PROVINCE OF ALBERTA

BEFORE THE ALBERTA ENERGY AND UTILITIES BOARD

ATCO Electric Ltd.	**)**	
2008 Distribution Tariff Application	**)**	**Application No. 1500878**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE ASSOCIATION OF MUNICIPAL DISTRICTS & COUNTIES

AND

THE ALBERTA FEDERATION OF REAS LTD

Resource Insight, Inc.

MAY 18, 2007

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honour society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Ontario Energy Board, Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Alberta Association of Municipal Districts & Counties ("AAMDC") and Alberta Federation of REAs Ltd ("AFREA").

Q: What is the purpose of your direct testimony?

A: My sponsors have asked me to evaluate the basis for the large increase in streetlighting revenue requirements that result from changes in direct assignment and cost allocations. To accomplish this task, I reviewed the analyses performed by ATCO Electric ("AE" or "the Company") and Foster Associates ("Foster") in response to Directions of the Board.

Q: Which of the Company's analyses does your testimony address?

A: I address the following analyses:

- direct assignments to streetlighting in response to Direction 11;
- the classification of all components of the distribution system, in particular overhead lines, in response to Direction 13;
- definition and calculation of streetlighting customer counts, in response to Direction 20;
- re-estimation of the customer weighting factors used in the cost-of-service study (COSS), in response to Direction 24.

Each of these studies was conducted by Foster Associates, apparently under the supervision of James J. Sarikas.

Q: What is the result of these analyses?

A: The Company's allocation of costs to streetlighting increases drastically from the 2004 COSS as shown in the revised Technical Session slides 13 and 14 dated March 16, 2007.

Q: What do you conclude from your evaluation?

A: The Company has not provided adequate documentation for its responses to the Board's Directions; as a result, the responses cannot be fully reviewed and therefore cannot be relied upon for setting rates. To the extent that I have been able to review portions of the studies by AE and Foster, those analyses are riddled with errors and overstate the costs of streetlighting. More specifically, the following list describes the problems with the response to each of these four directions:

- **Direction 11: direct assignments to streetlighting**: The direct-assignment analysis started with work orders that include equipment serving non-streetlighting loads, but neither AE nor Foster systematically identified or excluded investments that served non-streetlighting at the time of installation or today. Foster converts the work-order data to assignment factors by misinterpreting regression analyses that are largely undocumented and conceptually suspect, using incorrect and nonsensical data.
- **Direction 13: classification of non-assigned distribution costs**: Foster's treatment of some minimum equipment size as being customer-related is conceptually flawed and inconsistent with the considerations that determine the number of units and cost of distribution equipment. Foster also makes computational errors in this zero-intercept computations.
- **Direction 20: streetlighting customer counts**: Foster estimates a customer number for streetlighting that has no obvious relevance to the causation of any cost. The number of streetlight customers for customer-service purposes should be set at the number of entities requesting separate bills and retailer choice. Any distribution costs driven by the number of

streetlights are directly assigned, so the number of streetlighting customers for allocation of distribution costs should be set to zero.

- **Direction 24: customer weighting factors for transformers:** Foster's analysis is entirely hypothetical and unrelated to the actual distribution of customers served by various size transformers, or to the percentage of customers in each class who require an additional transformer. Streetlights are lumped together with the largest customers, resulting in a vast underestimate of the number of customers sharing a transformer with the typical streetlight.

Q: What are your recommendations to the Board on these issues?

A: I recommend that the Board should take the following steps:

- Reject AE's responses on all four of the issues discussed in this testimony;
- Not increase the share of revenue requirements borne by streetlighting in this proceeding;
- Direct AE to correct the errors discussed in this testimony;
- Direct AE to file corrected analyses addressing Directions 11, 13, 20 and 24, in its next rate application.

III. Direction 11: Direct Assignments to Streetlighting

Q: How substantial is AE's proposed direct assignment to streetlighting?

A: Even this information is not easily determined. AE does not even specify the total direct assignment in the explanation of its response to Direction 11. (Application, Section 4-Attachment 2, pp. 1-5). The parties to this proceeding have been told variously as follows:

- The total costs tabulated from the "streetlighting" work orders are $30M in Account Street Light 47-810 and $10.9M in non-streetlighting accounts (AAMDC/AFREA-ATCO-14(b)).
- Out of a total of $74.9 million of gross plant (including General Plant) that is allocated to streetlighting, $72.2 million was directly assigned, of which $66.9 million is non-rural and $4.5 million is rural. (PICA-ATCO-2(a), rbas43, " midyr_gross_PP&E").
- The assignable assets are $48.1M, $43.7M for non-rural and $4.5M for rural streetlighting (Mif3, "Assignable Assets")
- The plant capitalized to Street Light Account 47-810 is $46.4M, more than the total of all costs tabulated in the work-order study (March 9 2007 Technical Session, Slide 13, revised March 16 2007)

Without a clear statement of the amount of the direct assignment and how it was derived, the parties and the Board cannot separate the effects of changes in direct-assignment methodologies, allocation approaches and total distribution rate base.

Q: What is your understanding of the Company's direct-assignment method?

A: The documentation is inadequate and inconsistent. Most of the calculations have not been provided, despite our requests for the information. As best as I could determine, the data was derived from a detailed review of work orders dating back to 1950. It selected the 4,475 work orders that included at least some plant capitalized to Street Light Account 47-810 (AAMDC/AFREA-ATCO-8, Supplemental response, p. 1; Application, Section 4, Attachment 1, p. 3).[1] The

[1]The Company asserts, "ATCO Electric identified and analyzed all work orders where any capital was closed to streetlighting" (AAMDC/AFREA-ATCO-8 Attachment 1). This suggests that many of the work orders must have contained work for non-streetlighting customers, unless AE

Company summarized data from each work order, including plant by streetlighting (No. 47-810) and non-streetlighting account, number of existing and new poles by size, number of davits installed and other information useful for analysis of streetlighting costs (Application, Section 4, Attachment 2, pp. 2–3).

The Company provided the data summary, but not the individual work orders, to Foster Associates for further analysis. Foster performed some regressions, and perhaps some other analyses, and recommended that AE directly assign about 38 cents of non-streetlight plant to streetlighting for each dollar of actual streetlighting equipment (AAMDC/AFREA-ATCO-8, Attachment 1, p. 7). The Company claims to have used Foster's results to assign directly to streetlights much more than a dollar of non-lighting plant for each dollar of lighting plant.

Q: How did AE use the work orders and Foster's direct-assignment analysis in the cost-of-service study?

A: I do not know. The Company has not explained how the costs attributed to streetlighting in the Cost-of-Service Study were derived from AE's work-order analysis and Foster's direct-assignment analysis. In response to a request to "document the derivation of the overall direct assignment to streetlighting in the Cost of Service Study from the assignments by work order," AE refers only to the place in the cost-of-service study in which the final result appears as an input (AAMDC/AFREA-ATCO-12).

Also, AE has not demonstrated that the large contributions in aid of construction collected from customers were subtracted from the non-streetlighting plant assigned to streetlighting. In the work-order database, about

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was in the habit of issuing one work order to install poles, transformers, primary and secondary lines, and service drops, and a second work order just for streetlights on the same poles.

90% of Account 47-810 and 10% of the other accounts are covered by customer contributions.

A. The Work-Order Analysis

Q: In their direct-assignment methodology, how did AE and Foster treat work orders that include a mix of streetlighting and non-streetlighting investments?

A: The parties in this proceeding have been variously told as follows:

- One hundred percent of costs in the 4,475 work orders are directly assigned to streetlighting (Company statement on May 4, 2007 teleconference call);
- Only the portion of the non-Account 47-810 work order investments "that can be shown to be street light-related" are directly assigned to streetlighting (Application, Section 4, Attachment 2, pp. 3–4);
- The work order study "did not assign plant between streetlight and non-streetlight categories" (AAMDC/AFREA-ATCO-9(a));
- The work-order study did assign plant between streetlight and non-streetlight categories: The purpose of the study was to review "plant that was installed at the same time and in conjunction with streetlight plant…to determine if the plant (non-streetlight) should be directly assigned to the streetlight function" (AAMDC/AFREA-ATCO-9(a)).

In short, we do not even know whether the plant costs that serve a mix of customers are properly assigned between streetlighting and non-streetlighting categories.

Q: How did AE account for plant that originally served only streetlights but has subsequently been used to serve other customers?

A: It does not appear that AE identified such plant in the work-order study. Hence some unknown amount of plant now serving non-lighting load was included in the assignment to streetlights.

B. Foster Associates' Analysis

Q: What was the contribution of Foster Associates to the development of the direct assignment?

A: Foster was responsible for determining what portion of non-streetlighting costs should be assigned directly to streetlighting. It is not clear whether the analysis assigned the non-streetlighting investment included in the 4,475 work orders, a portion of secondary distribution backbone costs, or both. Foster recognized that the analysis should make the following two adjustments to the streetlighting assignment:

- A portion of the non-streetlighting plant that serves streetlighting is in the work orders and has been assigned to streetlighting,
- The work orders include plant that currently "supports" other rate classes, or "over time, may be used by other rate classes" (Application, Section 4, Attachment 2, pp. 3–4).

While AE does not explain how it increased the $30.1M of investment in Account 47-810 in the work orders to $72.2M directly assigned to streetlights in the cost-of-service study, the Foster assignment analysis appears to have been important.[2] The Company has not clearly explained the Foster assignment study and has not provided the study's data and calculations despite its huge role in

[2]The work orders included streetlighting plant that was since retired, but excluded streetlights added since 2003, so the other costs that AE assigned directly to streetlights may be more or less than $72.2 million.

the cost allocation. Until May 10, the only documentation that Foster Associates had provided to the parties, and apparently to the Company as well, were the six pages in the Application and the seven-page explanation in the response to AAMDC/AFREA-ATCO-8 Supplemental. On May 10, AE provided some of the data and a few calculations described in AAMDC/AFREA-ATCO-8.[3]

Q: How did Foster derive the direct assignments?

A: Despite multiple requests, AE has not provided a derivation of the direct assignments.[4] The assignment results, in some manner, from work-order data, regressions, and a 50% reduction in demand and customer allocators. [5]

The Company has offered general explanations of its regressions, such as that the "work orders were analyzed to determine a relationship between the number of lamps installed, the number and size of poles installed and the level of plant capitalized by account. The result of the review supported the determination that the primary reason for the installation of the poles was for streetlight function" (AAMDC/AFREA-ATCO-11(a)). In AAMDC/AFREA-ATCO-8, Foster indicates that it ran some regressions, and provides brief descriptions of those analyses, but leaves more questions than it resolves. Among other things, AE and Foster have not provided the following information:

- the data used in the regressions;

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[3]The Company has provided an Excel workbook that appears to have data from AE (some of which was redacted) on 4,472 work orders, as well as various computations and other additions from Foster.

[4]See, for example, AAMDC/AFREA-ATCO-5, and 8

[5]It is my understanding that the 50% reduction in the customer and demand allocators affects only the $2.7M of non-assigned plant. Foster intends to adjust for the use by other customers of the $72.2M of plant directly assigned to streetlighting. The adjusted allocators may also be used in deriving the direct assignment.

- adjustments to the data, including the price adjustments, and the basis for those adjustments;
- an account of how the regression analyses were used in the direct assignment;
- the numerical effect of the regression results on the direct assignment;
- whether and how the regression analyses were used in "further allocation of non-street light secondary distribution infrastructure costs" (Technical Session, Slide12, Revised March 16 2007);
- the total effect Foster's regression analyses had on the final streetlighting cost allocation.

In discovery, AAMDC/AFREA requested the following information that would have allowed the parties to understand and evaluate Foster's analysis:

- an electronic copy of all spreadsheets used in the preparation of the direct assignment of distribution plant and expenses to streetlighting, including all formulas, lookup tables, tables of functionalization, classification and allocation factors, and supporting calculations (AAMDC/AFREA-ATCO-5).
- an electronic copy of all spreadsheets used in the preparation of the partial allocation of distribution plant and expenses to streetlighting (AAMDC/AFREA-ATCO-5).
- the derivation of the direct assignment to streetlighting (AAMDC/AFREA-ATCO-5).
- the methodological rules and calculations for assignments of these investments between streetlighting and non-streetlighting (AAMDC/AFREA-ATCO-7).
- the data drawn from the work order on which the calculation relies.

- how the data for the calculation is derived from the work order (AAMDC/ AFREA-ATCO-7).
- how AE and the Foster analysis determine which non-streetlighting investments that are considered to "support" streetlighting (AAMDC/ AFREA-ATCO-8).
- the methodological rules and calculations for assignments of investments between streetlighting and general distribution plant (requested for different descriptions of the AE-Foster methodology in AAMDC/AFREA-ATCO-8; -9).
- the work-order-derived data on which the calculation relies (AAMDC/ AFREA-ATCO-9).
- other data used in the assignment and the source of that data (AAMDC/ AFREA-ATCO-9).
- the methodological rules for determining whether underground service lines and conduits serve as the foundation for davits, and the methodological rules and calculations for the assignment of this investment to streetlighting (AAMDC/AFREA-ATCO-10).
- how AE determined from work orders which wooden poles were built to serve streetlighting only, and the methodological rules and calculations for the assignment of this investment to streetlighting (AAMDC/AFREA-ATCO-11).

Until May 10, none of the information requested had been provided. The Company had not even provided a copy of the data it provided to Foster.[6]

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[6]In addition, Foster's explanations are often incomprehensible, or so vague as to be subject to widely varying interpretation.

In addition to all of the problems listed above, The Company has still not provided *any* documentation for the following analyses Foster claims to have performed and relied upon (Attachment 1, p. 5):

- "The pole work identified several work orders which were excluded from the study due to a [de] minimus streetlighting investment coupled with a major (e.g., greater than 5%) total non-streetlighting investment."
- "Several work orders where no new lamps were installed but seemed to represent a shifting of existing facilities associated with the widening of roads."[7]
- "A sample of work orders [for which] Foster requested ATCO Electric to perform a detailed analysis of facilities installed. Foster reviewed the analysis and used it to confirm both ATCO Electric's and Foster's assumptions."

Q: Does AE appear to understand what Foster did on its behalf?

A: No. In our telephone conversation of May 4, the AE staff claimed not to have received any documentation of the Foster study other than what few pages were provided in the Application. Hence, Foster had not even given AE the documentation that the Company would need to evaluate the analysis.

Q: What questions about the data used in the regressions were not answered in the Application or in responses to discovery?

A: The Company and Foster did not provide, for example, the following information:

- Which of the sixty-some data categories (Foster Report, pp. 2–3) were regressed against what other data. In AAMDC/AFREA-ATCO-8

[7] It is not clear what Foster intended to do with these costs.

Supplemental, AE provides three graphs, two of which (pp. 4 and 5) have identical labels ("Investment in Conductors vs. Number New Poles Non-Rural") but show different data.[8] Foster suggests that it performed additional regressions, and the ten assignment factors it recommends would require additional analyses, but no documentation of those have been provided.

- Which regressions were performed for rural installations, which for non-rural installations, and which for both.
- Whether the data used for the regression of conductor investment against the number of poles consist of (a) all poles and conductors on the system, (b) just the equipment in the 4,475 work orders, or (c) a subset of those work orders.[9]
- Whether Foster used 4,475 data points (one for each work order) or whether Foster aggregated the work orders by year. The small number of data points shown on the graph seems to suggest that Foster aggregated the data by year, which would result in the loss of about 99% of the data.[10]

Q: Has Foster explained how the regression analyses were used in "further allocation of non–street-light secondary distribution infrastructure costs."

[8]On May 10, less than a week before the due date of this evidence, AE finally provided us with some of Foster's work papers, which includes the figure on p. 5 of Attachment 1 labelled "Rural." As I discuss below, these two graphs represent neither investment in conductors nor the number of new poles.

[9]The file received May 10 suggests that at least a few of the regressions were performed for subsets of the work-order data. Foster provided only one of the three regressions it reported in AAMDC/AFREA-ATCO-8 Attachment 1.

[10]That conclusion was reinforced by worksheets provided on May 10.

A: Not in the Report. In AAMDC/AFREA-ATCO-8, Attachment 1, Foster introduces an entirely new step in its computations:

> The non-streetlight plant, by account, was compared with the streetlight plant to determine the average level of streetlight related plant investment in each non-street light account over the last ten years that occurs from each dollar of investment in the streetlight account. (P. 7)

Foster then lists the adders it applies to streetlighting, for five accounts, with different values for non-rural and rural lighting. For each dollar of street-light investment over "the last ten years," Foster claims to have found 38.2¢ of non-streetlight investment for non-rural lights and 36.1¢ for rural lights. Foster says, "These percentages…were multiplied by rural and non-rural streetlighting investment (Account 47-810) to calculate forecasted additions. These additions were directly assigned to the streetlighting function" (p. 7).

This discovery response was the first time that Foster mentioned the use of a ten-year period for a portion of the direct-assignment analysis. Neither the Company nor Foster has explained why, if the work orders included all the streetlighting investments from 1950 through 2002, Foster needed to use selected data for ten years and extrapolate to the entire streetlighting investment.[11] Consistent with its practice in other parts of the streetlighting assignment, AE has not provided a single computation regarding that important step in the analysis.

Q: Given the limited information available from Foster, can you form any opinion regarding the use of the regressions?

A: Yes, to a limited extent. It appears that Foster

[11]This step may account for how Foster and AE managed to inflate $10 million (in 2002 dollars) in non-streetlighting plant in work orders with streetlights, into about $40 million in mixed nominal dollars.

- set up the analysis in a manner that would be likely to produce spurious correlations,
- clearly used the wrong and meaningless data, and
- may have misinterpreted the results of the regressions.

Q: What was wrong with the structure of Foster's regression analysis?

A: While no one other than Foster knows all the regressions that Foster performed, we do have two examples: underground service investment as a function of the number of davits, and conductor investment as a function of the number of new poles.[12] In neither case has Foster revealed what the data comprise (all the work orders, a selection of work orders, total work orders for a year, or total annual book investment). I assume for this discussion that each data point is a work order, but the critique would be the same for any of the data sources.

Foster finds that years with more davits have greater investment in underground services. That is not surprising, since davits are used with lights served from underground distribution. In any underground distribution project, the services will be underground, whether they are services for a house, a store, a traffic light, or a streetlight.[13] A year with underground projects serving many houses (as in a large residential development) or many stores (as in a major redevelopment of a town center) and hence including many services, is also

[12]Foster provides two graphs labelled identically (as conductor investment as a function of the number of new poles, non-rural), with different data and data ranges. The text suggests that one of the regressions was intended to estimate conductor investment as a function of the number of "site/lamps" (whatever a site/lamp might be), but the graph matches results in the May 10 file for rural conductor investment as a function of the number of new poles.

