges follow NARUC guidelines but allocator usage varies fairly widely across utilities. Some allocate according to demand only, while others split distribution into demand and customer portions, using familiar, established methods (minimum system or zero intercept). Demand-related costs at the primary service level are allocated by a mix of coincident peak ("CP") and noncoincident peak ("NCP") allocators. At the secondary service level, NCP predominates, with use of both a "class NCP" and a "sum-of-the-customers" NCP. ComEd's use of CP allocators for electric service provided by primary voltage facilities is shared by several utilities, but not all.
- The costing practices of the surveyed utilities do not appear to generate controversy in regulatory proceedings. Few respondents reported methodology disputes of any consequence. Additionally, respondents' costing practices appear to be consistent with NARUC principles. All respondents reported this perception, and the allocators and primary/secondary splitting procedures reported can be found in the NARUC Cost of Service manual.

3.2 Results by Topic Area

Results of the survey appear below, summarized by topic. The specific questions from which responses are drawn are listed at the start of each topic write-up.

3.2.1 Primary/secondary differentiation and primary level segmentation

(Questions A, B, C, and D) All but two of the survey respondents differentiate in COS accounting between primary and secondary voltages. The practice of differentiation is well established, with a majority of utilities estimating that the split dates from the 1960s, 1970s or 1980s. Three utilities reported the conversion within the last decade or so. These utilities are all Midwestern, but the sample is small enough that it would be difficult to claim the existence of a geographic pattern.

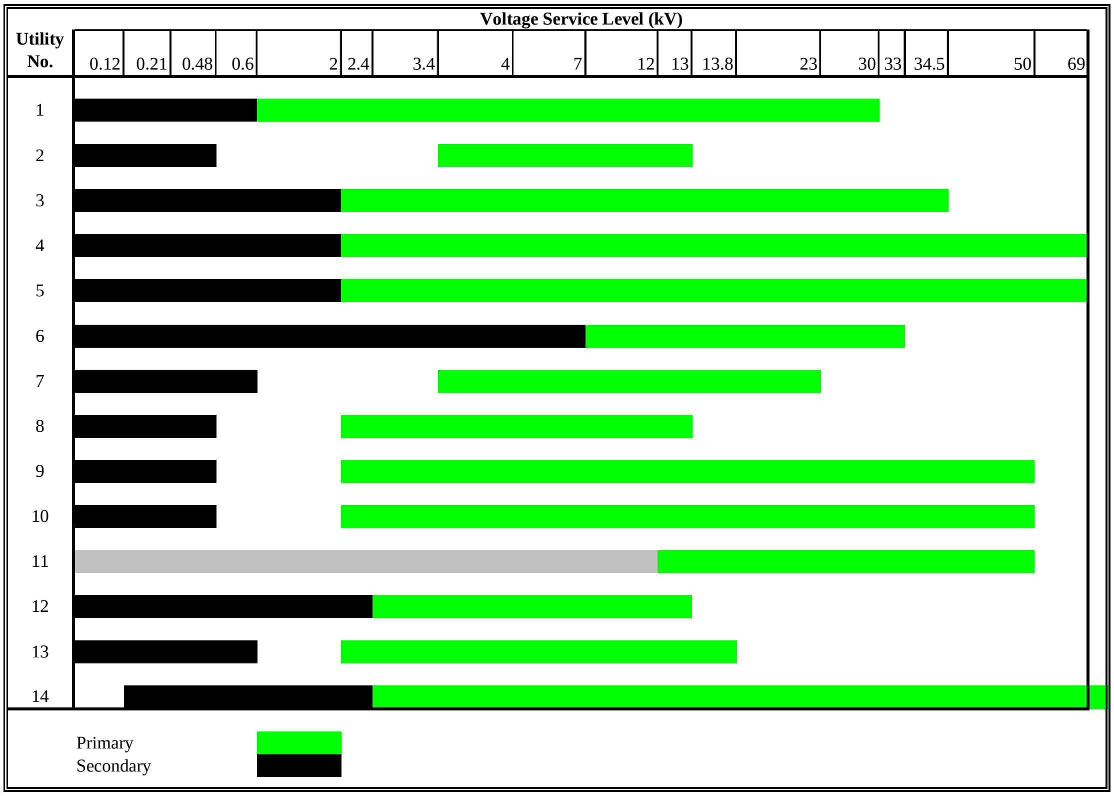
When asked about the impetus for introducing the split, utilities for which the conversion was recent were better able to respond than utilities where the practice is long established. Seven respondents stated that the utility initiated the practice on its own, while one thought that the change had been jointly advanced by the utility and its regulator. The remainder could not say how the change came about. For those who made the change, it is often remote enough in time that the reasons for initiating the change are not recollected by current staff.

