STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	)	CAUSE NO. 44688

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

REDACTED TESTIMONY OF

DWIGHT D. ETHERIDGE – PUBLIC'S EXHIBIT NO. 9

JANUARY 22, 2015

Respectfully submitted,

Scott C. Franson
Attorney No. 27839
Deputy Consumer Counselor

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***OUCC REDACTED TESTIMONY OF DWIGHT D. ETHERIDGE*** has been served upon the following parties of record in the captioned proceeding by electronic service on January 22, 2015.

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE	)	
COMPANY FOR AUTHORITY TO MODIFY ITS RATES	)	
AND CHARGES FOR ELECTRIC UTILITY SERVICE	)	
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CERTAIN RIDERS; (2) REVISED DEPRECIATION	)	
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CLEAN COAL TECHNOLOGY, CLEAN ENERGY	)	
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COMPLIANCE PROJECTS; AND (4) ACCOUNTING	)	
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TESTIMONY OF

DWIGHT D. ETHERIDGE – PUBLIC'S EXHIBIT NO. 9

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JANUARY 22, 2016

PUBLIC'S EXHIBIT NO. 9

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

NORTHERN INDIANA PUBLIC	)	
	)	CAUSE NO. 44688
SERVICE COMPANY	)	

DIRECT TESTIMONY

OF

DWIGHT D. ETHERIDGE

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JANUARY 22, 2016

EXETER

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<u>Schedules and Attachments (continued)</u>

TESTIMONY OF DWIGHT D. ETHERIDGE
CAUSE NO. 44688
NORTHERN INDIANA PUBLIC SERVICE COMPANY

I. Qualifications

Q. Please state your name and address.

A. My name is Dwight D. Etheridge. I am a Principal and Vice President with Exeter Associates, Inc. ("Exeter"), an economics consulting firm specializing in the economics of regulated industry. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science degree in Business Administration from the University of California, Berkeley. I have 29 years of experience in the public utility industry. My work has been focused on business plan development, industry restructuring, rate design, class cost-of-service studies, load forecasting, resource planning, transmission system evaluations, power procurement, distributed generation, telecommunications, and contract negotiations. From 1986 until 1999 I worked in progressively more responsible positions at Nevada Power Company, eventually reporting to the chief executive officer while leading a team of experts assigned to industry restructuring issues. After the merger of Sierra Pacific Resources and Nevada Power Company in 1999, I worked on a variety of strategic and diverse projects related to industry restructuring, mergers, telecommunications, and resource planning.

In 2004 I became an independent consultant and worked with clients on rate design, strategic planning, competitive market analyses, and industry restructuring projects. In 2006 I joined Exeter as a Senior Analyst and in 2008 I became a Principal and Vice President in the firm. My recent consulting work with Exeter has focused on a variety of projects related to wholesale commodity energy markets, options studies for federal facilities served at transmission voltage, review of retail service arrangements, and regulated ratemaking.

I have provided expert testimony on over thirty occasions before the Indiana Utility Regulatory Commission ("IURC" or "Commission"), Illinois Commerce Commission, Maryland Public Service Commission, Public Service Commission of Wyoming, Public Utilities Commission of Nevada, Public Utility Commission of Texas, and the Nevada Legislature on a variety of topics including: load forecasting, class cost-of-service studies and rate design, industry restructuring, hedging, transmission system evaluations, and various revenue requirement issues.

A summary of my qualifications is included as an appendix to this testimony.

Q. What is the purpose of your direct testimony in this proceeding?

A. The Indiana Office of Utility Consumer Counselor ("OUCC") asked Exeter to review the reasonableness of Northern Indiana Public Service Company's ("NIPSCO's" or "Company's") administrative and general ("A&G") operation and maintenance ("O&M) expenses. I performed a benchmarking study to evaluate NIPSCO's A&G cost containment performance relative to that of other electric utilities, and I present the results of that study in my testimony. In addition, as part of my review of O&M expenses, I analyzed NIPSCO's projected O&M savings associated with its automated meter reading ("AMR") project. Specifically, I present a recommendation that NIPSCO's test year O&M expenses be reduced to capture incremental O&M savings expected to be realized within the 12 months that follow the end of the test year.

II. Summary and Recommendations

Q. Please summarize your testimony?

A. NIPSCO's customers should expect to receive safe and reliable electricity service and at a reasonable price, and to be treated courteously and competently by NIPSCO employees when communicating with the utility. In fact, Violet Sistovaris, NIPSCO's Chief Executive Officer, sets forth NIPSCO's objectives of "safely providing our customers with top-tier reliability and service quality cost effectively...."[1] Several of NIPSCO's witnesses in this case, including Ms. Sistovaris, explain steps NIPSCO has taken in the last several years to increase the reliability of the electric service it provides to customers and to increase its customers' overall satisfaction levels. Clearly, both represent a positive trend for customers. On the other hand, rate increases are never pleasant from a customer's perspective.

The primary focus of my testimony is on whether NIPSCO is cost effectively managing its overall electric utility operations at an administrative level. This focus is not on NIPSCO's production, transmission, or distribution O&M expenses, but rather on NIPSCO's A&G expenses, including corporate salaries, outside services, materials and supplies, and rents. After fuel and purchased power costs, A&G expenses are the largest component of NIPSCO's total O&M costs, and therefore represent a significant component of NIPSCO's total costs and, in turn, the rates NIPSCO's customers pay.

NIPSCO's A&G expenses net of employee pensions and benefits expenses have been increasing at an extraordinary rate in recent years. So much so that when NIPSCO's performance at managing these expenses is benchmarked against other electric utilities, it becomes clear that, with respect to cost control, NIPSCO is far from being a "top-tier"

[1] Petitioner's Exhibit No. 1, Verified Direct Testimony of Violet Sistovaris, 9:10-12.

performer. To the contrary, NIPSCO ranks close to the bottom. My benchmarking study suggests that NIPSCO's A&G expenses would have to be reduced by $28 million or more just to achieve below average performance at managing A&G cost escalation compared with other electric utilities. Achieving just below average performance is not what customers should expect from their utility. This result brings into question the reasonableness of NIPSCO's current expense levels and likewise the reasonableness of NIPSCO's requested rate increase.

One recent step that NIPSCO has taken to increase customer satisfaction and reduce costs was the implementation of its AMR project. I analyzed the cost savings NIPSCO expects to achieve with this project and determined that a substantial amount of savings will occur in the 12 months following the end of the test year, and with additional cost savings still to occur thereafter. Cost savings associated with the AMR project expected to be realized in the 12 months following the end of the test year should be passed through to customers in this case.

Q. What are your recommendations?

A. So that NIPSCO's customers will receive the incremental cost savings expected to be realized as a result of the AMR project in the 12 months following the end of the test year, I recommend the Commission reduce NIPSCO's O&M expenses by approximately $1.6 million.

While I am not proposing a specific adjustment associated with my benchmarking study, when evaluating the overall revenue increase, if any, to be granted to NIPSCO in this case, I recommend the Commission consider the fact that NIPSCO's A&G expenses have been increasing at an extraordinary rate. Customers have a right to expect reliable electric service at a reasonable price, and my benchmarking study raises serious doubts concerning the reasonableness of NIPSCO's A&G expense levels.

III. Automated Meter Reading Operation and Maintenance Expense Savings

Q. Please explain NIPSCO's AMR project?

A. NIPSCO's AMR project involves capital investments in metering equipment and systems to allow NIPSCO to read meters from a receiver mounted in a NIPSCO vehicle rather than having meter readers physically read meters on customers' properties. NIPSCO explains some of the benefits of its AMR project as follows:

- AMR meters will help eliminate estimated meter readings by gathering your monthly reading through a receiver mounted in a NIPSCO vehicle that can read several households and businesses at once.
- Because monthly meter readings can be collected without needing to physically read each meter in person, customers enjoy greater privacy and convenience.
- The new AMR system will improve workplace safety for our meter readers by removing many of the hazards they face (severe weather, locked gates, tripping hazards and animal interference).[2]

NIPSCO selected Itron, Inc.'s ("Itron's") AMR solution for this project in January 2013.[3] As Itron explains in its AMR Business Case white paper, a major benefit of AMR projects is meter reading cost reductions that a utility can realize:

> In order to develop a business case that reflects the operations of a utility, an understanding must be gained of the utility's unique operating characteristics. Special attention needs to be paid to benefits each utility expects from automating their system. Regardless of the type of automation, the intended benefits should be weighed against the cost of enabling the technology. If the realized benefits exceed project costs, then the project should be undertaken. When looking at automation, it is easy to

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[2] NIPSCO website (https://www.nipsco.com/our-services/about-our-meters/automated-meter-reading, accessed on January 13, 2016).

[3] Iron News Release, *NIPSCO Selects Itron Automated Metering Solutions to Streamline Meter Reading and Improve Efficiency*, January 28, 2013 (http://investors.itron.com/releasedetail.cfm?releaseid=736028, accessed on January 13, 2016).

> see the reduction in basic meter reading costs. While the cost of meter reading can vary due to many factors, this is one of the main expenditures to be eliminated through automation. Costs for manual reading typically range from $.50 to $1.50 per read or, depending on labor costs and distance between meters, costs as high as $3.00. By deploying automation, costs can be reduced substantially, even from just electronic meter reading or offsite meter reading (a handheld equipped with a radio device to read meters from a distance). Other costs associated with manual meter reading that are all but eliminated with automation include salaries, benefits, vehicle costs, cellular phone expenses, handheld meter reading systems, maintenance and some general overhead expense, etc.[4]

In fact, NIPSCO's Senior Vice President Electric Operations, Michael Hooper, sponsored a business case dated January 28, 2013, which was presented to NIPSCO's Risk Management Committee[5] and approved because Itron announced that same day that it had been selected by NIPSCO to supply an automated metering solution.[6]

An additional benefit from an AMR project, as NIPSCO noted, is increased customer satisfaction levels associated with the elimination of estimated meter reads. This benefit was confirmed by Ms. Sistovaris in an August 2015 interview where the interviewer reported that:

> NIPSCO has seen a dramatic drop in one of its top customer complaints now that a changeover to automated meter reading is almost complete.
>
> The automated meter reads mean a customer's meter is read every month, with no more estimated readings and bills due to locked gates, menacing dogs or other obstacles, according to NIPSCO. Those estimated bills often raised the ire of customers who felt they were inaccurate or a backdoor way for NIPSCO to charge more.
>
> The automated meter reading system NIPSCO uses allows meter readers in specially equipped vehicles to read 800 to 900 meters per hour. They differ from so-called "smart meters" in that only the meter readings are transmitted and not personal customer information.

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[4] Bowers, Darla, Itron White Paper AMR Business Case, *Benefits Derived From Automating Meter Reading: Developing Your Business Case*, https://www.itron.com/PublishedContent/Benefits_Derived_From_Automating_Meter_ReadingDeveloping_Your_Business_Case.pdf, accessed on January 13, 2016).
[5] NIPSCO response to OUCC Set 4-007 Confidential Attachment A.
[6] Itron News Release, *op. cit.*

> With installation of automated meters nearly complete for all 1.15 million customer meters, complaints about estimated bills have dropped 87.5 percent, according to NIPSCO figures. It has been a multi-year project.[7]

With the AMR project nearly complete, NIPSCO has confirmed it has begun to realize the O&M savings projected in its 2013 AMR business case, and other added benefits from the project.

Q. Has NIPSCO provided you with documentation showing that the AMR project installations are nearly complete?

A. Yes it has. NIPSCO provided documentation that the number of AMR installations completed as of December 22, 2015 had reached 93 percent of the total anticipated installations listed in its business case for each of its electric and gas divisions.[8] In addition, NIPSCO provided documentation that its AMR related capital investments will have reached 98 percent of its business case projections by the end of December 2015.[9]

Q. Has NIPSCO provided you with documentation showing that it has begun to realize O&M cost savings associated with the AMR project?

A. Yes it has. As part of its AMR business case, NIPSCO projected that O&M cost savings were expected to increase as the number of AMR installations increased, and that savings would be fully realized within two years following the completion of all planned AMR installations. NIPSCO also projected that incremental year-over-year O&M cost savings associated with the AMR project would be most significant in the year when installations were completed and the subsequent year. With AMR installations nearly complete, those years when maximum incremental O&M cost savings would be realized are 2015 and 2016. That means that NIPSCO can be expected to realize substantial electric O&M cost

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[7] Benman, Keith, nwi.com, *NIPSCO automated meter reads nearly nix estimated bills*, August 15, 2105 http://www.nwitimes.com/business/nipsco-automated-meter-reads-nearly-nix-estimated-bills/article_6c69c4ed-97bb-5bb6-97ad-1e3e6b3650bb.html?print=true&cid=print, accessed January 13, 2016).
[8] NIPSCO response to OUCC Set 25-005 Confidential Attachment A.
[9] NIPSCO response to OUCC Set 15-003 Confidential Attachment A.

savings associated with its AMR project in the 12 months following the end of the test year, and which are not reflected in test year expenses. NIPSCO has provided the OUCC with documentation to that effect.[10]

Q. Have you developed an estimate of NIPSCO's O&M cost savings that will be realized in the 12 months following the end of the test year?

A. Yes. I used NIPSCO's business case estimates of projected O&M cost savings by calendar year, allocated a portion of those savings to the electric division using NIPSCO's most recent O&M allocation factor of 38.98 percent, and then linearly pro-rated those savings for the last nine months of 2015 and the first three months of 2016. The result is an estimate of incremental electric O&M cost savings NIPSCO can expect to realize in the 12 months following the end of the test year. These calculations are shown in Confidential Schedule DDE-1 attached to my testimony, and my recommended reduction to NIPSCO's O&M expenses of approximately $1.6 million is highlighted within a box on that schedule.

Q. Does NIPSCO expect to achieve additional O&M savings from its AMR project after March 31, 2016?

A. Yes. Additional O&M savings from the AMR project are expected to be realized after March 31, 2016, which is beyond the period reflected in my proposed adjustment, and those savings will accrue to the benefit of NIPSCO's shareholders.

[10] NIPSCO response to OUCC Set 25-001 Confidential Attachment A and 25-002 Confidential Attachment A.

IV. Administrative and General Expense Benchmarking

A. Benchmarking Study Overview

Q. What was the impetus for performing a benchmarking study of NIPSCO's A&G expenses?

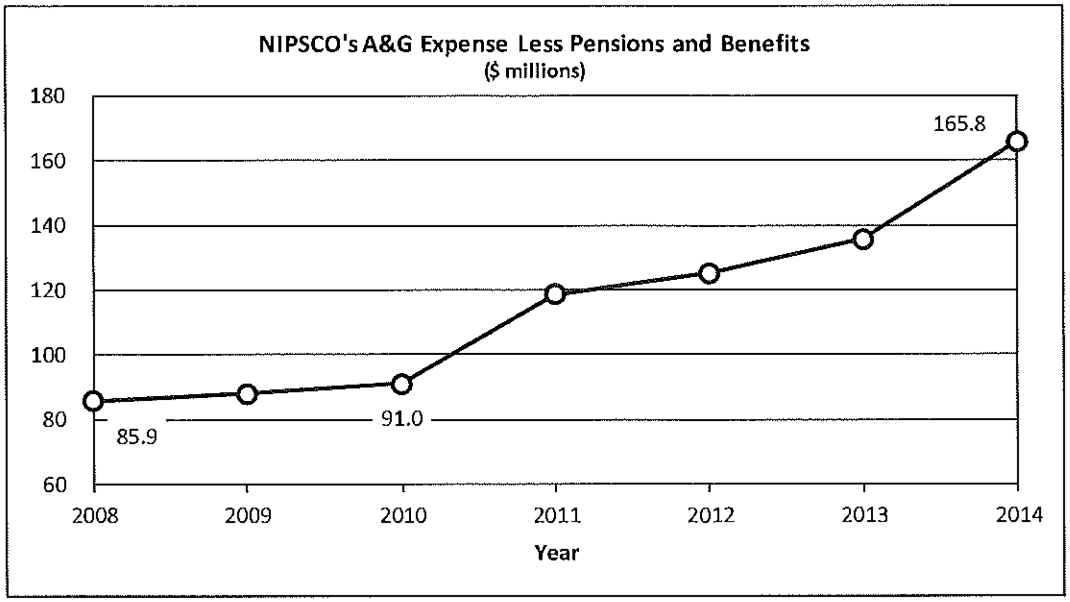
A. NIPSCO's A&G expenses as reported in its annual Form 1 filings made with the Federal Energy Regulatory Commission ("FERC") have been escalating at an extraordinary rate in the last four years. Excluding pension and benefits expenses, which can be influenced by factors outside of management's control, NIPSCO's A&G expenses have increased from \$91.0 million in 2010 to \$165.8 million in 2014.[11] This contrasts with the more modest escalation in these expenses reported by NIPSCO between 2008 and 2010. Figure 1, below, shows NIPSCO's A&G expenses net of pensions and benefits for the most recent seven years. Figure 2 shows these same expenses with trend lines that reflect the upward escalation in these expenses between 2008 and 2014 and between 2010 and 2014. From 2008 to 2014, these expenses increased at a compound annual growth rate ("CAGR") of 11.6 percent. Over the most recent four years that rate of escalation increased to 16.2 percent. Those are extraordinarily high cost escalation rates, which warrant further investigation.