[13]Overhead-served streetlights are generally served directly from the secondary lines, but some underground-served streetlights may be far enough from the secondary lines to require a service drop.

likely to include many streetlights, and hence require many davits. A year with few davits will have few new underground-served streetlights, and thus likely serve little additional areas with underground distribution and few new buildings with few services. Hence, the number of davits in a work order is likely to be correlated with the investment in services, even were none of the services actually serving the streetlights.

Similarly, Foster's conclusion that the years with more poles have more conductors would be true regardless of whether the poles or conductors are required for streetlights or some other customer type. Conductors run between poles; years in which many poles were added would require lots of conductor to span them. This correlation would not tell Foster anything useful about how streetlights cause the installation of conductors (even had Foster not made so many errors in the regressions).

Foster's correlations here may be entirely spurious, just as would the likely correlation of the number of burglaries in a city and the number of cars registered in the city. Both burglaries and cars rise with the size of the city; neither causes the other.

Q: Where did Foster use wrong and meaningless data?

A: In the two pole regressions described in Attachment 1, Foster claims to regress conductor investment on the number of new poles. In the May 10 file, the graphs provided in Attachment 1 are derived from regressions of inflation-adjusted annual values labelled "Sum of TotalSites" as a function of the sum of values labelled "Sum of Existing pole" and "Sum of TotalPoles." From other sheets in the May 10 file, it appears "Sum of TotalSites" has nothing to do with the sites identification numbers in the work-order database, and is simply the sum of "Sum of Existing pole" and "Sum of TotalPoles." The "Sum of Existing pole" value appears to be the total number of existing poles used in any way in the work orders for that year, and "Sum of TotalPoles" appears to be the total number of new poles added in the work orders for that year. In other words, Foster regressed the number of poles used in the work orders, times an inflation factor, against the number of poles. Neither the conductor investment nor the number of new poles was an input to this regression.

Q: Did Foster really regress the number of poles times an inflation factor against the number of poles, and claim the result was a regression of conductor investment versus new poles?

A: Yes.[14]

Q: Is there any possible justification for applying an inflation adjustment to the number of poles, or for performing the regression Foster performed?

A: No. Foster probably intended to perform completely different regressions.

Q: How may Foster have misinterpreted the results of the regressions?

A: In AAMDC/AFREA-ATCO-8, Attachment 1, Foster claims that regressing

> the price-level adjusted underground services and conduit investments in relation to the number of davits installed by year…. explained over 75% of underground services and conduit investments were related to the streetlighting function. (P. 3)

and that regressing

> price-level adjusted conductors…[against] the number of new poles and davits installed, as well as between price-level adjusted conductors and the number of site/lamps. These models seemed to explain that about 55–70% of conductor investment was related to the streetlighting function. (P. 4)

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[14]Foster did not even get the inflation adjustment right. The inflator Foster applied for 1950 was the inflator Foster computed for 2001. For rural investment, the inflators used for 1962–2002 were computed for five years earlier, and the inflators for 1954–60 were off by one to four years.

Foster did not provide any explanation of how it derived the percentages of plant that it assigned to streetlights. The appropriate approach would be to use the regression analyses (were those were performed properly, and without spurious correlations) to estimate the streetlight-related non-streetlight costs, and divide that estimate by the total streetlight investment. There is no evidence that Foster did anything of the sort.

It may be coincidental, but the regression that Foster provided for underground services had an R^2 of 0.7437, very close to Foster's claimed 75% of underground services and conduit attributable to streetlights.[15] Foster reported that the two regressions it thought were for conductors had R^2 values of 0.5658 and 0.7119, which would round off to the 55%–70% of conductor investment Foster claimed was related to streetlighting.[16] Hence, it appears that Foster may have confused the R^2, a measure of goodness of fit, with the portion of the other investments that would be explained by the coefficients of the regression equations.

Q: What additional steps would Foster have needed to convert regressions of the sort it reports in AAMDC/AFREA-ATCO-8, Attachment 1, pp. 3–5 to the assignment factors on page 7 of Attachment 1?

A: The description provided so far is missing at least three steps. First, Foster would have needed to perform the remainder of the regressions (or whatever other statistical analyses Foster refers to on page 3 of Attachment 1) for 1950–2002. At page 7 of Attachment 1, Foster provides ten ratios of various accounts to Account 48-710, for either rural or non-rural plant. Foster has only provided

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[15]Perhaps Foster had another regression for conduit with an R^2 slightly over 0.75.

[16]The workbook provided on May 10 included the graphs that Foster used on pages 4 and 5 of AAMDC/AFREA-ATCO-8, Attachment 1, but not the actual regression results.

three regressions, and one of those ("Investment in UG Services ($2002) vs. Number of Davits") does not differentiate between rural and non-rural areas.[17] Hence, eight additional regressions would be needed to do what Foster claims it did.

Second, all three of the regressions Foster has provided attempted to compare dollars of some category of non-lighting plant to physical units of lighting equipment (davits) or general distribution equipment (poles). In order to get to the assignment factors on page 7 of Attachment 1, which are in dollars on non-lighting plant per dollar of lighting plant. Foster would need another set of analyses to determine how dollars of each category of non-lighting plant vary with dollars of lighting plant.

Third, Foster claims to have done some analyses of costs over the past ten years, in some way modifying or supplementing the longer-term analyses. (Attachment 1, p. 7) Given the emphasis in the Application on the use of all the streetlighting work orders since 1950, it would be strange if Foster were to rely entirely on post-1992 data.

Foster has not documented any of these steps.

Q: Did Foster claim to do any other analyses to support its regressions?

A: Yes. Foster claims that

> an analysis of the number of poles installed in comparison to the number of site/lamps was undertaken. The pole work was done on a work order by work order basis to ensure consistency. A tight relationship of one pole per site/lamp was found. This analysis insured no statistical outliers existed to counter-balance each other. (AAMDC/AFREEA-ATCO-8, Attachment 1, p. 5)

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[17] The other two regressions, as described above, are nonsense.

While it is not clear what a site/lamp might be, the spreadsheet the Company provided on May 10 shows a total of 30,480 new lamps and 16,103 conversions, but only 6,427 new poles installed. Hence, no "tight relationship of one pole per site/lamp" could have been "found."

Q: Are the magnitudes of the assignment factors on p. 7 of Attachment 1 consistent with the data AE has provided?

A: No. Each assignment factor cannot be greater than the ratio in the work-order database of investment in the non-streetlighting account to streetlight investment. Foster seems to recognize the following costs in the work order database should not be treated as related to streetlights:

- portions of the conductors, conduit and underground services identified in the regression analyses (AAMDC/AFREA-ATCO-8, Attachment 1, pp. 3–5).
- several work orders with "a [de] minimus streetlighting investment coupled with a major non-streetlighting investment" (p. 5).
- "several work orders where no new lamps were installed but seemed to represent a shifting of existing facilities associated with the widening of roads" (p. 5).

Hence, the assignment ratios should be somewhat lower than the ratios in the database.

Yet the assignment ratios are *higher* than the investment ratios in the database. The following table compares the assignment factor for each account, averaged over non-rural and rural factors, to the database investment ratio, unadjusted and adjusted for the non-streetlight portions of conductor, conduit and services Foster reports from its regressions.[18]

Account	Foster Ratio	Database Ratio	
		All	*Modified*
Poles 47300	7.9%	7.5%	
Conductor 47400	4.6%	3.7%	2.0%–2.6%
Conduit 47500	16.3%	9.5%	7.1%
U/G Services 47510	6.0%	10.6%	8.0%
Line X'mers 47900	3.4%	2.3%	
Total	38.1%	33.6%	26.9%–27.4%

Only the underground service ratio could conceivably be correct. The Foster ratios for the other accounts range from 5% to 71% above the unadjusted ratios from the database and are more than double the adjusted rations for conductor and conduit. In other words, Foster somehow concludes that more than 100% of the non-streetlight costs in the database are due to the streetlights.

C. Reducing Streetlight Allocators to Reflect Assigned Plant

Q: How did AE adjust the amount of non-streetlight plant allocated to streetlighting, to recognize the fact that a large amount of secondary plant was directly assigned to this class?

A: In the Application, Foster states:

> Using professional judgment and the work order analysis, Foster Associates recommends street lighting billing determinants used to allocate secondary distribution system investments (e.g., non-Account 47-810) to street lighting be reduced by 50%. (Application, Section 4, Attachment 2, p. 4)

[18] I weighted the rural and non-rural assignment factors using the non-rural percentage (94.5%) of streetlight investment in the work orders whose location is identified. More than 20% of the streetlight investment in the work-order database is not identified in the "Rural/Non-rural" column.

> The non-street lighting investments do not suffice to totally displace the need for an allocation of secondary distribution costs to street lighting. (P. 5)

Foster expanded on its approach in discovery, where it said that this

> issue was more difficult to analyze. If such non-streetlighting directly assigned assets were found to be a complete substitute for the secondary distribution system (i.e., thus attaching to the primary distribution system), then such plant assets would not require the use of the secondary distribution system and no secondary distribution system costs should be apportioned to the streetlighting function.
>
> To answer this complex question, an analysis was performed for each plant account or asset. The following rationale was applied to each of the 4,475 work orders. If any non-streetlight work order, not included within Account 47-810, *contained a job which was not a complete substitute for the secondary distribution system*, then that non-streetlight plant, represented in that work order, would, by necessity, have to use a portion of the secondary distribution system and could not be a substitute for the secondary distribution system. Following this reasoning, some level of secondary distribution system costs would need to be allocated to streetlight Rate 61 customers. (AAMDC/AFREA-ATCO-8, Attachment 1, p. 6, emphasis in original)

Q: Does this description seem reasonable?

A: For the most part. The one problematic point in the description is the focus on the work order containing *a complete substitute for the secondary distribution system.* Any equipment that substitutes for any part of the secondary distribution system should be credited to the streetlighting class, whether or not the work order contains the entire secondary system. From this description, it is not clear whether Foster intended to count (properly) all plant that substitutes for any part of the secondary distribution system, or (improperly) only plant in work orders that included all the secondary equipment that the streetlights required.

Q: Did Foster's subsequent discussion of its method clarify this point?

A: No. The discussion on pages 6–7 of AAMDC/AFREA-ATCO-8, Attachment 1, regarding the rationale for determining which secondary costs are redundant with direct-assigned transformers, poles and lines is largely incomprehensible, and frequently incorrect. For example, Foster states as follows:

- "Only a minority of the work orders contained an investment in line transformers greater than $100. We termed this level of investment 'significant' meaning the investment was not de minimus and was at least $100." Foster's statement that investments "greater than $100" are "at least $100" is certainly true, but not very helpful in computing the portion of streetlighting that is served by direct-assigned transformers.
- Direct-assigned "line transformers comprise non-streetlight plant and could not be a substitute for the secondary distribution system," when clearly they could substitute for allocated transformers.
- "If the streetlights…with no new poles and…those only with davits were directly attached to the primary distribution system, then these streetlights would not utilize the secondary distribution system and thus could not be a substitute for the secondary distribution system." Again, Foster's assertion is false; if the streetlights do not use secondary distribution, the direct-assigned plant has replaced the general secondary system.
- "Streetlights…with new poles would utilize some level of secondary distribution pole system costs and would need to be allocated to streetlight Rate D61 customers." Of course, the streetlights would be allocated to Rate D61. However, if the new poles serve other classes, or the new pole has a transformer on it, or is adjacent to the pole with the transformer, not other secondary poles would be used by the streetlights and no pole costs would need to be allocated for those streetlights.

- “The analysis of lines was consistent with the apportionment of secondary distribution system costs for poles. This meant that some level of secondary distribution system costs for wires would need to be allocated to streetlight Rate D61 customers.” It is not clear what Foster means by “consistent with.” Perhaps Foster believes that streetlights with new poles should be allocated line costs, or that streetlights with new lines should be allocated line costs. Or something else.

Q: Has Foster provided any other detail on its determination of the share of streetlighting that can be served by the direct-assigned plant?

A: In the Application, Foster provides some information about its approach for line transformers.

> The ratio of total wattage of street lamps fed by the secondary distribution system’s line transformers (e.g., where such line transformer investment was significant) to the total wattage of all street lamps was calculated. The result showed approximately one-third of street light wattage was identified and corresponds to work orders showing significant line transformer investment. Thus, one-third of line transformer-supported street lamp investment did not require any additional allocation of secondary distribution system investment. (Section 4, Attachment 2, p. 4)

Foster does not provide its computation of the one-third values. Nor does Foster provide any comparable explanation for other accounts (conductor, conduit, services, poles).

Q: Did AE provide any work papers or computations showing how Foster progressed from the discussion you summarized above to the 50% reduction in streetlight allocators?

A: No.

D. Plant Assigned to Streetlighting that Also Serves Other Classes

Q: Does Foster acknowledge that the non-streetlight plant it assigns to streetlighting also serves other customers?

A: Yes. Foster makes that point very clearly:

> Foster recognizes this direct assignment includes some distribution investments that, overtime, may be used by other rate classes…. The analysis of total street lighting-related work orders provided evidence that plant investment in street lighting also serviced other secondary distribution system functions. For example, a certain level of line transformer investment was directly assigned to street lighting. Additionally, both poles and conductors used in street lights also may be used for other non-street lighting secondary distribution system functions. (Application, Section 4, Attachment 2, p. 4)

> A review of a sample of work orders showed the related secondary distribution system investment contained capacity investments that could be used to serve other rate classes. (P. 5)

Q: How did Foster reduce the assignments of non-streetlighting plant to streetlighting customers, to reflect the use of that plant to serve other classes?

A: Foster asserts that "an adjustment made prior to the allocation of related secondary distribution system investments to street lighting corrects for this and will be explained below" (Application, Section 4, Attachment 2, p. 4). I cannot find any such adjustment in the Application. The only adjustment following the promise quoted above turns out to be Foster's recommendation that the streetlighting allocators be reduced 50% to reflect the fact that assigned plant reduces the streetlights' need for allocated plant, as discussed in the previous section of this testimony.

Q: Could the 50% reduction in the streetlight allocators include a credit for the non-streetlight plant that AE assigns to streetlighting but also serves other customers?

A: No, for two reasons. First, the reduction in streetlight allocators is entirely the wrong type of computation to reflect this credit. Reducing the streetlight allocators to reflect the first consideration (the fact that assigned plant substitutes for allocated plant) would properly vary the adjustment in proportion to the amount of plant that would otherwise be allocated to streetlighting. But for this second consideration—the adjustment for streetlight-assigned plant that serves other classes—adjusting the streetlight allocators makes no sense. Foster recognizes that some assigned plant serves other customer classes but fails to follow through by reducing the plant assigned to streetlights. This second adjustment would properly vary with the amount of plant that would otherwise be assigned to streetlighting.

Second, the allocated plant is probably too small to reflect the amount of streetlight-assigned plant that serves other classes. Depending on which of the Company's data one starts with, at least $20 million (and perhaps as much as $40 million) in non-streetlighting plant is assigned to streetlighting. In contrast, only about $2.7 million in non-streetlighting plant is allocated to streetlighting (PICA-ATCO-2(a)). If as little as 14% of the non-lighting plant assigned to streetlighting serves other classes, even reducing the lighting allocators to zero could not capture that effect.

Q: Are there other peculiar results in the direct assignments or allocations to streetlighting?

A: Yes. One example would be Foster's attribution of $4.2 million of service drops to streetlighting in the current cost-of-service study (Schedule 4-Bs, p. 22). I say "attribution" because I cannot tell whether these costs are assigned or allocated. $3.2 million of service drops, of which Foster concludes only 75%, or $2.4 million, are assignable to streetlights.

Q: What is your recommendation to the Board regarding the direct assignments to streetlighting?

A: Directly assigning costs is desirable, where it is possible to identify the costs that are incurred for only one rate class and are dedicated to that rate class, and the assignment is not duplicative of allocations of plant used by multiple classes. When investments serve a mix of customers, they should be allocated, not assigned.

The Board cannot rely on the Foster study for direct assignment of distribution plant to streetlighting. The Company and Foster Associates have not been able to document most of the analyses, some of the few computations Foster provided are incorrect and nonsensical, Foster's explanations and reasoning are frequently incomprehensible, and Foster's recommended assignments require that more than 100% of the distribution plant in its database be directly assigned to streetlighting.

IV. Direction 13: Classification of Non-Assigned Distribution Costs

Q: What is the Foster study's approach to deriving distribution plant classification factors?

A: In Foster Associates' view, customer-related costs and demand-related costs are separable:

> In classifying the distribution function, the demand and customer relatedness split is based on the two distinct purposes of the distribution system. The first is to attach customers to the system and, from a cost of service perspective, such costs clearly are customer-related. The second purpose is to meet existing customers' demands beyond their minimum load. These costs clearly are demand-related. (Foster, p. 8)

In other words, Foster conceptualizes the division in cost causation between load and customer number by rules that amount to:

- The number of units (feet of line, number of meters) is due to the number of customers.
- The size of units is due to the load.

Q: Are these rules based on a realistic view of an electric distribution system?

A: No. This view is overly simplistic, for three reasons. First, much of the cost of a distribution system is required to cover an area, and is not really sensitive to either load or customer number. For example, serving many customers in one multi-family building is no more expensive than serving one commercial customer of the same size, other than metering. Extensions to span areas should not be allocated to streetlighting. Adding lights to an existing system will not add much more to the costs of the system other than the sum of the Streetlight Account and dedicated streetlighting expenditures.

The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or disbursed residential customers.[19]

Second, load levels help determine the number of units, as well as their size. As load grows, utilities add distribution feeders and transformers in parallel with existing equipment, such as adding a transformer to serve one end of a

[19]See Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, VA: Public Utilities Reports, 1988., p. 491.

block, as load grows beyond the capability of the transformer originally serving the block. Indeed, large customers may be served by multiple transformers to increase reliability.

In general, more small electric customers than large customers can be served from one transformer. Higher loads require larger service drops and secondary wires, so more transformers are added to reduce the length of the wires. This multiplication of transformer number is expensive because (1) transformers show large economies of scale in dollars of investment per kVA of capacity, and (2) dispersed transformers have lower diversity than transformers serving many customers, increasing the total installed kVA required to meet customer load.

Third, load can determine the type of equipment installed, in addition to size and number. Electric distribution systems are often relocated from overhead to more expensive underground because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, increasing the costs of equipment (e.g., insulation requirements for transformers and lines).

Q: Will these minimum-system approaches produce a reasonable classification of costs?

A: No. As Bonbright, Danielsen & Kamerschen explain, these approaches attempt to classify costs that are fundamentally "unassignable":

> the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible….[cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground…. (Pp. 491–492)

Small customers are especially burdened when a high percentage of costs are assumed to be customer-related; allocations should not rely on these flawed methods.