Survey respondents provided, in summary form, the range of voltages for each of the primary and secondary voltage levels. Figure 1 presents these ranges, with utility name excluded. Secondary service extends up to the voltage level at the right end of the black bar. Primary service extends up to the voltage level at the right end of the shaded bar. The bars highlight the full range of voltages, although distribution facilities are operated at discrete voltage levels only. Thus, the figure presents results in approximate form only. Discontinuities appear whenever there is a gap in the reported ranges. Additionally, the voltage boundaries are not drawn to scale, but distorted to reveal the voltages cited by respondents.

Utility 9’s primary voltage range is not defined clearly, as indicated by the gray shading on the left side of the figure. This is because the utility defines its voltage levels by number of stages from transmission level. Secondary is defined as no more than two transformation stages from transmission level, while primary is no more than one stage away. The bottom end of the primary voltage is about 12 kV.

The only other anomaly is utility 6’s definition of secondary as less than 7 kV. The figure perhaps misleads with respect to the difference due to the lack of fixed scaling.

Figure 1
Secondary and Primary Voltage Ranges of Survey Respondents



Only two respondents reported any differentiation in primary voltage for record keeping purposes. Utility 8 has two primary levels, the first consisting of 2.4 to 4 kV, and the second at 13.2 kV. They record equipment in these two ranges but no segmentation is done in accounting records for COS purposes. Utility 13 splits primary into two levels: 2.4 to 4 kV and 13.8 kV, but again they make no differentiation between levels in COS. Additionally, they are phasing out the lower segment, replacing lower voltage equipment with uniform 13.8 kV service. As a result, effectively no surveyed utilities can be said to split primary for COS accounting or cost allocation purposes.

The pattern of primary and secondary dividing lines suggests that, for many utilities, secondary covers voltages of 2.4 kV or less. A closer look indicates, though, that primary begins in several cases over 4 kV. For some utilities with 4 kV, the lower primary voltages of 2.4 and 4 kV are being eliminated, with replacement primary being at 13 kV. This is true of utilities 8 and 13. Utility 5, although officially drawing its dividing line at 2 kV, reports that most of its primary is at 9.9 and 34.5 kV. ComEd's own lower bound for primary is 4 kV, suggesting that its practice is in line with that of several other utilities, even some that ostensibly have lower boundaries.

3.2.2 Tariff specificity regarding voltage

(Question K) All survey respondents reported differentiating by voltage to some degree in their tariffs. This result parallels ComEd's previous research on tariffs, in which virtually all of the 35 utilities surveyed have a primary and secondary split between voltages.

Our survey did not inquire into how voltage differentiation was expressed in the tariffs. To some degree, such differentiation is implicit in that residential and small commercial customers are almost invariably served at secondary voltage. (Those not served at secondary voltage are often classified under a non-mass market tariff.) Another well known device is to attach price discounts for service at higher voltage than that established for the rate. In some few cases there is explicit and systematic differentiation of the sort found in OGE Energy's tariffs, with separately quoted prices by voltage. As noted previously, though, this is one of the few utilities that does not use voltage differentiation in its COS cost allocation.

3.2.3 Geographic diversity, urban-rural differentiation

(Question E) Geographical segmentation of costs is rare. Just three respondents reported such differentiation. One respondent identifies costs with its distribution planning areas, which allows to the utility to differentiate to some extent with respect to urban density. A second utility uses information from its GIS to differentiate costs by region. In the case of the third utility, the answer simply reflected the fact that they have service territories in several states. Thus, the first two utilities' approaches suggest increasing capability, through GIS, to undertake geographical differentiation of costs, but the practice cannot be said to be in general use. Neither of these utilities differentiates tariffs geographically within a single service territory. As a footnote, several utilities mentioned use of GIS capability but this was used to keep track of, or inventory utility assets, not to set up geographical costing.