Q. Please describe your benchmarking study of NIPSCO's A&G expenses.

A. My benchmarking study represents a detailed comparison of NIPSCO's A&G expenses with those of other U.S. investor-owned electric utilities. The study begins with Exeter's database of A&G expenses and various measures of the scale of a utility's size (e.g., retail sales and total plant in service). Data was gathered from detailed Form 1 reports

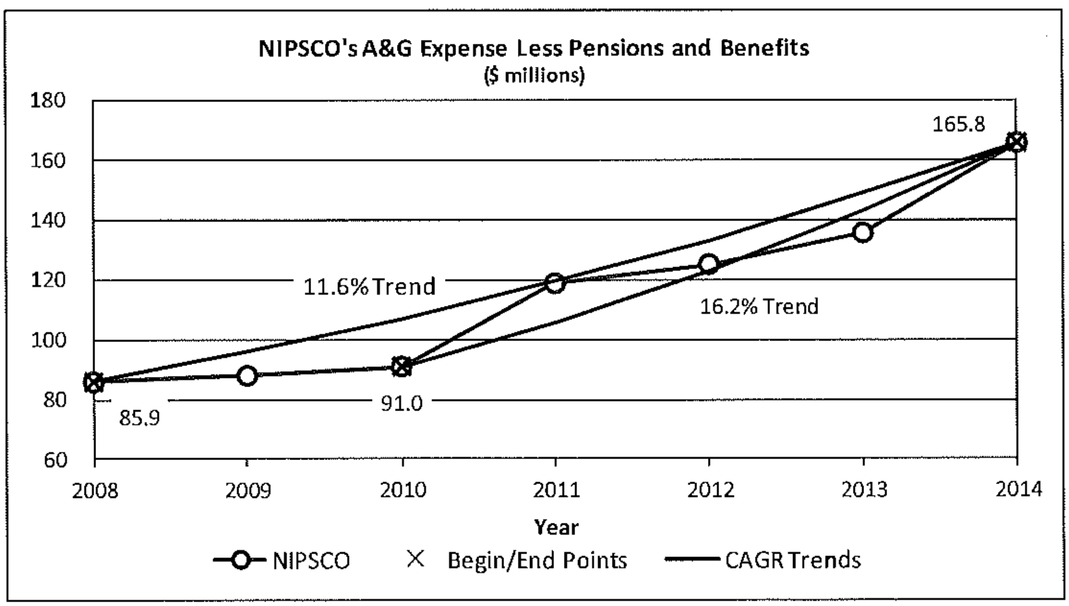
[11] Utilities typically file their Form 1s with FERC beginning in late-March of the following year (i.e., 2015 Form 1s will begin to be filed in late-March 2016).

FIGURE 1



Source: NIPSCO's FERC Form 1s. Etheridge workpapers for U.S. sample.

FIGURE 2



Source: NIPSCO's FERC Form 1s. Etheridge workpapers for U.S. sample.

that investor-owned utilities are required to file annually with the FERC, and which are publicly available on the FERC's website. Exeter compiled a database on 122 utilities, which represents the population of investor-owned U.S. electric utilities, except for a number of very small utilities, and for the years 2008 through 2014. I combined A&G expenses with measures of a utility's size to develop performance metrics that allowed for more rational comparisons between utilities than could have been made by looking only at A&G expenses, particularly given the widely-ranging size of utilities across the U.S. I then developed comparisons of NIPSCO's A&G expense performance metrics to A&G expense performance metrics for Exeter's database of U.S. utilities, and to performance metrics from subsets of that population of utilities that I constructed. Effectively, I was benchmarking NIPSCO's A&G expenses over time to A&G expenses for other utilities over the same time. Next, I performed trend analyses comparing the escalation in NIPSCO's A&G expense performance metrics over time to the escalation in A&G expense performance metrics for utilities in Exeter's database, and to selected subsets of that database. I then performed several sensitivity analyses to help me reach conclusions regarding NIPSCO's relative ability to manage its A&G expenses.

Q. Can you provide an example of where you obtained A&G expense information in NIPSCO's FERC Form 1?

A. Yes. The FERC Form 1 has standard formatting prescribed by FERC, and utilities report A&G expenses on page 323 of their Form 1 filings. I've attached NIPSCO's 2014 Form 1, page 323, to my testimony as Attachment DDE-1. NIPSCO's total A&G expenses for 2014 were $202,803,802 as shown on line 197, column (b). The prior year total A&G expenses were $183,441,266 as shown in column (c). For my benchmarking study, I examined utilities' total A&G expenses less employee pensions and benefits expenses, which are reported on line 187 (hereinafter, "net A&G expenses"). I do this because employee pensions and benefits expenses can fluctuate from year-to-year for reasons that are, in part, outside of utility management's control. This presents an additional layer of complexity for a benchmarking study that I chose to eliminate for my current study. NIPSCO's net A&G expenses for 2013 were $135,611,417 and increased to $165,810,867 in 2014.

Q. What FERC Form 1 data on utility size is included in Exeter's database?

A. Exeter's database includes information on utilities' retail customers, retail sales, retail revenue, total sales, and total plant in service. Utilities report retail revenues on page 300 of their Form 1, and retail sales, retail customers, and total sales on page 301.[12] Total plant in service is reported on page 207.

Q. What are the names of the 122 utilities that are included in your database?

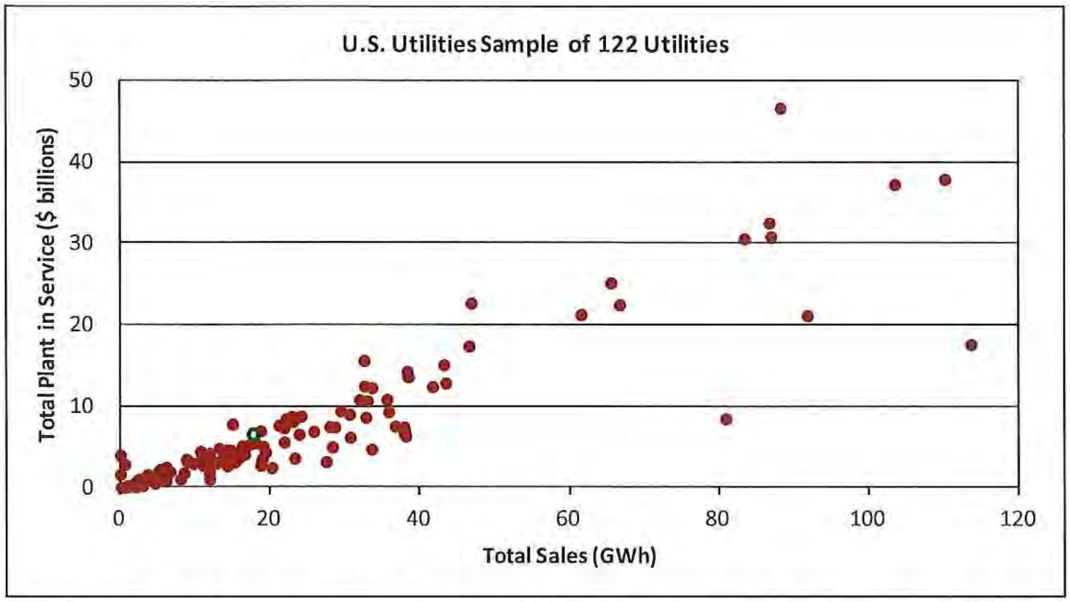
A. The 122 utilities included in my "U.S. sample" are listed in Schedule DDE-2. I have also plotted the average 2013 and 2014 total sales and total plant in service for these utilities in Figure 3.

Q. What subsets of your U.S. sample did you construct as part of your benchmarking analyses?

A. I bracketed utilities ranked by their total sales and total plant in service to include all five of Indiana's investor-owned utilities, including, in addition to NIPSCO: Indianapolis Power & Light Company ("IPL"), Indiana Michigan Power Company ("I&M"), Duke Energy Indiana, Inc. ("DEI"), and Southern Indiana Gas and Electric Company ("SIGE") (collectively, "Other IN" utilities).[13] SIGE is the smallest of Indiana's investor-owned utilities based upon total sales and total plant in service, and IMP and DEI are the largest

[12] Retail revenue, sales, and customers are also reported on page 304.
[13] I also refer to I&M as IMP and DEI as DEIN in my benchmarking study workpapers and Schedules DDE-2 and DDE-3.

FIGURE 3

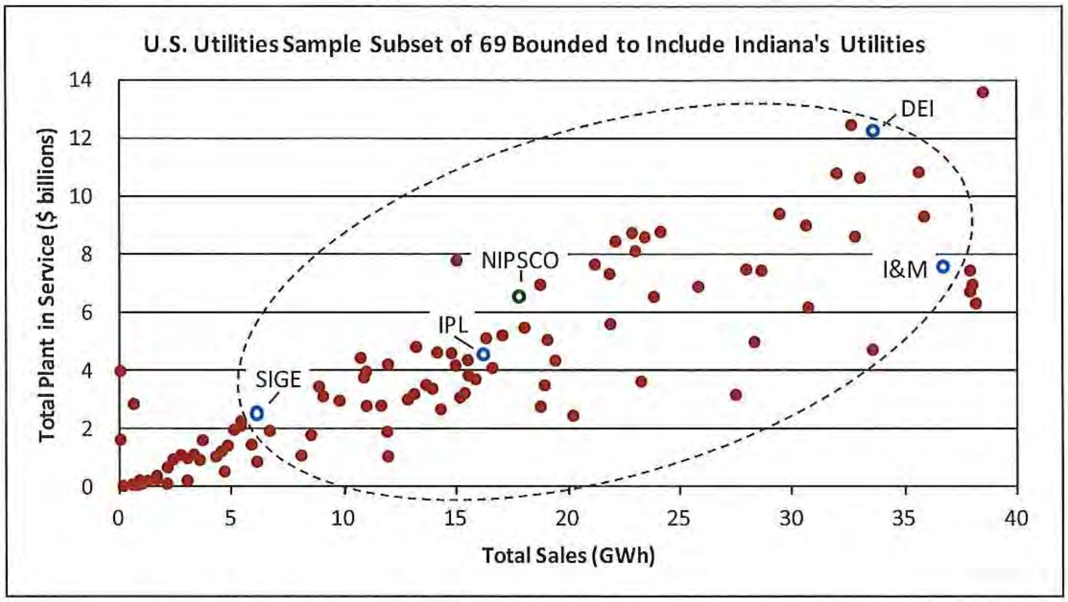


Source: Etheridge workpapers for the U.S. sample. Figures are averages for 2013 and 2014. NIPSCO is represented by a circle located at approximately 18 gigawatt hours ("GWh") on the x-axis and $7 billion on the y-axis.

based upon those measures. As shown in Figure 4, I bracketed the population in the U.S. sample to include SIGE on the low end and I&M and DEI on the high end to obtain a sample of 69 utilities for additional benchmarking analyses. These utilities are also listed in Schedule DDE-2.

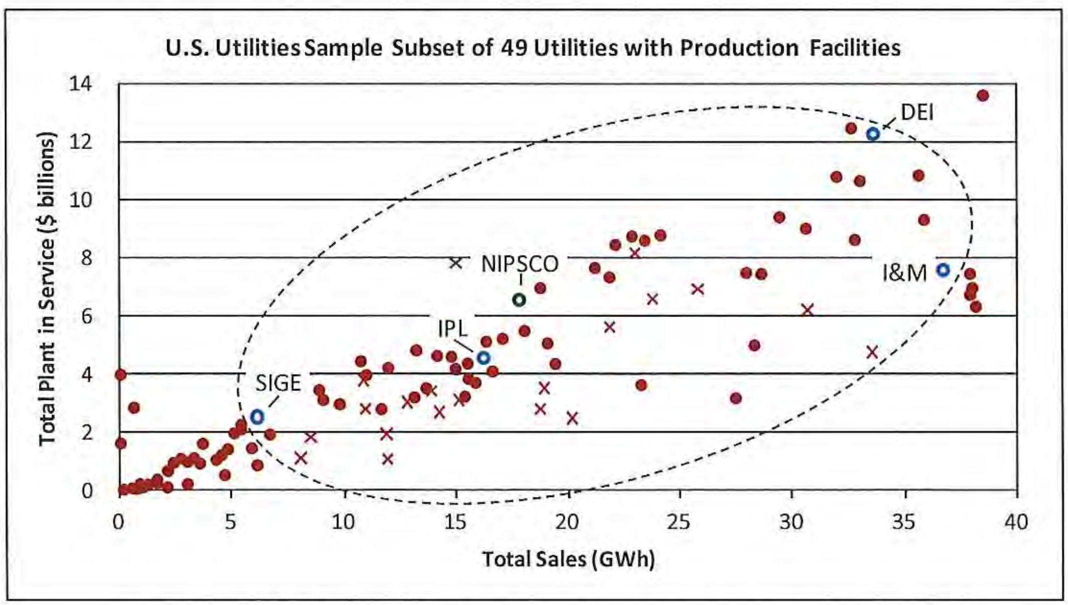
For an additional sample, I eliminated any of the 69 utilities that did not have production facilities. That left me with a third sample that included 49 utilities as shown in Figure 5. For my fourth and final sample, I included 25 of the U.S. utilities that operate within the MidContinent Independent System Operator's ("MISO's") marketplace, thereby retaining all but I&M of the Other IN utilities. These utilities are plotted in Figure 6. The utilities in my third and fourth samples are also listed in Schedule DDE-2.

FIGURE 4



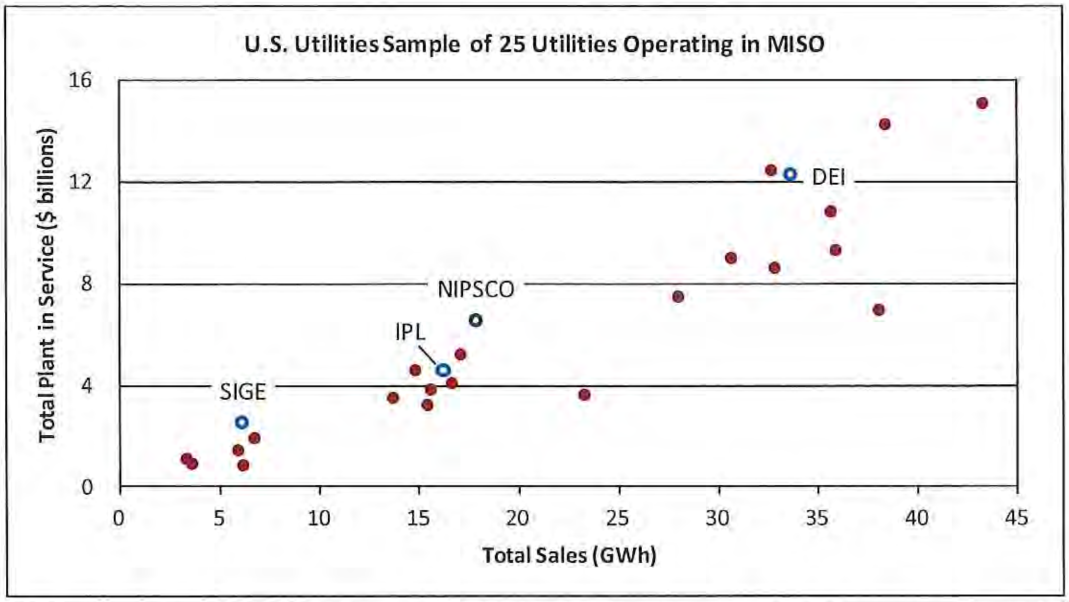
Source: Etheridge workpapers for the U.S. sample.

