

**BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA**

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR AN ORDER OF THE COMMISSION)
AUTHORIZING APPLICANT TO MODIFY ITS)
RATES, CHARGES, AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)

Cause No. PUD 200800398

FILED
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Direct Testimony

of

Mark Newton Lowry

On behalf of

Oklahoma Gas and Electric Company

February 27, 2009

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CORPORATION COMMISSION
OF OKLAHOMA

Mark Newton Lowry
Direct Testimony

I. INTRODUCTION

1

2 Q. **Please state your name and business address.**

3 A. My name is Mark Newton Lowry. My business address is 22 E. Mifflin St., Suite 302,
4 Madison, WI 53703.

5

6 Q. **By whom are you employed and in what capacity?**

7 A. I am a partner in the Madison, Wisconsin office of Pacific Economics Group ("PEG")
8 and President of Pacific Economics Group Research LLC. In addition to my managerial
9 responsibilities, I supervise an extensive program of statistical cost research, design
10 alternative regulation ("Altreg") plans, and provide expert witness testimony.

11

12 Q. **Please discuss your background and experience in the energy and utility industries.**

13 A. I have been an energy economist for twenty five years and have spent the last twenty as a
14 consultant on utility regulation. Before joining PEG I worked at Christensen Associates
15 in Madison, first as a Senior Economist and later as Vice President for Regulatory
16 Strategy. The primary focus of my consulting research has been the cost of gas and
17 electric service. I was a pioneer in the use of statistical cost research in energy utility
18 benchmarking and Altreg plan design. My practice is international in scope and has to
19 date included projects in seven countries.

20 Clients have included regulatory commissions as well as utilities. For example, power
21 distributors in the Canadian province of Ontario operate under multiyear rate plans with
22 terms that are linked to a benchmarking study I directed for the Ontario Energy Board.

1 Before becoming a consultant I spent five years as an academic economist. I was an
2 Assistant Professor of Mineral Economics at the Pennsylvania State University, where I
3 taught energy economics. I also worked as a Visiting Professor at l'Ecole des Hautes Etudes
4 Commerciales in Montreal. My academic research and teaching stressed the use of economic
5 theory and statistics in petroleum market analysis.

6 I have served as a referee for several scholarly journals and have an extensive record of
7 professional publications and public appearances. My publications include articles on
8 benchmarking in recent issues of the *Electricity Journal* and the *Energy Journal*. I hold a
9 Ph.D. in applied economics from the University of Wisconsin, which is noted for its strength
10 in economic statistics. My experience is described in more detail in Exhibit MNL-1 to my
11 testimony.

12
13 **Q. Have you appeared as an expert witness in other utility proceedings?**

14 **A.** Yes. I have testified many times on benchmarking and Altreg issues, and most of this
15 testimony has involved statistical cost research. In addition to Oklahoma, where I have
16 previously testified on Altreg and benchmarking issues for Oklahoma Gas & Electric
17 Company ("OG&E" or "Company"), I have testified in Alberta, British Columbia,
18 California, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri,
19 Oklahoma, New York, Ontario, Quebec, and Vermont. Further details of my testimony
20 can be found in Exhibit MNL-1.

II. PURPOSE OF TESTIMONY

Q. **What is the purpose of your direct testimony?**

A. I have been asked by OG&E to conduct a study of its efficiency in managing base rate operation and maintenance expenses ("O&M Cost Performance Study"). This testimony provides a summary of the study, which is described in greater detail in the report provided as Exhibit MNL-2.

Q. **Why is such a study important?**

A. Efforts to effectively manage costs are always important to the Company, its customers and the Commission. At a time when consumer budgets are pinched by a worsening recession, efforts to manage costs are even more critical. Base rate O&M expenses are the largest component of base rate costs that the Company can attempt to control in the short run. My study assesses the results of OG&E's base rate O&M expense management.

Q. **What are the general conclusions of your O&M Cost Performance Study?**

A. OG&E is exceptional at managing its base rate O&M expenses. The study uses two well established statistical benchmarking methods. Under the first benchmarking method, the econometric model, OG&E is 30 percent below where its costs were predicted to have been. When compared to similar benchmarks of 37 other utilities across the United States, OG&E is the third best cost performer. Under the second benchmarking method, peer group unit cost analysis, OG&E's costs are 23 percent below the average of past and present members of the Southwest Power Pool ("SPP").

III. SUMMARY OF STUDY

Q. **What is statistical benchmarking and how is it useful in measuring utility performance?**

A. Statistical benchmarking uses statistics to establish benchmarks that can be used in quantitative performance appraisals. Cost benchmarks can be used to gauge a particular utility's efficiency. The primary set of statistics used to establish cost benchmarks is utility operating data. These data are available from many forms and reports that utilities file with federal government agencies.

Accurate benchmarking is complicated because the costs of utilities vary more because of differences in the business conditions they face than because of differences in their operating efficiency. A cost benchmark for a particular utility should therefore reflect the typical performance that might be expected of managers given the local business conditions which that particular utility faced. Statistical cost research can identify important cost drivers and use such cost drivers to establish better performance metrics and benchmarks.

Q. **What component of the Company's cost did you address in the study?**

A. We addressed the efficiency of OG&E in managing its base rate O&M expenses. Base rate O&M expenses were defined as total O&M expenses less expenses for generation fuels, purchased power, employee pensions and benefits, load dispatching, transmission services by others, and regional market management. These expenses were excluded from the study because they are characteristically volatile, and/or are significantly subject to external influences and as such are substantially beyond the Company's control.

1 Q. **Please summarize the benchmarking methods that you used in your study of**
2 **OG&E.**

3 A. The cost performance of OG&E was appraised using two well-established benchmarking
4 methods: econometric modeling and unit cost indexing. Using both methods, we
5 calculated average performance results for the three most recent years, in keeping with
6 good benchmarking practice.

7
8 Q. **Please describe the econometric modeling.**

9 A. The econometric modeling involved the use of a model designed to explain the impact of
10 various quantifiable business conditions on the base rate O&M expenses of vertically
11 integrated electric utilities. The parameters of the model, which measure cost impact,
12 were estimated statistically using historical data on utility operations. A model fitted
13 with econometric parameter estimates and the specific business conditions faced by
14 OG&E during the appraisal years was used to generate cost benchmarks.