The case of PG&E is worth mentioning regarding pricing. Their geographic differentiation creates regional variation in its residential tariff blocks.[7] However, the price in the "nth" block is common to all regions. Regional costing, then, is expressed in pricing solely through block boundaries, as opposed to prices. Additionally, their Small General Service (A-1) tariff does not reference the ten geographical regions found in the residential tariff.

3.2.4 Allocators to rate class used in COS

(Question M) Respondents reported using customized versions of two general approaches to allocating distribution costs. The first involves allocating all costs by some form of demand allocator. The second begins with a demand- and customer-related split, and then uses some form of demand allocator for demand cost and customer allocator for customer cost. Under both systems, the use of coincident peak (CP) and non-coincident peak (NCP) allocators for demand cost vary in usage for primary only and secondary.

Four respondents reported splitting costs between demand- and customer-related categories, three via the minimum system method and one using the zero intercept

[7] PG&E's E-1 Residential tariff charges for generation and distribution with a multi-block tariff, where the blocks are a function of the customer's baseline usage, which is a function of season and geography. Ten geographic regions are identified in the tariff.

approach. For customer-related costs, number of customers was the standard allocator, although one used number of "services" (accounts).

Regarding demand allocators, just five utilities report using CP. This allocator is applied to primary service generally, and substations. NCP is used in some form by all respondents except one. Eight use NCP, computed on a class total basis, for at least some primary facilities. Two utilities report using hybrid allocators. One survey respondent uses a combination of NCP computed on a class basis with NCP computed as the sum of individual customers for secondary lines and transformer costs. Another respondent uses a combination of CP and sum-of-the-customers NCP for these two types of costs as well.

Two utilities provide examples of exceptions to the variety of arrangements described above. One respondent first divides its costs into "system" and "local" costs and then applies a CP allocator to system costs and a sum-of-the-customers NCP allocator to local costs. This produces a 50:50 system/local split at the primary level and, presumably results in all secondary costs being subject to the NCP allocator. (It also results in subtransmission costs being allocated on an 80:20 system/local basis, so that some of these costs are allocated via NCP as well.)[8]

The other exception is truly different from all others in the survey. A single respondent uses marginal distribution capacity cost and marginal customer cost (and no embedded cost) to allocate distribution costs in each of its distribution planning areas.

ComEd's recent rate case and rate design investigation proceedings focused to some degree on the treatment of primary lines and substations. The Commission determined that a CP allocator was appropriate for these components of the system. Several utilities in our survey use this same approach. Three survey respondents using conventional cost allocation apply this method, as does the utility that applies system vs. local splitting, but for its "system" assets alone. However, the use of NCP allocators is clearly accepted by the industry as well. Three utilities use a mix of CP and NCP allocators, and several utilities use NCP exclusively.

Table 5, below, summarizes cost allocation practices by voltage. The left-hand panel indicates that nine respondents report some use of customer allocators. In four cases, these allocators are applied in specific accounts. In five cases one or more accounts are split using either the minimum size method or the zero intercept method.[9] As noted above, one utility uses marginal capacity and customer costs.

The right-hand panel summarizes the use of demand allocators. Five utilities use the simple approach of a single NCP allocator for all demand-related costs. Three use the class NCP approach and two use the "sum of the customers" NCP. The bottom half of the panel shows how respondents apply allocators at various levels. The familiar tendency to use CP allocators for higher voltage and NCP for lower voltage is evident.

[8] Subtransmission voltage is loosely defined as the part of a transmission system that runs at low voltages but at voltages typically found at distribution level. This voltage level is typically included in the transmission function for cost-of-service purposes.

[9] NARUC describes these two methods and their application to FERC accounts 364-369 in its *Electric Utility Cost Allocation Manual*, January 1992, pp. 90-95.