FIGURE 5



Source: Etheridge workpapers for the U.S. sample. The selection of sample subsets was included in those workpapers. Each utility eliminated from the second sample to construct the third sample is denoted with an "x".

FIGURE 6



Source: Etheridge workpapers for the U.S. sample. The selection of sample subsets was included in those workpapers.

Q. Please explain the performance metrics you constructed.

A. I developed five performance metrics by dividing each utility's net A&G expenses by each measure of that utility's size. The five performance metrics used in my benchmarking study were:

- Net A&G expense per retail sales stated as dollars per megawatt-hour ("$/MWh");
- Net A&G expense per retail customer stated as dollars per customer;
- Net A&G expense per retail revenues stated as a percent;
- Net A&G expense per total sales stated as $/MWh; and
- Net A&G expense per total plant in service stated as cents per dollar ("¢/$").

Net A&G expenses are fairly well correlated with each of these measures of a utility's size, which is to be expected because it makes sense that a utility's net A&G expenses would increase as the scale of its electric utility business increases (i.e., managerial and support staffs and their associated expenses will increase as the size of the business increases).

Performance metrics calculated in this fashion allow for a more rational comparison of A&G expenses for two utilities that may be markedly different in size. For example, NIPSCO and Orange and Rockland Utilities, Inc. ("OAR") have nearly identical levels of net A&G expense per retail sales in 2014, with NIPSCO's performance metric equal to \$9.47/MWh and OAR's equal to \$9.43/MWh. Yet, NIPSCO's net A&G expenses at \$166 million are over four times greater than OAR's net A&G expenses of \$38 million.

B. Benchmarking Absolute Levels of Performance Metrics

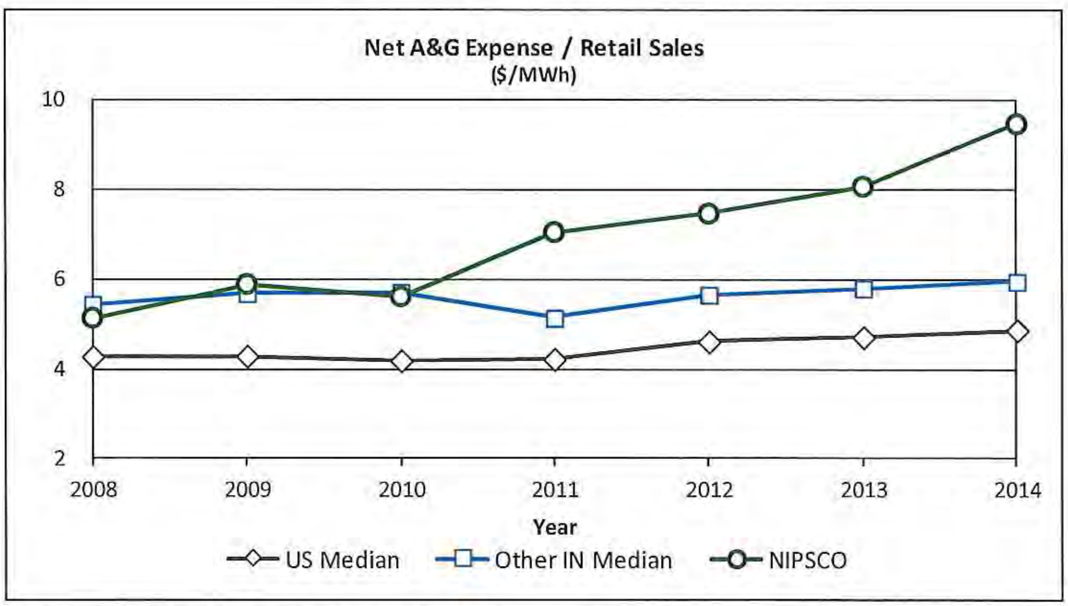
Q. Please explain what the performance metrics represent?

A. The performance metrics represent ratios of net A&G expense relative to a measure of size for each utility and for each year in my data range, with net A&G expense as the numerator and the measure of size as the denominator. When comparing performance metrics for any two utilities for any given year, the utility with the lower performance metric will be the utility with lower net A&G expenses after accounting for each utility's difference in size. Performance metrics for any given utility can also be compared with statistics on performance metrics (i.e., the median) derived from a sample of utilities for any given year or over a period of years. Utilities can also be ranked by their performance metrics from lowest to highest cost utility for any given year, and vice versa. Utilities' performance metrics and sample statistics on performance metrics will trend over time, and these trends can be examined. As a first step in my benchmarking study, I compared absolute levels of performance metrics and observed their general trends. As a subsequent step, I specifically analyzed trends in performance metrics.

Q. Please describe how you benchmarked NIPSCO's absolute levels of performance metrics to the U.S. sample?

A. First, I calculated the median level of each performance metric for the U.S. sample and for the Other IN utilities, and then I graphically compared NIPSCO's performance metrics to those medians. For example, Figure 7 shows NIPSCO's net A&G expense per retail sales compared with the U.S. median and the Other IN median. NIPSCO's performance metric tracked closely with the median for the Other IN utilities from 2008 through 2010 and then diverged upward and steadily away from the Other IN median and the U.S. median from 2011 through 2014.

FIGURE 7



Source: Etheridge workpapers for U.S. sample.

The extent to which a performance metric deviates from the U.S. median is difficult to put into context without additional information regarding the range of different utilities' performance metrics within the U.S. sample. Therefore, in addition to calculating the U.S. sample median, I separated the U.S. sample into quintiles so I could determine where NIPSCO and the Other IN utilities ranked relative to five segments of the U.S. sample. I find using quintiles for my benchmarking studies to be useful because of the intuitive nature of having the 3rd or middle quintile represent "average" performance. In turn, the 2nd and 4th quintiles represent above or below average performance, respectively. Finally, the 1st quintile represents "excellent" performance and the 5th quintile represents "poor" performance. As I will explain, the absolute levels of NIPSCO's net A&G expense performance metrics place it in the 4th or 5th quintile in recent years, which is a concern.

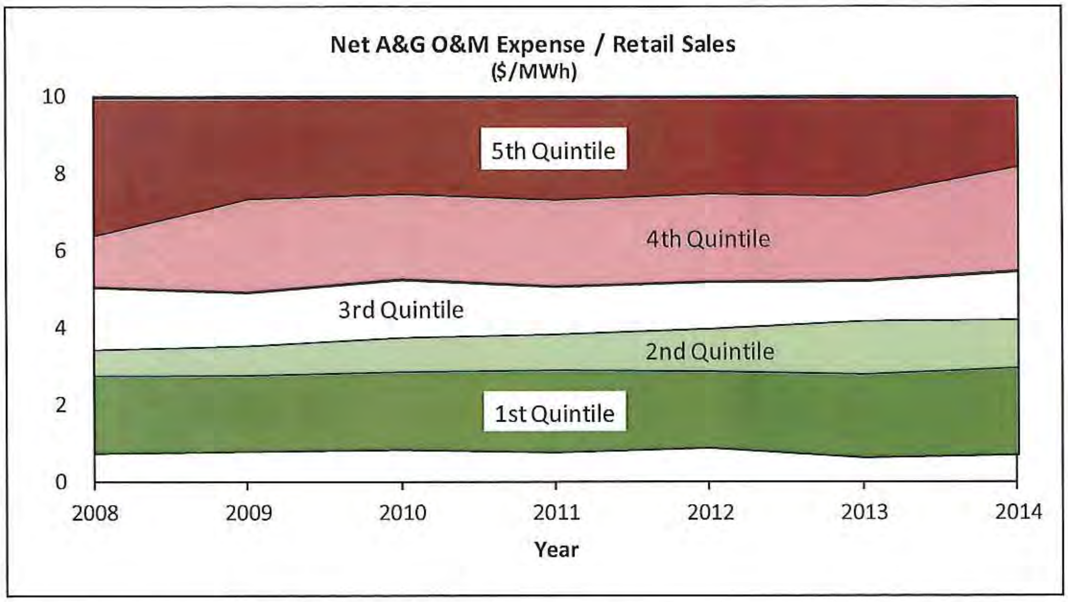
Figure 8 shows the U.S. sample separated into quintiles. The shaded area that represents the 1st quintile reflects the range of performance metrics for one-fifth of the utilities in the U.S. sample each year with the lowest net A&G expenses per retail sales. No utilities had a performance metric below the 1st quintile in the area that is not shaded, so the bottom of the 1st quintile range represents the minimum performance metric for the U.S. sample. At the top of Figure 8 is the 5th quintile with the utilities in the U.S. sample with the highest performance metrics. For purposes of presenting a broader scope of view for the 1st through 4th quintiles, I have not included the top end of the range for the 5th quintile because that would have extended the y-axis upward and collapsed the 1st through 4th quintiles into a small lower portion of the figure. Utilities with average performance metrics fall into the 3rd quintile, which I've not shaded. The 2nd and 4th quintiles bracket above and below average performance, respectively, or below average cost in the case of the 2nd quintile and above average cost in the case of the 4th quintile. Utilities that kept their net A&G expenses per retail sales below approximately $7/MWh during the years I examined avoided falling into the 5th quintile that represents poor performance. A performance metric below approximately $5/MWh would represent a utility that is an average or better performer depending upon how successful it was at driving its performance metric down.

In Figure 9, I removed the quintile shading and included only the top range or maximum performance metric level for each quintile. For example, the finely dashed line labeled as "1st" represents the top or maximum for the first quintile, or approximately $3/MWh as shown in both Figures 8 and 9. Likewise, the more widely spaced dashed line labeled "3rd" at approximately $5/MWh in Figures 8 and 9 represents the top or maximum for the 3rd quintile. I then overlaid NIPSCO's performance metric and the median for the Other IN utilities. The Other IN utilities' median performance metric is in the 4th quintile, representing below average performance, but tracks closely with the top of the 3rd quintile. NIPSCO does not perform nearly so well after 2010. Its net A&G expense per retail sales performance metric quickly escalates thereafter and reaches into the 5th quintile in 2013 and 2014.

Q. Do you have any other observations regarding Figure 9?

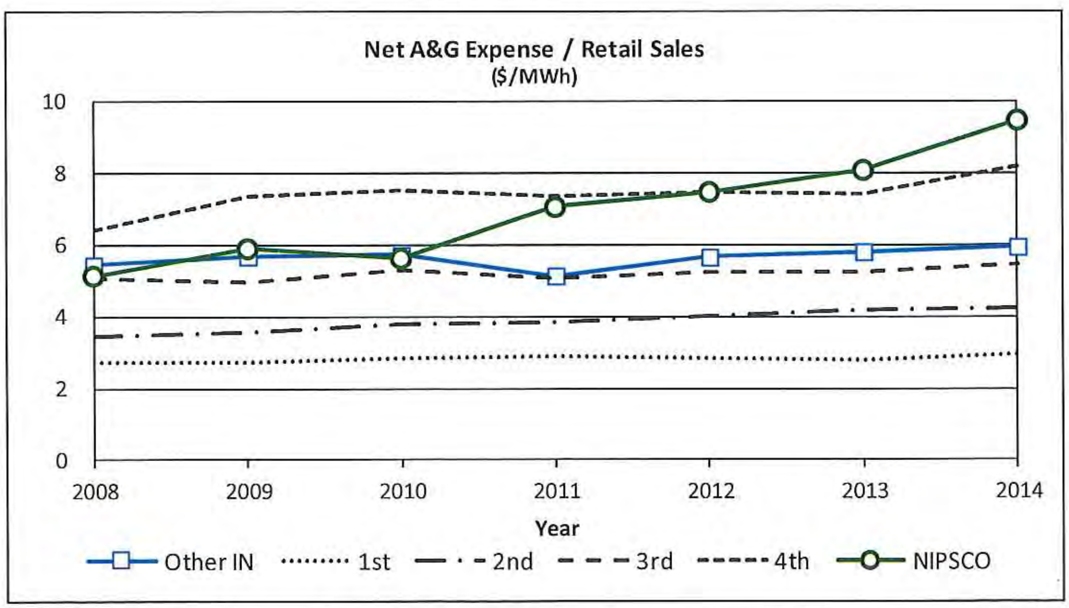
A. I do. There is a slight upward trend in the maximum levels for each of the 1st through 4th quintiles for the U.S. sample. There is also a slight upward trend in the median performance metric for the Other IN utilities. This represents a general trend of utilities' net A&G expenses increasing slightly faster than their retail sales. However, NIPSCO's rapidly escalating net A&G expenses relative to its retail sales far exceed this general trend.

FIGURE 8



Source: Etheridge workpapers for the U.S. sample.

FIGURE 9



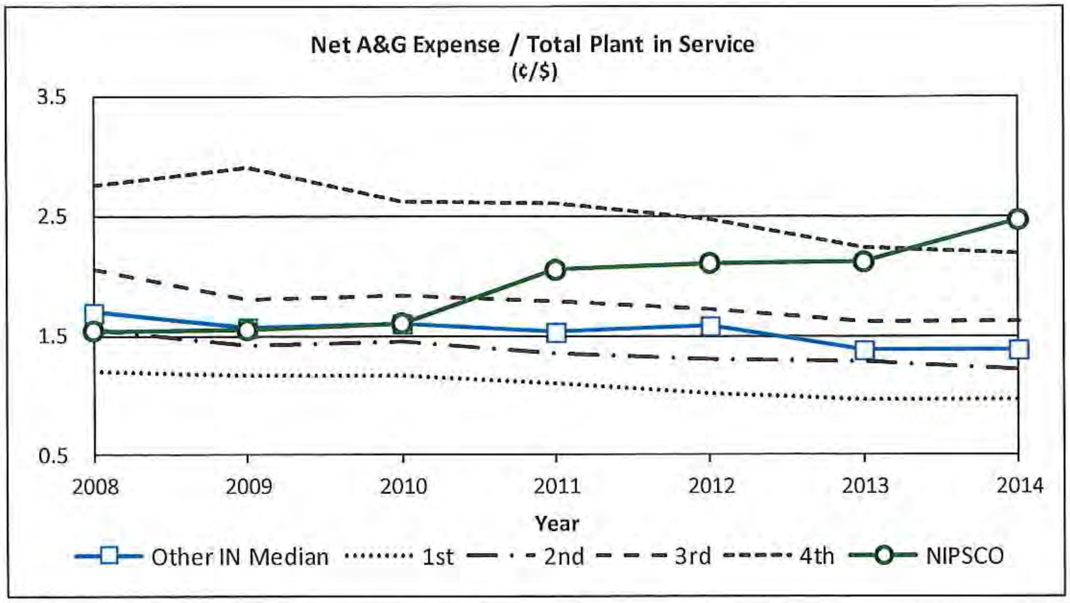
Source: Etheridge workpapers for the U.S. sample.

Q. How did NIPSCO benchmark against the U.S. utilities and Other IN utilities for your other four performance metrics?

A. Not well. For the net A&G expense per retail customer performance metric, NIPSCO and the Other IN utilities started out in the 5th quintile in 2008, but were close to breaking into the 4th quintile. The Other IN utilities were able to stay very close to the 4th quintile throughout the years I examined, but NIPSCO's escalating net A&G expenses drove it well into the 5th quintile. In fact, only four of the 122 utilities in the U.S. sample had a performance metric higher than NIPSCO in 2014. Indiana's utilities performed better with the net A&G expense per retail revenues. The Other IN utilities remained solidly in the 4th quintile over the seven years, but NIPSCO again drifted into the 5th quintile by 2013 and 2014. For the net A&G expense per total sales, NIPSCO and the Other IN utilities performed similarly to that discussed above for the retail sales performance metric. A noticeable improvement was seen with the net A&G expense per total plant in service metric, but only for the Other IN utilities where the median performance metric remained solidly within the 3rd quintile. NIPSCO's escalating net A&G expenses again pushed it into the 5th quintile by 2014 for this performance metric as shown in Figure 10.

I would also like to point out that the general trend in net A&G expenses per total plant in service for U.S. utilities including the Other IN utilities is downward, meaning utilities are investing in new plant at a rate that is faster than the escalation in their net A&G expenses. That is not the case with NIPSCO. Its net A&G expense per total plant in service placed it barely in the 2nd quintile in 2008 as shown in Figure 10, but three years later it had escalated into the 4th quintile. It took only three more years for it to escalate into the 5th quintile.

FIGURE 10



Source: Etheridge workpapers for U.S. sample.

Q. Did you repeat your benchmarking analyses using absolute levels for the performance metrics with your other three samples?

