DATABASE FOR DISTRIBUTION NETWORK SERVICES IN THE US AND AUSTRALIA

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

The Australian Energy Regulator ("AER") is updating price controls for jurisdictional power distribution network service providers ("DNSPs"). The operating expenses ("opex") incurred by DNSPs for network services are an important component of their revenue requirements. Pursuant to Australian government policies, the AER is using economic benchmarking to appraise the historical network services opex of the companies.

Data from the United States of America ("US") are potentially useful to the AER in its benchmarking program. Extensive, detailed data have been gathered by the federal government on the operations of US electric utilities for decades. Data on power distribution opex are itemized, and several cost categories can be removed to produce a definition of cost that is similar to the AER's network services opex. The itemized cost data utilities file must conform to a Uniform System of Accounts.

The personnel of Pacific Economics Group Research LLC ("PEG") have extensive experience in utility cost research. Work for diverse clients that include regulatory commissions and consumer advocates as well as utilities has given us a reputation for objectivity. We pioneered the use of scientific benchmarking and productivity research in North American regulation, and have prepared transnational benchmarking studies for Australian and Canadian clients. Company president and senior author Mark Newton Lowry has testified on statistical cost research in numerous proceedings.

The AER has retained PEG Research to develop a US data set that is compatible with the Australian electricity distribution data the AER has collected. Data on the following variables were requested.

- A comparable operating and maintenance cost series
- Delivery volume for residential and "other" customers
- Number of electricity residential and "other" customers
- Number of gas customers
- Total route (aka structure) miles, and if available split by overhead and underground

- Extent of system overheading
- Distribution substation capacity
- Distribution lines exceeding 100kv
- The price index and mechanism for comparing US and Australian prices
- Temperature
- Precipitation
- Peak demand, if available
- Transmission and generation dummy variables

We have also been tasked with developing illustrative econometric cost models using a popular software package to illustrate the potential use of transnational data. These models do not constitute a recommendation about how best to benchmark Australian DNSP opex.

This document is the report on our research. Following a brief summary of the work below, Section 2 discusses our data gathering, while Section 3 discusses the econometric research. There are brief concluding remarks. Some technical details of the research are presented in the Appendix.

1.2 Summary of Research

1.2.1 Data

We developed a set of data on the operations of US DNSPs which are consistent with the data for some key variables the AER has gathered for benchmarking. US data were drawn from public sources that included the Federal Energy Regulatory Commission and the US Energy Information Administration ("EIA"). Consistent data were unavailable, however, for several variables in the AER data set. These included variables pertaining to reliability, system age, and distribution transformer capacity.

Our econometric research was based on a sample of data for thirteen Australian DNSPs and fifteen US DNSPs. The sample period for the Australian companies was 2006-2013, while the sample periods for the US companies varied in a range from 1995 to 2013. The Australian data were obtained from the AER, the Australian Bureau of Statistics, and other respected public sources.

1.2.2 Illustrative Econometric Results

We developed a credible cost benchmarking model using the transnational data set and compared parameter estimates and benchmarking results to those obtained using a model based solely on Australian data. Parameter estimates and the relative rankings for Australian utilities were sensitive to the data set used. While US companies generally fared better in the benchmarking than their Australian counterparts, we believe that statistical tests would be unable to reject the hypothesis that most Australian utilities are average cost performers. Given, additionally, the small sample size, we cannot confidently conclude from the research that DNSPs in the United States tend to be more efficient in their management of network services opex than those in Australia.

2. CONSTRUCTING A COMPATIBLE US-AUSTRALIA DATABASE

2.1 Cost, Price, and Scale Data

2.1.1 US Data

Overview

Cost benchmarking of US energy utilities is facilitated by the detailed, standardized operating data the federal government has gathered for decades on many relevant variables, from numerous utilities. Reporting of these data is mandatory. The primary source of data used in this study on the cost of utilities and their distribution substation capacity was the FERC Form 1.[1] These data are filed annually by major (and a few minor) investor owned utilities ("IOUs").[2] Data reported on the Form 1 must conform to the FERC's Uniform System of Accounts.[3] The primary source of data used in this study on power delivery volumes and the number of customers served was Form EIA 861 ("Annual Electric Power Industry Report").[4]

The universe of IOUs for which data suitable for statistical cost research are available is limited by several problems. Salient amongst these problems are mergers, divestitures, and the transfer of assets between transmission and distribution. There are special data availability problems for utilities in Texas. Due to problems like these, we typically include data for 65-75 US utilities in our distribution cost research.

Data on the prices of O&M inputs were drawn from the Bureau of Labor Statistics ("BLS") of the US Department of Labor. Purchasing power parity data were obtained from the Organization for Economic Cooperation and Development ("OECD"). Weather data were obtained from the National Oceanic and Atmospheric Administration's National Climatic Data Center.

Data on route miles of distribution lines were obtained from annual 10-K financial reports to the US Securities and Exchange Commission. Data on line lengths in these

[1] Data on distribution transformer capacity are unavailable.
[2] Minor utilities do not file the full Form 1.
[3] Details of these accounts can be found in Title 18 of the Code of Federal Regulations.
[4] EIA 861 data for 2013 are not yet available and were imputed using the (generally accurate) FERC Form 1 data.

reports are neither mandatory nor standardized. However, companies do indicate whether the reported data are for circuits or routes. The AER gathers data on total distribution route miles and on overhead and underground circuit miles. 10-K data matching AER data are most abundant for total route miles, but are available for fewer than 20 utilities. This became the chief limiting factor in the size of our dataset.

US data are unavailable on the capacity of line transformers. Standardized reliability data are available for some US utilities from state regulators. However, the overlap between this group of utilities and the group that reports total distribution route miles isn't large. The EIA will for the first time release standardized reliability data for electric utilities this fall. We were unable to gather US data that are consistent with the AER data on the age of the capital stock as this would have required voluntary, time-consuming responses by utilities to a questionnaire.

Data were considered for inclusion in our sample from all major investor-owned US electric utilities that filed Form 1s from 1995 to 2013 and either published or provided us with data on their distribution route miles for at least two years of this period.[5] Data from fifteen US companies met these requirements and were used in the transnational econometric work. The sampled companies are listed in Table 1. Several of these companies provided extensive generation services as well as distribution services during some or all years of the sample period. All companies provided power transmission services throughout the period. Three of the companies (Fitchburg Gas and Electric, South Carolina Electric and Gas, and Southern Indiana Gas & Electric) also provide gas delivery services. A total of 170 consistent US observations were used in the illustrative cost model. These permit a substantial increase in the size of the dataset available for econometric model estimation.

The US data set sent to the AER comprises in totality data on 18 companies for the entire sample period, a total of 342 observations. Some of these data were excluded from the econometric work, for various reasons.

- Implausible substation capacity data (United Illuminating, West Penn Power, and Potomac Edison)

[5] Only one company, Fitchburg Gas and Electric, provided us with sufficient line mile data.

Table 1

Details of the Transnational Sample

Australia		United States of America			
Companies	**Observations**	**Companies**	**Substantial Generation Service in 2013?**	**States Served**	**Observations**
ActewAGL	8	Connecticut Light & Power	No	Connecticut	2
Aurora	8	Fitchburg Gas & Electric	No	Massachusetts	3
Ausgrid	8	Idaho Power	Yes	Idaho, Oregon	5
CitiPower	8	Jersey Central Power & Light	No	New Jersey	13
Endeavour Energy	8	Metropolitan Edison	No	Pennsylvania	13
Energex	8	Monongahela Power	Yes	West Virginia	12
Ergon Energy	8	Ohio Edison	No	Ohio	15
Essential Energy	8	Oklahoma Gas & Electric	Yes	Oklahoma, Arkansas	19
Jemena	8	Pennsylvania Electric	No	Pennsylvania	13
Powercor	8	Pennsylvania Power	No	Pennsylvania	15
SA Power Networks	8	Public Service Company of New Hampshire	Yes	New Hampshire	2
SP AusNet	8	South Carolina Electric & Gas	Yes	South Carolina	18
United Energy	8	Southern Indiana Gas & Electric	Yes	Indiana	19
		Tampa Electric	Yes	Florida	19
		Western Massachusetts Electric	No	Massachusetts	2
Total Observations:	**104**				**170**

- Lack of line mile data for some years, especially in the early years of the sample period (e.g., Fitchburg Gas & Electric, Connecticut Light & Power, Idaho Power, Public Service Company of New Hampshire, and Western Massachusetts Electric). Two companies, Ohio Edison, and Pennsylvania Power, had plausible line miles in earlier years of the sample period but not in later years

A summary of the number of observations per company that were included in the cost modeling is provided in Table 1. The specific observations that were included in the econometric modelling are provided in the sheet titled "Output Index" of the dataset file.

Calculating O&M Expenses

Network services opex as defined by the AER was approximated for US utilities as total distribution O&M expenses less the itemized expenses for metering, customer installations, and street lighting and signal systems, plus a sensible share of administrative and general ("A&G") expenses.[6] The A&G share was based on the share of network services opex in a utility's net opex for generation, transmission, distribution, and customer services.[7] The resultant shares of A&G expenses allocated to the network opex of US utilities are well below 100% and are particularly low for utilities with extensive generation.

The A&G expenses reported on the FERC Form 1 include expenses for pensions and other benefits. In the United States, "other benefits" include health insurance, which is not provided by DNSPs in Australia. To finesse this consistency problem, we subtracted pension and benefit expenses from total A&G expenses and then added back an imputation for pension expenses. The imputation was based on our estimate of the typical ratio of pension expenses to salaries and wages in the utility sector of the US economy in 2010. The estimate was based on Employer Costs for Employee Compensation ("ECEC") data, which are a product of the BLS National Compensation Survey ("NCS").

Operating Scale

We gathered US data on seven measures of operating scale:

[6] US and Australian data may still differ with respect to the capitalization of O&M expenses and the allocation of some expenses between cost categories.

[7] In this calculation, net opex was calculated by removing from the total O&M expenses reported the expenses for generation fuels, other power supply, transmission by others, and customer service and information. These expenses chiefly consist of goods and services purchased from others. They therefore have less impact on A&G expenses, a large portion of which are incurred in the management of labor. Customer service and information expenses include expenses for demand side management that are often sizable.

a) Delivery volumes for residential and “other” retail electric customers

b) Number of residential and “other” retail electric customers

c) Peak demand

d) Total route miles, and if available split by overhead and underground

e) Distribution substation capacity

f) Length of distribution lines rated 132 kV or higher

g) Elasticity-weighted scale index

Variables d)-f) are also scale-related measures of the capital stock.

The peak demand data reported on the FERC Form 1 pertain to the coincident peak. They are not an exact match for the coincident peak demand data gathered by the AER since they cover some deliveries by transmission systems that do not flow through the distribution system. The extra deliveries include those for “requirements sales for resale”.[8] These are chiefly sales via longer term contracts to other utilities. We attempt to make the FERC peak demand data more comparable to the AER data by multiplying the former by the ratio of the utility’s retail sales volume to the sum of its retail sales and requirements sales for resale.