Cost allocation practices, then, are varied. The survey documented an array of practices that adhere to the well-known tenets of cost causation in distribution. This suggests that ComEd's practices are well within the range displayed by the industry.

Table 5
Summary of Cost Allocation Methodologies

Customer-Related		**Demand-Related**			
	D/C split?		CP	NCP	
				Class	Sum
By Account	4	All Demand-Related		3	2
Account Splitting		By Account			
Minimum Size	3	Primary	3	4	
Zero Intercept	1	Substations	4	1	
Marginal Cost	1	Secondary		2	3

3.2.5 Treatment of single-phase vs. three-phase service

(Questions F and G) Distinction between single-phase and three-phase service is not much of a costing issue for the survey respondents. For some respondents, the distinction does not appear in COS analysis, although implicitly all, or most three-phase service occurs at the primary level while all, or almost all single-phase service is at secondary. At the primary level, four respondents stated that they had three-phase service only, four stated that they had both types and three indicated that their utility didn't make the distinction. The remainder did not know the exact situation, an indicator that the distinction is not important in their case.

With relatively little information available on the splits at primary and secondary based on the number of phases, it is not surprising that most utilities do not distinguish in COS analysis between single-phase and three-phase, other than the implicit distinction inherent in voltage. With single-phase and three-phase costs bundled by voltage, the share of three-phase service at secondary, for example, is generally not known.

3.2.6 Direct assignment of customer-specific standard cost

(Question H) Survey respondents were asked about the degree to which they used the actual equipment serving a customer in developing COS, as opposed to just average cost. Some respondents indicated that they utilize direct assignment to specific customers of the actual costs incurred for certain specific equipment such as dedicated substations. Alternatively, when the allocation of common equipment is performed, utilities tend to use average cost of equipment. This average cost of equipment would be based upon all equipment found at all the various voltage levels within a given voltage. For example, consider a utility having three voltage levels of *primary lines*: 34.5 kV, 12 kV, and 4 kV. The utility averages the costs of all these various primary lines for allocation purposes without distinguishing between which specific lines are actually delivering electricity to specific customers. For all survey respondents, there is no segmentation of primary voltage costs by voltage level within the primary voltage classification.

Regarding the issue of broad use of direct assignment, one utility offered street lighting as being directly assigned, but that is as close as any respondent came to direct assignment to large groups of customers. Treatment of specific and directly associated cost to known customers is close in theme to the topic of non-standard equipment, discussed immediately below.

3.2.7 Customer-specific charges for non-standard equipment

(Questions I and L) Survey respondents were asked about the degree to which customers can choose their level of service. The utilities indicated varying degrees of flexibility in this regard. However, respondents' answers, in whatever manner expressed, appeared to mean that customers could request a level of service that differs from what they would normally receive, and this request would be granted provided that the customer paid the incremental amount of the upgrade.

This perspective is confirmed by a related question regarding payment for non-standard services, the answers to which indicate that utilities are prepared for upgrade requests. Customers are generally expected to pay the full cost of the incremental cost of the upgrade. Payment is predominantly in the form of a facilities charge or fee, paid at the time of installation. Two utilities explicitly make provision for a monthly fee or carrying charge, while another offers an "accommodation bill rate" (a bill premium).

Utility treatment of the revenues and the extra costs associated with these upgrades varies widely in terms of the degree to which revenues and costs are allocated to classes. To some extent, the issue is not considered very important, as the amounts involved are small, justifying nonspecific treatment. Several respondents were not sure how costs or revenues were handled. Several, but not all utilities recognize revenues as contributions in aid of construction. One utility allocates revenues to its miscellaneous revenues account. Another treats revenues as a cost offset, but it is not clear whether the offset is made to a specific class.

Only one survey respondent stated that revenues were assigned to the class of the paying customer. This specificity is not repeated on the cost side, though. A single utility achieves symmetry, socializing all revenues and costs.

Another comparison is worth making. One survey respondent requires that special transformers be paid for by customers, and the customer owns the transformer. (As a result, this utility has no special costs requiring treatment in COS.) In contrast, another utility charges a fee, retains ownership of the transformer, and records the asset at zero cost on its books.