A. I did.

Q. How did NIPSCO's performance metrics benchmark against these other three samples?

A. Not well. NIPSCO's escalating net A&G expense pushed it into the 5th quintile or highest cost range for each of the five performance metrics and for each of the other three samples that I examined.[14]

[14] See Etheridge workpapers for the second, third, and fourth samples.

C. Trend Analyses Using the U.S. Sample

Q. What is a trend analysis?

A. A trend analysis involves calculating a trend between a beginning and an ending point. In the case of my benchmarking study, I calculated the trends in each utility's performance metrics over time, and those trends represent that utility's ability to control its own net A&G expenses relative to the changing size of its business. I then benchmarked the trends in NIPSCO's performance metrics to the trends exhibited in the performance metrics for my four samples of utilities.

Q. Why did you perform trend analyses as part of your benchmarking study?

A. From my perspective, absolute levels of performance metrics provide useful context, but trends are where the story begins to unfold. Any given utility's performance metric could be influenced by factors that are somewhat unique to that utility. A trend for any given utility neutralizes the influence of factors unique to that utility and provides for an "apples to apples" comparison between utilities. Think of it this way, a trend analysis examines how one utility is managing its own unique business relative to how another utility is managing its own unique business.

For example, NIPSCO has a high concentration of industrial sales and its retail sales per customer ranked in the top ten percent of my U.S. sample. SIGE and DEI had very similar levels of retail sales per customer with SIGE slightly higher and DEI slightly lower than NIPSCO. I&M and IPL also had retail sales per customer that were in the top half of my U.S. sample. Therefore, I would expect Indiana's investor-owned utilities to have fairly high absolute levels of net A&G expense per customer relative to other utilities in my U.S. sample because net A&G expense is highly correlated with retail sales (i.e., net A&G expenses increase as retail sales increase), yet Indiana's investor-owned utilities have relatively low customer counts relative to these sales.

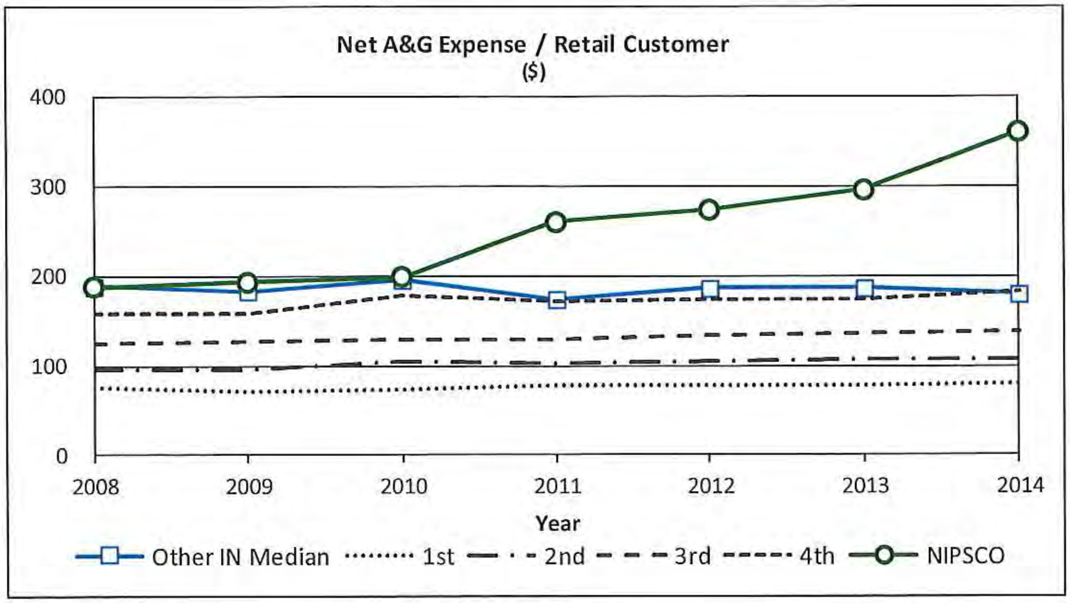
Figure 11 confirms that this is the case. Net A&G expense per retail customer for NIPSCO and the median for the Other IN utilities are in the 5th quintile or at the top of the 4th quintile relative to the U.S. sample for the seven years that I examined. While the y-axis has been expanded to capture NIPSCO's upwardly escalating performance metric, it is still possible to see that there is a slight upward trend in the quintile maximums for the U.S. sample. In Figure 12, I've collapsed the y-axis to provide a better view of the slight upward trend in those quintile maximums, recognizing that NIPSCO's performance metric is off the chart after 2010.

In examining Figures 11 and 12 below, it would be inappropriate to conclude that Indiana's investor-owned utilities are poor performers simply because their net A&G expense per retail customer is at relatively high levels. On the other hand, the escalation in NIPSCO's net A&G expense per retail sale performance metric raises serious concerns. That is why I say that absolute levels of performance metrics provide useful context, but trends are where the story begins to unfold.

Q. Please describe your trend analyses?

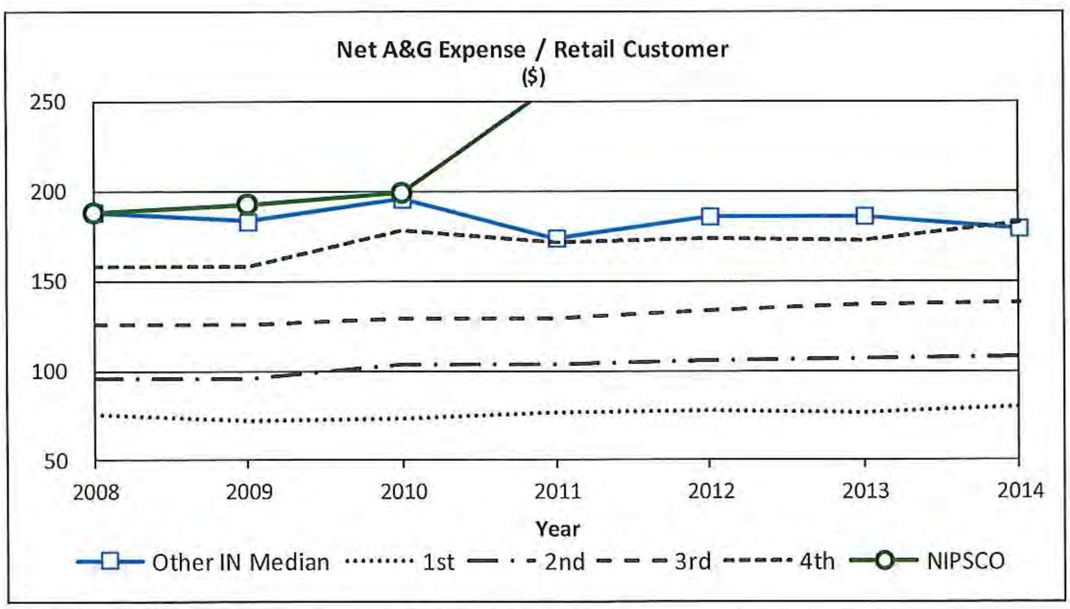
A. Exeter's database for utility A&G expenses begins in 2008 and ends in 2014, with 2014 representing the most recently available FERC Form 1s. For my trend analyses, I averaged data for the years 2008 and 2009 as my beginning point, and I used average data for the years 2013 and 2014 as my ending point. Averaging data in this way dampens any data anomalies that may be embedded in utilities' reported FERC Form 1 data for any single year. I calculated the performance metrics for each utility for the beginning and ending points. Then, I calculated the trend between the performance

FIGURE 11



Source: Etheridge workpapers for the U.S. sample.

FIGURE 12



Source: Etheridge workpapers for the U.S. sample.

metric's beginning and ending points as the CAGR between those two points, or effectively over the five-year period that I selected for my analyses.[15] A CAGR reflects the annual growth rate that when applied to a beginning value and the subsequent balance in each succeeding year will result in the ending value after the number of years at issue. I then ranked utilities based upon their CAGRs from lowest to highest and segmented them into quintiles. Utilities with the lowest CAGRs ranked in the 1st quintile, thereby demonstrating excellent performance at managing the escalation of their net A&G expenses relative to the changing size of their operations. Utilities falling into the 5th quintile demonstrated poor performance with respect to managing net A&G cost escalation in relation to the size of their operations.

Q. Can you provide an example of how you calculated a CAGR for NIPSCO for one of your five performance metrics?

A. Yes. Table 1 shows the calculation of NIPSCO's CAGR for the net A&G expense per total plant in service performance metric that is stated in cents of expense per dollar of plant in service. I calculated average net A&G expenses and total plant in service for the beginning and ending points as shown in columns (a) through (d). I then calculated the performance metric in column (e). The CAGR of 8.21 percent is calculated from the ending and beginning values for the performance metric and using the effective five-year period between those two values. I included a proof of that calculation in Table 1 to show that the beginning value of 1.55 ¢/$ will grow to 2.30 ¢/$ if an annual growth rate of 8.213 percent is applied each year to the prior year's ending value. I show this calculation graphically in Figure 13 below.

[15] The five-year period is effectively from mid-2008/2009 to mid-2013/2014 (i.e., 2013.5 minus 2008.5).

TABLE 1

Calculation of Compound Annual Growth Rates for NIPSCO's Net A&G Expense per Total Plant in Service Performance Metric

Year	*(a)* Reported Net A&G Expense (000s)	*(b)* Average Net A&G Expense[1] (000s)	*(c)* Reported Total Plant (000s)	*(d)* Average Total Plant[1] (000s)	*(e)* Net A&G Expense per Total Plant[1] (¢/$)
Formula/ Source	*Database Input*	*2-Year Average*	*Database Input*	*2-Year Average*	*(b) *100 / (d)*
2008	$85,875.085		$5,567,589.800		
Average		$86,909		$5,618,588	1.55
2009	$87,942.572		$5,669,585.500		
2013	$135,611.417		$6,401,903.200		
Average		$150,711		$6,560,330	2.30
2014	$165,810.867		$6,718,756.300		
				CAGR in Percent[2]:	8.21%

CAGR Proof

Year	Growth Rate[3]	Net A&G Expense per Total Plant (¢/$)
0		1.5500
1	8.213%	1.6773
2	8.213%	1.8151
3	8.213%	1.9641
4	8.213%	2.1254
5	8.213%	2.3000

(1) Rounded.

(2) The ending value divided by the beginning value to the one-fifth power for five years of growth, then minus one, or $((2.29 / 1.55)^{(1/5)}) - 1$.

(3) Not rounded.

Source: Etheridge workpapers for the U.S. sample.

Q. Can you show the CAGR calculation graphically for another Indiana utility?

A. Yes. Figure 14 shows the CAGR calculation for I&M for the net A&G expense per total plant in service performance metric. As can be seen in Figures 13 and 14 below, both NIPSCO and I&M had reasonably close beginning values for this performance metric. However, I&M's CAGR trend is downward at 2.16 percent while NIPSCO's CAGR trend is upward at 8.21 percent.

Q. How did NIPSCO rank among the 122 utilities for this performance metric?

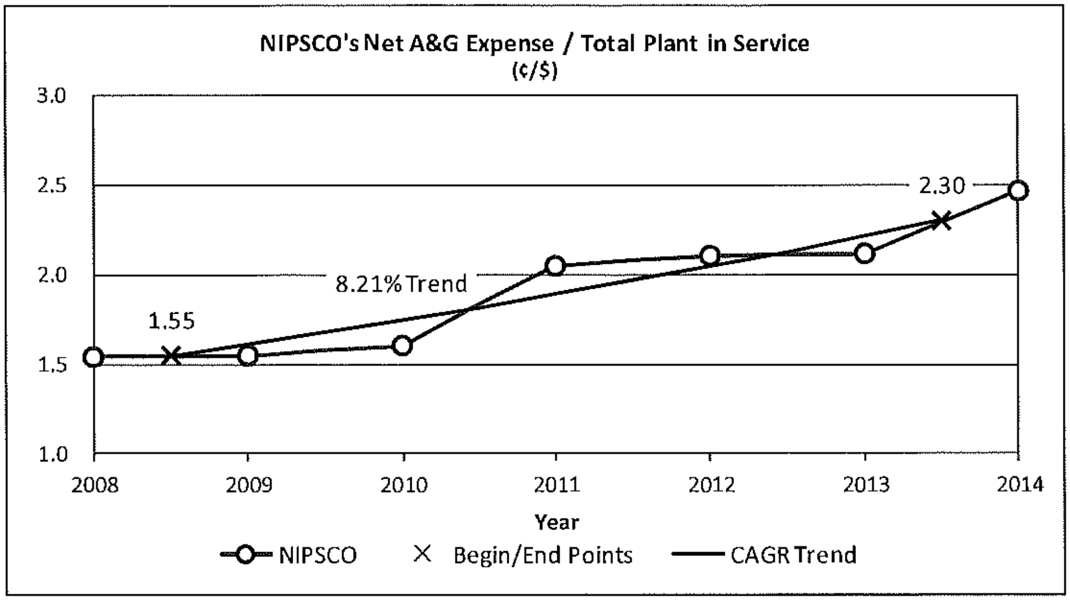
A. NIPSCO's CAGR of 8.21 percent and I&M's -2.16 percent CAGR represent two of the 122 CAGR's that I ranked as part of my trend analysis for this performance metric. At 8.21 percent, NIPSCO ranked 117 of 122, which placed it in the 5th or worst performing quintile. The rankings for this performance metric for all 122 utilities are shown in Schedule DDE-3.[16]

Q. What was the gap between NIPSCO's CAGR of 8.21 percent that put it in the 5th quintile and a CAGR that would have placed it in the 4th quintile?

A. The 5th and 4th quintiles divide at 0.88 percent (see Schedule DDE-3, page 3).[17] A lower number (i.e., a number reflecting lower cost escalation) would place the utility in the 4th or lower quintiles. A higher number would place the utility in the 5th quintile. Because lower CAGRs are good, 0.88 percent represents the maximum threshold (i.e., worst CAGR) for the 4th quintile. Likewise it represents the minimum threshold (i.e., best CAGR) for the 5th quintile, with any CAGR higher than that representing worse performance. Figure 15 shows the broad gap between NIPSCO's 8.21 percent CAGR and the maximum for the 4th quintile at 0.88 percent. Extrapolating the 4th quintile trend

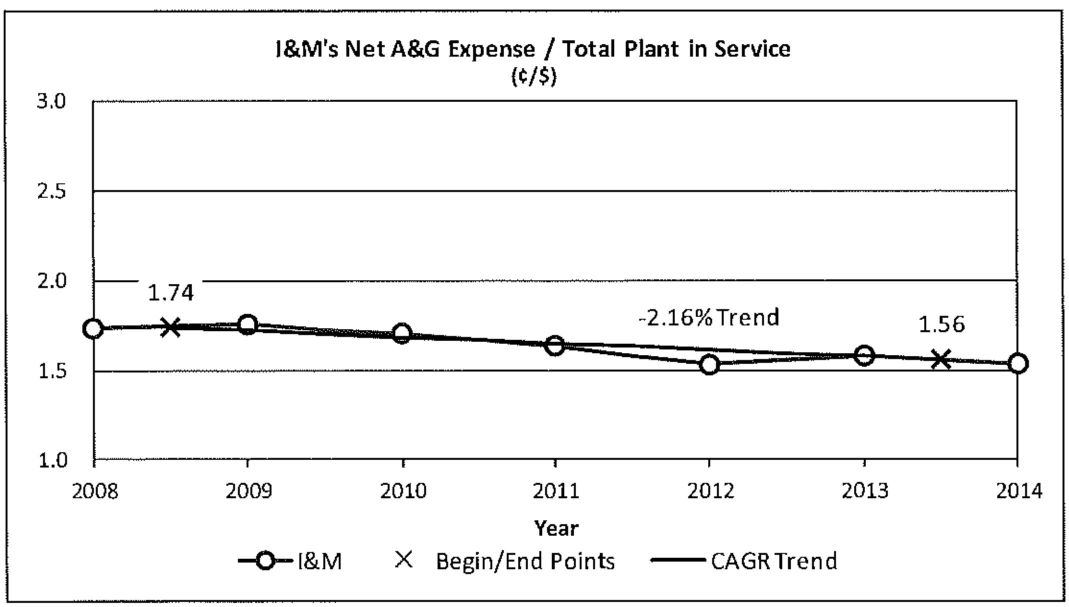
[16] I&M is listed as IMP and DEI is listed as DEIN in Schedule DDE-3.
[17] See the line at the bottom of Schedule DDE-3, page 3, labeled "4th Quintile Maximum". This represents the calculated split of the lowest one-fifth of the population and falls between the CAGRs for the 97th and 98th ranked utilities listed higher up on that page.