None of the sampled US utilities have 132 kV lines in their distribution systems. The value for this variable is thus zero for all US utilities. Our calculation of US substation capacity is discussed in the Appendix.

Input Prices

The method for constructing the US O&M input price index consisted of two broad steps. The first step was to establish relative price levels for companies in the sample in 2008. The second step was to construct an O&M price trend index that was used to calculate the price level in other years. Each step is discussed in turn.

O&M Input Price Levels We assumed that labor prices varied between utilities according to the prevailing wage rates in each utility’s service territory. We believe markets for many M&S inputs were more national in scope, so that prices for these inputs were more similar across territories. We assumed that local variations in M&S prices in 2008 were 25% of the variation in labor prices.

[8] The US peak demand data also include deliveries to large volume end users that do not pass through the distribution system.

The year chosen to establish US O&M price levels was 2008. The formula used to determine the level was:

O&M Input Price Level = Percent of Cost: Labor x Labor Price Level +
Percent of Cost: Materials x 0.25 x Labor Price Level +
Percent of Cost: Materials x 0.75 x 1.00.

The labor price levels were constructed using data published by the BLS from their Occupational Employment Statistics Survey ("OES"). This survey collects wage data for detailed job categories for a large number of US cities. Each utility was assigned all of the available cities in its service territory. Data for these cities were then aggregated to arrive at one wage rate per job category per utility. The BLS also publishes industry-level data for the US as a whole from which we obtained the percentage of labor cost given to each job category for the Electric Power Generation, Transmission, and Distribution sector.

The price level for each company was then calculated as a cost-weighted average of the prevailing wage rates for each job category. The results were then divided by the average for all companies such that the resulting value can be interpreted as the company-specific labor price relative to a national labor price of 1.00.

O&M Price Trend Indexes The index described above accounts for price level differences among companies, but only for one year. To extend this level forward and backward in time we constructed an O&M price trend index. This summary index is constructed from two price trend subindexes. The first is for labor inputs. The BLS publishes employment cost indexes ("ECIs") for different industries as well as for the economy as a whole. These indexes are the best available for measuring trends in labor prices. The best available match for electric power companies is the ECI for the utilities sector. This index, however, is only available for the US as a whole. In order to allow for some regional variation in labor price trends we obtained comprehensive ECIs for the United States and the East, South, Midwest, and West regions as defined by the BLS. For each region, a customized utility ECI growth rate was then constructed as follows:

$$\textit{growth Regional ECI}^{Utilities} = \textit{growth National ECI}^{Utilities} + (\textit{growth Regional ECI}^{Comprehensive} - \textit{growth National ECI}^{Comprehensive}).$$

Each company in the sample was assigned the labor price trend subindex for the BLS region it served.

The M&S price trend index for the United States was designed by PEG Research to reflect the non-labor components of A&G and distribution O&M. The trend in the index is a cost-weighted average of trends in Producer Price Indexes ("PPIs") published by the BLS.

PEG Research picked appropriate PPIs to include in the construction of the M&S price index. We compared the Uniform System of Accounts descriptions for expense categories to the PPIs available from 1996 onwards.[9] We attempted to find one or more PPIs for each relevant FERC Form 1 A&G and distribution O&M expense category. We were able to find unique sets of PPIs for each A&G expense account, but not for each distribution expense account. In particular, we found there was insufficient information to develop unique PPI groups for the operation and maintenance of overhead lines, underground lines, and stations and transformers. We divided distribution O&M expenses into five categories:

1) Distribution Supervision and Engineering
2) Overhead Line O&M
3) Underground Line O&M
4) Stations and Transformer O&M
5) Other Distribution O&M

After compiling PPIs for each expense category, M&S price trend subindexes were developed for A&G and distribution. To determine the weights for each subindex, we looked at 2012 FERC Form 1 data from a sample of 132 US electric utilities. We aggregated reported costs for each relevant distribution and A&G expense account over all companies in the sample. Cost subtotals were obtained for distribution and A&G by summing the expenses for these accounts. Each PPI was assigned a weight equal to the cost share of the corresponding account (or, in the case of distribution, account *group*) divided by the number of PPIs matched to that account (or account group).

The growth of the summary M&S price trend index for each company is a weighted average of the growth in the A&G and distribution M&S price trend indexes. Cost share

[9] In a few cases, the PPIs were not available until a later date. We assumed that inflation in the years before data were available was equal to the inflation in the first year for which data were available. Inflation in the early years of the sample period was generally slow.

weights were used for the summary index which are time-varying and company-specific. A Tornqvist index form was employed.

2.1.2 Australian Data

Data on network services opex, operating scale, and other dimensions of the operations of Australian DNSPs were provided by the AER. Data were available for thirteen DNSPs over the eight year 2006-2013 period, for a total of 104 observations. Data on Australian input prices were obtained from the Australian Bureau of Statistics ("ABS"). Australian weather data were obtained from the Australian Bureau of Meteorology.

A summary O&M input price index for Australia was constructed by PEG Research as a weighted average of price indexes for labor and M&S inputs. The index retains the 62%/38% Labor/M&S weights that Lawrence and Kain suggested in a report to the AER.[10]

The labor price subindex was levelized using the 2011 Census Database of Employment, Income and Unpaid work from the ABS.[11] This database details the number of employees working at various ranges of gross weekly personal income. These data are itemized by state, industry, and labor force status. We used the data for the Electricity, Gas, Water, and Waste Service ("EGWW") industry to construct weighted average wage rates for each Australian state and territory. The wage rate for each income bracket was the ABS-imputed median income for that bracket.[12] The weight for each wage rate was the share of the corresponding bracket in total state EGWW employment.

It would have been preferable to use a state-specific EGWW wage price trend index ("WPI") to deflate the 2011 levels to create values for other years of the sample period. The ABS, like the BLS, does not produce regional labor price trend indexes for specific industries but does produce state-specific and national *all industry* WPIs, as well as a national WPI for the EGWW industry.[13] In order to construct an appropriate labor price trend index for each state (one that accounts for both local and industry trends in labor

[10] Denis Lawrence and John Kain, *Economic Benchmarking of Electricity Network Service Providers: Report Prepared for the Australian Energy Regulator* (Eden, New South Wales: Economic Insights, 2013), p. 56.
[11] "Census TableBuilder," *Australian Bureau of Statistics*, accessed June 12, 2014, https://www.censusdata.abs.gov.a u/webapi/jsf/selectTopic.xhtml.
[12] "Income Data in the Census," *Australian Bureau of Statistics*, last modified July 30, 2012, accessed June 12, 2014, http://www.abs.gov.au/websitedbs/censushome.nsf/home/factsheetsuid?opendocument&navpos=450.
[13] "Wage Price Index, Australia, Mar 2014," *Australian Bureau of Statistics*, last modified May 21, 2014, accessed June 12, 2014, http://www.abs.gov.au/ausstats/abs@.nsf/mf/6345.0.

prices), the trend in the national WPI for the EGWW industry was adjusted for the difference between the state specific and national all industry WPIs so that

$$\Delta WPI_{ST}^{EGWW} = \Delta WPI_{NAT}^{EGWW} + \left(\Delta WPI_{ST}^{All} - \Delta WPI_{NAT}^{ALL}\right).$$

The resulting indexes were then used to adjust each state's 2011 EGWW labor price level for inflation.

For the 38% M&S portion of the O&M price trend index, the following decomposition, proposed by Lawrence and Kain, was used: 19.5% PPI for Intermediate Inputs – Domestic; 8.2% PPI for Data Processing, Web Hosting and Electronic Information Storage; 6.3% PPI for Other Administrative Services; 3.0% PPI for Legal and Accounting Services; and 1.0% PPI for Market Research and Statistical Services.[14] Prices for M&S inputs were assumed to have a 25% local labor content so that they tended to be a little higher in regions with higher labor prices. We used various labor prices to effect this levelization in 2011. For the Intermediate Inputs component, the state EGWW price levels explained above were used. For the other components, state labor prices from the same data source for other Australia and New Zealand Standard Industrial Classification ("ANZSIC") industries were used, as set forth below.

ANZSIC Division Used for Price Levelization	**PPI(s)**
Electricity, Gas, Water and Waste Services	Intermediate Inputs-Domestic
Information, Media and Telecommunications	Data Processing, Web Hosting, and Electronic Information Storage
Administrative and Support Services	Other Administrative Services
Professional, Scientific and Technical Services	Legal & Accounting Services and Market Research & Statistical Services

[14] Lawrence and Kain, *Economic Benchmarking*, p. 68.

The values of the M&S price indexes for other years were calculated by escalating them by their corresponding national price trend indexes.[15]

2.1.3 Transnational Price Patch

PEG constructed a transnational price "patch" that converted US input prices to Australian input prices by dividing the levelized US O&M input price index by a Transnational Levelization Factor (TLF). The TLF summarizes US/Australian comparisons of labor and M&S prices in 2010. The TLF is a bilateral price index of Tornqvist form with the US as the base country and can be expressed in log-change form as:

$$\ln(TLF) = \frac{(SL_{US} + SL_{AU})}{2} * \ln(LPR) + \frac{(SM_{US} + SM_{AU})}{2} * \ln(PPP)$$

Here are the definitions of the terms in this formula:

- SL_i is the average share of labor in network opex for companies in country *i* throughout the sample period.
- SM_i is the average share of M&S inputs in network opex for companies in country *i* throughout the sample period.
- *PPP* is the 2010 Purchasing Power Parity ("PPP") for GDP between the US and Australia, with US prices being the denominator. The value is 1.506.
- *LPR* is the 2010 Labor Price Ratio. This is calculated as follows:

$$2010\ LPR = \frac{2010\ Gross\ Hourly\ Earnings\ AU * (1 + 2010\ AU\ other\ labor\ costs\ ratio)}{2010\ Gross\ Hourly\ Earnings\ US * (1 + 2010\ US\ other\ labor\ costs\ ratio)}$$

In the calculation of the labor price ratio, each country's base labor price was defined as gross hourly earnings. These were then adjusted to reflect the additional labor costs that are reported as network opex in the data for each country. These adjustments were made using national "other labor costs" ratios. Each ratio was calculated as the sum of all categories of typical labor costs per employee not included in each country's base gross hourly earnings but included in network services opex, divided by typical gross earnings. For the US, only retirement benefits were included in the other labor costs ratio, since pensions is the only category beyond simple salaries and wages which is included in the US companies' network opex. For Australia, superannuation (e.g., utility-provided retirement

[15] "Producer Price Indexes, Australia, Mar 2014," *Australian Bureau of Statistics*, last modified May 2, 2014, accessed June 12, 2014, http://www.abs.gov.au/ausstats/abs@.nsf/mf/6427.0.

benefits), payroll taxes, and workers' compensation were included in the other labor costs ratio, since the AER's definition of labor costs for network opex includes all of them.

Data on hourly earnings of production and nonsupervisory employees of the US power generation and supply industry were obtained from the BLS Current Employment Statistics ("CES"). Adjustments for other US labor costs were calculated from data on the hourly cost of utility-provided retirement benefits and hourly gross earnings for all utility industry employees in the BLS Employer Cost of Employee Compensation ("ECEC") database.