Q: How is the cost of the minimum distribution system generally derived?

A: The most common methods used are:

- The Minimum-System Method,
- The Zero-Intercept Method.

Foster uses both approaches and averages their results

Q: Please describe the Minimum-System Method.

A: A minimum-system analysis attempts to calculate the cost (in constant dollars) of the utility's installed units (transformers, poles, conductor-feet, etc.), were each of them the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks, How much would it have cost to install the same number of units (poles, conductor-feet, transformers), but with the size of the units installed limited to the current minimum unit normally installed? This cost will be customer-related, and the remaining cost will be demand-related.[20]

The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

Q: Please describe the Zero-Intercept Method.

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[20]The customer-related portion (which is computed in constant dollars) must be compared to the actual installed cost of the entire account (in mixed dollars); translating actual mixed dollars into constant dollars can be difficult, especially under conditions of technical change and different inflation rates for large and small installations (small installations are often more related to labour costs than are large ones, for example).

A: The Zero-Intercept Method attempts to extrapolate the cost of equipment below the size of the minimum system, to the cost of equipment that carries zero load, as in 0-kVA transformers, or the smallest units legally allowed (as 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The idea is that this procedure identifies the amount of equipment required to connect existing customers, even if they had virtually no load.

Q: Does the minimum-system method exclude all demand-related investment?

A: No, for the following reasons:

- The minimum system includes equipment that would carry a large portion of the average customer's load. Foster recognizes that the minimum system it classifies as "clearly customer-related" does carry load (Application, Section 4-Attachment 2, pp. 2-3). For example, on the AE system, its minimum-sized 10 kVA transformer is adequate to serve many street lights. Since the minimum system probably carries all of the streetlighting load, the $1 million of non-assigned demand-related plant allocated to streetlighting is double-counting (rbast43, "Mid-yr_GrossPP+E").
- The current minimum unit is sized to carry expected demand. Consequently, as demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less-expensive small equipment because rising demand has resulted in very rare use of the small equipment and the cost of maintaining stock was no longer warranted.
- Minimum-system analyses usually ignore the effect of loads on the number of units installed, or the type of equipment installed. Hence, a portion of the costs allocated to customer number is really driven by demand.

- Minimum systems analyses fundamentally assume that all area-spanning investment is caused by the number of customers. As described above, this is not true.

Q: How should the number of units installed be categorized as customer or demand-related?

A: A type of equipment (e.g., transformer, conductor, pole, service drop or meter) should be considered dedicated investment and therefore customer-related only if the removal of one customer eliminates the unit. The number of meters and services (although not the size) are customer-related, while transformers, conductors and poles should be largely demand-related, especially in non-rural areas. Reducing the number of customers, without reducing the demand in an area, will

- occasionally eliminate a transformer, for an isolated customer, whose transformer serves no other customers.
- sometimes eliminate a span of secondary conductor, if the customer is the furthest one from the transformer on that secondary.
- rarely eliminate a pole, if the customer is at the end of the primary line.

In many situations, additional transformers and conductors are added to increase capacity, rather than to reach an additional customer.

Q: Can the zero-intercept method be relied on to determine the customer-related portion of plant?

A: No. The determination of the number of units required for a zero-demand system are far from simple. A system designed to connect customers but provide zero load would look very different from the existing system. For example, a zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers, that the real system uses. Street lighting, with its very low loads, uses a single distribution voltage, which eliminates a large number of conductor-feet, reduces the required height of many poles, and eliminates the need for line transformers, implying that all line-transformer costs are demand-related.

The zero-intercept method is so abstract that it can be interpreted in many ways, and can produce a wide range of results. Any use of this method must be grounded in a firm understanding of the purpose and conceptual framework for defining a zero-intercept.

Q: Have you identified any calculational errors in Foster Associates' zero-intercept system analysis?

A: Yes. In its zero-intercept analysis of each of the three distribution components, Foster incorrectly calculated the customer-related portion as the ratio of the zero-intercept to the cost (derived from the regression line) of the average-sized unit. The zero-intercept should instead be compared to the actual system average cost per unit, a larger number. As a result, the Foster analysis overstates the percentage of plant that is customer-related.

Q: Would correction of this error be enough to make the minimum system analysis a reliable basis for classification?

A: No. For the reasons discussed, the methods used by Foster are fundamentally flawed.

V. Direction 20: Definition and Calculation of Street Lighting Customer Counts for Allocation

Q: How did AE determine the number of streetlighting customers for allocation?

A: The Company delegated this determination to Foster Associates. In the Application, Foster points out that streetlighting "customers are no longer the Utility's direct customers" and asserts that, as a result, it has no "accurate count of the number of street lighting customers" (Application, Section 4, Attachment 2, p. 59).

I find it surprising that AE cannot determine the number of streetlighting customers it serves, since AE would need to know, for each light, who to contact if that light needs to be relocated for distribution-system work; who has authorization to add, remove or convert lights; and who is authorized to request information on streetlight counts for particular customers.[21]

The fact that AE does not know the number of streetlighting customers it serves strongly suggests that the number of streetlighting customers on AE's system does not impose any costs on AE, and should be set to zero for cost-allocation purposes.

Q: How many streetlighting customers does Foster estimate AE serves?

A: Foster claims that there are 1,046 "unique accounts," although these do not seem to be separate accounts that AE uses for any purpose. In Foster's view, a unique account is characterized by any "locational names representing the municipality's subcategories (i.e., school districts and departments of park and recreation) where such locations would also connect to AE's system" (Application, Section 4, Attachment 2, p. 59).

Q: Does Foster know how many streetlights the Company has on its system?

[21]The Company was so protective of customer privacy that it redacted all customer identifiers from the streetlighting work orders and the summary of those orders.

A: In Table 20.1 of the Application (Section 4, Attachment 2), Foster reports a "sum of customer count" of 28,989, a "count of customer count" of 29,640 and 35,800 lamps.[22] The "sum" is the average number of lights served each month, while the "count" is the total number of lights served at any time during the year (or whatever period Foster used in its analysis). Foster does not explain why the number of lamps is so much larger than the number of lights.[23] In the Application, Section 4, Attachment 4, Foster reports 34,400 streetlighting sites.

Q: When Foster uses the term "customer" in Table 20.1, does it mean "customer" in any sense relevant to cost allocation?

A: No. In various places, Foster uses "customer" to identify (1) a municipal entity with an identification number on AE's data system, (2) any identifiable "additional locational names representing the municipality's subcategories (i.e., school districts and departments of park and recreation)," and (3) any light.

Foster recognizes that each of the streetlights on the system is not a separate customer, but does not appear to have any specific cost-based definition of a streetlighting customer.

Q: What definition of "customer" is relevant for the allocation of costs to streetlighting?

A: Counts of customers (or similar measures) are used in several ways in AE's COSS, but those can be simplified to two basis cost-allocation issues: (1) billing, load-settlement, and other customer-service costs and (2) the portion of the secondary distribution system deemed to be customer-related.

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[22]Table 20.1 consists of only the first few lines and last few lines of a much larger table.

[23]Foster sometimes refers to lamps as "sites," further confusing the nomenclature.

Q: What definition of "customer" is relevant for the allocation of the customer-service group of costs?

A: For these categories, costs vary with the number of entities for which AE (and sometime other entities, such as I-Tek) must track and respond to usage, retailer choice, billing inquiries, and similar interactions. For streetlights, the relevant unit would appear to be the municipality, unless the municipality elects to split its streetlights as separate customers for billing and customer-choice purposes. For each municipality, the number of streetlights of various sizes is analogous to the number of kilowatts of billing demand and the kilowatt-hours of energy used by a commercial customer. Just as a store is treated as a single customer, regardless of how many kW and kWh it uses, a municipality is a single customer, regardless of how many streetlights it pays for. The store has a meter, gets a single bill, selects a single retailer, and is a single entity for the purpose of requesting data, upgrades, and other services. The municipal streetlighting load has a list of lights (which should be easier to administer and explain than meter reports), gets a single bill, elects a single retailer, and is a single entity for the purpose of requesting data, upgrades, and other services.[24]

Q: How many streetlighting customers should AE count for purposes of allocating load settlement and other customer-service costs?

A: The complete version of Table 20.1, which AE provided in response to AAMDC/AFREA-ATCO-22, lists a total of 204 municipalities. Unless some those municipalities choose to split into two streetlighting customers for billing and retailer choice, the streetlighting customer count should be 204. If the "Site Customer" column of Table 20.1 actually represents independent entities for

[24]Again, unless the municipality wishes to be treated as multiple customers.

billing and retailer choice, the streetlighting customer count could be as great as 321.

One temporary exception to this rule may be the allocation of costs under the Master Service Agreement (MSA) with ATCO I-Tek. From the Application, Section 4, Attachment 4, it appears that the MSA specifies a price per delivery site for the "Service Accounts" portion of the customer billing charge. Foster's applies that charge to 34,400 streetlighting sites (which is of the same order of magnitude as the number of lights or lamps, but not the same as any other measure of streetlights in the Application). That treatment may be rational, given the current MSA. As noted above, the number of sites is irrelevant for determining the real billing cost of a non-metered lighting customer. The bill is a number of lights of various sizes; so long as that bill is sent to a single customer, only a single billing fee should apply. The Company should be instructed to change the MSA to treat all non-metered usage on a single bill as a single unit for billing purposes. That charge should be no larger than the charge for billing a single metered customer.

Q: What definition of "customer" is relevant for the allocation of distribution costs?

A: As I discuss with reference to Direction 13, customer count is often used as a poor proxy for the effect of each class on the costs required to cover the service territory. The reasoning is that the number of poles and transformers and the kilometres of conductor are (to some extent) driven by the need to have the secondary system run to every occupied corner of the service territory, and that classes with more customers require service to more locations than classes with fewer customers. In this view, since there are many more residential customers than commercial customers, there are likely to be many more poles added to reach a residential customer at the end of a line, and many more transformers added to serve a residential customer who is too far from any existing transformer, compared the commercial class.

This argument does not apply for streetlighting, since Foster directly assigns to streetlighting the cost of every meter of line, every pole, and every transformer added to serve a streetlight (and probably much more). If AE must use customer number for allocating distribution plant, it should set streetlighting customer count to zero for this purpose.

VI. Direction 24: Re-estimation of Customer Weighting Factors

Q: What customer weighting factors did Foster derive?

A: Foster developed demand and customer weighting factors for transformers, service drops, and meters. For streetlighting, weighting factors were derived only for transformers, since streetlighting is not allocated any share of meters and non-assigned service drops. As I discuss in relation to Direction 20, customer number has a very small effect on the number of transformers.

Q: How did Foster derive the demand weights and customer weights to be applied to transformers?

A: First, Foster placed transformers into service categories. The service categories were defined by meter type and rate class. The transformers in each category vary in size according to the range set in Foster's analysis. The categorizations and transformer size ranges are provided on page 65 of Section 4, Attachment 2.

Second, Foster calculated the demand and customer weighting factors as the total transformer number and total kVa capacity assigned to each customer category divided by the category's customer number and total kW, respectively.

Q: Is the basis for the assignments adequately documented?

A: No. Foster omits the following information essential to the evaluation of the weighting factors:

- the source of the total number and kVa of transformers,
- the streetlighting customer number used in the derivation of the street-lighting weighting factors,
- a disaggregation of the number and kW of assigned customers by class,
- the basis for the maximum kVa transformer size for each service group,
- the number of transformers of each specific size assigned to each customer class,
- the number of transformers by kVa size that end up being assigned to the residual group, including streetlighting,
- The basis for these assignments.

Q: Have you identified specific problems with Foster's analysis?

A: Yes. Despite the limited documentation, I have identified two problems in the analysis. First, Foster's derivation of the weighting factors, especially the assignment of particular transformers to particular customer groups, is essentially a hypothetical exercise, not tied to how the system actually works. Foster simply assumes that certain types of customers are served by certain sizes of transformers. A large transformer can serve a cluster of residential customers; a bank of smaller transformers can serve one large customer, and a single transformer can serve a mix of customer types. The mix of transformer sizes serving each customer class is not as simple as Foster assumes. If AE wants to know the size of transformers serving various classes of customers, it should select a representative sample of customers and determine the size of transformer serving each customer by checking its records or the actual equipment. The same study would allow AE to determine how often a customer is critical in determining the need for an additional transformer, which would greatly improve AE's classification of transformer costs.

Second, Foster chose to group streetlights, the smallest of loads, with the large demand-metered customers, including the Large General Service customers. Foster computed a single hypothetical ratio of customers per transformer for this wildly heterogeneous group. As a result, the smallest customers are assumed to use as much of a transformer as the largest customers.

Q: Does this conclude your testimony?

A: Yes.

ATCO Electric Ltd.

2008 General Tariff Application, Phase II
No. 1500878

Before the
Alberta Electric and Utilities Board

Evidence of Drazen Consulting Group, Inc.

on Behalf of the
Industrial Power Consumers Association of Alberta

DRAZEN CONSULTING GROUP
Energy & Regulatory Economics

Project No. 071411
May, 2007

ATCO Electric Ltd.

2008 Distribution Tariff Application, Phase II
No. 1500878

Evidence of Drazen Consulting Group, Inc.

Introduction

The issues addressed in this evidence are the ATCO Electric (AE) Diversity Study and the resulting allocation of AESO DTS charges.

Overview of Conclusions

AE proposes to allocate AESO charges attributable to monthly POD peak demands based on monthly rate class contribution to these demands. AE's calculation utilizes the average monthly demand, whereas the calculation should reflect both the change in the POD demand billing by month and the change in rate class contribution over time.

AE's proposed allocation methodology also highlights that the allocation of DTS demand charges among rate classes is impacted by the contract demands selected by AE. Lowering contract demand levels at PODs shifts additional costs on to industrial customers.

ATCO's Proposed Allocation of DTS Demand Charges

In this Application, AE proposes to allocate AESO DTS demand charges on the basis of contribution to monthly and annual POD peaks. AE proposes to allocate DTS demand charges based on a weighting of contribution to annual POD peaks and monthly POD peaks, with the annual peak weighting reflecting DTS billing on the basis of contract and ratcheted demand and the monthly peak weighting reflecting DTS billing on the basis of monthly peak demand.

Diversity Study

In previous rate cases, ATCO Electric (AE) allocated AESO demand-related transmission charges on the basis of ratcheted monthly rate class NCP demand. In response to Board directions in Decision 2005-025, AE undertook a study of rate class contributions to POD peaks (the Diversity Study).

The intent of the diversity study was to determine class responsibility for the total POD NCP demands, not the class responsibility for each POD peak. In the study, AE utilized load research data to estimate the contribution of each rate class to the sum of POD peak demands.

In the Diversity Study, AE calculated the contribution to each monthly POD peak for each sample customer. These contributions were accumulated for each rate class (effectively by weighting them by annual energy consumption) and extrapolated to the entire rate class (again, based on annual energy consumption).

The averaging and extrapolation of contribution to POD peaks utilizes the same techniques as have been previously used to calculate rate class NCP demand.

As a basis for estimating the impact of the study, AE also determined the class NCP demands.

AESO DTS Billing Capacity

The AESO DTS demand charges are paid on the basis of billing capacity where billing capacity in each month is the higher of: 90% of contract demand, monthly POD peak demand or 90% of the highest POD peak demand in the past 24 months.

The following table presents a breakdown of AE's AESO billing capacity for 2003 through 2005[1] and those forecast for 2008.[2] On a forecast basis, AE expects nearly 50% of AESO DTS charges to be levied on the basis of monthly peak POD demands.[3]

Billing Capacity by Year

	2003 Act.	2004 Act.	2005 Act.	2008 Fcst.
MW-months				
Contract Demand	10,391	10,316	8,135	3,116
Metered Demand	6,808	5,978	6,365	10,083
Ratcheted Demand	3,434	4,491	6,005	8,069
Total	20,633	20,785	20,505	21,268
Percentage				
Contract Demand	50%	50%	40%	15%
Metered Demand	33%	29%	31%	47%
Ratcheted Demand	17%	22%	29%	38%
Total	100%	100%	100%	100%

The contrast between forecast and actual billing capacity suggests that AE is reducing its contract levels, thereby increasing the proportion of billing capacity determined on the basis of metered demand and ratcheted demand.

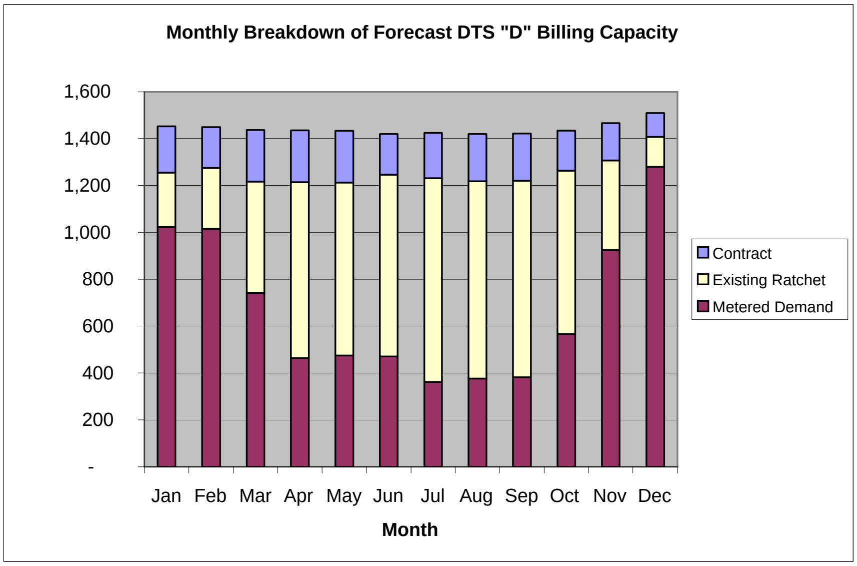
The breakdown of billing capacity varies significantly by month. The following graph presents the billing capacity forecast for 2008:[4]

[1] 2003 and 2004 data from IPCAA-AESO-25 from 2005 GTA, 2005 from IPCAA-AE-15 Schedule 2 and 2008 from IPCAA-AE-1 Schedule 1.

[2] IPCAA-AE-001 Schedule 1 for Rate D-31 "D" and "T" Customers. "T" Customers receive a flow-through of AESO charges and, therefore, are not impacted by the Diversity Study, but are included here for comparison with actual results that are provided with "T" customers included.

[3] IPCAA-AE-001 Sum of monthly Metered Demand under Schedule 1 DTS Total Billing Capacity less Metered Demand DTS "T" Billing Capacity. These values may differ from those used in the EDLA Model. The EDLA model indicates a 39% weighting on the basis of monthly POD peak demand, 37% based on ratchets and 24% billed on contract.

[4] IPCAA-AE-1 Schedule 1.