FIGURE 13



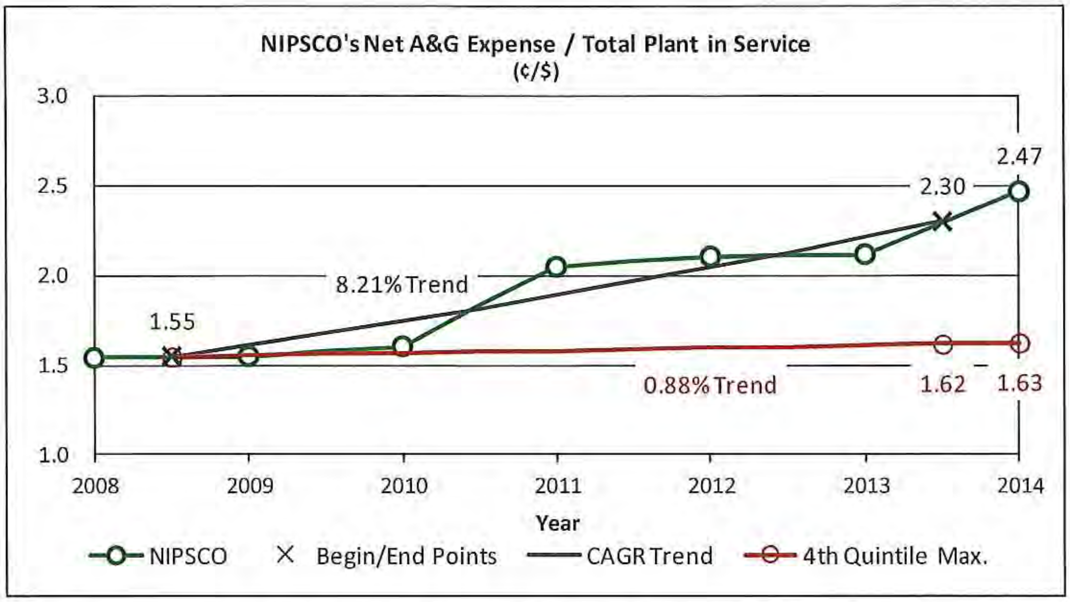
Source: Etheridge workpapers for the U.S. sample.

FIGURE 14



Source: Etheridge workpapers for the U.S. sample.

FIGURE 15



Source: Etheridge workpapers for the U.S. sample.

past the ending point (i.e., 2013 / 2014) to 2014 equates to a performance metric equal to 1.63 ¢/$ in 2014 as shown in Figure 15, or well below NIPSCO's figure of 2.47 ¢/$ for that year. In dollar terms, that equates to $56.4 million.[18] Stated another way, NIPSCO's net A&G expenses in 2014 would have been $56.4 million lower than they actually were if NIPSCO had managed the escalation of those expenses in line with the low end of below average performance as calculated using the U.S. sample.

Q. Do escalation rates equal to the 4th quintile maximum reflect laudable performance at controlling A&G expenses?

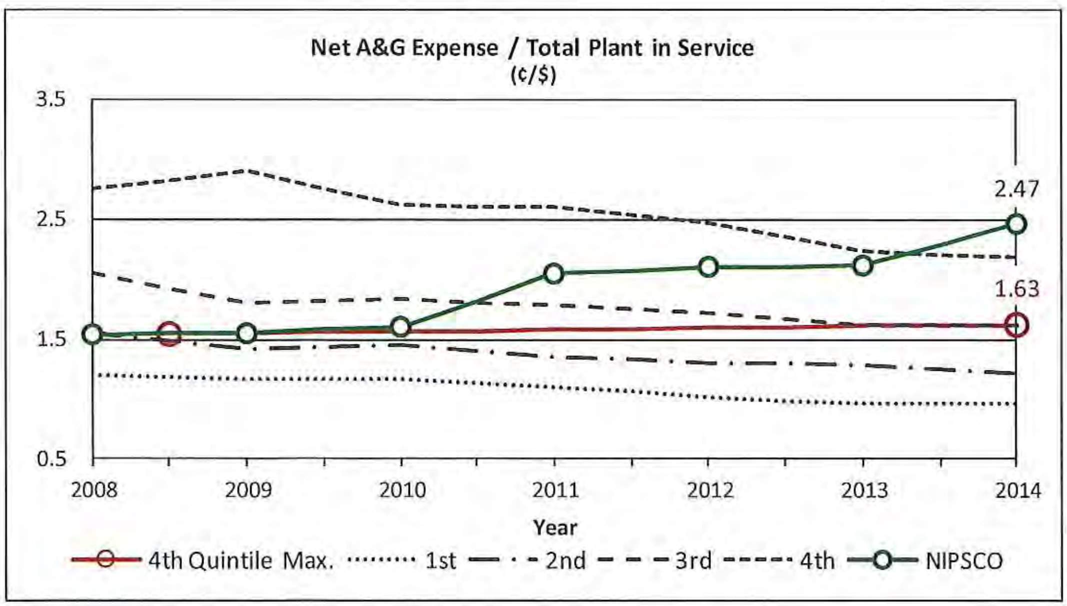
A. No.

[18] NIPSCO's performance metric at 2.47 ¢/$ in 2014 was 0.84 ¢/$ above 1.63 ¢/$. That translates into a gap of approximately $55.1 million (0.84¢ / 100 = $0.0084 and $0.0084 x $6,718,756,000 of total plant in service ≅ $56,438,000).

Q. Where would the absolute level of NIPSCO's net A&G expense per total plant in service performance metric be in 2014 relative to the U.S. sample had it been escalating in line with the 4th quintile maximum CAGR?

A. Figure 16 is a near duplication of Figure 10, but I've eliminated the line showing the Other IN utilities and I've added a line showing NIPSCO's performance metric if it had been increasing at the "4th Quintile Max." from my trend analysis, or the 0.88 percent shown also in Figure 15. Note that all of the dashed lines in Figure 16 that represent quintile maximums are downward sloped. A utility with a downward sloping performance metric would fall in line with this trend, and a utility with a flat to upward sloping trend would be demonstrating below average or poor performance at controlling A&G costs. A utility not managing the escalation in its A&G expense over time in relation to other utilities will lose ground relative to those utilities. This is clearly the case with NIPSCO and this performance metric. In three years, between 2008 and 2011,

FIGURE 16



Source: Etheridge workpapers for the U.S. sample.

NIPSCO's escalating net A&G expense per total plant in service moved it from the 2nd quintile into the 4th quintile for my U.S. sample. In three more years, by 2014, this performance metric had escalated into the 5th quintile.

If NIPSCO had been able to control the escalation of its net A&G expenses relative to its plant in service in line with even the U.S. sample's maximum 4th quintile escalation rate of 0.88 percent, then the absolute level of its performance metric in 2014 would have been 1.63 ¢/$ as shown in Figure 16. That would have placed it close to but just above the maximum of the 3rd quintile for my U.S. sample. NIPSCO would have lost ground relative to other utilities, but certainly not as badly as it actually did.

Q. How did NIPSCO's net A&G expense per total plant in service performance metric compare to other utilities in your U.S. sample in 2008 and then in 2014?

A. In 2008, NIPSCO's net A&G expense per total plant in service was 1.54 ¢/$ placing it just barely into the 2nd quintile. That figure ranked as the 47th lowest performance metric out of 122 utilities. By 2014, NIPSCO's net A&G expense per total plant in service had escalated to 2.47 ¢/$, a figure that ranked 102nd out of 122 utilities and placed NIPSCO in the 5th quintile. NIPSCO would not have lost as much ground if it had been able to control its net A&G cost escalation relative to total plant in service at 0.88 percent, the 4th quintile maximum escalation rate from my U.S. sample. Had that been the case, its net A&G expense per total plant in service metric would have been 1.63 ¢/$ in 2014, which would have ranked 75th out of 122 utilities.

Q. Do you have additional thoughts on the increases that have occurred in NIPSCO's net A&G expense per total plant in service performance metric?

A. Yes. A high cost utility that is improving its cost structure over time by reducing costs is demonstrating improving performance for the benefit of customers, which relatively speaking is a good result. Likewise, a low cost utility that is managing its cost structure in line with general trends will preserve the associated benefits of its low cost structure for customers, which again relatively speaking is a good result. NIPSCO does not fall into either category. NIPSCO's performance at managing net A&G expense per total plant in service over the years I've examined, and particularly since 2010, is not reflective of good or even average performance. In fact, viewed either from an absolute level or as a trend over time, NIPSCO's performance at managing its net A&G expense for this performance metric is poor.

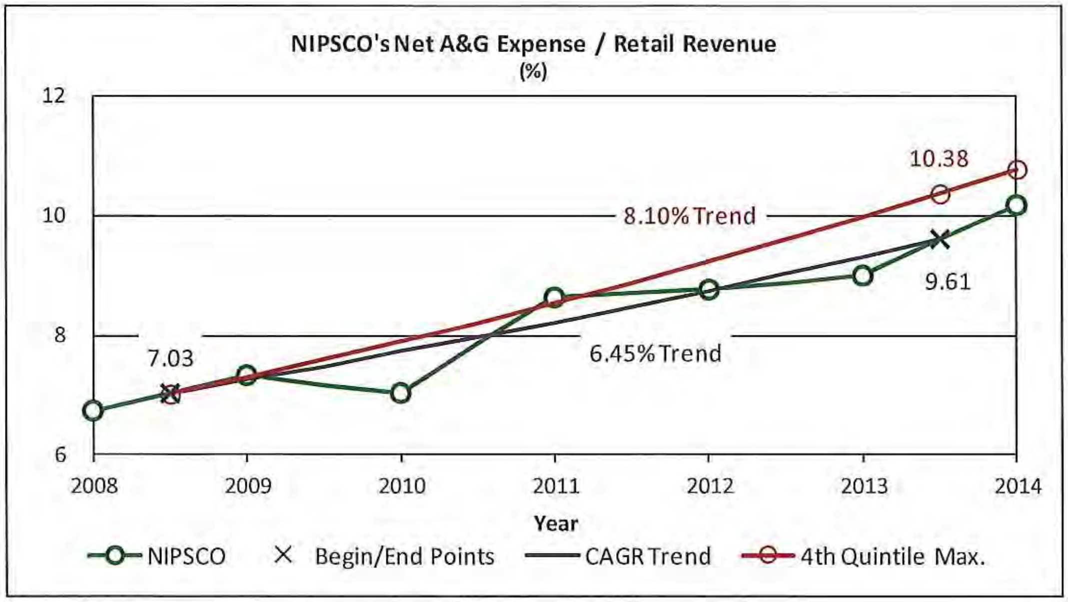
Q. Did NIPSCO's performance improve with respect to managing net A&G expense escalation for any of the other four performance metrics that you cxamined in your trend analyses?

A. NIPSCO performed only slightly better for the net A&G expense per retail revenue performance metric where its CAGR placed it in the 4th quintile. For the other three performance metrics, NIPSCO's CAGR fell into the 5th quintile.

Q. Can you show NIPSCO's net A&G expense per retail revenue graphically compared with the U.S. sample 4th quintile maximum CAGR?

A. Yes. Figure 17 shows that comparison. NIPSCO's CAGR of 6.45 percent was slightly below an escalation rate of 8.10 percent reflective of the U.S. sample 4th quintile maximum.

FIGURE 17



Source: Etheridge workpapers for the U.S. sample.

Q. How did NIPSCO compare with the Other IN utilities in terms of your trend analyses?

A. Table 2 below summarizes the results of my trend analyses for NIPSCO and the four other Indiana investor-owned utilities using the U.S. sample. NIPSCO ranked in the 4th quintile once and in the 5th quintile four times for my trend analyses using my five performance metrics. IPL also performed poorly at managing the escalation of net A&G expenses. Indiana's three other investor-owned utilities performed much better.

Q. Can you translate NIPSCO's performance in your trend analyses relative to the U.S. sample into the context of dollars as you did earlier for the net A&G expense per total plant in service performance metric?

A. Yes. Earlier in my testimony I explained that, in order to fall in line with 4th quintile maximum growth of 0.88 percent (Figure 15), NIPSCO's net A&G expense in 2014 would needed to have been $56.4 million lower than what it was in that year. I've made

TABLE 2

Quintile Rankings for NIPSCO and Other Indiana Utilities for CAGRs Calculated Using Data for U.S. Utilities and by Comparing the Average for 2008 and 2009 with the Average for 2013 and 2014 for Five Net A&G Expense Performance Metrics

Quintile	Relative Performance	NIPSCO	DEI	I&M	IPL	SIGE
First	Excellent Performance	0	5	1	0	0
Second	Above Average Performance	0	0	3	0	2
Third	Average Performance	0	0	1	0	3
Fourth	Below Average Performance	1	0	0	1	0
Fifth	Poor Performance	4	0	0	4	0
		5	5	5	5	5

Source: Etheridge workpapers for the U.S. sample.

similar calculations to show the gap between NIPSCO and the 4th quintile maximum escalation rates for the other four performance metrics and all five calculations are shown in Schedule DDE-4. NIPSCO's net A&G expenses would need to have been reduced by $27.9 million for NIPSCO to come into line with 4th quintile maximum cost escalation rates, on average, for the five performance metrics.

Q. What do you conclude from your benchmarking analyses using the U.S. sample?

A. NIPSCO's net A&G expenses are escalating at rates far in excess of other utilities. A material reduction in those expenses, on the order of $28 million, would be required to bring NIPSCO's A&G cost control just barely into the category of below average performance or the 4th quintile for my sample of U.S. utilities.

D. Benchmarking Analyses with Alternative Samples

Q. What analyses did you conduct using your second sample that included 69 utilities?

A. I undertook the same analyses with my sample of 69 utilities that I undertook with my U.S. sample. Again, my sample of 69 utilities included all Indiana investor-owned utilities and was bracketed on the low end with SIGE, the smallest of those Indiana utilities, and on the high end by I&M and DEI. I analyzed the same five performance metrics over the same data set and constructed the same graphical and analytical comparisons of NIPSCO to this sample for both absolute levels of performance metrics and trends in those performance metrics. The only change between my analyses of this sample and those for the U.S. sample was that the statistics for this sample differed from those for the U.S. sample. For example, the median absolute figures for the sample of 69 utilities changed from the same figures for the U.S. sample. Likewise, the CAGRs for the trend analysis for this sample changed from the same figures for the U.S. sample. Nothing else changed.

Q. What were the results of your benchmarking analyses with your second sample?

A. On average, very little changes using the second sample. As I mentioned earlier in my testimony, in terms of absolute levels of performance metrics, NIPSCO again reached into the 5th quintile for each of the five performance metrics by the end of the data set. Likewise, with my trend analyses, NIPSCO finished in the 5th quintile for four of the five performance metrics, again finishing in the 4th quintile for the net A&G expense per retail revenue performance metric. In terms of summary rankings for my trend analyses, nothing changed for any of the Indiana investor-owned utilities as shown in Table 3 (see also Table 2). In addition, my trend analyses with this sample suggest that NIPSCO's net A&G expenses would have to be reduced by $27.7 million in 2014 to reflect average maximum 4th quintile cost escalation for the five performance metrics as shown in Schedule DDE-5. This is almost identical to the $27.9 million reduction suggested by my U.S. sample.

TABLE 3

Quintile Rankings for NIPSCO and Other Indiana Utilities for CAGRs Calculated Using Data for 69 Utilities and by Comparing the Average for 2008 and 2009 with the Average for 2013 and 2014 for Five Net A&G Expense Performance Metrics

Quintile	Relative Perfor-mance	NIPSCO	DEI	I&M	IPL	SIGE
First	Excellent Performance	0	5	1	0	0
Second	Above Average Performance	0	0	3	0	2
Third	Average Performance	0	0	1	0	3
Fourth	Below Average Performance	1	0	0	1	0
Fifth	Poor Performance	4	0	0	4	0
		5	5	5	5	5

Source: Etheridge workpapers for the sample of 69 utilities.

Q. How did you arrive at the utilities in your third sample?

A. Starting with my second sample, I eliminated 20 utilities that did not have production facilities of any material nature resulting in a sample size of 49.