Australian hourly earnings data are for non-managerial employees in the Electricity Supply industry and were drawn from the ABS Survey of Employee Earnings and Hours ("EEH") (catalogue number 6306.0). The adjustment for other Australian labor costs was calculated from data on annual employee earnings, superannuation, payroll tax, workers compensation, and fringe benefits tax costs for the EGWW industry. These data are gathered by the ABS in its Survey of Major Labor Costs ("MLC") (catalogue number 6348.0).

US Other Labor Costs	Markup Factor	Australia Other Labor Costs	Markup Factor
Utility-Provided Pensions	13.88%	Utility-Provided Superannuation	9.75%
		Payroll Taxes	4.66%
		Workers Compensation	1.42%
Total Markup Factor	13.88%	Total Markup Factor	15.84%

2010 is chosen to compare input prices primarily because of the limited availability of some Australian labor cost data. The MLC survey is the most reliable and complete summary of the labor costs not included in ABS measures of gross hourly earnings but reported by Australian DNSP's as opex. This survey is performed irregularly. The latest iteration of the survey was in 2010-2011, a collection from June to June, so that averages should be approximately end-of-year 2010 values. The most recent iteration of the MLC before that was in 2002-2003.

It is also preferable to use data for the more recent year because we are more interested in benchmarking results for recent years. The econometric results are, however, insensitive to the choice of a year for the transnational price comparison to the extent that the trends in our input price indexes are accurate. If, for example, the PPP was lower in 2001 than in 2013, that should be reflected in more rapid price inflation in Australia between those years. In fact, the PPP averaged 1.09% annual growth from 2001-2013. During the same period, our input price index for Australia exceeded that for the U.S by 0.94% annually on average.

2.2 Other Business Conditions

We gathered data on the following additional business conditions.

Overheading

For Australian DNSPs, a system overheading variable was calculated as the share of overhead facilities in the closing regulatory asset value of overhead and underground network assets. These asset values are *net* of depreciation and expressed in *current* dollars. For the US DNSPs the most closely matching metric for which data are readily available is the share of overhead plant in the value of distribution line and structure (pole, tower, and conduit) plant. These calculations use *gross* plant value data expressed in *historic* dollars.

Since the numerators and denominators used in these calculations *for each country* use consistent accounting, it is hoped that a *pooling* of these data is reasonable. An examination of the data suggests that they yield comparisons that are generally sensible. For example, utilities serving large urban areas in each country tend to have low overheading. However, a ranking of the extent of overheading for the Australian utilities using plant value data is somewhat different from the rankings when analogous circuit kilometer data (e.g., $km^{overhead}/km^{total}$) are used.

Generation Activity

We developed a binary variable with a value of one for utilities that were extensively involved in power generation during the sample period. We expected the parameter for this variable to have a positive sign, indicating the presence of scope economies.

Temperature

We gathered data on the following temperature variables.

- Annual maximum temperature
- Average of the annual maximum temperatures 2006-2012

- Maximum of the annual maximum temperatures 2006-2012

We expected the parameters for these variables to have positive signs, reflecting the greater difficulty of voltage transformation at high temperatures.

Precipitation

It was not feasible to gather data for US utilities on the AER's forestation variables. As a practical alternative, we gathered data for the US and Australia on precipitation. This variable has a positive correlation with forestation and has been used in some of our previous cost benchmarking studies. We expected the sign of this parameter to be positive.

Elasticity-Weighted Scale Index

We developed an index of operating scale that featured three scale variables: route miles, substation capacity, and the number of customers served. The weight for each variable was the share of its corresponding cost elasticity in the sum of three cost elasticities. The cost elasticities were the same for all companies and were drawn from the econometric work. This index can potentially be imported for use in benchmarking and productivity research that is otherwise based entirely on Australian data.

Gas Distribution

We developed a binary variable with a value of 1 for companies that distributed gas as well as power.

3. Illustrative Econometric Research

3.1 Overview of the Research

We developed an econometric model of network services opex. Our general approach to model development was to first consider a model with a wide range of business conditions and then eliminate variables with implausible and highly insignificant parameter estimates. For example, if we believe that a variable indicating operation of a medium voltage delivery system is pertinent, and this variable has a parameter estimate of plausible sign and magnitude, we would keep this variable in the model even though one of the scale variables had an insignificant or implausible sign as a consequence. If peak demand has a negative parameter estimate when the number of customers has a positive and highly significant estimate, we remove peak demand from the model. The size of the transnational data set, while much larger than the size of the AER's Australian data set, is nonetheless small enough to limit the number of variables for which parameter estimates can be accurately estimated. Spurious correlations and multicollinearity are concerns.

A translogarithmic functional form was employed for the scale variables. The values of most other variables were logged. Model parameters were estimated using a procedure that corrected for problems commonly encountered in econometric cost research. Functional forms and estimation procedures are discussed more extensively in the Appendix.

3.2 Modelling Network Services Opex

3.2.1 Contributions from Cost Theory

Economic theory is useful for identifying business conditions that should be considered in an econometric cost model. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to the business conditions in its service territory. When the focus of benchmarking is opex, theory reveals that the relevant business conditions include the prices of O&M inputs, the operating scale of the company, and the quantities of capital inputs the company uses. Operating scale and capital quantities are multidimensional, so that several variables may be required to measure them accurately. Miscellaneous other business conditions may also drive cost.

3.2.2 Distribution Outputs

Cost theory suggests that the operating scale of a utility is an important cost driver. The "outputs" of a DNSP are sometimes narrowly defined as measures of its operating scale that also serve as billing determinants. Three billing determinants are salient: the delivery volume, peak demand, and the number of customers served. Another measure of network services output that is often discussed is the extensiveness of the distribution system.

The quality of local delivery service is important to customers. Important aspects of quality include reliability, the stability of voltage, and the speed with which requests for service are honored. Indicators of service quality may be reasonably regarded as output measures.

3.2.3 Capital Quantities

Capital quantities were noted above to be potentially important opex drivers. The stock of capital a company owns is multidimensional. Some of the dimensions are highly correlated with operating scale. For a DNSP, these include the length of distribution lines and the voltage stepdown capacity of distribution substations. Other dimensions of capital quantity that may matter in opex modelling include the kind of capital (e.g., overhead vs. underground lines) and the age of the system.

3.2.4 Services Provided

DNSPs vary in the network services they provide. These differences can have a sizable impact on the cost of service. Here are some examples.

- One important difference is in the transportation of power at medium voltage which DNSPs undertake. Where transmission and distribution services are provided by separate companies, the issue is which company provides any services of this kind. For example, several Australian DNSPs operate systems of 100+ kilovolt ("kV") lines but most do not. Where transmission and distribution services are provided by the same company, as is common in the United States, the issue is how these services are *classified*. In the United States, 132+ kV lines of utilities are almost always classified as transmission assets. Some utilities have 69 kV lines. Some companies classify these "subtransmission" lines as distribution assets but most do not.

- Another important difference is in the stepdown of voltage from the transmission to the distribution level. In Australia, the stepdown of voltage from transmission to distribution levels is usually though not always undertaken by the distributor. In the United States, substations that step down voltage to distribution levels are commonly classified as distribution facilities.
- DNSPs vary around the world in the services other than distribution services they provide. For example, DNSPs in Australia focus on energy distribution whereas major investor-owned DNSPs in the States usually own most transmission facilities in their service territory and many also provide generation services. The provision of generation and transmission services raises administrative and general expenses and increases the importance of the method used to allocate a share to distribution network services.

3.2.5 Other Network Characteristics

Power distribution networks vary in a number of other respects that affect their cost.

- Systems vary widely in customer density (e.g., customers per line mile). Density is highest in urban areas and lowest in sparsely populated rural areas.
- There is marked diversity in the extent of system undergrounding. Undergrounding is most common in the central cities of major urban areas such as Melbourne and Sydney. Its prevalence in other areas depends greatly on public policy.
- The shape of distribution systems must conform to special features of the landscape. For example, distribution lines will typically go around lakes and other water bodies.
- Distribution opex is generally lower the younger is the system.

3.2.6 Other Cost Drivers

Cost research by PEG and others has identified a wide range of additional business conditions that are drivers of local delivery costs.

- Cost is typically higher the greater is the degree of forestation. An obvious reason is the greater need for tree-trimming and other maintenance expenses.
- Another condition that affects the cost of power distribution is the number of gas customers that the company provides with distribution service. This presents opportunities for the realization of scope economies from the sharing of inputs.

3.3 Business Condition Variables

Operating Scale

Three measures of operating scale were used in the illustrative econometric models: distribution route km, distribution substation capacity, and the total number of customers served. The first two of these three variables also measure dimensions of the capital stock. The parameters of all three variables are expected to have positive signs.

Input Prices

We included in the econometric model the index of the prices of non-fuel O&M inputs. In estimating the cost model we divided cost by this input price index. This is commonly done in econometric cost research because it simplifies model estimation and ensures that the relationship between cost and input prices predicted by economic theory holds.[16]

Other Business Conditions

Seven other business condition variables were included in the illustrative econometric model. Two of these measure additional dimensions of the capital stock. One of these is the distribution system overheading variable. System overheading involves higher opex in most years because facilities are more exposed to the challenges posed by local weather (e.g., high winds and ice storms), flora, and fauna.[17] We therefore expect the sign of this variable's parameter to be positive. The other capital stock variable is the mileage of distribution circuits with a kV rating of 132 or greater. We expect the parameter for this variable to have a positive sign.

[16]Theory predicts that a 1% increase in the prices of all inputs will raise cost by 1% if all other business conditions are unchanged.
[17] Maintenance of underground delivery facilities occurs less frequently but can be quite costly.

A third supplemental variable is the product of the AER's bushfire risk metric for 2013 and a dummy variable that equals one for Victorian utilities for 2009 and later years of the sample period. It reflects the higher opex for compliance with policies of Victoria's state government regarding bushfire risk. The parameter for this variable should have a positive sign.

A fourth supplemental variable is the gas distribution binary variable. ActewAGL was the only Australian utility to offer gas service. We expect the parameter for this variable to have a negative sign.

A fifth supplemental variable is average annual rainfall. We used this as a proxy for forestation in the service territory. We expect the parameter for this variable to have a positive sign.

A sixth supplemental variable is a binary term that assumes a value of one for US utilities and a value of zero for Australian utilities. This captures the typical net effect of excluded business conditions (and any mismeasurement of transnational price differences) on the relative cost of US utilities. One such condition is the greater opportunity for the realization of scope economies that US utilities have due to their involvement in transmission. The predicted sign of this variable is nevertheless indeterminate.

The econometric model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business condition variables. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Although the sign of this parameter is indeterminate, such parameters often have a negative sign in statistical cost research.

Translog functional forms were used for the scale variables. As a consequence, the models include "second-order" (quadratic and interaction) terms for the scale variables. These are explained further in the Appendix.

3.4 Results of the Illustrative Econometric Research

Estimation results for the cost models using transnational and Australian samples are reported in Tables 2 and 3, respectively. Results for the quadratic and interaction terms are shaded in these tables.