The diversity of responses, and the common view that these revenues and costs are relatively insignificant, suggests that ComEd and the ICC have room for discretion, and can select an approach that is cost effective for accounting purposes, provided that the COS impact of its choices is small. However, it is recommended that wherever possible and practical in cost of service, revenue should follow cost and equate to it.

3.2.8 Treatment of poles

(Question J) Most respondents stated that they have "shared" poles, in which both primary and secondary lines are carried by the same pole. There is no uniform standard in use to resolve this costing issue. In some cases, the costs of the entire FERC account 364 – poles, towers and fixtures – is apportioned on the basis of cost shares in other accounts. In this approach, shared poles are not an issue because the split does not take account of actual data for that account. In most cases, some form of split based on a range of criteria is undertaken. Criteria include: length of high and low tension lines[10], information from GIS data on various pole characteristics, and pole height. Another respondent uses special studies based on the number of conductors to allocate shared pole costs. Sometimes the shared pole values can be identified and the method is applied to just these values. In other cases the splits are based on the total account value.

In one case the split is based on current expenditures on poles designed to support specific voltage levels. Still another utility bases its shares on survey work that directly observed types of poles and made apportionment based on field observation.

The diversity of approaches used by these utilities, and the discretion in formulating common-sense rules, suggests that there is no common practice against which ComEd can benchmark its own practices.

3.2.9 Degree of regulatory controversy

(Question O) Just three utilities reported primary/secondary split issues in recent memory with their regulator. One of these observed differences arose in a recent regulatory proceeding, with differing interpretations between the Public Service Commission ("PSC") and its Staff with respect to wires plant cost allocation. The PSC preferred an all-demand approach while the PSC Staff advocated a demand-customer split using the conventional statistical methods (minimum system or zero-intercept) but this difference of opinion does not bear on the primary/secondary voltage topic. Similarly, one other utility's commission favored peak-and-average allocators while the utility favored its current (NCP-based) cost allocation approach. Since peak-and-average shifts costs away from secondary (residential) customers, this has an indirect effect on the secondary/primary split.

No survey respondent reported any discrepancies between their practices and established NARUC standards. One utility reported that the use of CP demand allocators for some costs (substations and primary lines) at the distribution level was being considered by their regulator, a practice that would be somewhat at variance with industry methods. One respondent stated that he wasn't qualified to make that determination. All others affirmed that they were in compliance with NARUC practices.

It may be that NARUC standards are broad enough that utilities have sufficient discretion to select cost allocation methods by voltage that suit their practices. The NARUC Cost Allocation Manual does not dwell on voltage issues for distribution cost allocation,

[10] This utility defines "low tension" as service below 2 kV, and "high tension" as service between 2 kV and 69 kV. Transmission service is defined as operating at 69 kV. They equate low tension with secondary voltage and high tension with primary voltage.

focusing instead on the issue of compartmentalizing by cost causation: demand- vs. customer-related costs.[11]

On page 89, the manual states that "distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications". A subsequent table indicates that typical practice involves differentiation of distribution line-related costs into four groups – overhead primary, overhead secondary, underground primary and underground secondary – and, within each group, splitting costs into demand-related and customer-related components. However, the manual does not then prescribe methods for determining how such differentiation should occur.

4. Conclusions and Recommendations

This survey of distribution costing methods, focused on cost allocation into primary and secondary components, reveals that industry practices are variable across service territories, and yet within the range of proper COS practices identified by NARUC. Additionally, it appears that ComEd's costing practices are well within the range of those reported in the survey.

Specifically, CA Energy Consulting finds that almost all utilities conduct COS analysis that formally recognizes costs at separate primary and secondary distribution levels. None differentiated primary into different voltage levels of service within the primary function for COS purposes. Some, but not all, utilities classify costs at each voltage into customer-related and demand-related components, while others classify all costs as demand-related. Regardless of the classification approach, almost all utilities in the survey use well established methods in selecting allocators to spread embedded costs to customer classes and rates. (One exception uses marginal cost for cost allocation.) Again, ComEd's practices of using CP allocators at the primary voltage level and NCP allocators at the secondary voltage level are consistent with practices elsewhere.