15 The econometric model was based on a sample of good quality data for 38 U.S. vertically
16 integrated electric utilities (including OG&E). The sample period for model estimation
17 was 1995 to 2007. The year 2007 is the latest for which the requisite data are currently
18 available for most sampled companies. All data were drawn from respected public
19 sources. The sample was more than adequate for the development of a credible cost
20 model. The model had high explanatory power and all estimates of the key model
21 parameters were plausible and highly significant. Once the model estimation was
22 completed, the business conditions facing OG&E for 2006, 2007 and 2008 were inputted
23 into the model to determine the cost benchmarks.

1 Q. **What are the key empirical results of the econometric modeling?**

2 A. The base rate O&M expenses of OG&E were found to be about 30% below the
3 benchmark generated by our econometric cost model on average from 2006 to 2008.
4 This performance was in the top quartile and third best in the sample. We conclude that
5 OG&E was a significantly superior cost performer.
6

7 Q. **Please describe the unit cost indexing.**

8 A. As I stated earlier, the other benchmarking method we employed involved the
9 comparison of the base rate O&M expenses of OG&E to those of a peer group using unit
10 cost indexes. A unit cost index is the ratio of a cost index to an output index. Parameter
11 estimates from our cost model were used to design an output index that was a weighted
12 average of comparisons of sales volumes and customers served. We chose investor-
13 owned utilities that were current or former members of the SPP as a sensible peer group.
14 The year 2008 could not be appraised using the indexing method because of the lack of
15 data for peers, so we instead focused on the 2005-2007 period.
16

17 Q. **What are the key empirical results of the unit cost indexing?**

18 A. OG&E's unit cost index was about 23% below the mean for the sampled peer group on
19 average from 2005 to 2007. This performance was good for a virtual tie as the best in the
20 peer group. The unit cost results are consistent with the econometric results and support
21 a finding of superior cost management.

1 Q. **Does this conclude your direct testimony?**

2 A. Yes, it does.

**RESUME OF
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February 2009

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Date of Birth: August 7, 1952

Education: High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions:

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Leads internationally recognized practice in the field of statistical cost research for energy utility benchmarking and alternative regulation ("Altreg"). Other research specialties include utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**

January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.
- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.

Research on the behavior of inventories in metal markets.

Major Consulting Projects:

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
7. Incentive Regulation: Can it Pay for Interstate Gas Companies? Southern Natural Gas, 1989.
8. Measuring the Productivity Growth of Gas Transmission Companies. Interstate Natural Gas Association of America, 1990.
9. Measuring Productivity Trends in the Local Gas Distribution Industry. Niagara Mohawk Power, 1990.
10. Measurement of Productivity Trends for the U.S. Electric Power Industry. Niagara Mohawk Power, 1990-91.
11. Comprehensive Performance Indexes for Electric and Gas Distribution Utilities. Niagara Mohawk Power, 1990-1991.
12. Workshop on PBR for Electric Utilities. Southern Company Services, 1991.
13. Economics of Electric Revenue Adjustment Mechanisms. Niagara Mohawk Power, 1991.
14. Sales Promotion Policies of Gas Distributors. Northern States Power-Wisconsin, 1991.
15. Productivity Growth Estimates for U.S. Gas Distributors and Their Use in PBR. Southern California Gas, 1991.

16. Cost Performance Indexes for Gas and Electric Utilities. Niagara Mohawk Power, 1991.
17. Efficient Rate Design for Interstate Gas Transporters. AEPCO, 1991.
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19. Gas Supply Cost Indexes for Incentive Regulation. Pacific Gas & Electric, 1992.
20. Gas Transportation Strategy for an Arizona Electric Utility. AEPCO, 1992.
21. Design and Negotiation of a Comprehensive Benchmark Incentive Plans for Gas Distribution and Bundled Power Service. Niagara Mohawk Power, 1992.
22. Productivity Research, PBR Plan Design, and Testimony. Niagara Mohawk Power, 1993-94.
23. Development of Incentive Regulation Options. Southern California Edison, 1993.
24. Review of the Southwest Gas Transportation Market. Arizona Electric Power Cooperative, 1993.
25. Productivity Research and Testimony in Support of a Price Cap Plan. Central Maine Power, 1994.
26. Productivity Research for a Natural Gas Distributor, Southern California Gas, 1994.
27. White Paper on Price Cap Regulation For Electric Utilities. Edison Electric Institute, 1994.
28. Statistical Benchmarking for Bundled Power Services and Testimony. Southern California Edison, 1994.
29. White Paper on Performance-Based Regulation. Electric Power Research Institute, 1995.
30. Productivity Research and PBR Plan Design for Bundled Power Service and Gas Distribution. Public Service Electric & Gas, 1995.
31. Regulatory Strategy for a Restructuring Canadian Electric Utility. Alberta Power, 1995.
32. Incentive Regulation Support for a Japanese Electric Utility. Tokyo Electric Power, 1995.
33. Regulatory Strategy for a Restructuring Northeast Electric Utility. Niagara Mohawk Power, 1995.
34. Productivity and PBR Plan Design Research and Testimony for a Natural Gas Distributor. Southern California Gas, 1995.
35. Productivity Research and Testimony for a Natural Gas Distributor. NMGas, 1995.
36. Speech on PBR for Electric Utilities. Hawaiian Electric, 1995.
37. Development of a Price Cap Plan for a Midwest Gas Distributor. Illinois Power, 1996.
38. Stranded Cost Recovery and Power Distribution PBR for a Restructuring U.S. Electric Utility. Delmarva Power, 1996.
39. Productivity and Benchmarking Research and Testimony for a Natural Gas Distributor. Boston Gas, 1996.
40. Consultation on the Design and Implementation of Price Cap Plans for Natural Gas Production, Transmission, and Distribution. Comision Reguladora de Energia (Mexico), 1996.
41. Power Distribution Benchmarking for a PJM Utility. Delmarva Power, 1996.
42. Testimony on PBR for Power Distribution. Commonwealth Energy System, 1996.
43. PBR Plan Design for Bundled Power Services. Hawaiian Electric, 1996.
44. Design of Geographic Zones for Privatized Natural Gas Distributors. Comision Reguladora de Energia (Mexico), 1996.
45. Statistical Benchmarking for Bundled Power Service. Pennsylvania Power & Light, 1996.
46. Productivity Research and PBR Plan Design (including Service Quality) and Testimony for a Gas Distributor. BC Gas, 1997.
47. Price Cap Plan Design for Power Distribution Services. Comisión de Regulación de Energía y Gas (Colombia), 1997.
48. White Paper on Utility Brand Name Policy. Edison Electric Institute, 1997.
49. Statistical Benchmarking for Bundled Power Service and Testimony. Pacific Gas & Electric, 1997.
50. Review of a Power Purchase Contract Dispute. City of St. Cloud, MN, 1997.
51. Statistical Benchmarking and Stranded Cost Recovery. Edison Electric Institute, 1997.
52. Inflation and Productivity Trends of U.S. Power Distributors. Niagara Mohawk Power, 1997.
53. PBR Plan Design, Statistical Benchmarking, and Testimony for a Gas Distributor. Atlanta Gas Light, 1997.