Q. What were your benchmarking results with your third sample?

A. The only material change from the second sample was that NIPSCO fell into the 5th quintile for cost escalation associated with the net A&G expense per retail revenue performance metric. That also materially affected the reduction in 2014 A&G expenses necessary to bring NIPSCO into line with the 4th quintile maximum escalation rates, on average, for the five performance metrics. That reduction in net A&G expenses increased to $35.2 million as shown in Schedule DDE-6 from the $28 million range for both the U.S. sample and my second sample of 69 utilities.

Table 4 shows the summary rankings for my trend analyses for NIPSCO and the other Indiana investor-owned utilities. NIPSCO now falls into the 5th quintile for all five performance metrics. DEI remains solidly locked in the 1st quintile for all five performance metrics. I&M did not change and IPL and SIGE both dropped one quintile for one of the five performance metrics (see also Table 3).

TABLE 4

Quintile Rankings for NIPSCO and Other Indiana Utilities for CAGRs Calculated Using Data for 49 Utilities and by Comparing the Average for 2008 and 2009 with the Average for 2013 and 2014 for Five Net A&G Expense Performance Metrics

Quintile	Relative Perfor-mance	NIPSCO	DEI	I&M	IPL	SIGE
First	Excellent Performance	0	5	1	0	0
Second	Above Average Performance	0	0	3	0	2
Third	Average Performance	0	0	1	0	2
Fourth	Below Average Performance	0	0	0	0	1
Fifth	Poor Performance	5	0	0	5	0
		5	5	5	5	5

Source: Etheridge workpapers for the sample of 49 utilities.

Q. What were your benchmarking results when you used MISO utilities for your sample?

A. In summary, NIPSCO remained solidly locked in the 5th quintile for all five performance metrics for my trend analyses as shown in Table 5. If fact, out of 25 MISO utilities, NIPSCO ranked 23rd for one performance metric and 25th, or at the bottom, for the four other performance metrics. The 2014 reduction in net A&G expenses required to reach 4th quintile performance equated to $33.6 million, on average, for the five performance metrics as shown in Schedule DDE-7, or within the range of the other three samples. SIGE's performance fell by one notch for three performance metrics compared with the

TABLE 5

Quintile Rankings for NIPSCO and Other Indiana Utilities for CAGRs Calculated Using Data for 25 MISO Utilities and by Comparing the Average for 2008 and 2009 with the Average for 2013 and 2014 for Five Net A&G Expense Performance Metrics

Quintile	Relative Perfor-mance	NIPSCO	DEI	I&M	IPL	SIGE
First	Excellent Performance	0	5		0	0
Second	Above Average Performance	0	0		0	0
Third	Average Performance	0	0		0	4
Fourth	Below Average Performance	0	0		0	1
Fifth	Poor Performance	5	0		5	0
		5	5		5	5

Source: Etheridge workpapers for the sample of 25 MISO utilities. I&M does not operate in MISO and was not included in this sample.

sample of 49 utilities, and DEI's and IPL's performance did not change (see also Table 4).

Q. What do you conclude from your benchmarking analyses with alternative samples compared with same analyses for the U.S. sample?

A. My conclusion has not changed—NIPSCO's net A&G expenses are escalating at rates far in excess of other utilities and a material reduction in those expenses would be required to bring NIPSCO's A&G cost control just barely into the category of below average performance or the 4th quintile for my sample of U.S. utilities.

E. Benchmarking Sensitivity Analyses

Q. Did you perform a sensitivity analysis on your benchmarking results?

A. Yes.

Q. What is a sensitivity analysis and what is its purpose?

A. A sensitivity analysis entails varying inputs to a study to determine how sensitive the results are to changes in those inputs. Its purpose is to help gauge the level of confidence that can be placed in a study's results.

Q. What sensitivity analyses did you perform to examine your benchmarking results?

A. The focus of my sensitivity analyses was to test the gap in dollars between NIPSCO's 2014 net A&G expenses and those that would result had NIPSCO's performance metrics escalated, on average, at the 4th quintile maximum. Previously I explained that, on average, NIPSCO's net A&G expenses in 2014 would have to be reduced by $27.9 million using my U.S. sample, or $27.7 million using my sample of 69 utilities, to be in line with the 4th quintile maximum escalation rates for those samples. That reduction increased with my samples of 49 utilities and 25 MISO utilities to $35.2 million and $33.6 million, respectively. To take a conservative view, I focused my sensitivity analyses on the results for the U.S. sample and sample of 69 utilities, or those samples that produced the least net A&G expense reductions for NIPSCO. First, I pushed forward the beginning point of my range from an average of 2008 and 2009 data to an average of 2009 and 2010 data, leaving the ending point as an average of 2013 and 2014 data, and repeated my benchmarking analyses for each of the two samples. Second, I pushed back the ending point from an average of 2013 and 2014 data to an average of 2012 and 2013 data, leaving the beginning point as an average of 2008 and 2009 data, and then repeated my benchmarking analyses for each of the two samples.

Q. What were the results of your benchmarking sensitivity analyses when you pushed forward the beginning point?

A. The net A&G expense reduction in 2014 slightly increased for both samples to $32.3 million for the U.S. sample and to $30.8 million for the sample of 69 utilities. These results are shown in Schedules DDE-8 and DDE-9, respectively.

Q. What were the results of your benchmarking sensitivity analyses when you pushed back the ending point?

A. The net A&G expense reduction in 2014 decreased for both samples to $22.7 million for the U.S. sample and $19.1 million for the sample of 69 utilities. These results are shown in Schedules DDE-10 and DDE-11, respectively.

Q. What do you conclude from these sensitivity analyses?

A. I view these sensitivity runs as supporting my basic conclusion that a material reduction NIPSCO's net A&G expenses, on the order of $28 million, would be required to bring NIPSCO's A&G cost control just barely into the category of below average performance or the 4th quintile for my sample of U.S. utilities. The sensitivity runs bracket my benchmarking results, thereby lending support to that conclusion. In addition, I place more weight on the sensitivity runs that shift the beginning point forward and keep the ending point reflective of the most recently available data, and those sensitivity runs suggest that my basic conclusion may be conservative.

F. Benchmarking Study Summary and Conclusions

Q. Please summarize your benchmarking study?

A. My benchmarking study focused primarily on evaluating NIPSCO's performance at managing the escalation in its net A&G expenses relative to 122 U.S. utilities and sample subsets thereof. By using performance metrics and comparing the trends over time in each of those performance metrics I was able to produce an "apples to apples" comparison of each utility's relative performance at managing the escalation in its net A&G expenses. When benchmarked in this manner, NIPSCO's performance at managing the escalation in its net A&G expenses is revealed to be poor.

Q. What conclusions have you reached based upon your benchmarking study?

A. My benchmarking study indicates that NIPSCO's net A&G expenses would have to be reduced by $28 million or more just to achieve below average performance at managing A&G cost escalation compared with other electric utilities.

V. Conclusions and Recommendations

Q. What are your overall conclusions from your review of NIPSCO's net A&G expense levels?

A. I conclude that NIPSCO should give serious consideration to undertaking an in-depth review of it A&G cost structure. NiSource, Inc. ("NiSource") recently completed a corporate reorganization where it spun off its Columbia Pipeline Group into a separate publicly traded company. Following the corporate separation, NiSource's senior management team has been reorganized. In effect, NiSource has become a smaller company having shed its pipeline business. Therefore, A&G expenses incurred at its NiSource Corporate Services Company that previously were allocated across all of NiSource's businesses, including the Columbia Pipeline Group, will in the future be allocated on a more concentrated basis to NIPSCO. Synergies that may have existed in NiSource's cost structure when it included the Columbia Pipeline Group will have been lost. If action isn't taken to counteract any loss of synergies, then there will be upward pressure on NIPSCO's cost structure and ultimately its rates for electric service to its customers. Given the extraordinary rate at which NIPSCO's net A&G expenses have been escalating in recent years, and based upon the results of my benchmarking study, I think cost control warrants the close attention of NiSource's new management team.

Q. What are your recommendations?

A. I recommend that the Commission reduce NIPSCO's O&M expenses by approximately $1.6 million so that customers receive the incremental cost savings expected to be realized as a result of the AMR project in the 12 months following the end of the test year. When evaluating the overall revenue increase, if any, to be granted to NIPSCO, I recommend that the Commission consider the fact that NIPSCO's A&G expenses have been increasing at an extraordinary rate.

Q. Does this complete your direct testimony?

A. Yes.

APPENDIX

QUALIFICATIONS OF

DWIGHT D. ETHERIDGE

DWIGHT D. ETHERIDGE

Mr. Etheridge is a principal at Exeter Associates, Inc. with twenty-nine years of wide ranging experience in the electric utility industry. His areas of expertise include business plan development, industry restructuring, rate design, class cost-of-service studies, load forecasting, resource planning, transmission system evaluations, power procurement, distributed generation, telecommunications, and contract negotiations.

His management experience includes reporting to the CEO of a western utility during electric deregulation and a merger of two utilities, advising the CEO on many topics including regulatory issues, legislative negotiations, strategic focus, decision analysis, and merger integration. He also has substantial project management experience gained as a consultant and in various progressively more responsible leadership roles in utility management.

Mr. Etheridge has extensive experience developing analytical and strategic solutions on a variety of utility issues and communicating on those issues to regulatory commissions, legislatures, senior management, board of directors and the public. He has presented expert testimony on over thirty occasions and has acted as a spokesperson numerous times on television, radio and in print.

Education:

B.S. (Business Administration) – University of California, Berkeley, 1985.

Previous Employment:

2004-2005	-	Independent Strategy and Business Consultant
1999-2004	-	Strategic Director, Sierra Pacific Resources and its Subsidiaries
1986-1999	-	Nevada Power Company Leader of the Industry Restructuring Team Director, Pricing and Economic Analysis Economist Load Forecast Analyst

Professional Work:

Mr. Etheridge's work at Exeter Associates, Inc. has been focused in the following areas:

Contract negotiations for electricity and natural gas supply for U.S. Department of Energy (DOE) facilities.

Fuel switching studies for DOE facilities.

Development of electricity and renewable energy procurement plans and risk management strategies for DOE's Northern California national laboratories.

Natural gas options analyses and development of models to project implied volatilities.

Review of utility procurement strategies for multiple U.S. Air Force bases in an effort to identify areas for potential utility cost savings.

Evaluating the need for new transmission lines in the PJM market on behalf of an agency of the State of Maryland.

Provided analytical support to a southwestern municipal water and power utility in the areas of rate design, load forecasting, wholesale market modeling, and volatility analysis.

Review of the Regional Greenhouse Gas Initiative on behalf of a regulatory agency of the State of Maryland, and the development of technical memoranda on various carbon dioxide emissions related topics.

Development of multiple options studies for DOE facilities that address the power supply and transmission system capabilities of potential alternative suppliers for meeting DOE's long-term electrical requirements.

Review of utility procurement strategies and development of electric and natural gas long-term avoided cost projections for several of DOE's national laboratories

As an independent consultant, Mr. Etheridge:

Led an engagement for a western consulting firm to review the load forecasting methodologies and forward price curve models employed by a southwestern municipal water and power utility and to recommend improvements.

Led an engagement for a western consulting firm to develop rate design options for a southwestern municipal water and power utility. The rate design recommendation was designed to facilitate the implementation of operational strategies and the achievement of operational savings identified in a previous consulting engagement. It was also designed to accommodate additional electrical loads if other water municipalities decided to jointly participate in wholesale markets.

Worked with a team from an international consulting firm to support a Midwest utility's effort to ensure that its accounting and rates departments were prepared for the Midwest ISO's "Day 2" market opening scheduled for March 1, 2005. The project involved developing process flows of information required by the accounting and rates departments, and significant interaction with the corporate information technology department. The project also involved reviewing rates and regulatory strategies for potential changes under the Day 2 market rules.

Prepared a competitive analysis for a Midwest utility's unregulated subsidiary on behalf of an international consulting firm. The analysis focused on comparing the subsidiary's product and service offerings, and value propositions, against those of its competitors as well as evaluating the dynamics occurring within the various market segments.

Led an engagement for a western consulting firm to identify strategies for maximizing the savings potential of switching electricity suppliers for a southwestern municipal water and power utility. The economic analyses developed as part of the engagement identified multi-million dollar savings potential that could be achieved over ten years through changes in both suppliers and operational strategies. In addition, the client realized thousands in immediate savings from billing errors that were identified during the engagement, as well as the potential for hundreds of thousands in annual savings that could be realized through enforcement of the provisions of existing contracts.

Worked with a team from an international consulting firm to facilitate the development of a strategic plan for a western municipal power and water utility. The project included leading the utility's management team through an all-day planning session to develop divisional strategies consistent with the utility's mission statement.

As a strategic director for Sierra Pacific Resources, Mr. Etheridge:

Developed a forecasting model for power and gas prices that was capable of blending fundamentals-based power and gas price forecasts from multiple vendors while maintaining rational market implied heat rates as well as consistent relationships across various gas market centers and power trading hubs in the western U.S. The models enable forecasters to produce timely forecast updates as gas futures prices change or when vendors update their forecasts, while maintaining an easily audited trail of assumptions across forecast updates.

Developed sophisticated financial models to evaluate the ROI potential of distributed generation projects that might be deployed by large commercial and industrial customers. The models investigated gas-fired reciprocating engines and turbines, as well as multi-unit installations, varying performance characteristics and partial standby requirements. This project was undertaken in conjunction with the redesign of retail standby rates and the introduction of new interconnection rules.

Investigated the potential of using private equity partners to pursue power plant development and/or acquisition in southern Nevada, including the possibility of a public/private partnership to leverage the credit ratings of a local governmental entity.

Gained valuable indirect experience in the development and implementation of risk management and risk control procedures while working on energy supply projects during the period of time when new corporate risk policies were developed, implemented and defended in litigated proceedings.

Supported a telecommunications subsidiary by acting as the lead in the development of business plans for two metro area networks and a long-haul opportunity. Co-presented the business plans with the lead director for the subsidiary to the Board of Directors and obtained the required initial funding of $44 million.

Supported a telecommunications subsidiary by acting as the lead in the development of a fiber-to-the-home business plan with an external team of consultants. The plan addressed the feasibility of multiple bundled service offerings and a targeted deployment in several western markets. Participated in negotiations with subsidiary management and multiple potential partners, including service providers with a national footprint, technology partners and content providers. The plan was tabled when key partnership agreements could not be put in place to pursue a "beta" test of the technology and business model.

Participated on the team that developed a successful bid for a northwest electric utility, including due diligence, management presentations by the company being acquired, and strategy discussions with the CEO and financial advisors.

As leader of the industry restructuring team at Nevada Power Company, Mr. Etheridge:

Reported to the CEO and led an internal team of directors assigned full-time to electric industry restructuring. Directed and managed the team's development and presentation of company positions on restructuring to the Public Utilities Commission of Nevada ("PUCN") and to the Nevada Legislature.

Presented expert testimony before the PUCN and the Nevada Legislature. Was responsible for hiring multiple consultants and expert witnesses to facilitate the development of corporate strategy and to support the presentation of positions before the PUCN. In this assignment, represented the company on multiple occasions on television, taped and live radio, in press conferences and interviews, in consumer focus groups, and in presentations to large commercial and industrial customers.

As a member of the CEO's staff, participated in senior management discussions on corporate strategy prior to the merger announcement and throughout the merger integration process, including development of corporate strategy and business line focus for the combined company.

One of only several advisors to the CEO that directly participated with the CEOs from both Nevada Power Company and Sierra Pacific Resources in the final legislative negotiations on the merger and associated restructuring legislation.

In his other assignments at Nevada Power Company, Mr. Etheridge:

Directed a department responsible for rate design studies, marginal cost of service studies, the annualization of sales and revenues for general rate case applications, demand-side pricing, economic and load forecasting, tariff administration, wholesale pricing, and development of supporting testimony in these areas. Built a cohesive, progressive thinking team of experts that was well recognized throughout the company.

Made multiple presentations to executives and groups of large commercial and industrial customers on a variety of industry issues.

Represented the company in negotiations with customers considering alternative sources of supply. Negotiated an 8-year retail power purchase contract with Mirage Resorts, Incorporated to keep them from building a distributed generation project. Regularly briefed the Board of Directors during negotiations and gained Board approval for the final contract. Acted as a spokesperson on television and in the press on this highly publicized contract.

Acted as the lead in the development of economic forecasts, econometric load forecasts, weather normalization of sales and peak demand, short-term sales forecasts and testimony in these areas.

Expert Testimony:

Before the Public Utility Commission of Texas, Docket No. 43695 (May and June 2015), on behalf of DOE. Testimony addressed operations and maintenance cost benchmarking and rate design issues.