Table 2

Econometric Model of Network Services Opex: Results Using Transnational Data

VARIABLE KEY

N =	Number of Customers
SUB =	Distribution Substation Capacity
KM =	Distribution Structure Kilometers
OH =	Percent of Distribution Line Plant that Is Overhead
KM132 =	132 KV+ Circuit Kilometers
RFALL =	Average Rainfall
VF =	Victoria Bushfire Risk (2009-2013)
GAS =	Gas Service Provider
US =	US Firm Dummy
Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	Z-STATISTIC	P-VALUE
N[1]	0.589	4.42	0.000
SUB[1]	0.240	1.97	0.049
KM[1]	0.117	3.02	0.002
N*N	0.601	1.41	0.159
SUB*SUB	0.233	1.06	0.287
KM*KM	0.055	0.72	0.470
N*SUB	-0.208	-0.63	0.526
N*KM[1]	-0.261	-1.80	0.072
SUB*KM	0.078	0.58	0.564
OH[1]	0.180	2.06	0.040
KM132[1]	0.048	3.35	0.001
RFALL	0.004	0.11	0.913
VF[1]	0.420	2.71	0.007
GAS[1]	-0.142	-3.17	0.002
US[1]	-0.335	-3.16	0.002
Trend	-0.002	-0.49	0.624
Constant[1]	12.071	171.18	0.000
R-Squared	0.937		
Sample Period	1995-2013		
Number of Observations	274		

[1]Variable is significant at 90% confidence level.

Table 3

Econometric Model of Network Services Opex: Results Using Australian Data

VARIABLE KEY

N = Number of Customers
SUB = Distribution Substation Capacity
KM = Distribution Structure Kilometers
OH = Percent of Distribution Line Plant that Is Overhead
KM132 = 132 KV+ Circuit Kilometers
RFALL = Average Rainfall
VF = Victoria Bushfire Risk (2009-2013)
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	Z-STATISTIC	P-VALUE
N	0.477	1.48	0.139
SUB	0.084	0.42	0.676
KM[1]	0.178	4.60	0.000
N*N	-0.134	-0.26	0.797
SUB*SUB	-0.556	-1.35	0.178
KM*KM	-0.001	-0.01	0.993
N*SUB	0.654	1.24	0.214
N*KM	-0.296	-1.36	0.175
SUB*KM	0.130	1.19	0.234
OH	0.055	0.63	0.530
KM132[1]	0.052	3.34	0.001
RFALL	0.096	0.99	0.323
VF[1]	0.270	1.84	0.066
Trend[1]	0.043	11.32	0.000
Constant[1]	11.614	134.89	0.000

R-Squared	0.984
Sample Period	2006-2013
Number of Observations	104

[1]Variable is significant at 90% confidence level.

The tables also report z statistics and p values corresponding to each parameter estimate. A parameter estimate is deemed statistically significant if the null hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of the confidence level needed to reject the null hypothesis. In this study, we employed a confidence level of 90%, which corresponds to a critical value of the z statistic of about 1.65. The p value represents the specific estimated probability of incorrectly rejecting the null hypothesis. Thus, a p value of 0.10 indicates a 90% confidence level, 0.05 indicates a 95% confidence level, and 0.001 indicates a 99.9% confidence level.

Table 2 presents econometric results using the transnational dataset. Examining the results, it can be seen that all of the parameter estimates for the non-shaded terms are statistically significant save those for rainfall and the trend variable. Most parameter estimates for the second-order terms are not individually significant, but these estimates are significant as a group[18]. The 0.937 R^2 statistic suggests that the model has high explanatory power.

At the sample mean, cost was found to be higher the higher were the values of the three scale-related variables. At sample mean values of the business condition variables, the elasticities of cost with respect to customers, route miles, and substation capacity are 0.589, 0.117, and 0.241% respectively.[19] The parameter estimates for five other business condition variables were also sensible.

- Cost was higher the greater was the share of distribution plant overhead.
- Cost was higher the greater was the circuit mileage of lines rated 132 kV and higher.
- Cost was higher for Victorian DNSPs 2009-2013 to the extent that they faced higher bushfire risk.
- Cost was lower for utilities offering gas distribution service.
- Cost was a little higher the higher was average rainfall.

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[18] The parameter estimates for the second-order terms are jointly significant in both the transnational (p = 0.0375) and Australian (p = 0.0027) models.

[19] This produces a scale index with elasticity weights of 62.2%, 12.4%, and 25.4%.

The US firm dummy had a negative, statistically significant parameter estimate. The estimate of the trend variable parameter suggests a gradual 0.2% downward shift in cost each year for reasons other than the trends in the business condition variables. This parameter estimate is not statistically significant.

Table 3 presents econometric results developed using only Australian data. It can be seen that the results are broadly similar to those obtained using the transnational data. There are nonetheless noteworthy differences between the models estimated using transnational and Australian data in the parameter estimates for substation capacity, percentage of plant overhead, rainfall, Victorian bushfire risk, and the trend variable.[20] The trend variable parameter estimate is positive and highly significant. Estimates for the first-order terms of two of the three scale variables are not statistically significant at a high level of confidence. Evidently, the current size of the Australian dataset does not permit very accurate estimation of the parameters of a model of translog form. The R^2 statistic for this run is 0.984.

Other variables for which we gathered data for the AER were excluded from the illustrative models for various reasons.

Generation Dummy:	Parameter estimate insignificant
Delivery Volume:	Parameter estimate usually negative and sometimes significant
Peak Demand:	Parameter estimate typically negative when the number of customers included
Temperature:	Parameter estimate negative or positive but insignificant
Scale Index:	Parameter estimate positive and significant, but we chose to feature a translog model with second order terms in the report

3.5 Implications for Opex Productivity Trends

The marked differences in the estimates of the trend variable parameters using transnational and Australian data are symptomatic of transnational differences in the productivity trends of network service O&M inputs. Australian DNSPs have been experiencing declining O&M productivity as a group. PEG Research has, meanwhile, undertaken several recent studies that address the O&M productivity trends of U.S. power distributors. These studies address productivity in the provision of metering, customer

[20] Given the high p -values for some of the Australian parameter estimates, it is possible that a hypothesis that the true parameter value is equal to that from the transnational study could not be rejected for some variables.

installation, and customer account services as well as network services. The longer term trends in productivity were positive in all studies. Here is a summary of results:

Venue	Region Addressed	Number of Utilities	Sample Period	Average Annual O&M Productivity Growth
Maine[1]	Northeast	30	1994-2011	1.05%
	Northeast	30	2002-2011	1.48%
Massachusetts[2]	Northeast	23	2002-2011	1.66%
British Columbia[3]	U.S	75	2002-2011	1.51%

Sources:

1) Testimony of Mark Newton Lowry on behalf of Central Maine Power, May 1, 2013 before the Maine Public Utilities Commission in Case 2013-00168, p. 27.

2) Testimony of Mark Newton Lowry on behalf of Fitchburg Gas & Electric, July 15, 2013 before the Massachusetts Department of Public Utilities in D.P.U. 13-90, p. 57.

3) Testimony of Mark Newton Lowry on behalf of Commercial Energy Consumers Association of British Columbia, December 20, 2013 before the British Columbia Utilities Commission in Project 3698719, p. 36.

3.6 Benchmarking Results

Tables 4 and 5 contain benchmarking results from the illustrative econometric models using transnational and Australia-only datasets. The results reported are typically averages for the last three years for which data are available.[21] Examining the results in Table 4, it can be seen that US firms generally did better than their Australian counterparts. However, the sample contains numerous US companies that performed well in other O&M cost benchmarking exercises we have performed. For most Australian utilities, we believe that statistical tests would not reject the hypothesis that they are average cost performers.[22] Considering, additionally, the size of the sample, we cannot draw confident conclusions about the relative efficiency of US and Australian DNSPs.

[21] When only two years of data are available for a company, the result presented in the table is the average for those two years.

[22] We have not developed the ability to perform these tests in Stata.

Table 4

Benchmarking Results Using Transnational Data

Company	**Actual Cost (AUD)**	**Predicted Cost**	**Difference**[1]
Tampa Electric	71,320	95,863	-30%
Pennsylvania Power	22,501	28,577	-29%
Pennsylvania Electric	76,457	99,270	-27%
Ohio Edison	122,957	148,129	-19%
Oklahoma Gas and Electric	119,816	135,178	-12%
Metropolitan Edison	76,528	84,005	-11%
South Carolina Electric & Gas	84,264	90,261	-7%
United Energy	**115,268**	**119,157**	**-3%**
Endeavour Energy	**239,450**	**247,223**	**-3%**
Powercor	**157,324**	**161,375**	**-3%**
Fitchburg Gas and Electric Light	4,913	4,923	-1%
Idaho Power	81,921	81,823	0%
Ausgrid	**476,706**	**460,150**	**3%**
Monongahela Power	73,421	68,875	3%
SP AusNet	**152,840**	**146,699**	**4%**
Southern Indiana Gas and Electric	26,377	24,941	6%
Essential Energy	**356,789**	**330,862**	**7%**
Energex	**402,635**	**366,764**	**8%**
Jemena	**62,823**	**57,117**	**9%**
CitiPower	**47,483**	**41,328**	**13%**
Aurora	**73,946**	**63,008**	**16%**
Jersey Central Power & Light	202,497	159,323	20%
SA Power Networks	**198,769**	**155,572**	**24%**
Ergon Energy	**365,698**	**284,945**	**25%**
Western Massachusetts Electric	38,735	29,472	27%
Public Service of New Hampshire	109,275	79,151	32%
Connecticut Light and Power	258,778	180,822	36%
ActewAGL	**62,612**	**34,761**	**59%**

[1]Difference calculated as ln(actual cost/predicted cost) for each year, and then averaged during the relevant years.

Table 5

Benchmarking Results Using Only Australian Data

Company	Actual Cost	Predicted Cost	Difference[1]
Endeavour Energy	239,450	263,092	-9%
Ausgrid	476,706	507,269	-7%
Aurora	73,946	77,837	-5%
Energex	402,635	412,726	-4%
SP AusNet	152,840	158,304	-4%
Powercor	157,324	159,528	-2%
United Energy	115,268	116,466	-1%
Essential Energy	356,789	356,947	0%
Jemena	62,823	62,180	1%
CitiPower	47,483	46,576	1%
ActewAGL	62,612	60,350	4%
Ergon Energy	365,698	347,689	5%
SA Power Networks	198,769	184,149	8%

[1]Difference calculated as ln(actual cost/predicted cost) for each year, and then averaged during the relevant years.

Examining the results in Table 5 it can be seen that the relative rankings of Australian DNSPs are fairly different when Australian data are used exclusively. There are large changes in the efficiency appraisals for ActewAGL, Ergon, and SA Power Networks. Large changes can also be observed in the relative rankings of Ausgrid, Aurora, and United Energy.

4. Conclusions

Our study reveals that there is potential value in using transnational data to benchmark network services opex. While the data assembled by the AER seem to be generally of good quality, the small size of the data set and the limited variation in business conditions limit its usefulness in econometric model development and benchmarking. Transnational data can greatly increase both the size of the sample and the variety of business conditions that sampled utilities face.