Charges in the winter months are primarily based on metered demand, whereas billings in non-winter months are primarily based on either contract or ratcheted demands (both of which are related to maximum POD demands).

AE's Proposed Allocation of DTS Demand Charges

The following table compares the allocation based on annual NCP demand[5] with that based on contribution to annual POD peak demand and the weighted average contribution to monthly POD peak demand.

Rate Class Share of Demand Measures

	Rate Class NCP	Annual POD Peak	Monthly POD Peak
Residential total	17.4%	14.3%	13.1%
Farm total	7.3%	6.3%	5.6%
Small General Service total	9.8%	7.9%	8.5%
Irrigation total	0.2%	0.1%	0.0%
Lighting total	0.4%	0.3%	0.3%
Oil Field total	8.1%	3.9%	3.9%
Industrial SD Cust. total	53.7%	60.2%	61.5%
Industrial PD Cust. total	6.2%	7.0%	7.1%
AE Distribution total	100.0%	100.0%	100.0%

AE proposes to allocate AESO charges related to monthly peak demand on the basis of contribution to monthly POD peak and charges related to contract demand and demand ratchets on the basis of annual POD peak. AE has been reducing the level of contract demand over time (see earlier table), leading to an increase in demand ratchets (which AE proposes to allocate on the same basis as contract ratchets). Demand ratchets are increasing more slowly

[5] EDLA Model Tab: Annual Class NCP Column Q.

than contract ratchets so the proportion of charges based on monthly demand increases and the proportion of costs paid by industrial loads also increases. At a high level, it is not logical that a reduction in the overall level of DTS contract demand should increase the costs borne by industrial customers.

Where charges from the AESO are based on monthly POD peaks, AE proposes to allocate the costs based on rate class contributions to those peaks in the given month. As discussed later, AE's allocation effectively utilizes a simple average of the monthly rate class shares. A weighted average allocation would be more appropriate.

The table below shows the allocation of such costs between rate classes, by month:

Allocation of Monthly POD Demand Costs

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Wtd Avg.
Residential	15.4%	13.7%	13.4%	10.7%	9.6%	9.7%	9.4%	9.7%	10.1%	12.8%	14.5%	16.0%	13.1%
Farm total	6.8%	6.3%	5.8%	4.8%	4.1%	3.7%	3.6%	3.8%	4.5%	5.3%	6.1%	6.9%	5.6%
Small General Serv. total	7.8%	8.2%	8.1%	8.4%	9.0%	10.4%	10.4%	10.2%	9.0%	7.9%	8.2%	7.9%	8.5%
Irrigation total	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Lighting total	0.3%	0.3%	0.3%	0.1%	0.1%	0.0%	0.0%	0.1%	0.2%	0.2%	0.4%	0.4%	0.3%
Oil Field total	4.4%	4.4%	4.3%	3.9%	3.5%	3.2%	2.8%	2.8%	3.4%	3.8%	3.9%	3.9%	3.9%
Industrial SD Cust. total	58.5%	59.9%	61.0%	64.7%	66.1%	65.3%	66.1%	65.7%	65.4%	62.7%	60.0%	58.1%	61.5%
Industrial PD Cust. total	6.8%	7.2%	7.1%	7.4%	7.7%	7.5%	7.6%	7.5%	7.5%	7.2%	7.0%	6.7%	7.1%
AE Distribution Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The residential share of monthly demand charges drops by more than a third from winter to summer and the share borne by industrial loads increases from winter to summer, despite relatively uniform industrial loads throughout all months of the year.

In months where charges are based on ratcheted POD peaks or ratcheted contract demands, it is logical to allocate costs on the basis of the demand in the month in which the ratchet is incurred, not on the basis of the demand in the month in which the ratcheted charge is levied.[6]

Where charges are based on ratcheted demands, or contract demands, AE proposes to allocate charges based on ratcheted demands and contract demands on the basis of contribution to annual POD peak demands.

AE's Calculation of Blended Contribution to POD Peaks

In the Energy Demand and Loss Analysis (EDLA) model, AE provided the following breakdown[7] of DTS billing capacity:

[6] It is unlikely that the rate class contributions to contract demands could be determined on a POD by POD basis.

[7] EDLA Model, Tab: System Inputs Cells: A54:C57.

Billing Capacity by Component

Billed on Ratchet	37.0%
Billed on Contract	24.0%
Billed on POD Peak	39.0%

It is not clear what data these percentages are based on as these figures do not agree with the 2008 forecast values[8] or the 2005 actual results.[9] The weightings utilized in the EDLA model should be consistent with the 2008 forecast for "D" customers (as provided in IPCAA-AE-001 Schedule 1).

AE Blended Contribution to POD NCP

AE has proposed allocating a portion of AESO demand costs on the basis of contribution to monthly POD peaks and a portion on the basis of contribution to annual POD peaks. Rather than undertake these allocations separately then combining the results, AE chose instead to calculate a single "blended" monthly/annual demand[10].

Calculating a blended demand as AE has does not produce the same results as would be obtained by calculating the monthly and annual results separately and then combining them because the blended approach effectively computes a simple average of the monthly demands whereas it is more appropriate to utilize a weighted average.

The table below compares the weighted average monthly POD demand[11] versus the AE average monthly POD demand[12].

Weighted vs. Average Monthly POD Demand

	Weighted Monthly	Blended 100% Monthly
Residential total	13.1%	12.2%
Farm total	5.6%	5.2%
Small General Service total	8.5%	8.8%
Irrigation total	0.0%	0.0%
Lighting total	0.3%	0.2%
Oil Field total	3.9%	3.7%
Industrial SD Cust. total	61.5%	62.6%
Industrial PD Cust. total	7.1%	7.2%
AE Distribution Total	100.0%	100.0%

[8] Provided in IPCAA-AE-001 Schedule 1.
[9] Provided in IPCAA-AE-015 Schedule 2.
[10] The calculation of the blended demand is further distorted as the weighting factors do not add to 100%. This appears to have no effect on the allocations as it is the relative allocations between rate classes that impact the results.
[11] Calculated based on 2008 forecast monthly POD demand billing determinants.
[12] AE's "blended" POD demand from the EDLA model with the monthly weighting set to 100%.

The results demonstrate that the simple average/blended approach distorts the allocation of costs based on contribution to monthly POD demands and increases the allocation to Industrial loads.

When the monthly POD demand components are combined with the annual demand billing components (to permit comparison of the total demand allocation), the results are as shown below:

Combined vs. Blended Demand Allocation

	IPCAA Combined	AE Blended
Residential total	13.7%	13.5%
Farm total	6.0%	5.9%
Small General Service total	8.1%	8.2%
Irrigation total	0.1%	0.1%
Lighting total	0.3%	0.3%
Oil Field total	3.9%	3.8%
Industrial SD Cust. total	60.8%	61.2%
Industrial PD Cust. total	7.1%	7.1%
AE Distribution total	100.0%	100.0%

The distortion created by utilizing the simple average in allocating monthly POD demand costs persists in the overall results resulting in an over-allocation of costs to industrial customers. The weighted average is a more reasonable approach to allocate the monthly costs.

AESO Tariff Utilized for Calculation

AE has chosen to utilize a draft version of the AESO tariff that reflects neither the CP-based tariff currently in place nor the NCP tariff the AESO ultimately applied for. While the AESO Phase II proceeding is well underway, a decision on the form of the AESO tariff will not be available prior to the evidentiary portion of the present application concluding. This may well lead to a mismatch between the AESO tariff and the allocation of transmission charges in the AE tariff. It is likely that the AESO decision will be rendered before an AE decision and, if significant changes are made to the AESO tariff from the form utilized by AE, it may be desirable for the Board to direct AE to provide a proposal (or proposals) to address the mismatch in a refiling.

Conclusion

AE's Diversity Study has been utilized to allocate the contribution of rate classes to POD peak demands. The allocation should be revised to reflect a weighted average calculation for the allocation of monthly demand costs.

The allocation of DTS demand costs between rate classes is impacted by the POD contract levels selected by AE. This is not logical a logical result.

RMRF | Reynolds Mirth Richards & Farmer LLP
BARRISTERS | SOLICITORS

WRITER'S E-MAIL rmccreary@rmrf.com WRITER'S DIRECT PHONE (780) 497-3348
YOUR FILE OUR FILE 101228-027-CRM

May 15, 2007

EMAIL

Attention: Mr. Brian Ploof
Application Officer

Alberta Energy and Utilities Board
Utilities Branch
5th Floor, 640 – 5th Avenue, S.W.
Calgary, AB T2P 3G4

Dear Mr. Ploof:

Re: Application No. 1500878;
ATCO Electric Ltd. (AE)
2008 Distribution Tariff Phase II
Office of the Utilities Consumer Advocate Load Research and Loss Factor Evidence

Enclosed please find the Load Research and Loss Factor Evidence submitted on behalf of the Office of the Utilities Consumer Advocate with Appendices labelled "A" and "B" and Attachments numbered 1 to 5 inclusive.

If further explanation is required, please let me know.

Yours truly,

REYNOLDS, MIRTH, RICHARDS & FARMER LLP

PER:

C. RANDALL MCCREARY
CRM/sdw

cc: Ron Henderson

316206;May 15, 2007

ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF

ATCO ELECTRIC

2008 DISTRIBUTION TARIFF PHASE II

APPLICATION NO. 1500878

LOAD RESEARCH AND LOSS FACTOR EVIDENCE

Submitted on behalf of:

The Office of the Utilities Consumer Advocate

May 15, 2007

Q 1. Who has prepared this evidence?

A 1. This evidence was prepared for the Office of the Utilities Consumer Advocate (UCA) by Mr. Herb Vander Veen and Mr. Mark Lively, whose qualifications are attached as Appendices "A" and "B" respectively.

Q 2. Please describe the Office of the Utilities Consumer Advocate's (UCA) involvement in this proceeding.

A 2. The UCA has a statutory mandate to represent residential, farm and small commercial customers in regulatory proceedings. As AE's cost of service and rate design impact all three classes of customers, the UCA has taken an active role in this proceeding.

Q 3. What is the nature of the evidence filed in this proceeding?

A 3. In this submission, the UCA has focused its evidence on the following area:

- AE's Load Research study;
- AE's Loss Factor calculations by rate class

Q 4. What problems have you identified with the Load Research study that AE has presented in Section 10 of its filing?

A 4. The UCA has identified two issues with the AE calculation of losses by class of customer. First, AE has not appropriately recognized the basis for electrical losses. This results in the allocation of electrical losses on a MW-Mile basis instead of on a "piecemeal" MW-Squared Mile basis. The AE calculations create a bias in favor of those customers who are closest to the point of delivery; generally very large industrial customers, as is shown in the following table. For instance, on UCA Attachment 1 for Feeder 18, we calculated that the loss factor for the oilfields is overstated at 3.58% instead of 1.10%, while the loss factor for Industrial > 2 MW Secondary are understated at 0.63% instead of 0.84%.

Second, AE's selection of feeders has resulted in a group of feeders that seem to be less than random. Thus, there may be additional bias associated with the selection of the feeders for analysis. The following table shows the average distance customers are from the point of delivery for the two strata AE has used in its sample of feeders. As will be discussed in more detail later, Stratum 1 consists of lightly loaded feeders and Stratum 2 consists of more heavily loaded feeders. The mileage each customer is from the point of delivery as weighted by the annual energy used by the customer. This information comes from ASBG/PGA-ATCO-8 Customer_Details.xls, which presents distances in miles instead of the standard Canadian unit of kilometers. We have retained the mileage measurement to reduce the confusion of mixing these two measurement systems. Our calculations are slightly different from the results presented in Section 10, Attachment 1 of the filing at page 23, probably a difference in the way the mileage was weighted.

			Weighted Average Mileage		
			Stratum 1	Stratum 2	All
CLASS	GROUP	LEVEL			
Farm	< 2MW	SEC DIST	12.19	17.49	14.05
Industrial	< 2MW	PRIM DIST	5.94	25.00	12.37
Industrial	< 2MW	SEC DIST	10.28	8.49	8.87
Industrial	> 2MW	PRIM DIST	n/a	0.65	0.65
Industrial	> 2MW	SEC DIST	0.92	4.06	3.96
Irrigation	< 2MW	SEC DIST	2.19	25.01	25.00
Oilfield	< 2MW	SEC DIST	9.93	14.08	12.59
Private Lighting	< 2MW	SEC DIST	7.03	5.03	5.88
Residential	< 2MW	SEC DIST	7.36	5.98	6.64
Small GS	< 2MW	SEC DIST	8.61	4.81	5.52
Street Lighting	< 2MW	SEC DIST	7.61	6.07	6.57
Total			9.30	6.06	6.63

Based on our analysis of the 43 sample feeders, we have concluded that the loss factors are not appropriately calculated. Below is our estimation of the appropriate primary energy loss factors to be used in AE's Cost of Service Study (COSS).

Recommended Primary Energy Losses

CLASS	GROUP2	LEVEL	Stratum 1	Stratum 2	Total
Farm	< 2MW	SEC DIST	2.079%	3.424%	2.716%
Industrial	< 2MW	PRIM DIST	1.199%	6.985%	3.128%
Industrial	< 2MW	SEC DIST	1.700%	3.385%	2.496%
Industrial	> 2MW	PRIM DIST		0.243%	0.243%
Industrial	> 2MW	SEC DIST	0.434%	2.715%	2.487%
Irrigation	< 2MW	SEC DIST	0.293%	5.713%	2.461%
Oilfield	< 2MW	SEC DIST	1.440%	3.904%	2.527%
Private Lighting	< 2MW	SEC DIST	1.995%	3.281%	2.463%
Residential	< 2MW	SEC DIST	1.990%	2.946%	2.399%
Small GS	< 2MW	SEC DIST	1.493%	2.131%	1.794%
Street Lighting	< 2MW	SEC DIST	2.480%	2.832%	2.656%
Grand Total			1.721%	3.055%	2.362%

Below is our estimation of the appropriate primary winter demand loss factors to be used in AE's Cost of Service Study (COSS) based on our analysis of the 43 sample feeders.

Recommended Winter Primary Demand Loss Factors

CLASS	GROUP2	LEVEL	Stratum 1	Stratum 2	Total
Farm	< 2MW	SEC DIST	2.919%	3.865%	3.367%
Industrial	< 2MW	PRIM DIST	1.213%	6.509%	2.978%
Industrial	< 2MW	SEC DIST	2.303%	3.579%	2.906%
Industrial	> 2MW	PRIM DIST		0.269%	0.269%
Industrial	> 2MW	SEC DIST	0.481%	2.525%	2.320%
Oilfield	< 2MW	SEC DIST	1.948%	4.140%	2.915%
Private Lighting	< 2MW	SEC DIST	2.745%	3.726%	3.102%
Residential	< 2MW	SEC DIST	2.804%	3.344%	3.036%
Small GS	< 2MW	SEC DIST	2.082%	2.305%	2.187%
Street Lighting	< 2MW	SEC DIST	3.637%	3.224%	3.431%
Grand Total			2.438%	3.226%	2.819%

Q 5. How did you conclude that AE has not recognized the basis for electrical losses?

A 5. AE calculates total electrical losses on each sample feeder using a proprietary computer program, which is expected to provide an accurate estimate of those total losses. However, AE denies the way losses are incurred when AE allocates those losses to customer classes.

Q 6. How does AE calculate total electrical losses?

A 6. AE describes the use of proprietary software used in the calculation.

> "Load flow models are developed for the primary distribution portion of the feeders selected for the study. The load flows are conducted using PSS/Adept software distributed by Shaw Power Technologies, Inc. The customer level demands at the peak hour for each node calculated by the Node ID system are used as the initial estimates of loading on the feeder. The transmission substation bus from which the primary distribution line originates is the swing bus. The loads at the nodes on the feeder are scaled so that the demand supplied to the feeder from the substation bus in the model matches the actual demand for the feeder recorded during the peak hour. The output of the load flow program provides the primary distribution demand loss at the peak hour for each feeder in the sample." (Section 10-Attachment 1, Pages 5-6).

The UCA presumes that this software properly calculates losses as the system is likely to incur such losses. For instance, as lines become more heavily loaded, losses on the lines increase. **Absolute losses** are proportional to the square of the power flowing on the line. However, the **loss factor** is directly proportional to the flow of the power on the line.

For instance, if a line carrying 1 MW has a 1% **loss factor**, the same line, when carrying 5 MW, would have a 5% **loss factor**. The 5 fold change in the **loss factor** (from 1% to 5%) reflects the 5 fold change in the load being carried on the line (from 1 MW to 5 MW).

In the first case, a 1% **loss factor** on a 1 MW load is 10 KW of **absolute losses**. In the second case, a 5% **loss factor** on a 5 MW load is 250 KW of **absolute losses**. The 25 fold change in **absolute losses** (from 10 KW to 250 KW) demonstrates the square nature of absolute losses when there is a 5 fold change in loading (from 1 MW to 5 MW.)

Q 7. Did AE reflect this physical reality in its allocation of losses to customer classes?

A 7. No. AE ignores this principle in the way that AE allocates losses to customer classes.

> "Primary Distribution energy and demand losses are allocated to rate classes/subgroups on the basis of kWh-miles or kW-miles. The energy or demand at each node for each rate class/subgroup is multiplied by the node's distance from the substation. This quantity is called kWh-miles (energy) or kW-miles (demand). The kWh-miles or kW-miles for each rate class/subgroup on a feeder is found by summing the kWh-miles or kW-miles for each rate class/subgroup at all nodes on the feeder. Primary distribution losses are allocated to rate classes/subgroups based on each rate class's/subgroup's percentage of the total kWh-miles or kW-miles for the feeder." (Section 10-Attachment 1, Pages 9-10).

While the loss factor should increase and decrease with the loading on a line, AE keeps the **loss factor** constant in its allocation process. The effect is **absolute losses** changing in direct proportion with load instead of the **loss factor** changing in direct proportion with load.

Q 8. What is the effect on allocated losses to customer classes of incorrectly assuming that the loss factor is constant?

A 8. Assuming a constant loss factor in allocating losses to customer classes creates a bias in the allocation process. This bias in the allocation process works against the interests of those customers who are further from the point of delivery. The bias in the allocation process works in favor of those customers who are closer to the point of delivery, such as very large industrials (i.e. > 2 MW). This bias is typically inimical to the interests of farm and irrigation customers, since farm and irrigation customers are typically further from the point of delivery, as was shown in the above table. In the "mileage" table shown in A 3., irrigation customers averaged 25.00 miles from the point of delivery and farms averaged 14.05 miles from the point of delivery. The bias typically provides a subsidy to large industrial customers, since large industrial customers are generally closer to the point of delivery. As shown in the above table, large industrial customers (> 2 MW) are only 3.96 miles from the point of delivery for those with secondary service and only 0.65 miles from the point of delivery for those with primary service.