54. White Paper on Price Cap Regulation (including Service Quality) for Power Distribution. Edison Electric Institute, 1997-99.
55. White Paper and Public Appearances on PBR Options for Power Distributors in Australia. Distribution companies of Victoria, 1997-98.
56. Research and Testimony of Gas and Power Distribution TFP. San Diego Gas & Electric, 1997-98.
57. Cost Structure of Power Distribution. Edison Electric Institute, 1998.
58. Cross-Subsidization Measures for Restructuring Electric Utilities. Edison Electric Institute, 1998.
59. Testimony on Brand Names. Edison Electric Institute, 1998.
60. Research and Testimony on Economies of Scale in Power Supply. Hawaiian Electric Company, 1998.
61. Research and Testimony on Productivity and PBR Plan Design for Bundled Power Service. Hawaiian Electric and Hawaiian Electric Light & Maui Electric, 1998-99.
62. PBR Plan Design, Statistical Benchmarking, and Supporting Testimony. Kentucky Utilities & Louisville Gas & Electric, 1998-99.
63. Statistical Benchmarking for Power Distribution. Victorian distribution business, 1998-9.
64. Testimony on Functional Separation of Power Generation and Delivery in Illinois. Edison Electric Institute, 1998.
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66. Workshop on PBR for Energy Utilities. World Bank, 1998.
67. Advice on Code of Conduct Issues for a Western Electric Utility. Public Service of Colorado, 1999.
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66. Research and Testimony on Benchmarking and PBR Plan Design for Bundled Power Service. Oklahoma Gas & Electric, 1999.
67. Cost Benchmarking for Power Transmission and Distribution. Southern California Edison, 1999.
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74. Statistical Benchmarking for Power Transmission. Powerlink Queensland, 2000.
75. Testimony on PBR For Power Distribution. TXU Electric, 2000.
76. Workshop on PBR for Gas and Electric Distribution. Public Service Electric and Gas, 2000.
77. Economies of Scale and Scope in an Isolated Electric System. Western Power, 2000.
78. Research and Testimony on Economies of Scale in Local Power Delivery, Metering, and Billing. Electric distributors of Massachusetts, 2000.
79. Service Quality PBR Plan Design and Testimony. Gas and electric power distributors of Massachusetts, 2000.
80. Power and Natural Gas Procurement PBR. Western Resources, 2000.
81. PBR Plan Design for a Natural Gas Distributor. BC Gas, 2000.
82. Research on TFP and Benchmarking for Gas and Electric Power Distribution. Sempra Energy, 2000.
83. E-Forum on PBR for Power Procurement. Edison Electric Institute, 2001.
84. Statistical Benchmarking for Power Distribution, Queensland Competition Authority, 2001.
85. Productivity Research and PBR Plan Design. Hydro One Networks, 2001.
86. PBR Presentation to Governor Bush Energy 2000 Commission. Edison Electric Institute, 2001.
87. Competition Policy in the Power Market of Western Australia, Western Power, 2001.