The United States is one promising source of data for Australian benchmarking. Advantages include the large amount of data, its standardization, the itemization of expenses, and the varied conditions under which U.S. utilities operate. Data are not readily available for a large sample on some key variables (e.g., reliability) that interest the AER. However, reliability data are improving and the AER can take steps to make its own data more consistent with America's so that more American data can be used.

Cooperation between the AER and US regulators can improve the consistency of data and make them more useful for benchmarking in both countries. As one example, statistical benchmarking of US power distributor cost and reliability would be greatly facilitated by requiring utilities to submit several years of detailed, standardized data on reliability and line lengths. Cooperation with regulators in jurisdictions of other countries (e.g., Ontario, Canada) which use benchmarking in utility regulation also merits consideration.

APPENDIX

This section provides additional and more technical details of our empirical research. We consider first the construction of the substation variable and then discuss the form of the cost model, mean scaling, the estimation procedure, and some additional details of the calculation of the M&S price trend index and other data.

Calculation of Substation Capacity

Data on US distribution substation capacity were developed to be consistent with Australian data consisting of total "one-step" capacity plus the total "first step of two steps" capacity. The variable is calculated from raw data found on the FERC Form 1, pages 426-427. For each substation, companies list on the Form its name, character (e.g., distribution or transmission), primary, secondary, and tertiary voltages, conversion capacity in megavolt amperes, and the number of transformers it includes.

Substation capacity marked as distribution could be simply summed for each company. Since some distribution systems step down electricity in multiple steps, however, this method has the effect of counting certain amounts of companies' capacity more than once. Furthermore, such a method excludes distribution capacity included in entries listed as transmission substations. It is not uncommon for transmission substations to step down electricity to two different voltages, a secondary voltage at a transmission level and a tertiary voltage at a distribution level.

The following procedure for measuring each company's distribution capacity was performed to address these challenges. First, a standard classification for the character of each substation was created. Then, a dataset for distribution substations was extracted from the full data. Once this dataset was isolated and modified appropriately, substation capacity for each company was calculated by measuring how much electricity could be stepped down through a specific voltage, which varied by company and year.

The "substation character" field of the Form 1 data was standardized as follows: 0 – distribution; 1 – purely transmission; 2 – listed as transmission, but with a tertiary voltage at distribution levels; 3 - information on, or aggregation of, substations listed elsewhere; 4 – step-up transformer at generating station; 5 – other.

For every company-year observation, a listing of the tertiary voltages for those substations with standardized substation character “2” was created. Subsets of the company’s distribution substations (e.g., with standardized substation character “0”) with secondary voltage within 5 kV of each tertiary voltage in that list were then drawn from the company’s data. After that, the mean of the substation capacity for each subset was calculated, so each tertiary voltage corresponded to a “mean distribution substation capacity at like voltages.” If a company in a given year had no distribution substations with secondary voltage within 5 kV of one of its transmission substations’ tertiary voltages, the capacity was imputed for that substation as 10% of its original capacity. The listed substation capacities for each company’s substations with substation character “2” were then replaced with the imputed capacities for their tertiary voltages.

In order to create a measure of distribution substation system capacity that avoided the problem of double counting, it was assumed that, once a company bought or generated and stepped up electricity to a high voltage, it would only be stepped down to lower voltages. In other words, no company would step down electricity to a lower voltage and then step it back up to a higher voltage again. For this reason, it should be possible to consistently measure distribution substation capacity by calculating how much electricity is stepped down through some specific voltage. This eliminates potential double counting, since any electricity that a company distributes can only pass through each voltage level once. The only remaining problem is determining which voltage level to use. We believe that higher values are more indicative of the peak demand a system is designed to handle since power may be distributed to some customers at relatively high voltages.

The final calculations followed the following steps. First, for each company-year observation, the full range of voltages for the relevant substations was determined by finding the highest primary voltage and the lowest secondary voltage of those substations. Then a list of every integer voltage between those two numbers was created. For each voltage level in that list, the sum of substation capacities with primary voltage above it and secondary voltage below it was calculated. We have named this quantity “Crossover MVA.” The maximum Crossover MVA produced was then stored as the company’s distribution substation capacity in that year.

Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log and translog. Here is a simple example of a linear cost model. For each company h in year t,

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot L_{h,t}\,. \qquad [A1]$$

Here is an analogous cost model of double log form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln L_{h,t}\,. \qquad [A2]$$

In the double log model the dependent variable and both business condition variables (customers and generation volume) have been logged. This specification makes the parameters corresponding to most business condition variables the elasticities of cost with respect to those variables.[23] For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the number of customers. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This is restrictive, and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of translog form:

$$\begin{aligned} \ln C_{h,t} = {} & a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln L_{h,t} + a_3 \cdot (1/2) \ln N_{h,t} \cdot \ln N_{h,t} \\ & + a_4 \cdot (1/2) \ln L_{h,t} \cdot \ln L_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln N_{h,t}\,. \end{aligned} \qquad [A3]$$

This form differs in the addition of quadratic and interaction terms to the first-order terms that are featured in a double log form. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to an output variable may, for example, be lower for a small utility than for a large utility because the smaller utility has more potential to realize incremental scale economies. Interaction terms like $\ln L_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in customers may depend on the length of distribution lines.

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[23] Since the dummy variables and trend variables in a model are typically not logged, their parameters are not elasticities.

The translog is an example of a “flexible” functional form. Flexible forms can accommodate a greater variety of possible relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables subject to the translog treatment increases, the precision of a model’s cost prediction falls. It is therefore common to limit the variables in a cost model that are translogged to input prices and/or scale variables.

Mean Scaling

Data for the explanatory variables were mean scaled prior to model estimation. When this is done to scale variables in a cost function of translog form, the first-order terms for those variables reflect cost elasticities at sample mean values of the business conditions. The parameter estimates for the first-order scale variables in the transnational cost model were used to develop the scale index.

Estimation Procedure

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares (“OLS”), is readily available in over-the-counter econometric software. Another class of procedures, called feasible generalized least squares (“FGLS”), is appropriate under assumptions of more complicated and realistic error specifications. For example, FGLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

In order to achieve a more efficient estimator, we corrected for group-specific first-order autoregressive (“AR1”) processes and groupwise heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The statistical software package Stata (Version 12) was used for this procedure.

The chosen estimation procedure did not address the likely pervasiveness of operating inefficiency in the samples. As a consequence, cost projections made using the models reflect the typical level of operating inefficiency of sampled utilities. The benchmarks do not reflect a frontier cost performance standard.

M&S Price Trend Index

This section provides additional details of the calculation of the M&S price trend indexes. Tables A1a and A1b detail the assignment of US PPIs to categories of distribution and A&G expenses. Tables A2a and A2b detail the assignment of weights to the PPIs. Tables A3a and A3b detail the calculation of growth rates for the US distribution and A&G M&S price indexes.

Other Data Details

Additional details of the US data we gathered for the AER are provided in Table A4. Details of weather station data are provided in Table A5.

Table A1a

Mapping of PPIs to Distribution O&M Cost Categories

Subindex Category	USOA Account Number	USOA Account Name	PPI ID	PPI category name
Overhead Lines O&M	583, 593	Overhead line expenses, Maintenance of overhead lines	WPU1135	Cutting tools and accessories
			WPU1136	Abrasive products
			WPU057303	No. 2 diesel fuel
			WPU071	Rubber and rubber products
			WPU0945	Manifold business forms
			WPU1042	Hand and edge tools
			WPU108905	Other metal products
			WPU1132	Power-driven handtools, including parts and attachments
Station and Transformers O&M	582, 592, 591, 595	Station expenses, Maintenance of station equipment, Maintenance of structures, Maintenance of line transformers	WPU057303	No. 2 diesel fuel
			WPU071	Rubber and rubber products
			WPU1136	Abrasive products
			WPU057604	Lubricating and similar oils
			WPU0945	Manifold business forms
Underground Line O&M	584, 594	Underground line expenses, Maintenance of underground lines	WPU1135	Cutting tools and accessories
			WPU1136	Abrasive products
			WPU057303	No. 2 diesel fuel
			WPU071	Rubber and rubber products
			WPU0945	Manifold business forms
			WPU1042	Hand and edge tools
			WPU108905	Other metal products
			WPU1132	Power-driven hand tools, including parts and attachments
Other O&M	581, 588, 598, 589	Load dispatching, Miscellaneous distribution expenses, Maintenance of miscellaneous distribution plant, Rents	PCU5172--5172--/ PDU4812#	Wireless telecommunications services
			PDU7349#1/	Janitorial services
			WPU091506	Office supplies and accessories
			PCUBMNR--BMNR--	Non-residential maintenance and repair
			PCU53112-53112-/ PDU6512#	Lessors of nonresidential buildings (except miniwarehouses)
Distribution Supervision and Engineering	580, 590	Operation supervision and engineering, Maintenance supervision and engineering	PCU54133-54133-/ PDU8711#	Engineering services

Table A1b

Mapping of PPIs to Administrative and General M&S Cost Categories

USOA Account Number	USOA Account Name	PPI ID	PPI category name
920	Administrative and general salaries	Excluded from construction of M&S Price Index	
921	Office supplies and expenses	WPU091506	Office supplies and accessories
		PDU7349#1/ PCU56172-56172-	Janitorial services
		PDU4813#/ PCU5171--5171--	Business wired telephone service
922	Administrative expenses transferred- Credit	Excluded from construction of M&S Price Index	
923	Outside services employed	PCU5411--5411--	Legal services
		PDU8721#/ PCU541211541211	Accounting, auditing, and bookkeeping/ Offices of certified public accountants
924	Property insurance	PCU524126524126	Property and casualty insurance
		PCU9241269241263	Premiums for commercial auto insurance
925	Injuries and damages	PCU524126524126	Property and casualty insurance
		PCU6211--6211--	Offices of physicians
926	Employee pensions and benefits	Excluded from construction of M&S Price Index	
927	Franchise requirements	Excluded from construction of M&S Price Index	
928	Regulatory commission expenses	PCU5411--5411--	Legal services
		PDU7011#/ PCU72111-72111-	Hotels and motels
929	Duplicate charges- Credit	Excluded from construction of M&S Price Index	
930.1	General advertising expenses	PDU7311#/ PCU54181-54181-	Advertising agencies
930.2	Miscellaneous general expenses	PDU4813#/ PCU5171--5171--	Wired telecommunication carriers
		PDU7011#/ PCU72111-72111-	Hotels and motels
		PDU2752#/ PCU32311-32311-	Commercial printing
932	Rents	PDU6512#/ PCU53112-53112-	Lessors of nonresidential buildings (except miniwarehouses)
935	Maintenance of general plant	PDU7349#1/ PCU56172-56172-	Janitorial services
		PCUBMNR--BMNR--	Non-residential maintenance and repair