The methods that the surveyed utilities use to develop the data that underpin allocators are not uniform. A particular issue in ComEd's 2010 rate case pertained to FERC Account 364, poles, towers and fixtures. With respect to the ways in which the surveyed utilities develop allocators for this account, a wide range of practices is evident. Some utilities apply cost shares from related accounts to total Account 364 costs. Others make use of pole count data, either from traditional company records of assets or from more contemporary GIS sources, surveys, and use engineering judgment to apportion/allocate total costs to the applicable voltages. Some, but not all, investigate "shared poles" with both primary and secondary lines attached and allocate costs associated with these poles based on a sharing rule of some sort.

Regarding the extent to which single-phase and three-phase service information is considered in preparing a COS study, most utilities assume that primary service is delivered via three-phase wiring while secondary service is provided by single-phase wiring. Most utilities do not appear to study the incidence of such wires at other than their assumed voltages to be able to say more than whether this occurs, and to confirm

[11] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992. Chapter 6 focuses on Distribution.

that the incidence of this practice is low. Costing to reflect wiring differences within voltage levels is typically not done. This does not imply that single-phase costs associated with primary service should be excluded from cost allocation to primary customers, especially if it is costly to disentangle such costs. No respondents report undertaking such efforts. For most, recognition of single-phase vs. three-phase service is not an issue.

The survey also investigates COS methods relating to direct assignment of costs for actual equipment and the treatment of requests for special service. These topics are linked to some degree. All respondents find ways to undertake direct assignment of costs, but on a limited basis in cost of service. It turns out that such assignment for customer billing often occurs when special requests for non-standard service are made. Survey respondents uniformly charged customers for the full costs of special arrangements. However, the accounting treatment of revenues and costs is not consistent and usually does not involve recognition at the class level in cost of service. The explanation for this treatment for this treatment is that the small amounts of money involved do not warrant detailed attention.

The survey also inquired into the incidence of geographic cost differentiation. While the ability to document the location of assets has grown considerably with the arrival of GIS systems, costing practice has not sought to take advantage of this information as yet. Just one utility in our survey develops cost information by distribution costing area and their methods do not involve the use of embedded cost.

Lastly, costing practices surrounding the demarcation of primary and secondary voltages does not appear to be generating regular methodological disputes in regulatory proceedings. All but two of the survey respondents reported virtually no contention in recent regulatory proceedings between their regulator and the utility on COS methodology in this area. Those who reported methodological issues did not suggest that the sources of difference of opinion were major, or likely to delay a rate case. As well, all respondents regarded their methods as within the bounds of industry practice as defined by the NARUC Cost Allocation manual.

Implications for work on this project. CA Energy Consulting, on behalf of ComEd, has three upcoming tasks required to complete its analysis of its costing methods in this proceeding. These are: 1) treatment of poles, weather-resistant wire and underground conduit, and the evidentiary requirements for its approach; 2) the handling of costs for its railroad customers (4 kV asset allocation); and 3) cost allocation as it pertains to its Extra Large Load customers.

Regarding research on poles, the survey reveals that utilities approach the data underpinning and cost allocation in a number of ways. The survey found that using cost shares from related accounts suffices in some jurisdictions, and there may be indications from other respondents as to how sampled data may be used. Regarding the issue of 4 kV asset allocation, it appears that utilities do not make a practice of splitting primary into two sub-levels, based either on a defined voltage level or on what types of customers are served by the primary line. The 4 kV level is a common lower bound for primary. However, this boundary may be moving upward for some utilities as old low voltage equipment is replaced with new higher voltage assets.

As for treatment of Extra Large Load customers, other utilities conduct costing by function and voltage. They perform load research which identifies the voltage at which customer groups (or possibly an entire rate class) are served and their resultant contribution to the allocators for these voltages. Allocators are then applied to the voltages' costs such that customers who are served at higher voltages are not allocated cost from lower voltages.