Before the Missouri Public Service Commission, Case No. ER-2012-0174 (August and October 2012), on behalf of the United States Department of Energy (DOE). Testimony addressed off-system sales margins.

Before the Public Utility Commission of Texas, Docket No. 39896 (March and April 2012), on behalf of DOE. Testimony addressed rate design issues relevant to DOE's Strategic Petroleum Reserve.

Before the Illinois Commerce Commission (ICC), Docket No. 10-0467 (November and December 2010), on behalf of DOE. Testimony addressed proposed distribution loss factors.

Before the Public Utilities Commission of Nevada (PUCN), Docket No. 11-06006 (October 2011), on behalf of DOE. Direct and rebuttal testimony addressed Nevada Power Company's (NPC) proposed class revenue requirement allocation with respect to DOE's Nevada National Security Site (Security Site, formerly the Nevada Test Site) and the U.S. Air Force's Nellis Air Force Base (Nellis AFB) .

Before the Wyoming Public Service Commission, Docket No. 20000-384-ER-10 (May 2011), on behalf of DOE. Testimony addressed class cost of service proposals.

Before the Indiana Utility Regulatory Commission (IRUC), Cause No. 38707 FAC87 (March 2011), on behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Testimony provided comments on Duke Energy Indiana's electric hedging policy.

Before the IRUC, Cause No. 43849 (November 2010), on behalf of the OUCC. Testimony provided comments on an electric hedging policy proposed by the Northern Indiana Public Service Company.

Before the ICC, Docket No. 10-0467 (November and December 2010), on behalf of DOE. Testimony addressed proposed distribution loss factors.

Before the Maryland Public Service Commission (MPSC), Case No. 9179 (December 2009), on behalf of the Maryland Department of Natural Resources. Testimony addressed a proposed transmission line in eastern Maryland.

Before the PUCN, Docket No. 08-12002 (April and May 2009), on behalf of DOE. Direct and supplemental testimony addressed NPC's proposed class revenue requirement allocation with respect to DOE's Nevada Test Site (Test Site) and Nellis AFB.

Before the MPSC, Case No. 9165 (March 2009), on behalf of the Maryland Department of Natural Resources. Testimony addressed a proposed and alternative transmission lines in southern Maryland.

Before the PUCN, Docket No. 06-11022 (March 2007), on behalf of DOE. Testimony addressed NPC's proposed class revenue requirement allocation with respect to the Test Site and Nellis AFB.

Before the PUCN in NPC's last deferred energy case before a rate freeze, Docket No. 99-7035, February 2000. Rebuttal testimony addressed the issue of splitting purchased power capacity payments out of deferred energy cases and into general rate cases for cost recovery purposes.

Before the Nevada Legislature, Senate Commerce and Labor Committee, March 1999. Testimony responded to questions on deregulation.

Before the PUCN in NPC's application to provide potentially competitive services as part of industry restructuring, Docket No. 98-12009, June 1999 and December 1998. Testimony addressed steps being taking to establish an arms length affiliate to provide potentially competitive services.

Before the PUCN in its Investigation of Issues to be Considered as a Result of Restructuring of the Electric Industry (pursuant to Assembly Bill 366), Docket No. 97-8001, September 1997. Testimony addressed NPC's efforts to address restructuring issues and cost unbundling issues.

Before the PUCN in NPC's deferred energy case, Docket No. 97-7030, July 1997. Testimony addressed matching deferred energy rates with rapidly changing deferred energy balances given upward swings in market prices for fuel and purchased energy.

Before the Nevada Legislature, Senate Commerce and Labor Committee, February 1997. Testimony addressed rates during hearings on deregulation.

Before the Public Service Commission of Nevada (PSCN) in a gas utility's filing for approval of a residential gas air conditioning rate schedule, Docket No. 96-10005, February 1997. Testimony on behalf of NPC addressed the potential benefits of pricing strategies that support technological innovation.

Before the PSCN in NPC's deferred energy case and request to move capacity costs into general rates, Docket No. 96-7020, July 1996. Testimony addressed competition, marginal costs, confidentiality issues, and rate design in support of the largest ever-proposed rate reductions for large customers.

Before the PSCN in support of NPC's proposed line extension policies, Docket No. 95-6076, February 1996. Testimony addressed line extension policies in light of competition and marginal costs.

Before the PSCN in a proposed rate schedule in response to DOE's competitive solicitation for the Test Site, Docket No. 95-8038, November 1995 and January 1996. Direct and supplemental testimony addressed a proposal to serve the Test Site under a new partial requirements rate schedule. The case was withdrawn when DOE did not award contracts.

Before the PSCN in NPC's deferred energy case, Docket No. 95-7021, July 1995 and November 1995. Direct testimony and supplemental testimony addressed a request to implement improved cost allocation procedures for calculating base tariff energy rates across rate classes.

Before the PSCN in NPC's application for approval of a negotiated service agreement with Mirage Resorts, Incorporated, Docket No. 95-4061, July 1995. Testimony addressed competition, and the negotiations and cost studies that supported the service agreement.

Before the PSCN in NPC's application for approval of a resource plan, Docket No. 94-7001, February 1995. Testimony addressed load forecasting, competition, long-term avoided costs and econometric modeling.

Before the PSCN in NPC's proposed line extension rules, Docket No. 94-4085, October 1994. Testimony addressed marginal costs relative to line extensions and in total.

Before the PSCN in NPC's application for approval of a resource plan, Docket No. 94-7001, July 1994 and August 1994. Direct and supplemental testimony addressed economic and load forecasting issues.

Before the PSCN in an over-earnings investigation involving NPC, Docket No. 93-11045, June 1994. Direct and supplemental testimony addressed rate design and cost of service.

Before the PSCN in a complaint case brought by a rural cooperative over service to the Test Site, Docket No. 92-9055, January 1994. Testimony addressed the impact of lost sales to the Test Site on remaining retail customers.

Before the PSCN in NPC's general rate case, Docket No. 92-1067, January 1992. Direct and rebuttal testimony addressed rate design and cost of service.

Before the PSCN in NPC's general rate case, Docket No. 91-5055, May 1991. Testimony addressed rate design and cost of service.

Before the PSCN in NPC's application for approval of a resource plan, Docket No. 88-701, July 1988. Testimony addressed economic and load forecasting.

O&M Savings Associated with the AMR Project by Calendar Year and Fiscal Years Ended March 31st

Calendar Year	Projected Cumulative Total O&M Savings[1]	Incremental Total O&M Savings	Projected Cumulative Electric O&M Savings @ 38.98% [2]	Incremental Electric O&M Savings
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]

Calendar Year	Incremental Electric O&M Savings	First Quarter of the Year @ 25.0%	Last Three Quarters of the Year @ 75.0%
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
	[redacted]		

Fiscal Years Ended	Last Three Quarters of the Prior Year	First Quarter of the Current Year	Incremental Electric O&M Savings
3/31/2014	[redacted]	[redacted]	[redacted]
3/31/2015	[redacted]	[redacted]	[redacted]
3/31/2016	[redacted]	[redacted]	1,592,750
3/31/2017	[redacted]	[redacted]	[redacted]
3/31/2018	[redacted]	[redacted]	[redacted]
			[redacted]

(1) NIPSCO response to OUCC Set 4-007, Confidential Attachment B, p. 23.

(2) Electric O&M allocation factor as of March 2015 provided in Petitioner's Exhibit No. 7, Attachment 7-B (Public).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Indiana Public Service Company	(1) ☐ An Original (2) ☒ A Resubmission	12/04/2015	End of 2014/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses		
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	505,233	576,190
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	505,233	576,190
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	86,870	27,108
176	(913) Advertising Expenses	880,430	916,729
177	(916) Miscellaneous Sales Expenses		-21,097
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	967,300	922,740
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	73,579,396	23,947,739
182	(921) Office Supplies and Expenses	23,323,167	19,398,907
183	(Less) (922) Administrative Expenses Transferred-Credit	3,165,177	3,350,544
184	(923) Outside Services Employed	48,161,090	76,216,099
185	(924) Property Insurance	7,091,085	7,441,246
186	(925) Injuries and Damages	8,780,708	7,419,082
187	(926) Employee Pensions and Benefits	36,992,935	47,829,849
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,122,962	1,064,205
190	(929) (Less) Duplicate Charges-Cr.		89,019
191	(930.1) General Advertising Expenses	44,120	27,690
192	(930.2) Miscellaneous General Expenses	3,176,307	2,557,887
193	(931) Rents	2,812,216	909,335
194	TOTAL Operation (Enter Total of lines 181 thru 193)	201,918,809	183,372,476
195	Maintenance		
196	(935) Maintenance of General Plant	884,993	68,790
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	202,803,802	183,441,266
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,097,462,084	1,002,902,730

Utilities Included in the Benchmarking Samples

#	Utility Identifier	Utility Name[(1),(2)]	Benchmarking Samples (X=Included) U.S.	69	49	MISO
1	AEPOH	AEP Ohio	X			
2	AEPTC	AEP Texas Central Company	X			
3	AEPTN	AEP Texas North Company	X			
4	AILM	Ameren Illinois (Merged Company)	X			X
5	ALE	Allete, Inc.	X	X	X	X
6	AMO	Ameren Missouri - Union Electric Company	X			X
7	APC	Appalachian Power Company	X			
8	APS	Arizona Public Service Company	X			
9	ATLC	Atlantic City Electric Company	X	X		
10	AVS	Avista Corporation	X	X	X	
11	BGE	Baltimore Gas and Electric Company	X	X		
12	BHP	Black Hills Power, Inc.	X			
13	CEC	Consumer's Energy Company	X	X	X	X
14	CEI	The Cleveland Electric Illuminating Company	X	X		
15	CHGE	Central Hudson Gas & Electric Company	X			
16	CLECO	CLECO	X	X	X	X
17	CLFP	Cheyenne Light, Fuel and Power Company	X			
18	CMP	Central Maine Power Company	X			
19	COMED	Commonwealth Edison Company	X			
20	CONED	Consolidated Edison Company of New York	X			
21	CPE	CenterPoint Energy Houston Electric LLC	X			
22	CTLP	The Connecticut Light and Power Company	X	X		
23	DECA	Duke Energy Carolinas, Inc.	X			
24	DEFL	Duke Energy Florida, Inc.	X			
25	DEIN	Duke Energy Indiana, Inc.	X	X	X	X
26	DEKY	Duke Energy Kentucky, Inc.	X			
27	DEOH	Duke Energy Ohio, Inc.	X	X		
28	DEPG	Duke Energy Progress, Inc.	X			
29	DMPL	Delmarva Power and Light Company	X	X		
30	DQL	Duquesne Light Company	X	X		
31	DTE	DTE Electric Company	X			
32	DYPL	Dayton Power and Light Company	X	X	X	
33	EAI	Entergy Arkansas, Inc.	X	X	X	X
34	EDE	The Empire District Electric Company	X			
35	EGSL	Entergy Gulf States Louisiana, L.L.C.	X	X	X	X
36	ELL	Entergy Lousiana, LLC	X	X	X	X
37	EM	Emera Maine	X			
38	EMI	Entergy Mississippi, Inc.	X	X	X	X
39	ENO	Entergy New Orleans, Inc.	X			X
40	EPE	El Paso Electric Company	X	X	X	
41	ETI	Entergy Texas, Inc.	X	X	X	X
42	FGEL	Fitchburg Gas and Electric Light Company	X			
43	FPL	Florida Power and Light Company	X			
44	GMPM	Green Mountain Power (Merged Company)	X			

Utilities Included in the Benchmarking Samples

#	Utility Identifier	Utility Name[1],[2]	Benchmarking Samples (X=Included)			
			U.S.	69	49	MISO
45	GNSE	Granite State Electric Company	X			
46	GSWC	Golden State Water Company	X			
47	IMP	Indiana Michigan Power Company	X	X	X	
48	IPC	Idaho Power Company	X	X	X	
49	IPL	Indianapolis Power and Light Company	X	X	X	X
50	ISPL	Interstate Power and Light Company	X	X	X	X
51	JCPL	Jersey Central Power & Light Company	X	X		
52	KCPL	Kansas City Power & Light Company	X	X	X	
53	KGE	Kansas Gas and Electric Company	X	X	X	
54	KNGP	Kingsport Power Company	X			
55	KPC	Kentucky Power Company	X	X	X	
56	KU	Kentucky Utilities Company	X	X	X	
57	LGE	Lousiville Gas and Electric Company	X	X	X	
58	MAE	MidAmerican Energy Company	X	X	X	X
59	MDU	MDU Resources Group, Inc.	X			X
60	MEC	Massachusetts Electric Company	X	X		
61	MED	Metropolitan Edison Company	X	X		
62	MGE	Madison Gas and Electric Company	X			X
63	MONP	Monongahela Power Company	X	X	X	
64	NIMO	Niagara Mohawk Power Corporation	X	X		
65	NIPSCO	Northern Indiana Public Service Company	X	X	X	X
66	NPC	Nevada Power Company	X	X	X	
67	NRGE	The Narragansett Electric Company	X			
68	NSP-MN	Northern States Power - Minnesota	X			X
69	NSP-WI	Northern States Power - Wisconsin	X	X	X	X
70	NSTAR	NSTAR Electric Company	X	X		
71	NWC	NorthWestern Corporation	X	X	X	
72	NYSEG	New York State Electric & Gas Corporation	X	X		
73	OAR	Orange and Rockland Utilities, Inc.	X			
74	OCE	Oncor Energy Electric Delivery Company	X			
75	OGE	Oklahoma Gas and Electric Company	X	X	X	
76	OHEC	Ohio Edison Company	X	X	X	
77	OTP	Otter Tail Power Company	X			X
78	PACGE	Pacific Gas and Electric Company	X			
79	PACRP	PacifiCorp	X			
80	PEC	Pennsylvania Electric Company	X	X		
81	PECO	PECO Energy Company	X			
82	PEPCO	Potomac Electric Power Company	X	X		
83	POED	The Potomac Edison Company	X	X		
84	PPC	Pennsylvania Power Company	X			
85	PPL	PPL Electric Utilities Corporation	X			
86	PRTGE	Portland General Electric Company	X	X	X	
87	PSCo	Public Service Company of Colorado	X	X	X	
88	PSE	Puget Sound Energy	X	X	X	

Utilities Included in the Benchmarking Samples

#	Utility Identifier	Utility Name[(1),(2)]	Benchmarking Samples (X=Included) U.S.	69	49	MISO
89	PSEG	Public Service Electric and Gas Company	X			
90	PSNH	Public Service Company of New Hampshire	X	X	X	
91	PSNM	Public Service Company of New Mexico	X	X	X	
92	PSOK	Public Service Company of Oklahoma	X	X	X	
93	REC	Rockland Electric Company	X			
94	RGE	Rochester Gas and Electric Corporation	X	X		
95	SCAL	Alabama Power Company	X			
96	SCE	Southen California Edison Company	X			
97	SCEG	South Carolina Electric and Gas Company	X	X	X	
98	SCGA	Georgia Power Company	X			
99	SCGF	Gulf Power Company	X	X	X	
100	SCMS	Mississippi Power Company	X	X	X	
101	SDGE	San Diego Gas and Electric Company	X	X	X	
102	SIGE	Southern Indiana Gas and Electric Company	X	X	X	X
103	SPPC	Sierra Pacific Power Company	X	X	X	
104	SPS	Southwestern Public Service Company	X	X	X	
105	SWEPCO	Southwestern Electric Power Company	X	X	X	
106	TED	The Toledo Edison Company	X	X		
107	TEP	Tucson Electric Power Company	X	X	X	
108	TMPEC	Tampa Electric Company	X	X	X	
109	TNMP	Texas New Mexico Power Company	X	X		
110	UGI	UGI Utilities, Inc.	X			
111	UIC	The United Illuminating Company	X			
112	UNS	UNS Electric, Inc.	X			
113	UNTL	Unitil Energy Systems, Inc.	X			
114	UPPC	Upper Peninsula Power Company	X			
115	VEPCO	Virginia Electric Power Company	X			
116	WEP	Wisconsin Electric Power Company	X	X	X	X
117	WMEC	Western Massachusetts Electric Company	X			
118	WPC	Wheeling Power Company	X			
119	WPL	Wisconsin Power and Light Company	X	X	X	X
120	WPP	West Penn Power Company	X	X		
121	WPS	Wisconsin Public Service Corporation	X	X	X	X
122	WSTR	Westar Energy, Inc.	X	X	X	

(1) AEPTN and AEPTC do not report retail sales, retail customers, and total sales and were excluded from performance metrics that required those inputs. CMP does not report retail sales and was excluded from the net A&G expense per retail sales performance metric.