Table A2a

M&S Price Trend Subindex Weights: Distribution

		PPI ID	PDU8711#/ PCU54133-54133-	WPU057303	PDU6512#/ PCU53112-53112-	PCUBMNR--BMNR--	PCU5172--5172--/ PDU4812#	WPU0945	PDU7349#1 / PCU56172-56172-	WPU071	WPU1136	WPU057604	WPU091506	WPU1135	WPU1042	WPU108905	WPU1132	
Account Category Name	**Account Number**	**PPI Category Name**	Engineering services	No. 2 Diesel fuel	Lessors of non-res buildings (except miniwarehouses)	Non-res maintenance	Wireless telecom services	Manifold business forms	Janitorial services	Rubber and rubber products	Abrasive products	Lubricating and similar oils	Office supplies and accesories	Cutting Tools and accessories	Hand and edge tools	Other Metal products	Power-driven handtools, including parts and attachmens	**Total Cost Category Weight**
Overhead Lines O&M	583 593			6.08%				6.08%		6.08%	6.08%			6.08%	6.08%	6.08%	6.08%	**48.62%**
Station and Transformers O&M	582 592 591 595			1.91%				1.91%		1.91%	1.91%	1.91%						**9.55%**
Underground Line O&M	584 594			1.44%				1.44%		1.44%	1.44%			1.44%	1.44%	1.44%	1.44%	**11.54%**
Other O&M	581 588 598 589				4.21%	4.21%	4.21%		4.21%				4.21%					**21.04%**
Distribution Supervision and Engineering	580 590		9.25%															**9.25%**
		Total PPI Weight	**9.25%**	**9.43%**	**4.21%**	**4.21%**	**4.21%**	**9.43%**	**4.21%**	**9.43%**	**9.43%**	**1.91%**	**4.21%**	**7.52%**	**7.52%**	**7.52%**	**7.52%**	

Table A2b

M&S Price Trend Subindex Weights: A&G

	USOA Account Number	921	923	925	924	928	930.1	930.2	932	935	
PPI ID	**PPI Category Name**	Office supplies and expenses	Outside services employed	Injuries and damages	Property insurance	Regulatory commission expenses	General advertising expenses	Miscellaneous general expenses	Rents	Maintenance of general plant	**Total Cost Category Weight**
PCU524126524126	Property and casualty insurance			6.2%	3.6%						**9.8%**
PCU5411--5411--	Legal Services		15.8%			5.2%					**21.0%**
PCU9241269241263	Premiums for commercial auto insurance				3.6%						**3.6%**
PDU4813#/ PCU5171--5171--	Business wired telephone service	5.9%						3.0%			**8.8%**
PDU7311#/ PCU54181-54181-	Advertising agencies						1.0%				**1.0%**
PDU7349#1/ PCU56172-56172-	Janitorial Services	5.9%								2.5%	**8.4%**
PDU8721#/ PCU541211541211	Accounting, auditing, and bookkeeping/ Offices of certified public accountants		15.8%								**15.8%**
PDU2752#/ PCU32311-32311-	Commercial Printing							3.0%			**3.0%**
PCU6211--6211--	Offices of Physicians			6.2%							**6.2%**
PDU7011#/ PCU72111-72111-	Hotels and Motels					5.2%		3.0%			**8.2%**
PDU6512#/ PCU53112-53112-	Lessors of nonresidential buildings (except miniwarehouses)								5.8%		**5.8%**
PCUBMNR--BMNR--	Non-residential maintenance and repair									2.5%	**2.5%**
WPU091506	Office supplies and accesories	5.9%									**5.9%**
	Total PPI Weight:	**17.6%**	**31.6%**	**12.4%**	**7.2%**	**10.5%**	**1.0%**	**9.0%**	**5.8%**	**5.0%**	100.0%

Table A3a

Calculating US Distribution M&S Price Trends

Weight:	ENGINEERING SERVICES	NO. 2 DIESEL FUEL	LESSORS OF NON-RES BUILDINGS	NON-RES MAINTENANCE AND REPAIR	WIRELESS TELECOM SERVICES	MANIFOLD BUSINESS FORMS	JANITORIAL SERVICES	RUBBER AND RUBBER PRODUCTS	ABRASIVE PRODUCTS	LUBRICATING AND SIMILAR OILS	OFFICE SUPPLIES AND ACCESORIES	CUTTING TOOLS AND ACCESSORIES	HAND AND EDGE TOOLS	OTHER METAL PRODUCTS	POWER-DRIVEN HANDTOOLS, INCLUDING PARTS AND ATTACHMENT	**SUMMARY M&S INDEX**
	9.3%	9.4%	4.2%	4.2%	4.2%	9.4%	4.2%	9.4%	9.4%	1.9%	4.2%	7.5%	7.5%	7.5%	7.5%	**100.0%**
1995																
1996	***2.61%***	20.54%	***1.40%***	1.80%	***-4.34%***	2.96%	1.28%	-0.60%	2.22%	-0.77%	-1.49%	2.40%	2.14%	0.96%	1.40%	**3.06%**
1997	***2.61%***	-8.18%	1.40%	1.69%	***-4.34%***	-1.44%	2.03%	-0.52%	0.99%	0.86%	-1.44%	1.32%	1.42%	0.32%	0.80%	**-0.34%**
1998	**2.61%**	-30.80%	2.25%	-0.30%	***-4.34%***	0.58%	0.86%	-0.43%	0.49%	-1.99%	0.15%	1.81%	1.28%	-0.08%	1.37%	**-2.37%**
1999	2.72%	18.97%	2.49%	1.44%	***-4.34%***	2.23%	2.44%	-0.96%	-1.48%	7.81%	-1.30%	0.71%	1.14%	-0.32%	0.71%	**2.37%**
2000	2.92%	48.75%	2.89%	3.11%	***-4.34%***	8.80%	2.92%	0.96%	0.07%	0.08%	3.27%	0.85%	1.01%	0.24%	0.28%	**6.31%**
2001	3.88%	-11.22%	2.36%	0.58%	-4.34%	3.75%	4.83%	1.29%	0.00%	5.50%	2.29%	1.75%	2.92%	1.02%	2.03%	**0.70%**
2002	4.98%	-6.82%	2.48%	-0.65%	1.65%	0.69%	1.28%	0.00%	-0.35%	8.98%	-0.88%	0.69%	1.20%	-0.39%	0.21%	**0.31%**
2003	3.00%	25.47%	1.04%	1.95%	0.76%	0.00%	***1.13%***	2.12%	0.28%	8.63%	1.24%	0.41%	0.17%	0.31%	0.21%	**3.41%**
2004	***2.43%***	24.34%	***1.87%***	8.24%	***-6.12%***	3.69%	***1.13%***	2.97%	-0.21%	4.14%	0.15%	1.02%	2.30%	1.71%	0.89%	**3.88%**
2005	1.85%	38.87%	2.70%	8.46%	-13.01%	6.33%	0.99%	5.62%	3.21%	16.30%	3.92%	3.86%	4.39%	2.66%	1.22%	**6.62%**
2006	3.98%	13.72%	2.44%	7.86%	-6.58%	7.54%	1.75%	4.81%	4.24%	22.28%	2.14%	3.66%	3.70%	2.52%	-0.54%	**4.67%**
2007	4.19%	8.23%	-0.47%	3.90%	-0.62%	4.66%	2.19%	3.03%	2.86%	6.98%	3.23%	1.31%	2.02%	1.89%	1.08%	**3.11%**
2008	0.71%	32.18%	3.12%	9.55%	-5.50%	11.19%	2.88%	9.17%	5.96%	15.93%	4.72%	1.79%	4.55%	4.22%	2.06%	**7.46%**
2009	1.67%	-58.72%	-1.09%	-4.71%	-3.34%	4.53%	0.82%	0.13%	5.74%	1.09%	0.38%	1.70%	3.80%	2.65%	0.46%	**-4.07%**
2010	0.52%	25.43%	0.00%	7.60%	-4.45%	2.28%	0.63%	5.91%	-0.80%	5.06%	0.63%	1.25%	-0.74%	-0.20%	0.26%	**3.47%**
2011	1.72%	30.58%	0.36%	8.65%	-3.76%	5.06%	1.52%	11.74%	3.38%	17.66%	2.96%	4.52%	0.65%	1.87%	0.72%	**6.28%**
2012	1.69%	3.08%	0.36%	0.00%	-2.39%	2.24%	1.15%	2.57%	2.47%	3.65%	1.81%	1.80%	2.14%	0.79%	1.35%	**1.70%**
2013	1.66%	-2.61%	1.71%	0.26%	-1.06%	2.43%	0.96%	-3.12%	2.04%	-3.99%	2.01%	0.28%	2.23%	0.46%	1.97%	**0.49%**
Average Annual Growth Rates (1996-2013)	**2.54%**	**9.54%**	**1.52%**	**3.30%**	**-3.92%**	**3.75%**	**1.71%**	**2.48%**	**1.73%**	**6.57%**	**1.32%**	**1.73%**	**2.02%**	**1.15%**	**0.92%**	**2.61%**

Note:

1) Italicized and bolded values imply growth rates imputed by PEG Research due to data availability issues. Imputed value is average of two adjacent growth rates.