88. Research and Testimony on Productivity and PBR Plan Design for a Power Distributor. Bangor Hydro Electric, 2001.
89. Statistical Benchmarking for three Australian Gas Utilities. Client name confidential, 2001.
90. Statistical Benchmarking for Electric Power Transmission. Transend, 2002.
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93. Research on Power Distribution Productivity and Inflation Trends. NSTAR, 2002.
94. Research and Testimony on Power and Natural Gas Distribution Productivity and Benchmarking. Sempra Energy, 2002.
95. Future of T&D Regulation, Southern California Edison. October 2002.
96. Research on the Incentive Power of Alternative Regulatory Systems. Hydro One Networks, 2002.
97. Workshop on Recent Trends in PBR. Entergy Services, 2003.
98. Workshop on PBR for Louisiana's Public Service Commission. Entergy Services, February 2003.
99. Research, Testimony, and Settlement Support on the Cost Efficiency of O&M Expenses. Enbridge Gas Distribution, 2003.
100. Advice on Performance Goals for a U.S. Transmission Company. American Transmission, 2003.
101. Workshop on PBR for Canadian Regulators. Canadian Electricity Association, 2003.
102. General consultation on PBR Initiative. Union Gas, 2003.
103. Statistical Benchmarking of Four Bolivian Power Distributors. Superintendencia de Electricidad, 2003.
104. Statistical Benchmarking of Power Transmission. Central Research Institute for the Electric Power Industry (Japan), 2003.
105. Statistical Benchmarking, Productivity, and Incentive Power Research for a Combined Gas and Electric Company. Baltimore Gas and Electric, 2003.
106. Advice on Statistical Benchmarking for Two British Power Distributors. Northern Electric and Yorkshire Electricity Distribution, 2003.
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109. Research and Testimony on Power and Natural Gas Distribution Productivity and Benchmarking for a U.S. Utility. Sempra Energy. 2004.
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121. White Paper: Use of Statistical Benchmarking in Regulation. Canadian Electricity Association. 2005.
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123. Statistical Benchmarking of a California Nuclear Plant. San Diego Gas & Electric. 2005.
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129. White Paper on Alternative Regulation for Major Plant Additions for a U.S. Trade Association. EEI. 2006.
130. Consultation on Price Cap Regulation for Provincial Power Distributors. Ontario Energy Board. 2006.
131. Statistical Benchmarking of A&G Expenses. Michigan Public Service Commission. 2006.
132. Workshop on Alternative Regulation of Major Plant Additions. EEI. 2006.
133. White Paper on Power Distribution Benchmarking for a Canadian Trade Association. Canadian Electricity Association. 2006.
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135. Testimony on Statistical Benchmarking of Power Distribution. FortisAlberta. 2006.
136. Consultation on a Canadian Trade Association's Benchmarking Program. Canadian Electricity Association. 2007.
137. Gas Distribution Productivity Research and Testimony for a Canadian Regulator. Ontario Energy Board. 2007.
138. Statistical Cost Benchmarking of Canadian Power Distributors. Ontario Energy Board. 2007-2008.
139. Testimony on Tax Issues for a Canadian Regulator. Ontario Energy Board. 2008.
140. Research and Testimony in Support of a Revenue Adjustment Mechanism for Central Vermont Public Service. 2008.
141. Consultation on Alternative Regulation for a Midwestern Electric Utility. Xcel Energy. 2008.
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4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November, 1987.
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14. Competitive Speculative Storage and the Cost of Petroleum Supply. The Energy Journal 10 (1) 1989.
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16. Futures Prices and Hidden Stocks of Refined Oil Products. In O. Guvanan, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.
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19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.

23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.
29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
33. "Econometric Cost Benchmarking of Power Distribution Cost" " (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
34. "Alternative Regulation for North American Electric Utilities" (With Lawrence Kaufmann), Electricity Journal, July 2006.
35. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
36. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde, and Steve Fenrick), Natural Gas and Electricity, 2008.
37. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009
38. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), forthcoming in the International Handbook on the Economics of Energy.
39. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, forthcoming.

Professional Presentations:

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3. American Agricultural Economics Association, Knoxville, TN, August 1988
4. Association d'Econometrie Appliquée, Washington, DC, October 1988
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O&M COST PERFORMANCE OF OKLAHOMA GAS & ELECTRIC



Pacific Economics Group Research, LLC

O&M COST PERFORMANCE OF OKLAHOMA GAS & ELECTRIC

26 February 2009

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

Statistical benchmarking has in recent years become a widely used tool in the assessment of utility operating performance. Managers use benchmarking to gauge how well their companies are doing. Benchmarking also plays a growing role in regulation. Such studies can, for instance, be used to assess the reasonableness of utility proposals to establish new rates or rate adjustment mechanisms.

The benchmarking of utilities is facilitated by the extensive data that they report to regulators. However, accurate performance appraisals are still difficult to make. There are important differences between utilities in the character of services that they provide, the overall scale of their operations, the prices they pay for inputs, and other business conditions that influence their cost.

The personnel of Pacific Economics Group (“PEG”) Research have been active for more than a decade in the field of utility benchmarking. We pioneered the use of rigorous benchmarking methods in U.S. regulation. Senior author Mark Newton Lowry has testified on benchmarking issues in numerous proceedings.

Oklahoma Gas & Electric (“OG&E” or “the Company”) is filing in this proceeding for an increase in the base rates that recover the cost of its nonfuel inputs. Evidence of good cost management is highly relevant to the proceeding. The Company has retained PEG to benchmark its base rate operation and maintenance (“O&M”) expenses. These expenses account for the bulk of the cost of base rate inputs over which the Company can exercise control in the short run.

Following a brief summary of the work below, Section 2 provides an introduction to benchmarking methods. Section 3 discusses our research for OG&E. More technical details of our research are presented in the Appendix.



1.2 Summary of Research

We addressed the efficiency of OG&E in managing its base rate O&M expenses. Cost was defined as total O&M expenses less expenses for generation fuel, purchased power, employee pensions and benefits, transmission dispatching, transmission services by others, and regional market management. Expenses were excluded on the grounds that they, were exceptionally volatile, or were substantially beyond the control of OG&E.

The cost performance of OG&E was appraised using two well established benchmarking methods: econometric modeling and unit cost indexing. Guided by economic theory, we developed a model of the impact that various quantifiable business conditions have on the base rate O&M expenses of vertically integrated electric utilities (“VIEUs”). The parameters of the model, which measure cost impact, were estimated statistically using historical data on the operations of VIEUs. A model fitted with econometric parameter estimates was used to benchmark the recent historical cost of OG&E given the business conditions that it faced.

The study was based on a sample of good quality data for 38 U.S. VIEUs. The sample period was 1995 to 2007.¹ All data were drawn from respected public sources. The sample was more than adequate for the development of a credible cost model. The model had high explanatory power and all estimates of the key model parameters were plausible and highly significant.

The base rate O&M cost of OG&E was found to be about 30% below the benchmark generated by the econometric model on average from 2006 to 2008. This performance was the third best in the sample. The hypothesis that OG&E was an average or inferior cost performer during these years can be rejected at a high level of confidence. We conclude that OG&E was a significantly superior cost performer.

PEG has also compared the unit cost of OG&E to those of a peer group using unit cost indexes. A unit cost index is the ratio of a cost index to an output index. We chose investor-owned utilities that are currently or historically participants in the Southwest Power Pool (SPP) as the peer group. OG&E’s unit cost index was about 23% below the mean for

¹ PEG also incorporated preliminary 2008 data provided by OG&E in the benchmarking study. 2008 data for the other sampled companies are as yet unavailable.



the sampled utilities on average during the 2005-2007 period. This result placed the Company in a virtual tie for the best performance in the peer group. The unit cost results are consistent with the econometric results and support a finding of superior cost management.