We have used the methodology shown in UCA Attachment 1 to develop loss factors for all 43 feeders.

Q 9. Can you illustrate the effects of the AE calculations?

A 9. Yes. Table 1 and Table 2 of UCA Attachment 1 summarize the loss allocation performed by AE for feeder 18. The data for the two tables are taken from the attachment to ASBG/PGA-ATCO-8 Customer_Details.xls.

Table 1 of UCA Attachment 1 is Winter Peak on Feeder 18 (KW). The information in Table 1 of UCA Attachment 1 is a compilation of the data in column R of the worksheet ASBG/PGA-ATCO-8 Customer_Details.xls. Column R is titled Winter Demand Sales (KW). Table 1 of UCA Attachment 1 is presented as a graph in UCA Attachment 1A.

Table 2 of UCA Attachment 1 is AE Winter Peak Loss on Feeder 18 (KW). The information in Table 2 of UCA Attachment 1 is a compilation of data from column S of the worksheet ASBG/PGA-ATCO-8 Customer_Details.xls. Column S is titled Winter Primary Loss (KW). Table 2 of UCA Attachment 1 is presented as a graph in UCA Attachment 1B.

The penultimate line of UCA Attachment 1, page 1, is titled Grand Total Losses (AE). The line contains loss factors calculated from the Grand Total lines of the two tables. Thus, the Grand Total Losses (AE) of 0.626% is the Grand Total of 36.41 KW for 0.72 miles in Table 1 of UCA Attachment 1 divided by the Grand Total of 5,812.55 KW for 0.72 miles in Table 1 of UCA Attachment 1. Similarly, the last Grand Total Losses (AE) of 4.569% is the Grand Total of 0.91 KW for 5.26 miles in Table 2 of UCA Attachment 1 divided by the Grand Total of 19.82 KW for 5.26 miles in Table 1 of UCA Attachment 1.

The last line of UCA Attachment 1, page 1, normalizes the loss factors for distance, creating Grand Total Losses Per Mile (AE). These numbers are obtained by dividing the Grand Total Losses (AE) on the penultimate line by the distance each group of customers is from the point of delivery. Thus, the first Grand Total Losses Per Mile (AE), 0.870%, is the Grand Total Losses (AE), 0.626%, divided by 0.72 miles. Similarly, the last Grand Total Losses Per Mile (AE), 0.869%, is the last Grand Total Losses (AE), 4.569%, divided by 5.26 miles.

The slight variation in the Grand Total Losses Per Mile (AE) is the result of the rounding associated with the data in ASBG/PGA-ATCO-8 Customer_Details.xls. The rounding is more pronounced when the numbers are very small. The near uniformity of the Grand Total Losses Per Mile (AE) (varying from a low of 0.867% to a high of 0.870%, or one part in 300) demonstrates the effect of the AE loss allocation method, that is, that losses are presumed to be invariant with the load being carried by the primary distribution, at least for losses as a percentage of the load being carried. This is an incomplete allocation methodology that does not take into account the data that AE has developed and used in its analysis.

We have used the methodology shown in UCA Attachment 1 to develop loss factors for all 43 sample feeders. We have previously presented a summary of the analysis in Answer 4.

Q 10. Why do you describe the AE loss allocation methodology as incomplete?

A 10. We describe the AE loss allocation methodology as incomplete because it ignores detailed data that are available to AE in the programs used to calculate total losses on the primary distribution system. By ignoring this data, AE biases its results against those customers who are further away from the point of delivery in favor of those customers who are closer to the point of delivery. AE introduces this bias even though AE has data that show the magnitude of that bias. Without that data, the bias might be excusable, but given that AE has the data to calculate the size of the bias, AE should be required to make the more precise allocation.

Q 11. Were you able to make the calculation that AE should have made?

A 11. Yes. The allocations are shown in the Table 4 of UCA Attachment 1. Table 4 of UCA Attachment 1 presents UCA Winter Peak Losses on Feeder 18 (KW). The information in Table 4 of UCA Attachment 1 is shown graphically in UCA Attachment 1D. The losses on each segment of Feeder 18 are allocated to all of the loads that use that segment of Feeder 18.

For the first segment, the 0.72 miles from the point of delivery to the first cluster of customers, the losses are allocated to all loads served by Feeder 18. The losses on the first segment are allocated to all loads served by Feeder 18 since all loads are effectively served by that first segment.

For the second segment, the 2.40 miles from the first cluster of customers at 0.72 miles from the point of delivery to the second cluster of customers at 3.12 miles from the point of delivery, the losses are allocated to customers at that second cluster and to all customers beyond the second cluster of customers. Thus, the losses incurred on the second segment of Feeder 18 are allocated to the second cluster of customers, the third cluster of customers, the fourth cluster of customers, the fifth cluster of customers, and sixth cluster of customers, all customers except those in the first cluster at 0.72 miles form the point of delivery.

The actual allocation of losses to customer classes is based on the Table 3 of UCA Attachment 1. Table 3 of UCA Attachment 1 presents Winter Peak Served This Point and Beyond (KW). This information is shown graphically in UCA Attachment 1C. At 0.72 miles, the table presents the total demand for all customers served on Feeder 18. At 3.12 miles, Table 3 of UCA Attachment 1 presents the total for all customers except those served at 0.72 miles. At 4.09 miles, the Table 3 of UCA Attachment 1 presents the total demand for all customers except those served at 0.72 miles and those served at 3.12 miles.

Q 12. Did AE provide the losses by segment that are contained in Table 3 of UCA Attachment 1?

A 12. No. We had to calculate those losses from the data available from the attachment included in ASBG/PGA-ATCO-8 Customer_Details.xls. The UCA had asked for losses by segment in UCA-ATCO-18 (c).

> "For feeder 25, please provide the primary distribution demand loss at the peak hour for each segment of the primary distribution feeder, where a segment is defined as the portion of the feeder between adjacent nodes, providing an identification of the nodes connected by the segment. Also, please provide the same information for each other feeder."

AE responded:

> "Primary distribution demand loss at the peak hour for each segment is not readily available in the form requested. Pursuant to Rules 29(1)(b), ATCO Electric can not provide this information with reasonable effort."

Accordingly, we had to allocate the total loss at the peak hour to the various segments, as is shown in the middle of UCA Attachment 1, page 2.

We note that in this proceeding we have been able to calculate losses by segment. This contrasts greatly with the situation in the FortisAlberta proceeding. AE has provided enough information by feeder for us to estimate the losses on individual feeders, as we show in UCA Attachment 1. FortisAlberta did not provide similar detail. Thus, in the FortisAlberta proceeding, the allocation could not be done on an individual feeder basis and had to be done on an aggregate basis, which was much less precise.

Q 13. How did you determine the losses by segment of Feeder 18?

A 13. The first step in allocating total loss at the peak hour to the various segments involved developing a set of indices, where each index was proportional to the losses that were experienced on the corresponding segment. The standard engineering approach is to calculate losses pursuant to the concept of "I Squared R", where "I" refers to the current that is being carried on the wire and "R" is the resistance of the wire.

Since the load being carried on the wire is proportional to the current, the total load being served by a segment can be used as a proxy for the current in the development of an index. Under the assumption that the feeder has consistent wire sizes, then the length of the wire can be used as a proxy for the resistance in the development of an index.

UCA Attachment 1, page 2, has a line titled Segment I Squared R (Index). The numbers on that line are calculated from the length of the segment times the square of the load being served by that segment. In the case of the first segment, the length is 0.72 miles and the load being served is 6,309.8 KW. The Segment I Squared R (Index) for the first segment is thus 0.72 * 6,309.8 * 6,309.8, which is 28,665,983.73, the first number on the line. The other numbers on that line are calculated in the same manner except that the length of each segment is the difference between the mileage markers. Thus, the second segment has a length of 2.40 miles, the difference between 3.12 miles and 0.72 miles. The Segment I Squared R (Index) for the second segment is 2.40 * 497.28 * 497.28, which is 593,479.2537, the second number on the identified line.

The next line on UCA Attachment 1, page 2, is titled Segment Losses (KW). The total losses at peak on Feeder 18 were 54.21 KW, according to the data presented in ASBG/PGA-ATCO-8 Customer_Details.xls. The total losses at peak are shown in Table 2 of UCA Attachment 1, page 2. This has been mentioned before. The 54.21 KW total losses were allocated to segment based on the Segment I Squared R (Index). Since the first index from the Segment I Squared R (Index) is approximately 97% of the total of the indices from the Segment I Squared R (Index), the first segment is allocated approximately 97% of the losses. Thus, about 97% of the primary losses on this 5.26 mile feeder occur on the first 0.72 mile.

The losses on each segment are then allocated to the classes served by that segment in proportion to the Winter Peak (KW) Served This Point and Beyond, as presented in Table 3 of UCA Attachment 1.

Q 14. What is shown on the last two lines on page 2 of UCA Attachment 1?

A 14. These two lines duplicate the calculations shown on the last two lines of page 1 of UCA Attachment 1, except for the appropriate recognition of UCA Winter Peak Losses (KW) as calculated in Table 4 of UCA Attachment 1. As the load carried on progressive segments declines, as shown in Table 3 of UCA Attachment 1, the Grand Total Losses Per Mile declines. This is consistent with the physics of the losses on the system.

For instance, Table 3 of UCA Attachment 1 shows that the first segment is carrying 6,309.82 KW versus the 497.28 KW being carried on the second segment. This is a difference of about a factor of 12. The Grand Total Losses Per Mile (UCA) can be seen to decrease by about a factor of 12 between the first segment and the second segment.

The relation between Grand Total Losses Per Mile (UCA) and the loading on the line segment is shown graphically in UCA Attachment 1E, which is presented in two parts, UCA Attachment 1E1 and UCA Attachment 1E2. Both UCA Attachment 1E1 and UCA Attachment 1E2 plot the Grand Total Losses Per Mile (UCA) against the Grand Total in Table 3 of UCA Attachment 1. UCA Attachment 1E2 differs from Attachment 1E1 by limiting the range of the plot so that the data points for last five segments can be seen more clearly. In Attachment 1E1 the six data points are so close together that there seem to be only three data points. Indeed, even for UCA Attachment 1E2, two data points (27.85 KW, 0.00512%; 26.97 KW, 0.00496%) are almost indistinguishable.

Q 15. What is the result of a proper allocation of the primary losses?

A 15. Table 5 of UCA Attachment 1 presents a Summary for Feeder 18. The Industrial Class, < 2MW, Secondary Distribution, for Feeder 18 would be allocated a loss factor of 3.49% under the AE methodology, but only 1.13% under the UCA methodology. The Oilfield Class, < 2MW, Secondary Distribution, for Feeder 18 would similarly see a reduction in the allocated loss factor, from 3.58% to 1.10%. In contrast, Industrial Class, > 2MW, Secondary Distribution, for Feeder 18 would see an increase in its allocated loss factor from 0.63% to 0.84%. Similarly, the Small GS Class, < 2MW, Secondary Distribution, for Feeder 18 would see an increase from 0.60% to 0.84%.

Q 16. Would all feeders experience the same effect?

A 16. All feeders with multiple clusters of customers would see the loss factors having a smaller spread, just as the loss factors for UCA Losses in Table 5 of UCA Attachment 1 have a smaller spread than do the loss factors in AE Losses in Table 5 of UCA Attachment 1. However, though the Industrial Class, < 2MW, Secondary Distribution, would be a beneficiary using this analysis for Feeder 18, the Industrial Class, < 2MW, Secondary Distribution will not always be the beneficiary of the change in methodology for allocating loss factors. On some feeders the Industrial Class, < 2MW, Secondary Distribution, will be closer than average to the Point of Delivery and will see an increase in its allocated loss factor. In that case, removing the bias created by the AE methodology for allocating losses would increase the loss factor for the Industrial Class, < 2MW, Secondary Distribution.

Q 17. What problems have you identified in the method used by AE for selecting feeders to be analyzed for its loss analysis?

A 17. The primary problem with the sample selection is that the sample size was not large enough. The sample produces results that have too great of uncertainty relative to the estimated loss factors. This can be illustrated by looking at the effect of removing a specific feeder from the mix and determining the effect on the estimated percentage loss factors for each feeder, as is done in UCA Attachment 2.

Another problem is that the sample of feeders chosen by AE appears to be less than random. AE analyzed a sample of feeders to determine the percentage loss factors for each customer class. The sample of feeders is normally supposed to be random to reduce the bias in the in the result. The sample appears to be less than random. This can be illustrated by comparing the distribution of the feeders in the sample with the distribution of all AE feeders, as is done in UCA Attachment 5.

Finally, though AE adopted the conventional practice of a stratified random sample, the stratification seems to be ineffective. The purpose of stratification is to reduce the uncertainty associated with the answer, in this case, the percentage loss factors for each class. However, for the stratification to be effective in reducing uncertainty, the stratification needs to be in regard to a variable that is associated with that uncertainty. AE choose to use annual energy. Other possible variables, such as annual percentage loss factors, might be more likely to be associated with the variation in the percentage loss factors for each class. We will show the lack of correlation between the chosen variable and an alternative variable.

Q 18. Why do you say that AE chose too small a sample size?

A 18. We looked at the range of values AE calculated as loss factors for the various customer classes. For some customer classes, AE calculated loss factors on as few as three feeders. For other customer classes, AE calculated loss factors on as many as thirty-six feeders. The loss factors on these feeders varied widely for most customer classes. Some of the class loss factors were quite sensitive to the selection of the feeder for the sample. We tested this sensitivity by selectively eliminating a feeder to determine the effect on the class loss factor. UCA Attachment 2 presents the analysis of the AE Precision in Estimating Class Loss Factors. The precision is presented in a way that the larger the number, the more precise the estimate.

Q 19. How did you calculate the Precisions in UCA Attachment 2?

A 19. We first calculated the AE average loss factor for each class of customers across all of the feeders presented by AE in ASBG-PGA-Atco 8.xls. We then eliminated one feeder to determine the effect on that average. We next selected the feeder that had the highest loss factor for that class of customers. We also determined the effect of eliminating the feeder that had the lowest loss factor for that class of customers. The alternative elimination of these feeders resulted in a range of loss factors for the customer class, a range that could occur if AE had happened to exclude that feeder in its random selection of feeders. We then divided this range into the AE average loss factor, producing the precision factor presented in UCA Attachment 2. We did this for each class of customer and voltage level and for total losses, primary losses, and secondary losses. High numbers indicate very precise boundaries on the estimation of the average loss factor for a customer class.

Q 20. What were some of your findings in regard to the precision calculations?

A 20. Some classes were very imprecise in the estimation of their loss factors, most noticeably Industrial, < 2MW, Primary Distribution. The attachment to ASBG-PGA-AE 8 has information for this class on three feeders. The loss factors are 0.135% for feeder 34, 1.985% for feeder 32, and 7.155% for feeder 38. The average for these three feeders is 3.217%. Without the largest loss factor, that is, with the elimination of feeder 38, this class would have an average loss factor of 1.060%. Without the smallest loss factor, that is, with the elimination of feeder 34, this class would have an average loss factor of 4.570%. This is a spread of 3.510%. The AE average loss factor for this class of 3.217% is only 0.88 times the calculated spread. Thus, there is not a very precise estimate for the loss factor associated with Industrial customers, <2MW, Primary Distribution.

Q 21. Why did AE use a sample of its feeders to analyze the percentage loss factor for each customer class?

A 21. It is a complicated and expensive process to analyze a distribution feeder to determine the loss factor for each customer class on that feeder. That cost can be reduced by looking at a sample of feeders instead of all feeders. Since each feeder will have a different percentage loss factor, both in total and for each customer class, there will be some uncertainty in the result. The uncertainty in the result can be reduced by analyzing more feeders. For instance, analyzing all of the feeders should reduce the uncertainty almost entirely. AE chose to analyze 43 out of 314 of its feeders.

Q 22. Did AE choose to analyze the right number of feeders?

A 22. We don't know. Often, the "right number of feeders" is determined by the precision that is sought in the answer. For instance, perfect precision would require that all of the feeders should be analyzed. The question becomes what is good enough for the current purpose. We have not seen any specification of how good that precision is supposed to be for percentage losses by class, such as those presented in UCA Attachment 2.

Q 23. Are there other ways to increase the precision of the estimate without increasing the number of samples?

A 23. Yes. The most common method is a stratified random sample, which is partially described by AE, first in its application and then in its response to the Information Requests, such as in response to Information Request UCA-AE-19. A stratified random sample breaks the sample into two or more strata, and then allocates a certain number of the samples to each stratum. The hope is that the variable to be estimated, in this case the percentage losses by rate class, has more consistency within each stratum than the variable has consistency within the whole universe, that is, for all feeders. Since the estimate of the variable should be more precise within each stratum, then the estimate of the variable for the whole universe should be more precise. Unfortunately, AE did not choose its strata in a way that improved consistency within each stratum.

Q 24. How did AE choose it strata boundary?

A 24. AE describes the process in response to Information Request UCA-AE-19 (a) through (c)

> "(a) Feeders within the ATCO Electric distribution system are stratified based on the energy supplied to the feeder to obtain the most accuracy from the study for the resources used. Most of this benefit of stratification is realized using 2 strata.
>
> (b) Stratum 1 is composed of all feeders with an energy supply less than or equal to 34,741.381 MWh and stratum 2 is composed of all feeders with an energy supply greater than 34,741.381 MWh.
>
> (c) The strata boundary is selected based on the Dalenius methodology using feeder energy supplied"

> (William G. Cochran, Sampling Techniques, Third Edition. New York: John Wiley & Sons Inc. 1977, pp. 127-131).

Though AE asserts that "benefit of stratification is realized using 2 strata", AE presents no evidence of this benefit. UCA Attachment 3 is a plot of the Residential Primary Distribution Percentage Loss Factors for each of the feeders in Stratum 1 and Stratum 2. There is extensive vertical overlap between the percentage loss factors for the two strata. Indeed, the standard deviation for each stratum is greater than the difference between the averages of the strata. In regard to the alleged benefit of stratification, there appears to be none in regard to determination of the average Residential Primary Distribution Percentage Loss Factors.

The horizontal overlap is the result of the nomenclature adopted by AE and is irrelevant for this analysis. Further, 11 feeders in Strata 1 have no residential load. Thus, these 11 feeders are not plotted in UCA Attachment 3. Perhaps by coincidence, there are also 11 feeders in Strata 2 that have no residential load. These 11 Strata 2 feeders are also not plotted in UCA Attachment 3.