Table A3b

Calculating US Administration and General M&S Price Trends

	OFFICES OF PHYSICIANS	COMMERCIAL PRINTING	HOTELS AND MOTELS	LESSORS OF NON-RES BUILDINGS (EXCPET MINIWAREHOUSES)	NON-RES MAINTENANCE AND REPAIR	PROPERTY AND CASUALTY INSURANCE	LEGAL SERVICES	PREMIUMS FOR COMMERCIAL AUTO INSURANCE	BUSINESS WIRED TELEPHONE SERVICES	ADVERTISING AGENCIES	JANITORIAL SERVICES	ACCOUNTING, AUDITING, AND BOOKKEEPING/ OFFICES OF CERTIFIED PUBLIC ACCOUNTANTS	OFFICE SUPPLIES AND ACCESSORIES	**SUMMARY M&S INDEX**
Weight:	6.20%	2.99%	8.21%	5.83%	2.50%	9.81%	21.01%	3.61%	8.84%	1.00%	8.35%	15.79%	5.86%	**100%**
1995														
1996	***2.15%***	2.72%	3.70%	***1.40%***	1.80%	***1.18%***	***3.45%***	***1.78%***	***-0.30%***	***2.04%***	1.28%	***2.68%***	-1.49%	**1.99%**
1997	***2.15%***	0.54%	4.87%	1.40%	1.69%	***1.18%***	***3.45%***	***1.78%***	-0.30%	2.04%	2.03%	2.68%	-1.44%	**2.08%**
1998	2.15%	2.31%	3.65%	2.25%	-0.30%	***1.18%***	3.45%	***1.78%***	-1.21%	1.43%	0.86%	2.34%	0.15%	**1.89%**
1999	2.20%	-0.07%	4.09%	2.49%	1.44%	***1.18%***	2.42%	***1.78%***	-2.47%	1.97%	2.44%	3.36%	-1.30%	**1.80%**
2000	1.69%	1.81%	3.07%	2.89%	3.11%	1.18%	3.44%	1.78%	***-2.71%***	2.57%	2.92%	3.08%	3.27%	**2.27%**
2001	2.85%	1.34%	4.40%	2.36%	0.58%	2.33%	4.69%	1.94%	-2.95%	5.30%	4.83%	1.80%	2.29%	**2.63%**
2002	-0.09%	-0.70%	-0.07%	2.48%	-0.65%	4.13%	3.17%	2.93%	-4.03%	2.30%	1.28%	2.19%	-0.88%	**1.34%**
2003	1.62%	0.00%	0.59%	1.04%	1.95%	5.63%	3.15%	4.19%	-2.02%	1.67%	***1.13%***	2.79%	1.24%	**2.07%**
2004	1.94%	***1.03%***	***3.34%***	***1.87%***	8.24%	3.16%	4.82%	1.86%	-2.06%	***1.48%***	***1.13%***	***2.42%***	0.15%	**2.45%**
2005	1.82%	2.05%	6.09%	2.70%	8.46%	1.92%	4.96%	0.26%	-0.58%	1.29%	0.99%	2.05%	3.92%	**2.88%**
2006	0.94%	2.49%	3.66%	2.44%	7.86%	0.58%	4.72%	-0.35%	0.93%	2.63%	1.75%	3.61%	2.14%	**2.76%**
2007	4.00%	1.13%	4.87%	-0.47%	3.90%	0.33%	5.62%	-0.79%	3.07%	0.86%	2.19%	4.03%	3.23%	**3.23%**
2008	1.06%	2.58%	3.61%	3.12%	9.55%	1.22%	5.08%	-0.89%	1.56%	0.95%	2.88%	2.74%	4.72%	**3.11%**
2009	2.40%	-0.09%	-2.78%	-1.09%	-4.71%	2.48%	2.81%	0.09%	0.44%	-0.85%	0.82%	0.26%	0.38%	**0.73%**
2010	2.42%	0.54%	-0.91%	0.00%	7.60%	1.64%	3.37%	-0.09%	0.77%	0.00%	0.63%	-1.31%	0.63%	**1.10%**
2011	1.45%	1.71%	1.74%	0.36%	8.65%	2.68%	3.43%	-1.62%	1.19%	0.76%	1.52%	-1.24%	2.96%	**1.66%**
2012	1.21%	0.18%	3.15%	0.36%	0.00%	2.39%	2.72%	-0.45%	1.07%	1.41%	1.15%	0.53%	1.81%	**1.54%**
2013	0.15%	0.44%	1.97%	1.71%	0.26%	1.39%	2.75%	-0.27%	1.06%	1.57%	0.96%	0.97%	2.01%	**1.46%**
Average Annual Growth Rates (1996-2013)	**1.79%**	**1.11%**	**2.73%**	**1.52%**	**3.30%**	**1.99%**	**3.75%**	**0.87%**	**-0.48%**	**1.63%**	**1.71%**	**1.94%**	**1.32%**	**2.05%**

Note:
Italicized values imply growth rates imputed by PEG Research due to data availability issues. If unavailable data were at the beginning of sample period, imputed value is equal to first available growth rate. This method is reasonable for the period in question, which was one of fairly stable inflation rates. If unavailable data were after first available growth rate then imputed value is average of two adjacent growth rates.

Table A4a

US Variable Key

Data Used in Econometric Database

Variable	*Definition*	*Units*	*Availability*	*Source*	*Transformations (if any)*
Year	Year	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Pegid	Company ID	Not Applicable	Not Applicable	PEG Research assignment	Not Applicable
Company	Company name	Not Applicable	Not Applicable	Not Applicable	Not Applicable
state	State	Not Applicable	Not Applicable	US Assignments rely on EIA 861 customers by state in 2012	Not Applicable
cntwst	Distribution O&M expenses less Operation and Maintenance expenses for Customer Installations, Meters, and Street Lighting & Signals plus an allocated share of Administrative & General expenses	Australian dollars	1995-2013	PEG Research calculation using FERC Form 1, p. 320-323.	Conversion from US dollars to Australian, other transformations in file
yv	Total energy delivered (GWh)	GWh	1995-2013	For 1995-2000 and 2013: FERC Form 1, p. 301, line 10 column (d). For 2001-2012: Form EIA 861.	Summed bundled deliveries and delivery-only deliveries, Imputed 1995-2000 and 2013 values using FERC Form 1
yvres	Residential Deliveries	GWh	1995-2013	For 1995-2000 and 2013: FERC Form 1, p. 301, line 2 column (d). For 2001-2012: Form EIA 861.	
yvoth	Non-Residential Deliveries	GWh	1995-2013	Calculated by subtracting residential deliveries from total retail deliveries.	
ntot	Total number of customers	Number	1995-2013	For 1995-2000 and 2013: FERC Form 1, p. 301, line 10 column (f). For 2001-2012: Form EIA 861.	Summed bundled customers and delivery-only customers. Imputed 1995-2000 and 2013 values using FERC Form 1
nres	Residential Customers	Number	1995-2013	For 1995-2000 and 2013: FERC Form 1, p. 301, line 2 column (f). For 2001-2012: Form EIA 861.	
noth	Nonresidential Customers	Number	1995-2013	Calculated by subtracting residential customers from total retail customers.	
ypctrs	Coincident Raw System Annual Maximum Demand	MW	1995-2013	Calculated by PEG Research using FERC Form 1, p. 401a and p.401 b	Formulas for transformation supplied in database file
rfall	Annual Rainfall in mm for representative weather station	mm	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.4.	Conversion of rainfall from inches to mm
rfallave	Average Value of rfall for 2006-2013	mm	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.4.	Formula for transformation supplied in database file
capcomb3	Distribution substation maximum capacity (compares to 1-step plus 1st stage of 2-step)	Megavolt-Amperes	1995-2013	Calculated by PEG Research using FERC Form 1, p. 426-427.	See Appendix of Report for Method
badcap	Indicator for bad or missing capacity data	binary	1995-2013	PEG Research Assignment	Not Applicable
mroute	Total Route line length	Km	Varies by Company	US Securities & Exchange Commission form 10Ks and correspondence with companies	Conversion of line miles to kilometers
badmroute	indicator for bad or missing mile data	Km	Not Applicable	PEG Research Assignment	Not Applicable
tmpmnmax	Annual average daily high temperature	Degrees Celsius	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	Conversion of temperature from Fahrenheit to Celsius
tmpmnmaxave2	2006-2012 average of tmpmnmax	Degrees Celsius	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	Conversion to Celsius, Average of 2006-2012 observations
tmphh	Annual maximum temperature	Degrees Celsius	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	Conversion of temperature from Fahrenheit to Celsius
tmphav	2006-2012 average of tmphh	Degrees Celsius	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	Conversion of temperature from Fahrenheit to Celsius; average of 2006-2012 values
MaxTemp	Maximum temperature during 2006-2012 period	Degrees Celsius	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	Conversion of temperature from Fahrenheit to Celsius, maximum value for 2006-2012 period
wom	O&M input price index	Index Numbers	1995-2013	Calculated by PEG Research	
pctoh	Percentage of Plant that is Overhead: End of Year Gross Plant Value of Poles, Towers, and Fixtures Plus Overhead Conductors and Devices Divided by the Gross Plant Value of Poles, Towers, and Fixtures, Overhead Conductors and Devices, Underground Conduit, and Underground Conductors and Devices.	Percentage	1995-2013	Calculated by PEG Research using FERC Form 1, p. 207, column (g)	Formula provided in database
gassvc	Identifier for Companies with Gas Service	Binary	1995-2013	State LDC Filings	Not Applicable
tx dummy	Identifier for companies with transmission	Binary	1995-2013	PEG Research assignments using FERC Form 1, p. 204-207	Not Applicable
gen dummy	Identifier for companies with substantial generation	Binary	1995-2013	PEG Research Assignments using FERC Form 1, p. 401a	Not Applicable

Table A4b

Input Price Variables

Variable	Definition	Units	Availability	Source	Transformations (if any)
ECI Region	Regional identifier for companies	Integer	1995-2013	Regions Outlined by Bureau of Labor Statistics and Companies Assigned by PEG Research	Not Applicable
WLt	Labor Price trend Index (regionalized)	Index Number	1995-2013	Calculated by PEG Research using Employment Cost Index data from Bureau of Labor Statistics	
WMdxt	Distribution M&S Price trend Index	Index Number	1995-2013	Calculated by PEG Research from BLS, BEA, and FERC data	Some PPI growth rates for early years imputed using first available growth rate
Wmaget	A&G M&S Price trend Index	Index Number	1995-2013	Calculated by PEG Research	Some PPI growth rates for early years imputed using first available growth rate
dwmt	Cost-weighted M&S price index growth rate	Percentage	1995-2013	Calculated by PEG Research	Growth rate calculated logarithmically
dWOMt	Cost-weighted O&M price index growth rate	Percentage	1995-2013	Calculated by PEG Research	Growth rate calculated logarithmically
Price Level	2008 Levelized O&M input price index value	Index Number	2008 only	Calculated by PEG Research	None
WOM	Summary O&M input price index	Index Number	1995-2013	Calculated by PEG Research	Formula provided in database
PPP (average)	Materials input price patch (2010 PPP value for GDP	Index Number	1995-2013	OECD	None
AUS/US labor	Labor input price patch	Index Number	1995-2013	Calculated by PEG Research	Formula provided in database
WOMau08	US O&M input price index after patching and levelization	Index Number	1995-2013	Calculated by PEG Research	Formula provided in database
Levelization factor	Application of price patch to US companies	Index Number	1995-2013	Calculated by PEG Research	Formula provided in database
sl	Share of salaries & wages in cntwst	Percentage	1995-2013	Calculated by PEG Research	Formula provided in database
sm	Share of remaining costs in cntwst	Percentage	1995-2013	Calculated by PEG Research	Formula provided in database