2. AN INTRODUCTION TO BENCHMARKING

In this section of the report we provide a non-technical discussion of some important benchmarking concepts. The two benchmarking methods used in the study are explained. More technical details of our methodology are discussed in the Appendix.

2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise commonly involves one or more gauges of activity. These are sometimes called key performance indicators (“KPIs”) or metrics. The values of the indicators achieved by an entity under scrutiny are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\text{Cost Performance} = \text{Cost}^{\text{Actual}} / \text{Cost}^{\text{Benchmark}}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in both the calculation of benchmarks and in the process of drawing conclusions about performance from benchmark comparisons. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in benchmarking. These standards often reflect statistical concepts. One sensible standard is the average performance of the utilities



in the sample. An alternative standard that is popular is the performance that would define the margin of the top quartile of performers.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Running backs, for example, are evaluated using multiple performance indicators that include touchdowns, rushing yardage, and fumbles. The values achieved by Hall of Fame members like Barry Sanders are useful benchmarks. These values reflect a Hall of Fame performance standard.

2.2 Importance of Business Conditions

For costs and many other kinds of business performance indicators, it is widely recognized that differences in the values of the indicators that companies achieve depend as much or more on differences in the business conditions that they face than on differences in performance. In cost research these conditions are sometimes called cost “drivers”. The cost performance of a company depends on the cost that it achieves given the business conditions that it faces. Benchmarks must reflect local business conditions if they are to reflect a chosen performance standard faithfully.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to business conditions in its service territory. When the focus of benchmarking is a subset of total cost such as base rate O&M expenses, the relevant business conditions include the prices of base rate O&M inputs, the operating scale of the company and, additionally, the amounts of *other inputs* that the company uses.

The existence of other input variables in cost functions means that a fair appraisal of the efficiency with which a utility uses a certain class of inputs must consider the amounts of other inputs it uses. This result is important for several reasons. One is that opportunities exist for the substitution of inputs in production. Suppose, for example, that the focus of benchmarking is a utility’s base rate O&M expenses. Theory indicates that the level of these expenses depends on the amounts of fuel, purchased power, and capital that the company uses. Another reason that “other inputs” matter is that there are inconsistencies in



the manner in which utilities classify costs. Utilities may, for instance, differ in the way that they categorize certain expenditures between administrative and direct operating expenses. This discussion suggests that benchmarking will tend to be simpler and more accurate to the extent that the scope of costs under consideration is comprehensive. It will, for example, be easier to accurately benchmark *total* base rate O&M expenses than it will be to accurately benchmark *labor* expenses.

Whichever cost function is applicable, economic theory allows for the existence of *multiple* output variables. This is important because it is often impossible to accurately measure the workload of a utility using only one output variable. The cost of a VIEU, for instance, depends on the number of customers that it serves as well as its sales volume. It is also noteworthy that theory allows for the possibility that numerous business conditions other than input prices and output quantities affect the minimum cost of service.

2.3 Benchmarking Methods

In this section we discuss the two benchmarking methods that we used in our study for OG&E: econometric modeling and unit cost indexing. The econometric approach is discussed first to establish a context for the appraisal of the index approach. The section concludes by discussing the merits of averaging benchmark results over several years.

2.3.1 Econometric Modeling

Basic Assumptions

Relationships between the costs of utilities and the business conditions that they face can be estimated using statistics. A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.² The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a panel data set that pools time series data for several companies.

² The act of estimating model parameters is sometimes called regression.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. In a benchmarking study used in utility regulation it is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates may be called an econometric cost model. We can use such a model to predict a company's cost given local values for the business condition variables. These predictions are econometric benchmarks. Cost performance is measured by comparing a company's cost in year t to the cost projected for that year and company by the econometric model.

Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Southwest Power. We might then predict the cost of Southwest in period t using the following model.

$$\hat{C}_{Southwest,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Southwest,t} + \hat{a}_2 \cdot W_{Southwest,t}.$$

Here $\hat{C}_{Southwest,t}$ denotes the predicted cost of the Company, $N_{Southwest,t}$ is the number of customers it served, and $W_{Southwest,t}$ measures its wage rate. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = \left(\frac{C_{Southwest,t}}{\hat{C}_{Southwest,t}} \right).$$

Accuracy of Benchmarking Results

A cost prediction like that generated in the manner just described is our best *single* guess of the Company's cost given the business conditions it faces. This is an example of a "point" prediction. Such predictions are likely to differ from the true benchmark, which



accurately embodies the desired performance standard and properly controls for the impact of business conditions on cost.

Statistical theory provides useful guidance regarding the extent of inaccuracy. One important result is that an econometric cost model can yield *biased* predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.

Even when an econometric benchmarking model is unbiased it can be imprecise, yielding predictions that are sometimes too high and on other occasions too low. Statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible predictions that are consistent with the sample data at a given level of confidence. In general, it can be shown that confidence intervals are wider, suggesting greater uncertainty, to the extent that:

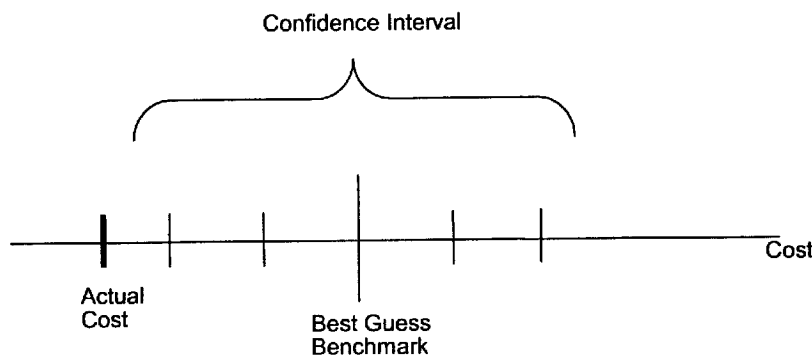
- the model is not successful in explaining the variation in cost in the historical data used in its development;
- the size of the sample is small;
- the number of cost driver variables included in the model is large;
- the business conditions of sampled companies are not varied; and
- the business conditions of the subject utility are dissimilar to those of the typical firm in the sample.