The above analysis in regard to residential has been presented as an example. Residential is not the only class for which AE is seeking to establish loss factors. UCA Attachment 4 shows a similar analysis for total losses on each feeder, not just losses associated with residential. But to make the analysis slightly more meaningful, we show the annual energy on each feeder and sort the feeders on that quantity. Thus, Attachment 4 shows how total losses vary by the size of the feeder. Since "Stratum 1 is composed of all feeders with an energy supply less than or equal to 34,741.381 MWh and Stratum 2 is composed of all feeders with an energy supply greater than 34,741.381 MWh", the data points on UCA Attachment 4 are organized by Stratum. All of the data points for Stratum 1 end up being on the left of UCA Attachment 4 and all of the data points for Stratum 2 end up being on the right of UCA Attachment 4.

UCA Attachment 4 shows that there is no correlation between the annual energy on a feeder and the loss factor experienced on the feeder, either in total or for each of the strata. Indeed, UCA Attachment 4 is presented in 3 parts, based on total losses on the feeder in UCA Attachment 4A, primary losses on the feeder in UCA Attachment 4B, and secondary losses on the feeder in UCA Attachment 4C. Of the six correlations estimated on the three graphs, only one appears to be significant, the correlation for primary losses on Stratum 1. However, this correlation is contraindicated by the correlation primary losses for Stratum 2, which is in the opposite direction.

Q 25. Why did you say that the selection of feeders appears to be biased?

A 25. Under the sampling technique AE presented, the selection of the feeders should be based on a random sample of the feeders. Because they have selected to do use two strata, there should be two random samples, one of the smaller feeders, *i.e.*, feeders that carry annual energy that is less than 34,741.381 MWh, and one of the larger feeders, *i.e.*, feeders that carry annual energy in excess of 34,741.381 MWh. But the distribution of the annual energy on the feeders selected for the sample appears to be slightly different from what we expect for a random sample, as is illustrated in UCA Attachment 5.

Q 26. What is shown on UCA Attachment 5?

A 26. UCA Attachment 5 presents the annual energy for each of the AE feeders identified on ASBG-PGA-ATCO-8 Schedule 1. The information has been sorted by the annual energy. Accordingly, the feeder with the least annual energy appears on the left of the graph and the feeder with the most annual energy appears on the right of the graph. The horizontal placement on the graph is based on the fraction of all feeders. As a result, each plot on the graph represents the fraction of the number of feeders that use that carried the indicated amount of annual energy or less. In some respects, it is the reverse of a load duration curve. Thus, 30% of the feeders carried an annual energy of about 10 GWH or less and

50% of the feeders carried an annual energy of about 20 GWH or less. A similar graph of an unbiased random sample of feeders would be expected to have the same pattern, at least without the use of a stratified sample.

The use of a stratified sample should produce a distribution close to the indicated target. The target reflects AE stratification with 23 samples in the range under 34,741.381 MWh and 20 samples in the range above 34,741.381 MWh. The target curve represents a molding of curve for all feeders in a way that allows the distribution of the samples to be 23 samples in the range under 34,741.381 MWh and 20 samples in the range above 34,741.381 MWh. The sample selection appears to be biased in favor of smaller feeders, where we use the phrase smaller feeders to represent those feeders with a less annual energy. This bias appears in the range from 20% to 40%, where the samples fall significantly below the target line, indeed even fall below the line showing the size of all feeders. The sample of 20 feeders in the range above 34,741.381 MWh appears to have less bias, in that they tend to be closer to the target line.

Q27. What conclusions do you draw from your analysis?

A27. We conclude that AE has done an inadequate job of allocating losses to customer classes. Though losses do increase with distance from the point of delivery, the loss factor does not increase nearly as quickly as is suggested by the AE method. On the first mile, losses are indeed very large. But as customers are served from the line, losses per mile decrease, a point not recognized in the AE method. The result is that AE under estimates the losses associated with very large industrial loads that are close to points of delivery and over estimates the losses associated with smaller loads that are further from the points of delivery. This issue should be examined in more detail the next phase II proceeding. Similarly, the next phase II proceeding should also examine the procedure AE uses to determine the random sample of feeders to be analyzed for determining losses. We repeat our recommendation for energy and winter demand losses.

Recommended Primary Energy Losses

CLASS	GROUP2	LEVEL	Stratum 1	Stratum 2	Total
Farm	< 2MW	SEC DIST	2.079%	3.424%	2.716%
Industrial	< 2MW	PRIM DIST	1.199%	6.985%	3.128%
Industrial	< 2MW	SEC DIST	1.700%	3.385%	2.496%
Industrial	> 2MW	PRIM DIST		0.243%	0.243%
Industrial	> 2MW	SEC DIST	0.434%	2.715%	2.487%
Irrigation	< 2MW	SEC DIST	0.293%	5.713%	2.461%
Oilfield	< 2MW	SEC DIST	1.440%	3.904%	2.527%
Private Lighting	< 2MW	SEC DIST	1.995%	3.281%	2.463%
Residential	< 2MW	SEC DIST	1.990%	2.946%	2.399%
Small GS	< 2MW	SEC DIST	1.493%	2.131%	1.794%
Street Lighting	< 2MW	SEC DIST	2.480%	2.832%	2.656%
Grand Total			1.721%	3.055%	2.362%

Below is our estimation of the appropriate primary winter demand loss factors to be used in AE's Cost of Service Study (COSS).

Recommended Winter Primary Demand Loss Factors

CLASS	GROUP2	LEVEL	Stratum 1	Stratum 2	Total
Farm	< 2MW	SEC DIST	2.919%	3.865%	3.367%
Industrial	< 2MW	PRIM DIST	1.213%	6.509%	2.978%
Industrial	< 2MW	SEC DIST	2.303%	3.579%	2.906%
Industrial	> 2MW	PRIM DIST		0.269%	0.269%
Industrial	> 2MW	SEC DIST	0.481%	2.525%	2.320%
Oilfield	< 2MW	SEC DIST	1.948%	4.140%	2.915%
Private Lighting	< 2MW	SEC DIST	2.745%	3.726%	3.102%
Residential	< 2MW	SEC DIST	2.804%	3.344%	3.036%
Small GS	< 2MW	SEC DIST	2.082%	2.305%	2.187%
Street Lighting	< 2MW	SEC DIST	3.637%	3.224%	3.431%
Grand Total			2.438%	3.226%	2.819%

Q 28. Does this conclude your evidence?

A 28. Yes, at this time.

316205;May 15, 2007

Winter Peak on Feeder 18 (KW)
Table 1

			(miles)						
CLASS	GROUP2	LEVEL	0.72	3.12	4.09	4.64	4.84	5.26	Grand Total
Industrial	< 2MW	SEC DIST	9.65		443.71				453.36
	> 2MW	SEC DIST	5,797.92						5,797.92
Oilfield	< 2MW	SEC DIST	4.83	10.82	14.89	0.89	7.14	19.82	58.40
Small GS	< 2MW	SEC DIST	0.15						0.15
Grand Total			5,812.55	10.82	458.60	0.89	7.14	19.82	6,309.82

AE Winter Peak Losses on Feeder 18 (KW)
Table 2

			(miles)						
CLASS	GROUP2	LEVEL	0.72	3.12	4.09	4.64	4.84	5.26	Grand Total
Industrial	< 2MW	SEC DIST	0.06		15.74				15.80
	> 2MW	SEC DIST	36.31						36.31
Oilfield	< 2MW	SEC DIST	0.03	0.29	0.53	0.04	0.30	0.91	2.09
Small GS	< 2MW	SEC DIST	0.00						0.00
Grand Total			36.41	0.29	16.27	0.04	0.30	0.91	54.21

Grand Total Losses (AE)	0.626%	2.709%	3.548%	4.027%	4.199%	4.569%
Grand Total Losses Per Mile (AE)	0.870%	0.868%	0.867%	0.868%	0.868%	0.869%

Winter Peak Served This Point and Beyond on Feeder 18 (KW)
Table 3

			(miles)						
CLASS	GROUP2	LEVEL	0.72	3.12	4.09	4.64	4.84	5.26	Grand Total
Industrial	< 2MW	SEC DIST	453.36	443.71	443.71	-	-	-	453.36
	> 2MW	SEC DIST	5,797.92	-	-	-	-	-	5,797.92
Oilfield	< 2MW	SEC DIST	58.40	53.56	42.74	27.85	26.97	19.82	58.40
Small GS	< 2MW	SEC DIST	0.15	-	-	-	-	-	0.15
Grand Total			6,309.82	497.28	486.45	27.85	26.97	19.82	6,309.82

Segment I Squared R (Index)	28665984	593479.254	229537.5	426.6659	145.432	165.0545	29489737.7
Segment Losses (KW)	52.69582	1.09097511	0.421952	0.000784	0.000267	0.000303	54.2101

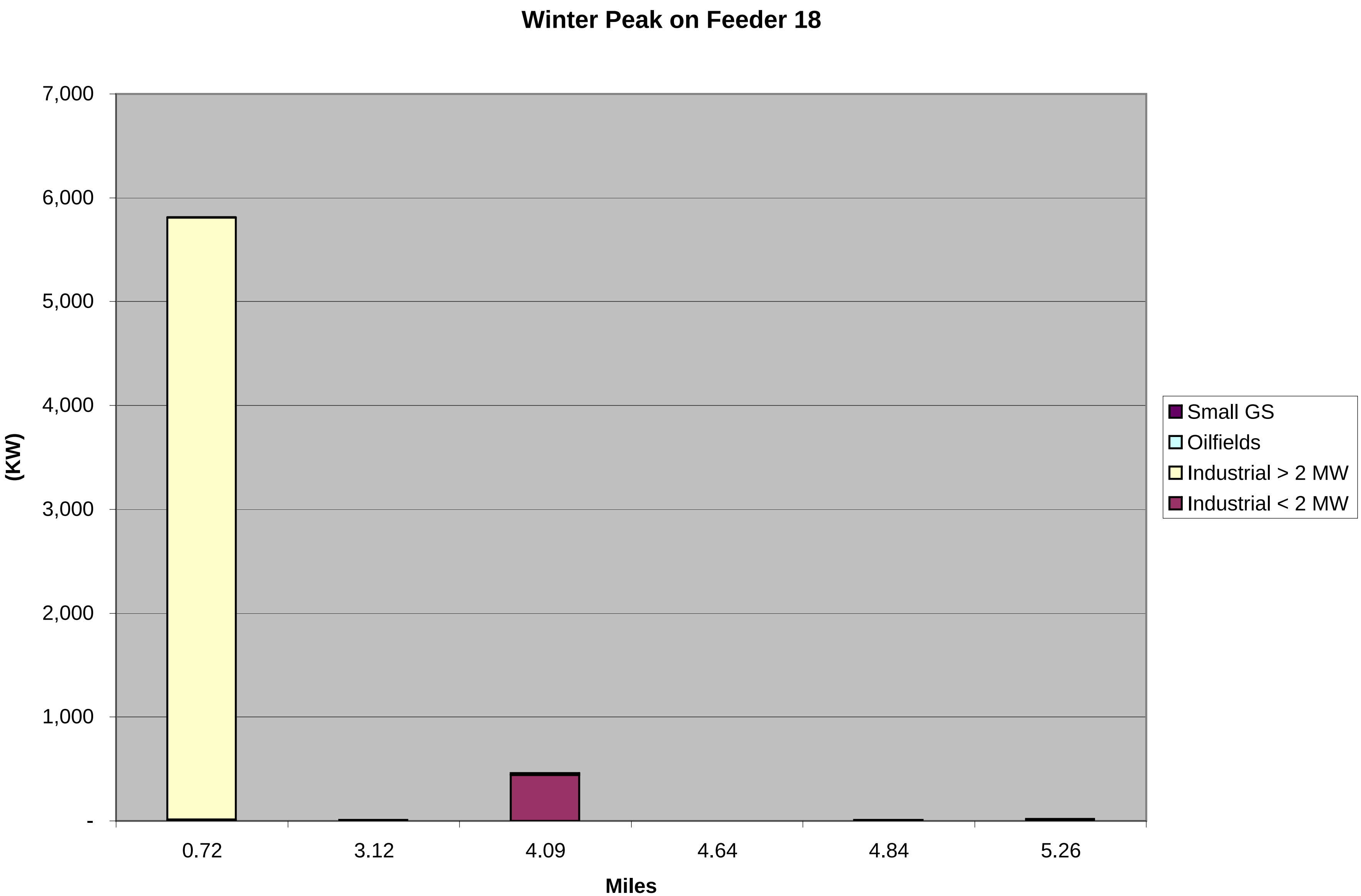
UCA Winter Peak Losses on Feeder 18 (KW)
Table 4

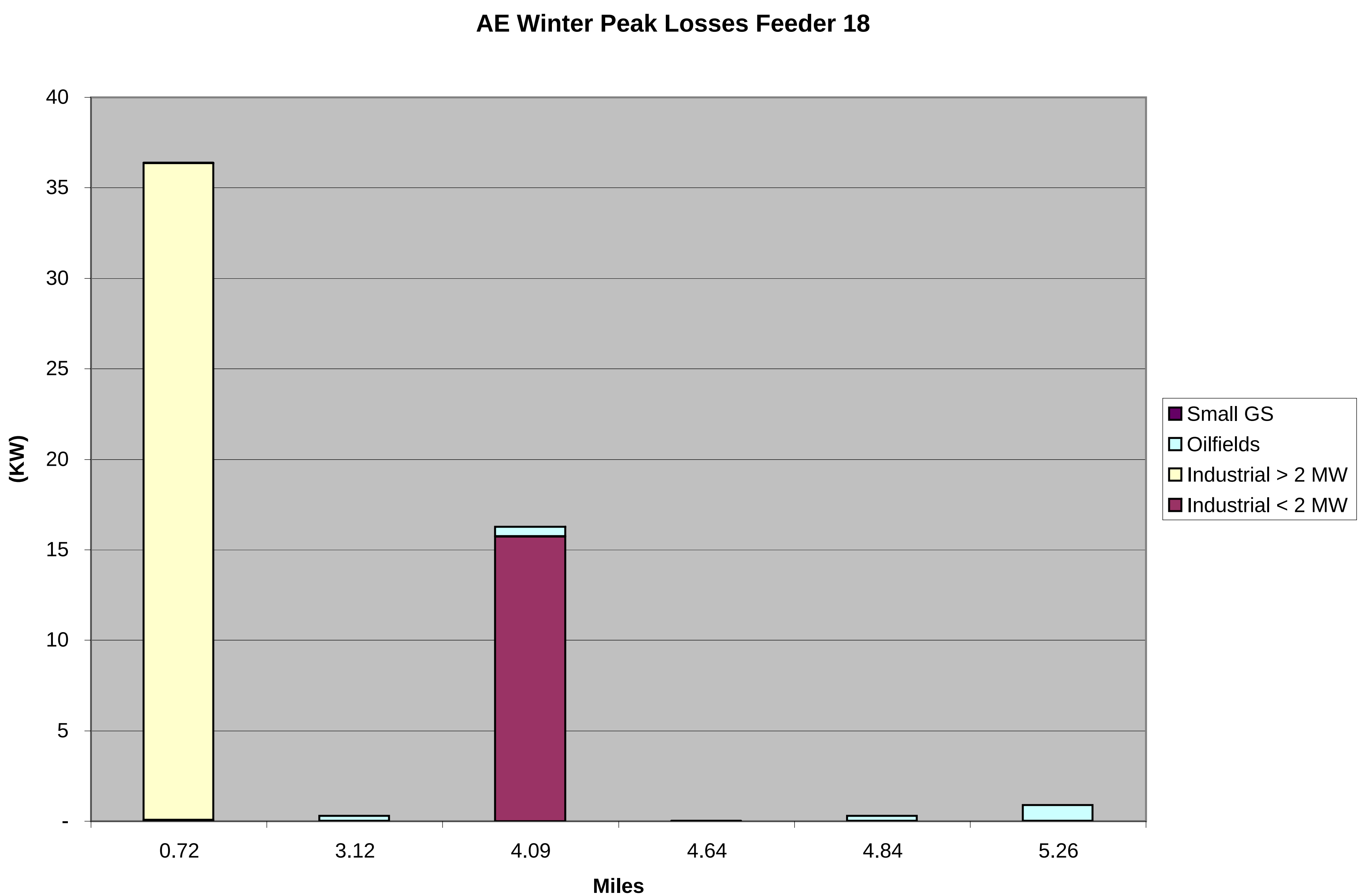
			(miles)						
CLASS	GROUP2	LEVEL	0.72	3.12	4.09	4.64	4.84	5.26	Grand Total
Industrial	< 2MW	SEC DIST	3.7862	0.9735	0.3849	-	-	-	5.1445
	> 2MW	SEC DIST	48.4207	-	-	-	-	-	48.4207
Oilfield	< 2MW	SEC DIST	0.4877	0.1175	0.0371	0.0008	0.0003	0.0003	0.6436
Small GS	< 2MW	SEC DIST	0.0012	-	-	-	-	-	0.0012
Grand Total			52.6958	1.0910	0.4220	0.0008	0.0003	0.0003	54.2101