Cost Variables

Variable	Definition	Units	Availability	Source	Transformations (if any)
costlab	Total Labor expenses in cntwst	US dollars	1995-2013	PEG Research calculation	Formula provided in database
costoth	Total M&S expenses in cntwst	US dollars	1995-2013	PEG Research calculation	Formula provided in database
costothdx	Distribution M&S expenses in cntwst	US dollars	1995-2013	PEG Research calculation	Formula provided in database
pctothdx	Share of Distribution M&S expenses in Total M&S expenses	Percentage	1995-2013	PEG Research calculation	Formula provided in database
pctothgnl	Share of A&G M&S expenses in Total M&S expenses	Percentage	1995-2013	PEG Research calculation	Formula provided in database
costdx	Distribution expenses net of O&M expense for meters, customer installations, and street lighting and signal systems	US dollars	1995-2013	PEG Research calculation	Formula provided in database
costage	A&G expenses net of pensions & benefits and franchise fees	US dollars	1995-2013	PEG Research calculation	Formula provided in database
cmagetot	Total M&S expenses corresponding to costage	US dollars	1995-2013	PEG Research calculation	Formula provided in database
allocator	% of costdx in total net O&M	Percentage	1995-2013	PEG Research calculation	Formula provided in database
net cost	Total O&M expenses less expenses for fuel, other power supply, transmission for others, and A&G	US dollars	1995-2013	PEG Research calculation	Formula provided in database
sagee	Direct Payroll-Electric A&G O&M	US dollars	1995-2013	FERC Form 1, p. 354	None
sdste	Direct Payroll-Electric Distribution O&M	US dollars	1995-2013	FERC Form 1, p. 354	None
costdx/cdst	Ratio of net distribution expenses to total distribution expenses	Percentage	1995-2013	PEG Research calculation	Formula provided in database
sdstenet	Net Distribution Salaries & Wages (sdste*costdx/cdst)	US dollars	1995-2013	PEG Research calculation	Formula provided in database
cage	Total Administrative & General O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 323	None
cageadv	Admin & General Expenses: General Expenseseral Advertising	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 930.1	None
cagedup	Admin & General Expenses: Duplicate Charges (Credit)	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 929	None
cageinj	Admin & General Expenses: Injuries & Damage	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 925	None
cageins	Admin & General Expenses: Property Insurance	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 924	None
cagemnt	Adminstrative & General Total Maintenance Expenses	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 935	None
cagemsc	Admin & General Expenses: Miscellaneous Expenses	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 930.2	None
cageopr	Adminstrative & General Total Operations Expenses	US dollars	1995-2013	FERC Form 1, p. 323	None
cageout	Admin & General Expenses: Outside Services Employed	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 923	None
cagepen	Admin & General Expenses: Employee Pensions & Benefits	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 926	None
cagereg	Admin & General Expenses: Regulatory Commission	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 928	None
cagernt	Admin & General Expenses: Rents	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 931	None
cagesup	Admin & General Expenses: Office Supplies	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 921	None
cagetrn	Admin & General Expenses: Admin Expenses Transferred (Credit)	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 922	None
cagewag	Admin & General Expenses: Salaries	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 920	None
cagefrc	Admin & General Expenses: Franchise Requirements	US dollars	1995-2013	FERC Form 1, p. 323, FERC Account 927	None
cdst	Total Distribution O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 322	None
cdstdsp	Distribution: Operating Expenses: Load Dispatching	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 581	None
cdsteng	Distribution: Operating Expenses: Supervision & Engineering	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 580	None
cdstengm	Distribution: Maintenance Expenses: Supervision & Engineering	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 590	None
cdstmsc	Distribution: Operating Expenses: Miscellaneous	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 588	None
cdstmscm	Distribution: Maintenance Expenses: Miscellaneous	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 598	None

Table A4c

Cost Variables Continued

Variable	Definition	Units	Availability	Source	Transformations (if any)
cdstohl	Distribution: Operating Expenses: Overhead Lines	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 583	None
cdstohlm	Distribution: Maintenance Expenses: Overhead Lines	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 593	None
cdstrnt	Distribution: Operating Expenses: Rents	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 589	None
cdststa	Distribution: Operating Expenses: Station	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 582	None
cdststam	Distribution: Maintenance Expenses: Station Equipment	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 592	None
cdststrm	Distribution: Maintenance Expenses: Structures	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 591	None
cdsttrnm	Distribution: Maintenance Expenses: Line Transformers	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 595	None
cdstund	Distribution: Operating Expenses: Underground Lines	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 584	None
cdstundm	Distribution: Maintenance Expenses: Underground Lines	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 594	None
cdstins	Distribution: Operating Expenses: Customer Installations	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 587	None
cdstmtr	Distribution: Operating Expenses: Meter	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 586	None
cdstmtrm	Distribution: Maintenance Expenses: Meters	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 597	None
cdststl	Distribution: Operating Expenses: Street Lighting & Signal Sys	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 585	None
cdststlm	Distribution: Maintenance Expenses: Street Lighting & Signal Sys	US dollars	1995-2013	FERC Form 1, p. 322, FERC Account 596	None
ccae	Total Customer Account Expenses	US dollars	1995-2013	FERC Form 1, p. 322	None
ccsi	Total Customer Service & Informational Expenses	US dollars	1995-2013	FERC Form 1, p. 323	None
cfos	Total Steam Production O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 320	None
cfosful	Steam Generation Fuel Expenses	US dollars	1995-2013	FERC Form 1, p. 320, FERC Account 501	None
chyd	Total Hydro Production O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 320	None
cnuc	Total Nuclear Production O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 320	None
cnucful	Nuclear Generation Fuel Expenses	US dollars	1995-2013	FERC Form 1, p. 320, FERC Account 518	None
copg	Total Other Power Generation O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 321	None
copgful	Other Power Generation Fuel Expenses	US dollars	1995-2013	FERC Form 1, p. 321, FERC Account 547	None
cops	Total Other Power Supply Expenses	US dollars	1995-2013	FERC Form 1, p. 321	None
copspur	Other Power Supply Expenses: Purchased Power	US dollars	1995-2013	FERC Form 1, p. 321, FERC Account 555	None
cprd	Total Power Production O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 321	None
creg	Regional Market O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 322	None
csal	Total Sales Expenses	US dollars	1995-2013	FERC Form 1, p. 323	None
ctot	Total Electric Operation & Maintenance Expenses	US dollars	1995-2013	FERC Form 1, p. 323	None
ctrs	Total Transmission O&M Expenses	US dollars	1995-2013	FERC Form 1, p. 321	None
ctrswhl	Transmission of Electricity by Others	US dollars	1995-2013	FERC Form 1, p. 321, FERC Account 565	None

Plant In Service Variables

Variable	Definition	Units	Availability	Source	Transformations (if any)
pdstohl	End of Year Distribution Plant: Overhead Conductors	US dollars	1995-2013	FERC Form 1, p. 207, column g, FERC Account 365	None
pdstpol	End of Year Distribution Plant: Poles & Fixtures	US dollars	1995-2013	FERC Form 1, p. 207, column g, FERC Account 364	None
pdstunc	End of Year Distribution Plant: Underground Conductors	US dollars	1995-2013	FERC Form 1, p. 207, column g, FERC Account 367	None
pdstund	End of Year Distribution Plant: Underground Conduit	US dollars	1995-2013	FERC Form 1, p. 207, column g, FERC Account 366	None

Weather Variables

Variable	Definition	Units	Availability	Source	Transformations (if any)
aircode	Airport Identifier for weather data	Not Applicable	Not Applicable	Codes provided by National Oceanic and Atmospheric Association's National Climatic Data Center	Not Applicable
precipi	Annual precipitation	inches	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.4.	None
mhtemf	Annual maximum high temperature	Degrees Fahrenheit	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	None
mmmtf	Average daily high temperature	Degrees Fahrenheit	1995-2013	National Oceanic and Atmospheric Association's National Climatic Data Center, Local Climatological Data Annual Summary with Comparative Data, p.2.	None

Line Miles Variables

Variable	Definition	Units	Availability	Source	Transformations (if any)
midxpo	Pole Miles	Km	Varies by Company	US Securities & Exchange Commission form 10Ks and correspondence with companies	Conversion from Miles to Kilometers
midxco	Circuit-bank or underground structure miles	Km	Varies by Company	US Securities & Exchange Commission form 10Ks and correspondence with companies	Conversion from Miles to Kilometers
midxst	Total Structure Miles	Km	Varies by Company	US Securities & Exchange Commission form 10Ks and correspondence with companies	Conversion from Miles to Kilometers
m100kV	Distribution line length for 100kV or greater lines	Km	Not Available	NA	NA

Table A4d

Output Variables

Variable	Definition	Units	Availability	Source	Transformations (if any)
yres861	Residential Electric Volume	MWh	2001-2012	Form EIA 861	Sum of delivery & bundled
nres861	Residential Electric Customers	Number	2001-2012	Form EIA 861	Sum of delivery & bundled
ytot861	Total Retail Electric Volume	MWh	1995-2013	Form EIA 861	Sum of delivery & bundled
ntot861	Total Retail Electric Customers	Number	1995-2013	Form EIA 861	Sum of delivery & bundled
yng	Number of Natural Gas Customers	Number	1995-2013	Form EIA 176	Sum of all retail customer groups
syspeak	Maximum Transmission system peak	MW	1995-2013	FERC Form 1, p. 401b, column d, lines 29-40	Maximum value only
gret	Sales to Ultimate Consumers	MWh	1995-2013	FERC Form 1, p. 401a, line 22	None
grslreq	Non-Requirements Sales for Resale	MWh	1995-2013	FERC Form 1, p. 401a, line 24	None
gtot2	Total sales	MWh	1995-2013	FERC Form 1, p. 401a, line 28	None
tx load factor	(gret+grslreq)/gtot2	Percentage	1995-2013	Calculated by PEG Research	Formula provided in database
yres1	Residential Electric Sales Volume	MWh	1995-2013	FERC Form 1, p. 301, line 2 column (d).	None
yret1	Total Sales to Ultimate Consumer: Megawatt-hours sold	MWh	1995-2013	FERC Form 1, p. 301, line 10 column (d).	None
nres1	Residential Electric Customers	Number	1995-2013	FERC Form 1, p. 301, line 2 column (f).	None
nret1	Total Retail Electric Customers	Number	1995-2013	FERC Form 1, p. 301, line 10 column (f).	None

Table A5

Sources of US Climate Data[1]

Utility	State	Location of Weather Station	Weather Station Identifier
Endeavour Energy	NSW	Penrith Lakes	67113
Aurora Energy	Tasmania	Hobart	94029
Jemena	Victoria	Melbourne Airport	86282
Citipower	Victoria	Melbourne	86071
SP AusNet	Victoria	Scoresby	86104
ActewAGL	NSW and ACT	Isabella Plains	70339
Powercor	Victoria	Horsham	79100
United Energy	Victoria	Cerebus	86361
Energex	Queensland	Brisbane Aero	40842
Ausgrid	NSW	Sydney Observatory Hill (Miller's Point)	66062
Essential Energy	NSW and Queensland	Dubbo	65070
Ergon Energy	Queensland	Toowoomba Airport (Wilsonton)	41529
SA Power Networks	South Australia	Adelaide (Kent Town)	23090
Connecticut Light & Power	Connecticut	Windsor Lake, CT	BDL
Idaho Power	Idaho	Boise, ID	BOI
Jersey Central Power & Light	New Jersey	Newark, NJ[1]	EWR
Fitchburg Gas & Electric	Massachusetts	Worcester, MA[1]	ORH
Metropolitan Edison	Pennsylvania	Allentown, PA[1]	ABE
Monongahela Power	West Virginia	Elkins, WV	EKN
Ohio Edison	Ohio	Akron, OH	CAK
Oklahoma Gas & Electric	Oklahoma	Oklahoma City, OH	OKC
Pennsylvania Electric	Pennsylvania	Williamsport, PA[1]	IPT
Pennsylvania Power	Pennsylvania	Youngstown/Warren, OH[1]	YNG
Potomac Edison	Maryland	Baltimore, MD[1]	BWI
Public Service Company of New Hampshire	New Hampshire	Concord, NH	CON
South Carolina Electric & Gas	South Carolina	Columbia, SC	CAE
Southern Indiana Gas & Electric	Indiana	Evansville, IN	EVV
Tampa Electric	Florida	Tampa, FL	TPA
United Illuminating	Connecticut	Bridgeport, CT	BDR
West Penn Power	Pennsylvania	Pittsburgh, PA[1]	PIT
Western Massachusetts Electric	Massachusetts	Worcester, MA[1]	ORH

[1]The weather station assigned to this utility is not in its service territory but nonetheless provides data that are typical of its territory.

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