These results suggest that econometric benchmarking will be more accurate to the extent that it is based on a large sample of good operating data. When the sample is small, it will be difficult to identify all of the relevant cost drivers and benchmarks are more likely to be biased. It follows that it will generally be preferable to use panel data when these are available instead of a single cross section of data. Panel sets of data on the operations of electric utilities are, fortunately, readily available in the United States. Notice also that the precision of an econometric benchmarking exercise is *enhanced* by using data from companies with diverse operating conditions.



Testing Efficiency Hypotheses

Confidence intervals developed from econometric results permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average performance standard and compute the confidence interval that corresponds to the 90% confidence level. It is then possible to test the hypothesis that the company is an average cost performer. If the company's actual cost is less than the benchmark generated by the model but nonetheless lies within the confidence interval, this hypothesis cannot be rejected. In other words, the company is not a *significantly* superior cost performer. Suppose, alternatively, that the company's cost is below the cost predicted by the model by enough to be outside the confidence interval, as in the figure below. We may then conclude that the company is a *significantly superior* cost performer.



An important advantage of efficiency hypothesis tests is that they take into account the accuracy of the benchmarking exercise. As we have just discussed, there is uncertainty involved in the calculation of benchmarks. These uncertainties are reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be larger the greater is the uncertainty regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered. Accurate benchmarking of companies facing business conditions that are atypical of the sample can be problematic. But with econometric benchmarking regulators at least have a notion of how much they don't know.

2.3.2 Benchmarking Indexes

The index-based approach to benchmarking is the one that is commonly employed by utilities in internal reviews of operating performance. Benchmarking indexes are also used in the regulatory arena. We begin our discussion with a review of index basics and then consider unit cost indexes.

Index Basics

An index is defined in one respected dictionary as “a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)”.³ In utility performance benchmarking, indexing involves the calculation of ratios of the values of KPIs for a subject utility to the corresponding values for a sample of utilities. The group of companies represented in the sample is sometimes called a peer group.

Indexes can be designed to summarize the results of multiple comparisons. Such summaries commonly involve the calculation of weighted averages of the comparisons. Consumer price indexes are familiar examples. These commonly summarize the inflation (year to year comparisons) in the prices of hundreds of goods and services. The weight for the inflation in the price of each product is its share of the value of all of the products considered.

To better appreciate the advantages of multi-category indexes in benchmarking, recall from our discussion in Section 2.2 that multiple variables are often needed to accurately measure utility workload. We might, then, wish to construct an output index that takes a weighted average of two or three output comparisons. In a cost benchmarking application, it makes sense for the weights of an output index to reflect the relative importance of the individual output variables as cost drivers. The importance of each variable is conventionally measured by its cost elasticity. The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate the required elasticities

³ *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

using econometric estimates of cost function parameters. We can then use as the weight for each output variable in the index its share in the sum of the estimated cost elasticities of the included output variables.

Unit Cost Indexes

A unit cost index is the ratio of a cost index to an output index. The output index may be multicategory. Unit cost indexes are effectively cost performance indicators that have a built in control for differences between companies in one of the most important cost drivers: operating scale.

Unit cost indexes by themselves do not control for all of the other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility. The choice of the peer group is thus an important step in a unit cost benchmarking exercise. Econometric research is useful for identifying the cost conditions that should be similar.

2.3.3 Averaging

Utilities plan their systems for expected business conditions over a series of years and not for conditions in a single year. Appraisals of cost efficiency are, therefore, best made over a multiyear timeframe. For this reason, we routinely assess efficiency over the most recent three years over which data have been gathered.



3. EMPIRICAL RESEARCH FOR OG&E

3.1 Data

The primary source of the cost and quantity data used in our benchmarking work for OG&E was the Federal Energy Regulatory Commission (FERC) Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Data were considered for inclusion in the sample from all major U.S. investor-owned utilities that filed the Form 1 continuously over the years of the sample period and had substantial involvement in power production, transmission, distribution, and customer care functions during the sample period. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from 39 companies were used in the econometric work. These companies are listed in Table 1. Companies included in the SPP peer group are noted. Notice that two of these companies, Entergy Arkansas and Entergy Louisiana, are former members of the SPP RTO. We included these companies because their size was similar to OG&E's.

The sample period was 1995-2007. The year 2007 is the latest for which the data needed for the study are currently available. The resultant data set has 489 observations on each model variable.⁴ This sample is large and varied enough to permit the recognition of a number of O&M cost drivers.

Other sources of data were also accessed in the research. These were used primarily to measure input prices. The supplemental data sources included the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce; the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor; and Form 861 and Form 423 of the U.S. Energy Information Administration ("EIA"). 2008 data for OG&E were based upon preliminary data provided to PEG by the Company.

⁴ Some observations for companies with data included in the sample were excluded due to data problems.



Table 1

SAMPLE OF VERTICALLY INTEGRATED ELECTRIC UTILITIES USED FOR ECONOMETRIC RESEARCH

Utility	2007 Customers	Utility	2007 Customers
Alabama Power	1,425,243	Louisville Gas & Electric	400,703
Appalachian Power	951,693	Nevada Power	817,587
Arizona Public Service	1,086,328	Northern Indiana Public Service	454,471
Avista	347,097	Northern States Power (MN)	1,327,035
Carolina Power & Light	1,423,759	Ohio Power	711,406
Cleco Power*	273,046	Oklahoma Gas and Electric*	759,575
Columbus Southern Power	745,133	Otter Tail Power	129,175
Dayton Power & Light	514,405	Public Service Company of Colorado	1,355,715
Duke Energy	2,330,251	Public Service Company of Oklahoma*	522,419
Empire District Electric*	166,473	Pacificorp	1,683,619
Entergy Arkansas*	685,502	Puget Sound Energy	1,048,402
Entergy Louisiana*	653,493	Sierra Pacific Power	363,422
Florida Power & Light	4,496,593	South Carolina Electric & Gas	633,567
Florida Power	1,632,430	Southern Indiana Gas & Electric	146,473
Georgia Power	2,324,874	Southwestern Electric Power*	464,792
Idaho Power	477,094	Southwestern Public Service*	391,510
Kansas City Power & Light*	506,502	Tampa Electric	666,354
Kentucky Power	175,705	Tucson Electric Power	395,063
Kentucky Utilities	533,512	Virginia Electric & Power	2,362,318

* Southwest Power Pool peer group.