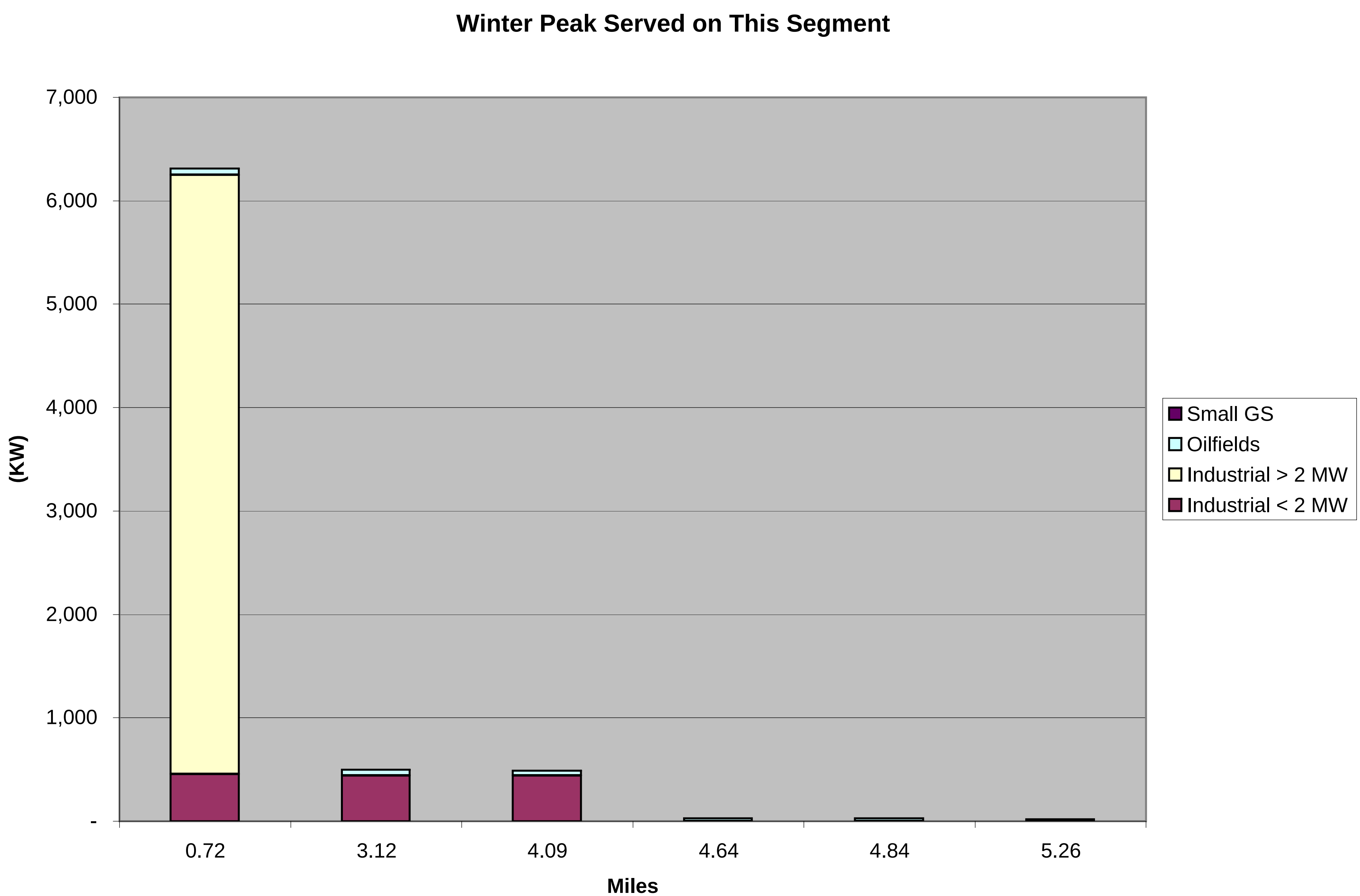
Grand Total Losses (UCA)	0.83514%	0.21939%	0.08674%	0.00282%	0.00099%	0.00153%
Grand Total Losses Per Mile (UCA)	1.15992%	0.09141%	0.08942%	0.00512%	0.00496%	0.00364%

Summary for Feeder 18
Table 5

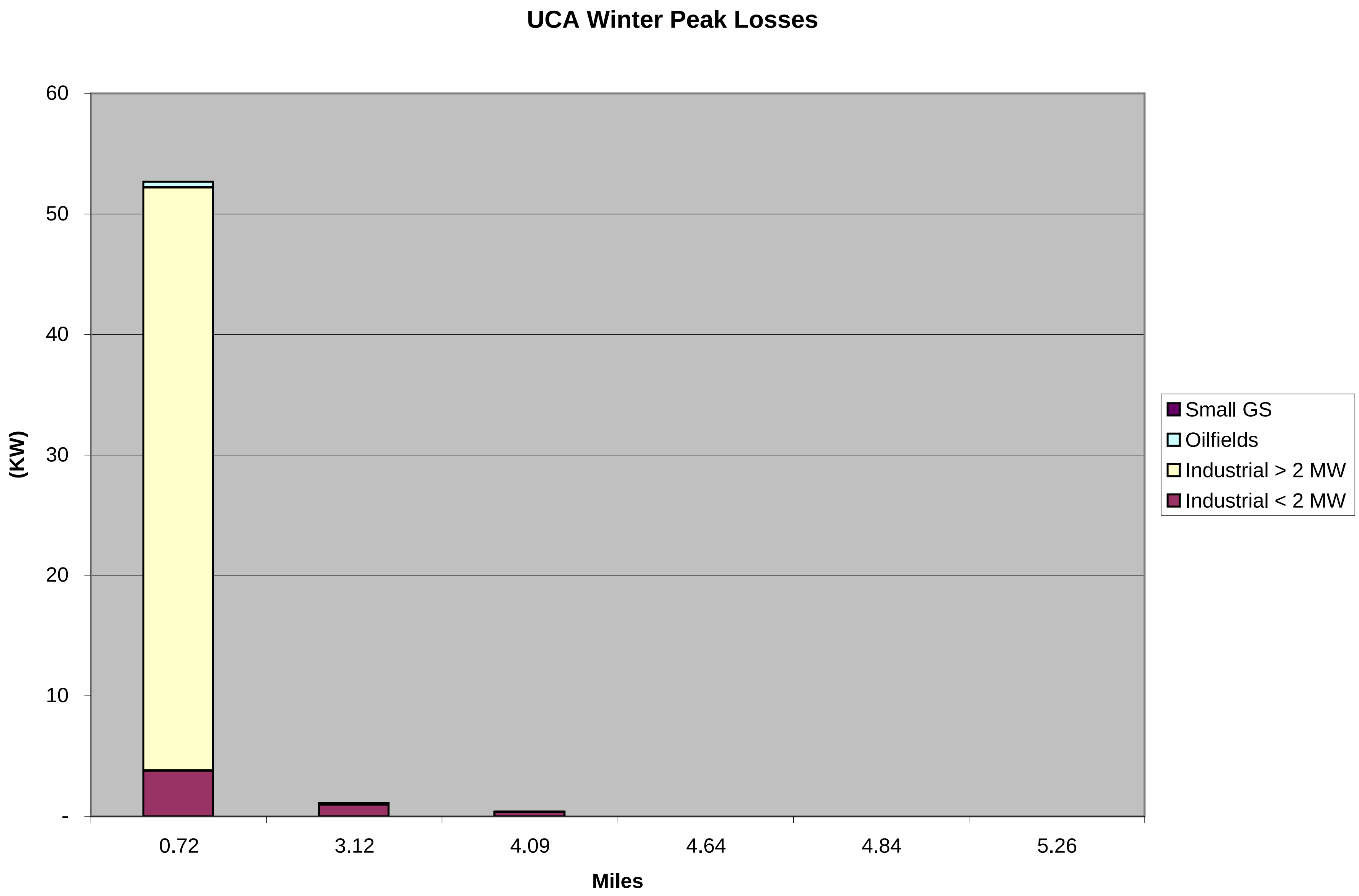
					AE Losses		UCA Losses	
CLASS	GROUP2	LEVEL		Winter Peak	(KW)	(%)	(KW)	(%)
Industrial	< 2MW	SEC DIST	Feeder18	453.36	15.80	3.49%	5.14	1.13%
	> 2MW	SEC DIST	Feeder18	5,797.92	36.31	0.63%	48.42	0.84%
Oilfield	< 2MW	SEC DIST	Feeder18	58.40	2.09	3.58%	0.64	1.10%
Small GS	< 2MW	SEC DIST	Feeder18	0.15	0.00	0.60%	0.00	0.84%
Grand Total				6,309.82	54.21	0.86%	54.21	0.86%

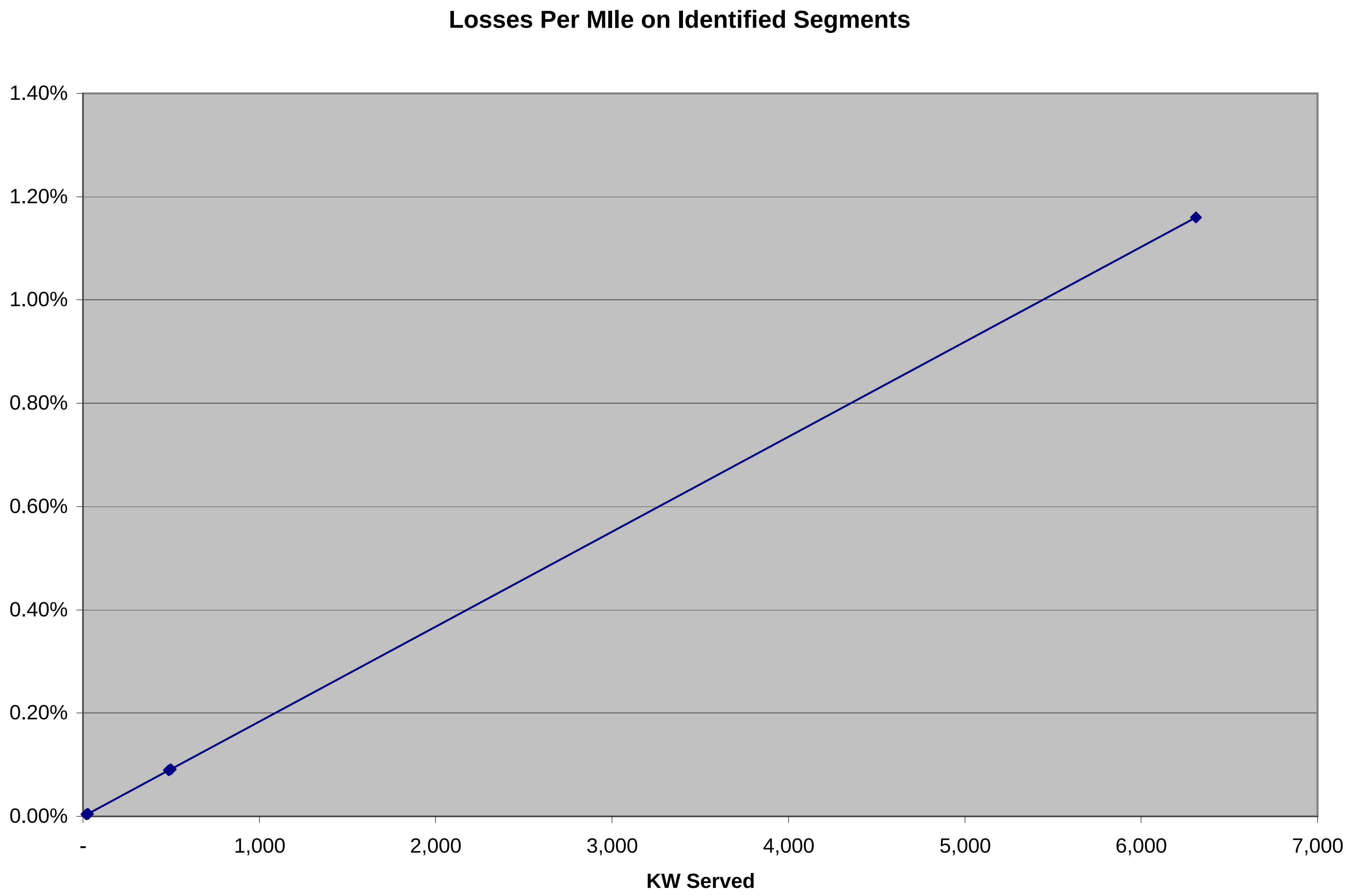

Winter Peak on Feeder 18
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
(KW)
0.72
3.12
4.09
4.64
4.84
5.26
Miles
Small GS
Oilfields
Industrial > 2 MW
Industrial < 2 MW

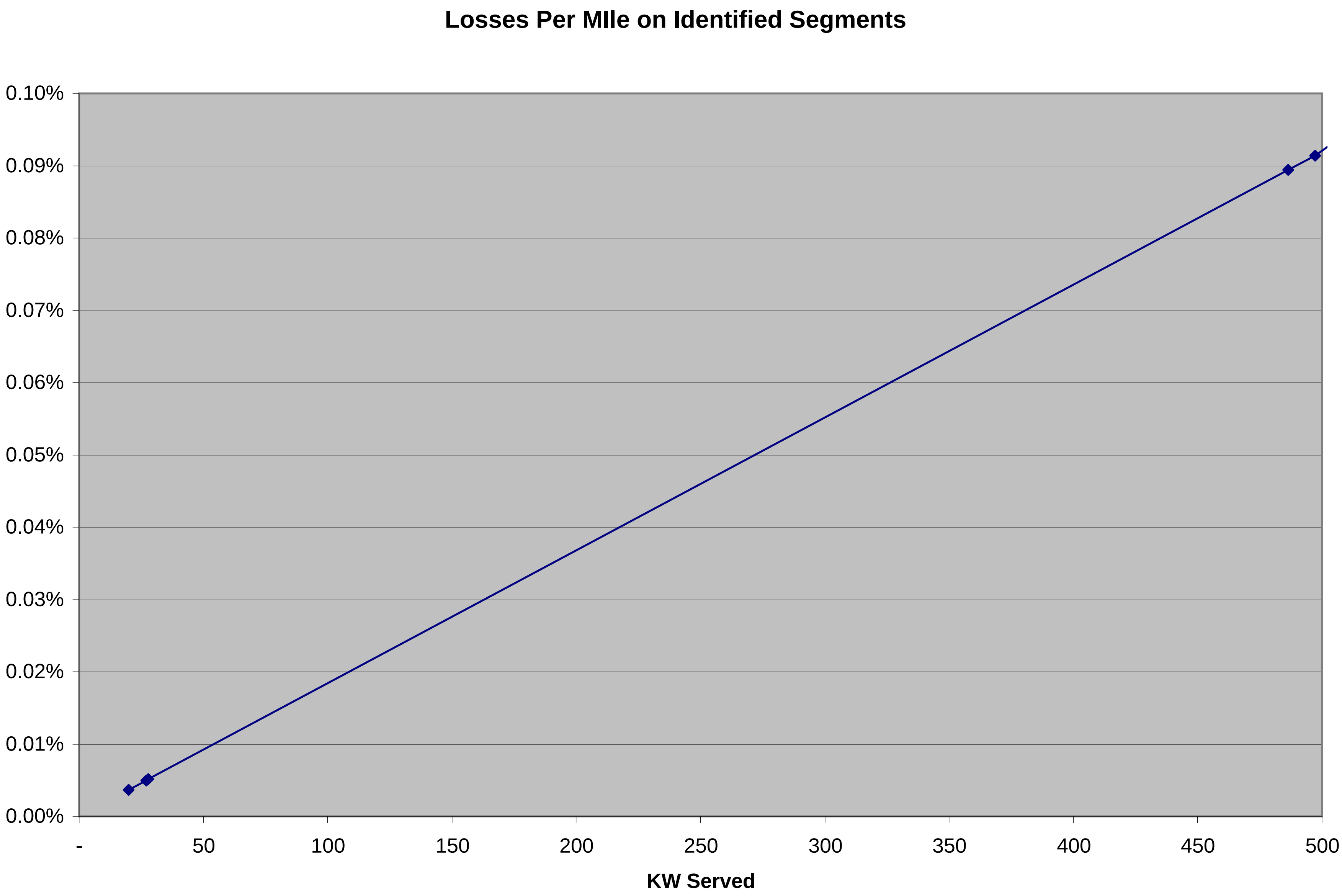

AE Winter Peak Losses Feeder 18
40
35
30
25
20
15
10
5
-
(KW)
0.72
3.12
4.09
4.64
4.84
5.26
Miles
Small GS
Oilfields
Industrial > 2 MW
Industrial < 2 MW


Winter Peak Served on This Segment
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
(KW)
0.72
3.12
4.09
4.64
4.84
5.26
Miles
Small GS
Oilfields
Industrial > 2 MW
Industrial < 2 MW