(2) KCP&L Greater Missouri Operations Company ("KGMO"), Black Hills / Colorado Electric Company ("BHC"), and Sharyland Utilities, L.P. ("SRY") were excluded from the U.S. sample. KGMO and BHC were excluded because of merger/divesture activity associated with Kansas City Power & Light Company's purchase of Aquila that prevented 2008 data for either utility from being reconstructed into useable data for the benchmarking study. SRY was excluded because it did not file Form 1s prior to 2010.

Net A&G Expense per Total Plant in Service
Average for 2008 and 2009 Compared to
Average for 2013 and 2014

		A&G / Total EPIS				
#	Utility	Begin (¢/$)	End (¢/$)	CAGR (%)	Quintile	NIPSCO
1	UIC	4.69	0.63	(33.07)	1st	
2	MONP	1.97	0.71	(18.46)	1st	
3	EM	1.68	0.77	(14.45)	1st	
4	CLECO	1.40	0.69	(13.20)	1st	
5	VEPCO	1.41	0.70	(13.07)	1st	
6	AEPTC	1.83	0.92	(12.85)	1st	
7	DEIN	2.02	1.06	(12.10)	1st	
8	GMPM	4.06	2.17	(11.78)	1st	
9	AILM	2.74	1.48	(11.59)	1st	
10	KPC	1.07	0.58	(11.53)	1st	
11	WMEC	3.58	2.03	(10.73)	1st	
12	KNGP	1.76	1.00	(10.69)	1st	
13	WPC	1.28	0.73	(10.62)	1st	
14	SWEPCO	1.19	0.68	(10.59)	1st	
15	PSEG	1.49	0.86	(10.41)	1st	
16	OHEC	2.17	1.30	(9.74)	1st	
17	MAE	0.61	0.37	(9.52)	1st	
18	POED	1.81	1.11	(9.32)	1st	
19	CEI	1.74	1.08	(9.10)	1st	
20	PACRP	0.88	0.55	(8.97)	1st	
21	APC	1.07	0.67	(8.94)	1st	
22	SCGF	2.09	1.31	(8.92)	1st	
23	FGEL	4.48	2.82	(8.84)	1st	
24	UPPC	3.74	2.37	(8.72)	1st	
25	TED	2.56	1.64	(8.52)	1st	
26	WEP	1.83	1.18	(8.40)	2nd	
27	CMP	3.02	2.01	(7.82)	2nd	
28	ALE	3.04	2.07	(7.40)	2nd	
29	KCPL	1.47	1.01	(7.23)	2nd	
30	DEKY	1.81	1.25	(7.14)	2nd	
31	RGE	5.39	3.73	(7.10)	2nd	
32	WPS	2.37	1.66	(6.87)	2nd	
33	NWC	3.02	2.13	(6.74)	2nd	
34	PSOK	1.36	0.97	(6.54)	2nd	
35	AEPTN	1.12	0.80	(6.51)	2nd	
36	DEOH	2.36	1.73	(6.02)	2nd	
37	CTLP	2.82	2.10	(5.73)	2nd	
38	PSNH	3.07	2.31	(5.53)	2nd	
39	UGI	3.91	2.96	(5.41)	2nd	
40	SCMS	2.24	1.72	(5.15)	2nd	
41	PSCo	1.25	0.97	(4.95)	2nd	
42	PPL	2.19	1.70	(4.94)	2nd	

**Net A&G Expense per Total Plant in Service
Average for 2008 and 2009 Compared to
Average for 2013 and 2014**

		A&G / Total EPIS				
#	Utility	Begin (¢/$)	End (¢/$)	CAGR (%)	Quintile	NIPSCO
43	DQL	2.53	2.00	(4.59)	2nd	
44	SPPC	1.58	1.25	(4.58)	2nd	
45	PSE	1.13	0.90	(4.45)	2nd	
46	DECA	1.52	1.22	(4.30)	2nd	
47	CONED	2.55	2.05	(4.27)	2nd	
48	MDU	1.43	1.16	(4.10)	2nd	
49	PACGE	1.70	1.38	(4.09)	2nd	
50	ENO	4.57	3.72	(4.03)	3rd	
51	WPL	1.56	1.27	(4.03)	3rd	
52	SPS	1.53	1.25	(3.96)	3rd	
53	IMP	1.43	1.17	(3.93)	3rd	
54	NPC	1.41	1.16	(3.83)	3rd	
55	EMI	1.82	1.51	(3.67)	3rd	
56	DTE	1.41	1.17	(3.66)	3rd	
57	ELL	1.10	0.92	(3.51)	3rd	
58	PRTGE	1.54	1.30	(3.33)	3rd	
59	AMO	1.38	1.17	(3.25)	3rd	
60	CEC	1.02	0.89	(2.69)	3rd	
61	WPP	2.04	1.78	(2.69)	3rd	
62	UNTL	2.84	2.48	(2.67)	3rd	
63	JCPL	1.04	0.91	(2.64)	3rd	
64	SCGA	1.13	0.99	(2.61)	3rd	
65	NSTAR	1.62	1.42	(2.60)	3rd	
66	OGE	0.83	0.73	(2.53)	3rd	
67	BGE	2.25	1.99	(2.43)	3rd	
68	IPC	2.00	1.77	(2.41)	3rd	
69	DEFL	1.60	1.43	(2.22)	3rd	
70	NSP-MN	1.35	1.21	(2.17)	3rd	
71	SIGE	1.74	1.56	(2.16)	3rd	
72	UNS	1.28	1.15	(2.12)	3rd	
73	OAR	3.77	3.41	(1.99)	3rd	
74	WSTR	1.44	1.31	(1.87)	4th	
75	MGE	2.96	2.71	(1.75)	4th	
76	AVS	2.16	1.98	(1.73)	4th	
77	KU	1.08	0.99	(1.73)	4th	
78	KGE	1.46	1.34	(1.70)	4th	
79	COMED	1.41	1.30	(1.61)	4th	
80	SCEG	1.44	1.34	(1.43)	4th	
81	BHP	3.11	2.90	(1.39)	4th	
82	DMPL	1.96	1.83	(1.36)	4th	
83	REC	3.77	3.55	(1.20)	4th	
84	TEP	1.57	1.49	(1.04)	4th	

**Net A&G Expense per Total Plant in Service
Average for 2008 and 2009 Compared to
Average for 2013 and 2014**

		A&G / Total EPIS				
#	Utility	Begin (¢/$)	End (¢/$)	CAGR (%)	Quintile	NIPSCO
85	NSP-WI	1.42	1.35	(1.01)	4th	
86	TNMP	2.85	2.72	(0.93)	4th	
87	SCAL	1.29	1.25	(0.63)	4th	
88	EDE	1.07	1.04	(0.57)	4th	
89	EPE	2.26	2.20	(0.54)	4th	
90	FPL	0.77	0.76	(0.26)	4th	
91	OTP	2.54	2.52	(0.16)	4th	
92	SCE	2.59	2.57	(0.15)	4th	
93	ATLC	1.86	1.85	(0.11)	4th	
94	NRGE	3.10	3.15	0.32	4th	
95	CPE	1.88	1.92	0.42	4th	
96	PECO	1.90	1.95	0.52	4th	
97	PSNM	2.48	2.56	0.64	4th	
98	DEPG	1.04	1.09	0.94	5th	
99	PEPCO	1.44	1.51	0.95	5th	
100	NYSEG	3.09	3.31	1.39	5th	
101	GSWC	8.99	9.67	1.47	5th	
102	ETI	1.56	1.70	1.73	5th	
103	MED	1.30	1.44	2.07	5th	
104	ISPL	1.24	1.38	2.16	5th	
105	TMPEC	1.09	1.22	2.28	5th	
106	EGSL	0.84	0.95	2.49	5th	
107	LGE	1.12	1.27	2.55	5th	
108	CHGE	4.28	4.95	2.95	5th	
109	APS	0.62	0.72	3.04	5th	
110	CLFP	1.64	2.00	4.05	5th	
111	DYPL	0.85	1.04	4.12	5th	
112	NIMO	3.20	4.04	4.77	5th	
113	EAI	0.88	1.13	5.13	5th	
114	OCE	1.19	1.53	5.15	5th	
115	IPL	1.51	2.02	5.99	5th	
116	PEC	0.79	1.16	7.99	5th	
117	NIPSCO	1.55	2.30	8.21	5th	NIPSCO
118	MEC	3.25	5.05	9.21	5th	
119	AEPOH	0.84	1.34	9.79	5th	
120	SDGE	2.62	5.11	14.29	5th	
121	PPC	0.77	1.66	16.61	5th	
122	GNSE	3.05	6.70	17.05	5th	
	1st Quintile Maximum:			(8.50)		
	2nd Quintile Maximum:			(4.06)		
	Median:			(2.68)		
	3rd Quintile Maximum:			(1.92)		
	4th Quintile Maximum:			0.88		

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for the U.S. Sample

Performance Metric	Unit	*(a)* NIPSCO Metric in 2014[1]	*(b)* Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	*(c)* Change to Bring NIPSCO in Line with 4th Quintile Escalation	*(d)* NIPSCO's Measure of Size for Each Metric in 2014	*(e)* Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	7.89	(1.58)	17,511 GWh	(27.7)
Net A&G Expense per Retail Customer	$	360.57	257.07	(103.50)	459,863	(47.6)
Net A&G Expense per Retail Revenue	%	10.18	10.79	0.61	1,628,645 (000s)	9.9
Net A&G Expense per Total Sales	$/MWh	9.12	8.15	(0.97)	18,186 GWh	(17.6)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.63	(0.84)	6,718,756 (000s)	(56.4)
					Average:	(27.9)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for a Sample of 69 Utilities

Performance Metric	Unit	*(a)* NIPSCO Metric in 2014[1]	*(b)* Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	*(c)* Change to Bring NIPSCO in Line with 4th Quintile Escalation	*(d)* NIPSCO's Measure of Size for Each Metric in 2014	*(e)* Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	7.92	(1.55)	17,511 GWh	(27.1)
Net A&G Expense per Retail Customer	$	360.57	257.22	(103.35)	459,863	(47.5)
Net A&G Expense per Retail Revenue	%	10.18	10.95	0.77	1,628,645 (000s)	12.5
Net A&G Expense per Total Sales	$/MWh	9.12	7.85	(1.27)	18,186 GWh	(23.1)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.68	(0.79)	6,718,756 (000s)	(53.1)
					Average:	(27.7)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for a Sample of 49 Utilities

Performance Metric	Unit	*(a)* NIPSCO Metric in 2014[1]	*(b)* Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	*(c)* Change to Bring NIPSCO in Line with 4th Quintile Escalation	*(d)* NIPSCO's Measure of Size for Each Metric in 2014	*(e)* Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	7.69	(1.78)	17,511 GWh	(31.2)
Net A&G Expense per Retail Customer	$	360.57	257.22	(103.35)	459,863	(47.5)
Net A&G Expense per Retail Revenue	%	10.18	9.18	(1.00)	1,628,645 (000s)	(16.3)
Net A&G Expense per Total Sales	$/MWh	9.12	7.74	(1.38)	18,186 GWh	(25.1)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.64	(0.83)	6,718,756 (000s)	(55.8)
					Average:	(35.2)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for a Sample of 25 MISO Utilities

Performance Metric	Unit	*(a)* NIPSCO Metric in 2014[1]	*(b)* Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	*(c)* Change to Bring NIPSCO in Line with 4th Quintile Escalation	*(d)* NIPSCO's Measure of Size for Each Metric in 2014	*(e)* Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	7.61	(1.86)	17,511 GWh	(32.6)
Net A&G Expense per Retail Customer	$	360.57	262.10	(98.47)	459,863	(45.3)
Net A&G Expense per Retail Revenue	%	10.18	9.18	(1.00)	1,628,645 (000s)	(16.3)
Net A&G Expense per Total Sales	$/MWh	9.12	7.86	(1.26)	18,186 GWh	(22.9)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.71	(0.76)	6,718,756 (000s)	(51.1)
					Average:	(33.6)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for the U.S. Sample
Sensitivity Run with Average Data from 2009 and 2010 as the Beginning Point

Performance Metric	Unit	(a) NIPSCO Metric in 2014[1]	(b) Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	(c) Change to Bring NIPSCO in Line with 4th Quintile Escalation	(d) NIPSCO's Measure of Size for Each Metric in 2014	(e) Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	7.81	(1.66)	17,511 GWh	(29.1)
Net A&G Expense per Retail Customer	$	360.57	257.65	(102.92)	459,863	(47.3)
Net A&G Expense per Retail Revenue	%	10.18	10.00	(0.18)	1,628,645 (000s)	(2.9)
Net A&G Expense per Total Sales	$/MWh	9.12	7.63	(1.49)	18,186 GWh	(27.1)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.65	(0.82)	6,718,756 (000s)	(55.1)
					Average:	(32.3)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for a Sample of 69 Utilities
Sensitivity Run with Average Data from 2009 and 2010 as the Beginning Point

Performance Metric	Unit	(a) NIPSCO Metric in 2014[1]	(b) Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	(c) Change to Bring NIPSCO in Line with 4th Quintile Escalation	(d) NIPSCO's Measure of Size for Each Metric in 2014	(e) Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	7.90	(1.57)	17,511 GWh	(27.5)
Net A&G Expense per Retail Customer	$	360.57	264.51	(96.06)	459,863	(44.2)
Net A&G Expense per Retail Revenue	%	10.18	10.28	0.10	1,628,645 (000s)	1.6
Net A&G Expense per Total Sales	$/MWh	9.12	7.62	(1.50)	18,186 GWh	(27.3)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.63	(0.84)	6,718,756 (000s)	(56.4)
					Average:	(30.8)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for the U.S. Sample
Sensitivity Run with Average Data from 2012 and 2013 as the Ending Point

Performance Metric	Unit	(a) NIPSCO Metric in 2014[1]	(b) Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	(c) Change to Bring NIPSCO in Line with 4th Quintile Escalation	(d) NIPSCO's Measure of Size for Each Metric in 2014	(e) Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	8.09	(1.38)	17,511 GWh	(24.2)
Net A&G Expense per Retail Customer	$	360.57	276.49	(84.08)	459,863	(38.7)
Net A&G Expense per Retail Revenue	%	10.18	11.84	1.66	1,628,645 (000s)	27.0
Net A&G Expense per Total Sales	$/MWh	9.12	7.89	(1.23)	18,186 GWh	(22.4)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.65	(0.82)	6,718,756 (000s)	(55.1)
					Average:	(22.7)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

Net A&G Expense Change Required to Bring NIPSCO in Line with Cost Escalation Rates that Reflect Maximum 4th Quintile Escalation Rates for a Sample of 69 Utilities
Sensitivity Run with Average Data from 2012 and 2013 as the Ending Point

Performance Metric	Unit	*(a)* NIPSCO Metric in 2014[1]	*(b)* Metric in 2014 with Escalation at the 4th Quintile Maximum[1]	*(c)* Change to Bring NIPSCO in Line with 4th Quintile Escalation	*(d)* NIPSCO's Measure of Size for Each Metric in 2014	*(e)* Required Net A&G Expense Change[2] ($ millions)
Formula/ Source		*Etheridge Workpapers*	*Etheridge Workpapers*	*(b) - (a)*	*Etheridge Workpapers*	*(c) x (d)*
Net A&G Expense per Retail Sales	$/MWh	9.47	8.03	(1.44)	17,511 GWh	(25.2)
Net A&G Expense per Retail Customer	$	360.57	276.85	(83.72)	459,863	(38.5)
Net A&G Expense per Retail Revenue	%	10.18	12.65	2.47	1,628,645 (000s)	40.2
Net A&G Expense per Total Sales	$/MWh	9.12	7.70	(1.42)	18,186 GWh	(25.8)
Net A&G Expense per Total Plant in Service	¢/$	2.47	1.78	(0.69)	6,718,756 (000s)	(46.4)
					Average:	(19.1)

(1) Rounded.

(2) The retail and total sales calculations reflect (c) x (d) / 1,000.
The retail customer caluclation is (c) x (d) / 1,000,000.
The retail revenue and total plant in service calculations reflect (c) / 100 x (d) / 1,000.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Dwight D. Etheridge

Dwight D. Etheridge
Consultant for
Indiana Office of Utility Consumer Counselor

January 22, 2016
Date

Cause No. 44688
NIPSCO