3.2 Definition of Variables

3.2.1 Cost

Cost figures play a key role in both of our benchmarking methods. Our approach to calculating cost is therefore important. The applicable base rate O&M expenses were defined as total electric O&M expenses less all expenses for fuel, purchased power, employee pensions and benefits, transmission dispatching, transmission by others, and market monitoring.⁵ We routinely exclude pension and benefit expenses from our cost benchmarking work on the grounds that they are volatile and, to a considerable degree, beyond the control of utility management. Dispatching and market monitoring expenses were excluded because these services have in recent years been provided increasingly by regional transmission organizations.

3.2.2 Output Measures

Two output measures are utilized in both benchmarking approaches. One is the annual average number of customers served. The other is the total annual megawatt hours of power sold to customers. The sales volume variable includes sales for resale. To better capture the cost impact of variations in operating scale, we include in the cost model squared terms for each of the output variables (*e.g.* customers²) and an interaction term (customers * sales volume).

3.2.3 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. We therefore included in the model an index of the prices of base rate O&M inputs. The O&M input price for each utility is constructed by combining the labor and non-labor prices by utility specific cost share weights. In estimating the model we divide cost by this input price index.

⁵ In addition to Purchased Power expenses as reported on the FERC Form 1, we also exclude the Other Expenses category of Other Power Supply Expenses. We believe that power purchase expenses are sometimes reported in this category.

The labor price component of the input price index was constructed by PEG using data from the BLS. National Compensation Survey (“NCS”) data for 2004 were used to construct average wage rates that correspond to each utility’s service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sector for the U.S. as a whole. Values for other years were calculated by adjusting the 2004 level for changes in regional indexes of employment cost trends for the EGS sector. These indexes were also constructed from publicly available BLS data.

Prices for other O&M inputs are assumed to be the same in a given year for all companies. They are escalated by the U.S. gross domestic product price index. This index is calculated by the BEA and is the federal government’s featured measure of inflation in the prices of final goods and services.

3.2.4 Other Business Conditions

Six other business condition variables are included in the cost model. One is the number of customers per transmission line mile. This variable does not change greatly from year to year and was fixed at its 2003 level for all companies. The source of our transmission line mile data is a directory that is currently entitled *Directory of Electric Power Producers and Distributors*, an annual publication of McGraw-Hill. This variable accounts for the extensiveness of the transmission system relative to the number of customers served. We would expect that as the number of customers per transmission line mile (*i.e.* customer “density”) increases cost would decrease.

A second additional business condition variable is the percent generation that was not derived from hydroelectric resources. It is intended to capture the extent to which the company does not benefit from the low costs of hydroelectric generation. We would expect a VIEU that produces less electricity from hydro resources to have higher costs.

A third business condition that has been added to the model is the megawatt hours of power that were purchased. Recall that our measure of base rate O&M expenses excludes the costs of purchased power but includes the sales volume. The inclusion of this variable in the model levels the playing field for those utilities that generate most of their power, and thus incur more O&M production expenses than companies that purchase a lot of power.



Since purchasing power allows a utility to save on O&M production expenses we would expect that the higher the number of purchased megawatt hours the lower costs would be.

A fourth business condition variable added to the model is a measure of the quantity of fossil fuel used by a utility. This variable controls for the possible substitution effects that might exist between fuel and base rate O&M inputs. There is a considerable amount of such substitution inasmuch as gas-fired generation uses a comparatively high value fuel but economizes on base rate O&M inputs. As such, we would expect that the higher the fuel quantity the lower base rate O&M expenses would be.

The quantity of fuel is measured as the ratio of the fuel expenses to a fuel price index. The fuel price index is a cost-weighted average of the prices of coal, gas, and petroleum products. Data on the average prices of these three fuels in each state were used in these indexes. These were drawn primarily from Form EIA-423. The corresponding cost shares were utility specific and drawn from that form and FERC Form 1.

A fifth business condition variable that has been added to the model is the total generation capacity measured in megawatts. Data for this variable were processed from FERC Form 1 data on individual power plants. Our research team aggregated the nameplate capacity of each sampled utility's operational power plants to arrive at a total capacity figure. We would expect that as the amount of capacity increases the O&M costs of maintaining and operating that capacity would also increase.

A sixth business condition variable added to the model is a measure of the demand side management (DSM) work being done by each utility. Due to a lack of explicit itemization of DSM expenses on the FERC Form 1, this variable is estimated by the percentage of total distribution and customer care expenses that is not attributable to customer service, information, and sales. This is, effectively, a measure of the *lack* of DSM work. Given this form, we would expect that the higher the value of the variable the lower total base rate O&M expenses would be.

The model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of changes in diverse business conditions, including



technological change, that are otherwise excluded from the model. Parameters for such variables typically have a negative sign in statistical cost research.

3.3 Parameter Estimates

Estimation results for the cost model are reported in Table 2. The parameter estimates for the first order terms of the two output variables and for the six additional business conditions are elasticities of cost, under sample mean values of the business conditions, with respect to the basic variable.⁶ The table shades the results for these terms for reader convenience.

The table also reports the values of the asymptotic t ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic t statistic. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t statistic corresponding to this confidence level was about 1.65.

The t statistics were used in model specification. All first order terms were required to have statistically significant and sensibly-signed parameter estimates. Examining the results in Table 2, it can be seen that the cost function parameter estimates were plausible as to sign and magnitude. Cost was found to be higher the higher were output quantities. At the sample mean, a 1% increase in the number of customers was estimated to raise cost by about 0.51%. A 1% hike in the delivery volume was estimated to raise cost by about 0.40%.

The parameter estimates for the additional business condition variables were also sensible.