UCA Attachment 1D

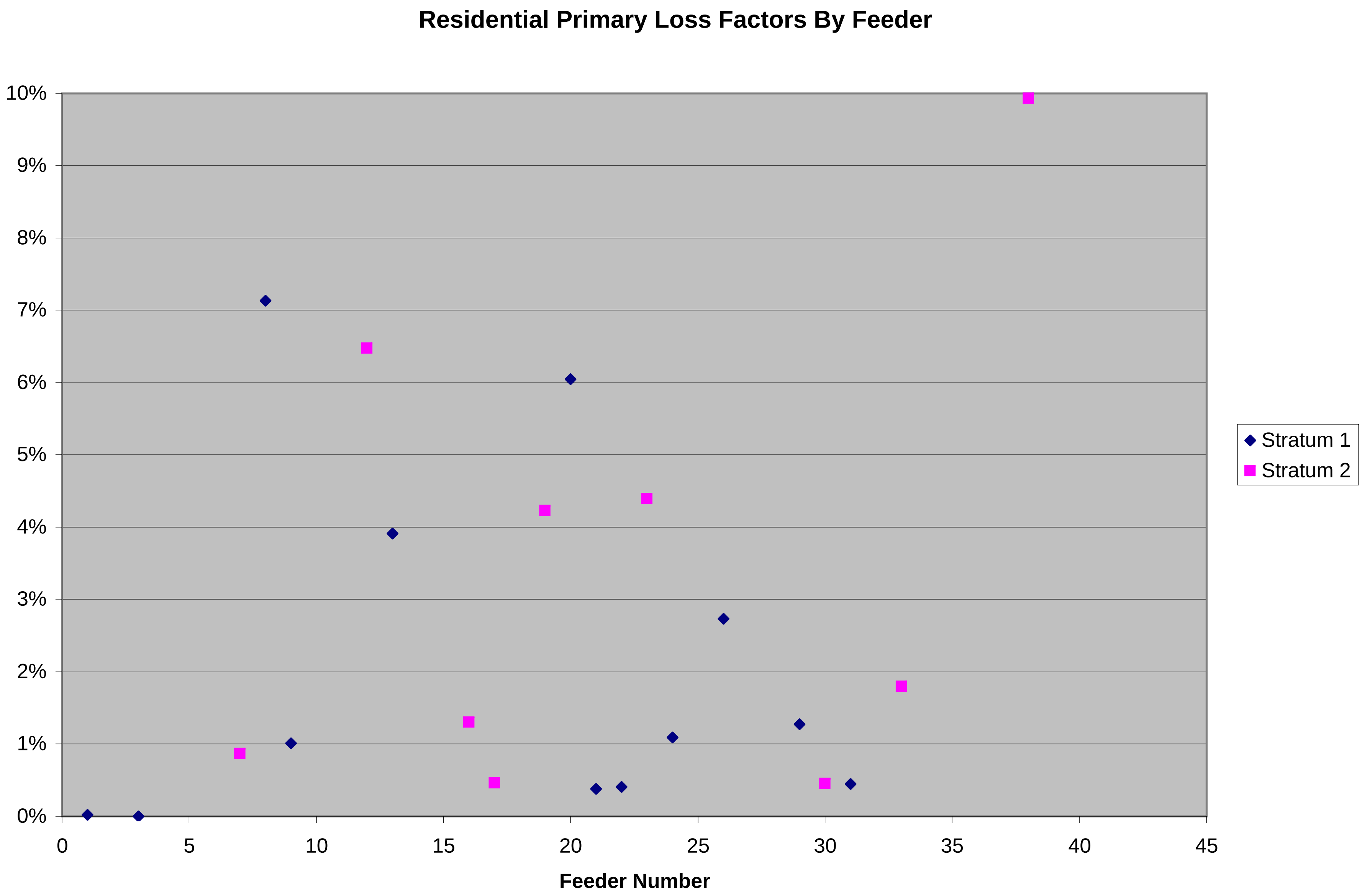


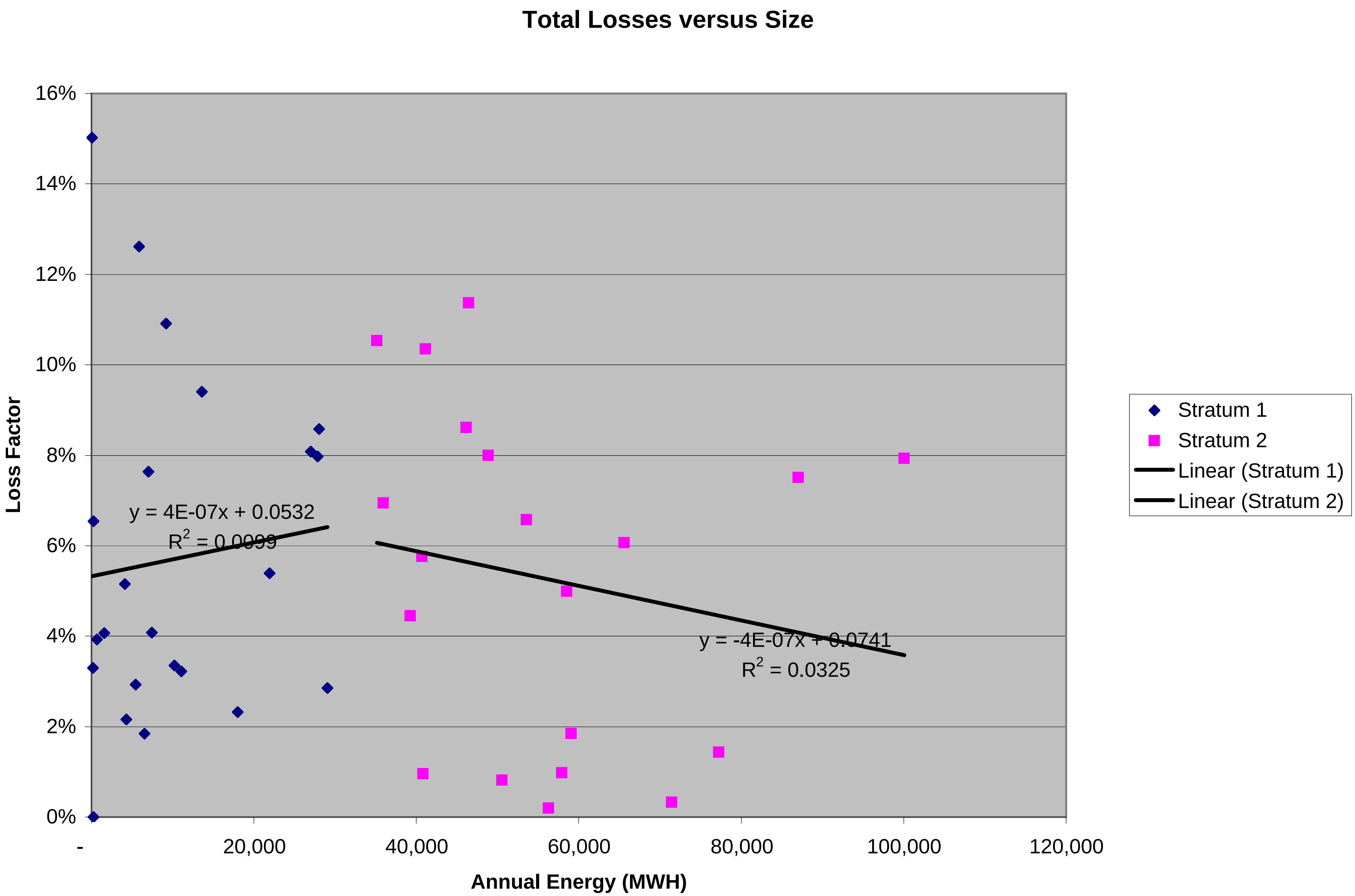

Losses Per MIle on Identified Segments
1.40%
1.20%
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
-
1,000
2,000
3,000
4,000
5,000
6,000
7,000
KW Served

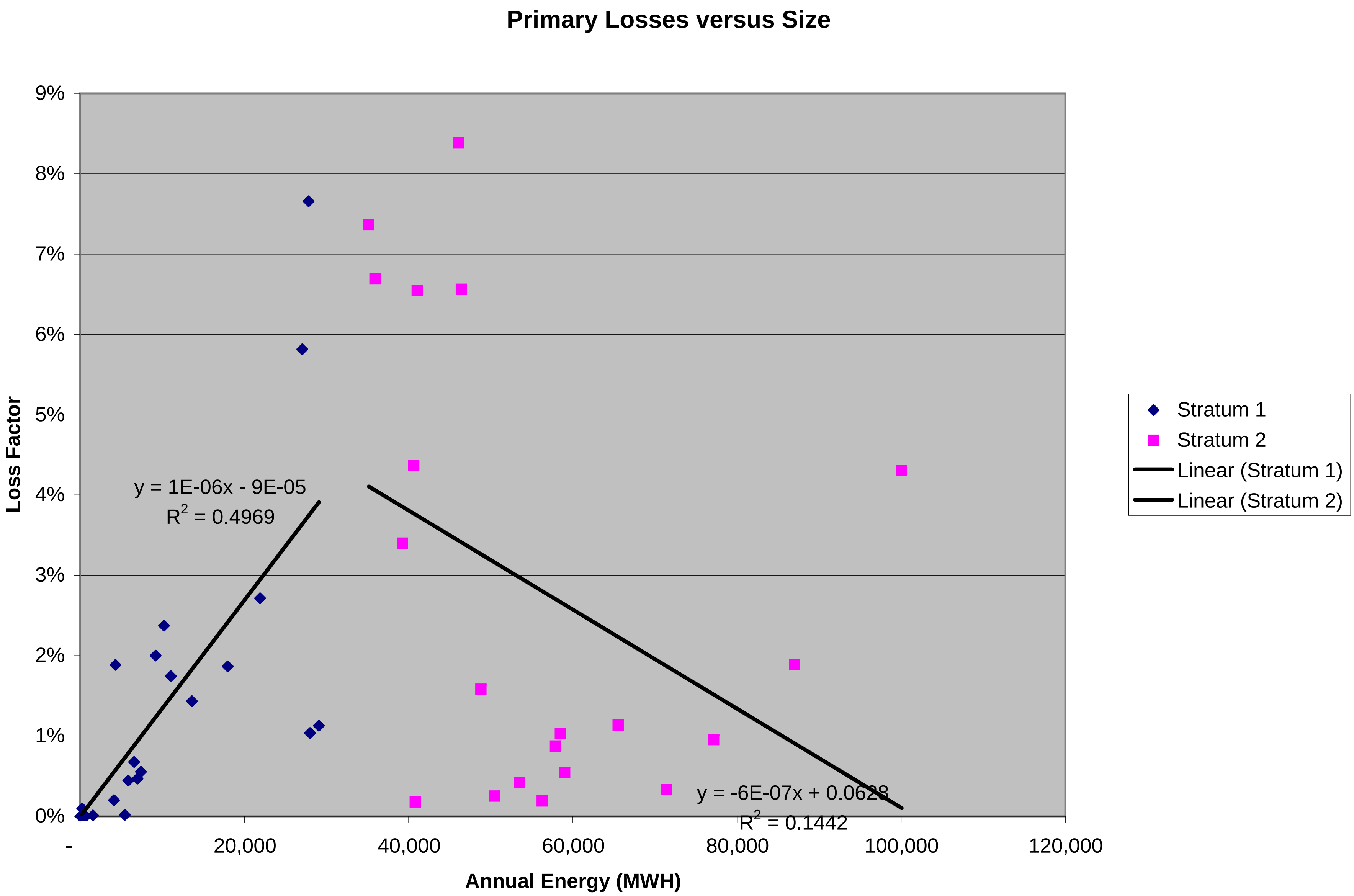

Losses Per MIle on Identified Segments
0.10%
0.09%
0.08%
0.07%
0.06%
0.05%
0.04%
0.03%
0.02%
0.01%
0.00%
-
50
100
150
200
250
300
350
400
450
500
KW Served

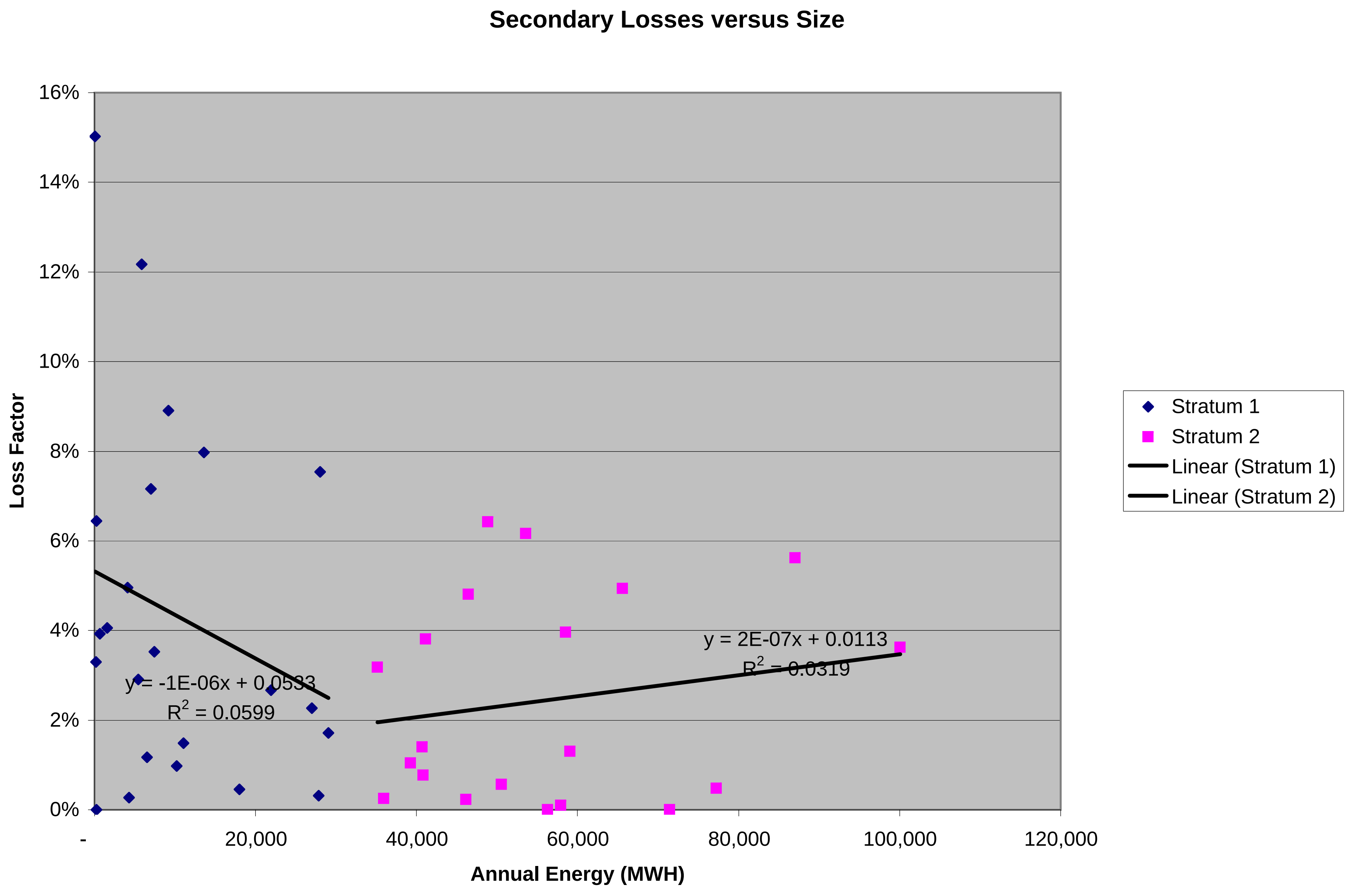
AE Precision in Estimating Class Loss Factors
Average Class Loss Factor For All Feeders Divided by Spread Absent One Feeder

RATE CLASS	SIZE GROUP	VOLTAGE LEVEL	Precision Total	Precision Primary	Precision Secondary
Farm	< 2MW	SEC DIST	12.88	6.65	6.48
Industrial	< 2MW	PRIM DIST	0.88	0.88	N/A
Industrial	< 2MW	SEC DIST	17.28	10.62	10.09
Industrial	> 2MW	PRIM DIST	4.26	4.26	N/A
Industrial	> 2MW	SEC DIST	4.15	3.45	2.58
Irrigation	< 2MW	SEC DIST	3.39	1.29	4.01
Oilfield	< 2MW	SEC DIST	14.21	10.58	9.71
Private Lighting	< 2MW	SEC DIST	13.18	5.58	8.15
Residential	< 2MW	SEC DIST	11.62	5.21	7.40
Small GS	< 2MW	SEC DIST	15.00	7.28	10.31
Street Lighting	< 2MW	SEC DIST	6.99	4.31	5.61
All Classes			15.41	10.38	9.62

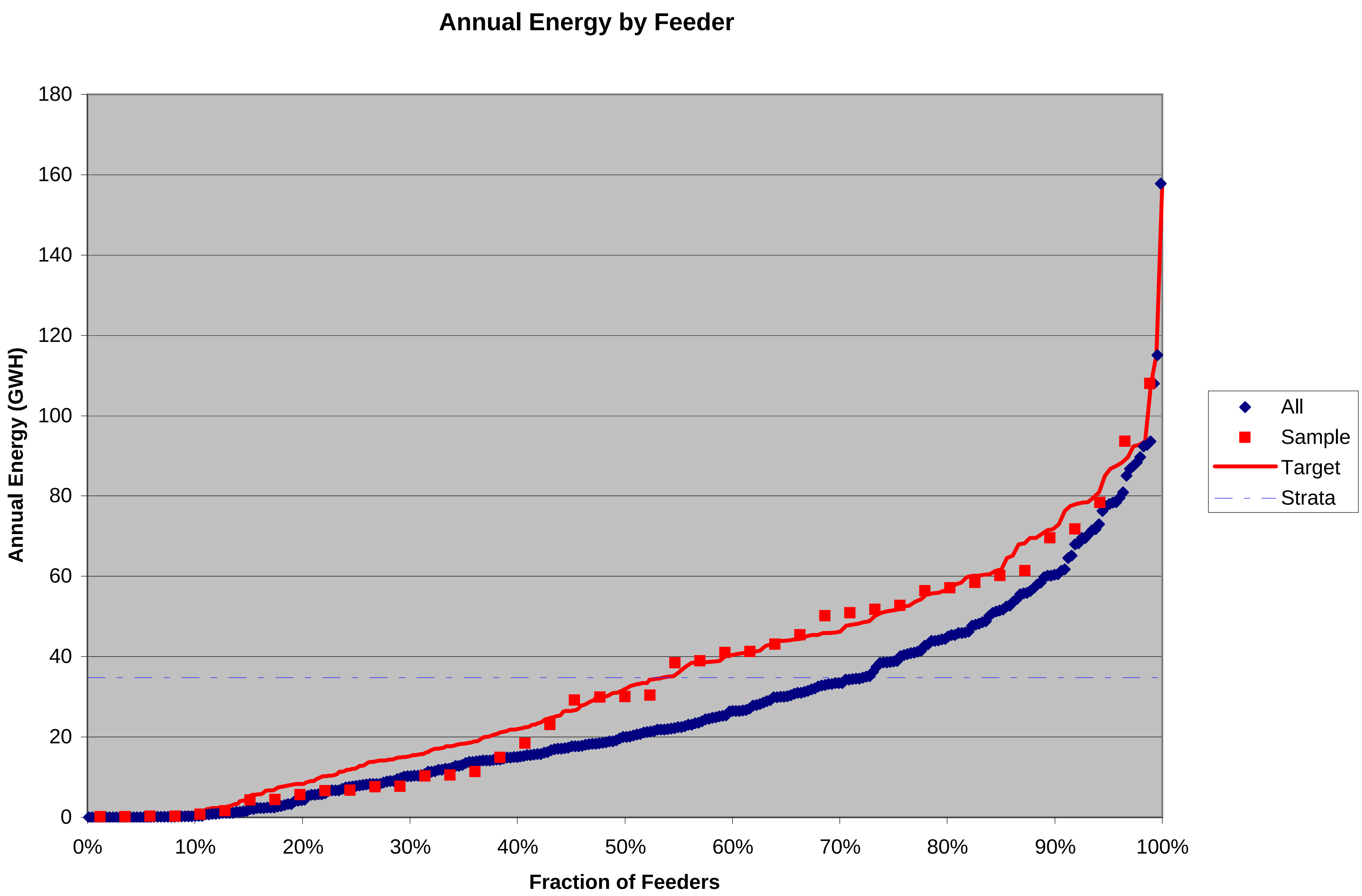

Residential Primary Loss Factors By Feeder
10%
9%
8%
7%
6%
5%
4%
3%
2%
1%
0%
0
5
10
15
20
25
30
35
40
45
Feeder Number
Stratum 1
Stratum 2


Total Losses versus Size
Loss Factor
16%
14%
12%
10%
8%
6%
4%
2%
0%
-
20,000
40,000
60,000
80,000
100,000
120,000
Annual Energy (MWH)
y = 4E-07x + 0.0532
R2 = 0.0099
y = -4E-07x + 0.0741
R2 = 0.0325
Stratum 1
Stratum 2
Linear (Stratum 1)
Linear (Stratum 2)


Primary Losses versus Size
Loss Factor
9%
8%
7%
6%
5%
4%
3%
2%
1%
0%
-
20,000
40,000
60,000
80,000
100,000
120,000
Annual Energy (MWH)
y = 1E-06x - 9E-05
R2 = 0.4969
y = -6E-07x + 0.0628
R2 = 0.1442
Stratum 1
Stratum 2
Linear (Stratum 1)
Linear (Stratum 2)



Secondary Losses versus Size
Loss Factor
16%
14%
12%
10%
8%
6%
4%
2%
0%
-
20,000
40,000
60,000
80,000
100,000
120,000
Annual Energy (MWH)
y = -1E-06x + 0.0533
R2 = 0.0599
y = 2E-07x + 0.0113
R2 = 0.0319
Stratum 1
Stratum 2
Linear (Stratum 1)
Linear (Stratum 2)


Annual Energy by Feeder
Annual Energy (GWH)
180
160
140
120
100
80
60
40
20
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Fraction of Feeders
All
Sample
Target
Strata

Application 1500878

CURRICULUM VITAE OF
Mark Lively for the UCA

To protect the privacy of the individual, the complete curriculum vitae cannot be viewed on this web site.

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CURRICULUM VITAE OF
H.J. Herb Vander Veen for the UCA

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