Appendix: Survey Document

UTILITY TELEPHONE SURVEY

Questions Re Cost Treatment of Distribution Service Levels
For Commonwealth Edison Project

By Christensen Associates Energy Consulting
July, 2011

A. In your cost of service (COS) studies, do you have separate service levels commonly called "Primary" and "Secondary"?

a. If the answer to A is no, is the distribution function allocated to rate groups or customer classes in aggregate or do you still split distribution somehow (such as by voltage levels) and then allocate to rate groups or customer classes? *Now, please proceed to Item L in this survey.*

b. If the answer to A is yes, *i.e.* you do separate service levels into Primary and Secondary, can you estimate the year when you first began separating into "Primary" and Secondary?

c. If the answer to A is yes, *i.e.* you do separate service levels into Primary and Secondary, do you remember whose idea it was to make that division between primary and secondary?

i. The utility?
ii. Customers?
iii. The Commission?
iv. Other interested parties?

B. Do you split distribution FERC accounts into primary and secondary?

a. If yes, how do you do so?

i. Established process or special analysis?
ii. Sampling circuits?
iii. Size of equipment?
iv. Long-standing tradition?
v. Other?

b. If you do not split distribution FERC accounts into primary and secondary, is the distribution function allocated to rate groups or customer classes in aggregate?

C. If you split into primary and secondary, what is your "working definition" of primary and secondary? *E.g. Primary is between 4 kV and 33 kV (inclusive), transmission and subtransmission are > 33 kV, and secondary is < 4 kV.*

D. If you split into primary and secondary, do you further subdivide primary into more than one voltage level of service for COS? *e.g.* 4 kV, 12 kV, and >12kV.

a. If yes, do you know accounting detail by size of equipment? If no, how do you split into these voltage service levels:

i. Established process or special analysis?
ii. Sampling?
iii. Size of equipment?
iv. Long-standing tradition?
v. Other?
vi. If you have a primary / secondary study, could you please provide it in electronic form?

E. Do you perform geographic cost segregation? If so, how?

F. Do you allocate the costs for single-phase circuits and three-phase circuits differently such that one class of customers is responsible for the costs of a major portion of such single-phase or three-phase circuits?

a. If yes, are these single-phase circuits and related equipment allocated only to secondary voltage customers?

b. If the secondary voltage customers are allocated the majority of the costs for single-phase circuits, are the three-phase circuits also allocated to the secondary voltage customers and in what manner?

G. For the primary voltage level of service, do you have circuits with single-phase load or just three-phase load?

a. If you have single-phase circuits at primary, do you have:

i. **Single-phase primary customers** being served from these **single-phase primary circuits**,
ii. **Three-phase customers** being served from these **single-phase primary circuits** with appropriate necessary **equipment to enable three-phase service**, and/or
iii. **Single-phase secondary customers** served from these **single-phase primary circuits**?

b. For COS allocation purposes do you place the costs of these single-phase primary circuits as part of your primary voltage level of service or do you place these single-phase primary circuits into your secondary voltage level of service?

H. Do you consider actual equipment serving a rate group or simply consider the average cost of equipment necessary to serve a rate group for COS purposes?

a. If actual, does your accounting system keep this separate?

I. Is the decision of voltage level of service a customer choice or a utility choice?

J. In the primary system (or specific voltage level of service), do poles (FERC Account 364) sometimes support both primary and secondary lines?

a. If so, do you split this cost between primary and secondary, and, if so, how do you split it?

K. Do your tariff charges differentiate between primary and secondary voltage?

L. If applicable, how do you charge individual customers for non-standard service like requests for dual feeds, oversized transformers for interfering load, multiple points of service, etc. and how do you account in the COS for the cost of the equipment and the revenues collected for the non-standard service?

M. How do you allocate distribution costs (*i.e.*, primary distribution lines, transformers, secondary lines, service drops, and substations) to rate group or classes? Do you use a CP- or an NCP-based allocator?

   a. If you use an NCP allocator, is it based upon peak loads at the customer-class level, the individual customer level, or a combination of the two?

N. Is your most recent cost-of-service study available in pdf form?

O. Does the PUC or their staff have any issues with these approaches? Do you feel your approach matches NARUC standards? Why/why not?