- Cost was lower the greater was the number of customers per transmission line mile.

⁶ The first order terms are the terms that do not involve squared values of variables or interactions between these variables. See Appendix Section A.1.1 for further discussion.

Table 2

ECONOMETRIC COST MODEL OF O&M BUNDLED POWER SERVICE

Variable Key

N= Number Retail Customers
 V = Total Deliveries
 NMT= Customers per Transmission Line Mile
 GNH= % of Generation Non-Hydro
 XF= Fossil Fuel Quantity
 XP= Quantity of Purchased Power
 CAP= Total Generation Capacity
 PNC= % of Distribution and Customer Care Expenses
 Not Attributable to Customer Service and Sales

O&M Cost for Bundled Power Distributors

EXPLANATORY VARIABLE	ESTIMATED ELASTICITY	T-STATISTIC
N	0.512	12.92
NN	-0.355	-2.72
NV	0.346	2.41
V	0.395	8.57
VV	-0.272	-1.69
NMT	-0.113	-6.46
GNH	0.185	3.95
XF	-0.106	-4.63
XP	-0.064	-4.82
CAP	0.270	8.05
PNC	-0.417	-6.97
Trend	-0.0089	-6.07
Constant	19.752	1380.66
R-squared	0.937	
Number of Observations	476	
Sample Period	1995-2007 ¹	

¹ The sample also includes 2008 data for OG&E.

- Cost was higher the higher was the percentage of generation that was not derived from hydro.
- Cost was lower the greater was the amount of power purchased.
- Cost was lower the greater was the fossil fuel quantity.
- Cost was higher the greater was the amount of generation capacity that the utility owned.
- Cost was lower the lower was the apparent amount of DSM work undertaken.
- The estimate of the trend variable parameter suggests a 0.89% annual downward shift in cost for reasons other than the trends in the business condition variables.

The table also reports the adjusted R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was about 0.94, suggesting that the explanatory power of the model was high.

3.4 Business Conditions of OG&E

OG&E is a VIEU based in Oklahoma City. The heart of its service territory is a broad corridor running from north to south across the center of the state. OG&E also serves customers in corridors to the east and west of this main axis. The eastern corridor extends into northwest Arkansas and includes Fort Smith, the second largest city in that state. In total, the Company currently serves about 760,000 customers in a region of about 30,000 square miles. Most of the company's 7,000 MW of nameplate generation capacity is fueled by low sulfur western coal. The Company also owns substantial gas-fired generation capacity.

The Company operates approximately 4,300 miles of transmission lines in Oklahoma and Arkansas. Operational authority over the transmission system has been transferred to the SPP regional transmission organization. The SPP provides certain dispatching, planning, and regional market services.

Table 3 compares the average values over the 2005-2007 period of cost model



Table 3

Comparison of OG&E Business Conditions To National Sample Norms, 2005-2007

Business Condition	Units	OG&E / National Mean, 2005-2007
Bundled Power Service O&M Cost	Dollars	0.60
Number of Retail Customers	Count	0.84
Total Deliveries	MWh	0.79
Price of Labor and Materials	Index Number	0.98
Customers per Transmission Line Mile	Ratio	0.69
Percent of Generation Not Hydro	Percent	1.04
Fossil Fuel Quantity	Index	1.53
Purchased Power Quantity	MWh	0.47
Total Generation Capacity	MW	1.11
% of Distribution Cost Not Attributable to Customer Service and Sales	Percent	0.97

business conditions for OG&E to the sample mean values of these variables during the same years. It can be seen that the cost of OG&E was only 0.60 times the sample mean. In other words, cost was about 40% below the mean. The number of customers served was, meanwhile, 0.84 times the mean, while the sales volume was 0.79 times the sample mean. Turning next to input prices, the table shows that the O&M input prices faced by OG&E were about 2% below the mean.

As for the other business condition variables, the number of customers per transmission line mile was about 0.69 times the sample mean, suggesting that the company had below average customer density. The percentage of generation that is not hydro was 1.04 times the mean. This reflects the shortage of good opportunities for hydroelectric generation in the Company's service territory. The fossil fuel quantity of OG&E was 1.53 times the mean. The amount of power purchased was 0.47 times the mean, whereas the total generation capacity of OG&E was 1.11 times the mean. These statistics suggest that the Company generated an unusually large percentage of the power that it sold, using fuel intensive technology, and owns extra capacity to meet summer demand surges. The DSM control variable for OG&E was 0.97 times the U.S. sample mean, suggesting that the Company does not have a large DSM program.

3.5 Econometric Benchmarking Results

Table 4 presents the results of our appraisals of the base rate O&M cost of OG&E using the econometric model. The Company's cost was found to be about 30% below its predicted value on average over the 2006-2008 period. This was the third best score amongst the 38 sampled utilities. The hypothesis that OG&E was an average or inferior cost performer was rejected at a high level of confidence. It is reasonable to conclude from this test that OG&E was a significantly superior performer in the management of base rate O&M expenses.

3.6 Unit Cost Results

OG&E has compared its base rate O&M expenses to those of other Southwest Power Pool member utilities in past proceedings. Based on our experience and the results of our



Table 4

Econometric Comparison of Actual and Predicted O&M Cost for OG&E, 2006-2008

<u>Year</u>	<u>Difference (%)</u>	<u>t-Statistic*</u>	<u>P-Value*</u>
2006	-32.6%	-1.899	0.029
2007	-30.9%	-1.779	0.038
2008	-27.9%	-1.577	0.058
Average	-30.46%	-3.025	0.001

*t-Statistic and P-values are computed separately for the averages and are not simple averages of the annual values.

econometric research on the drivers of base rate O&M expenses, we believe that the past and present members of the SPP constitute a good peer group for unit cost comparisons. There are notable similarities between OG&E and peer group utilities in the business conditions that drive base rate O&M expenses. Most peer group utilities face cost drivers that are similar to those of OG&E. For example, they

- have an operating scale that is below the national sample norm;
- face labor prices below the national average;
- use extensive amounts of low sulfur western coal and natural gas in generation;
- generate most of the power that they sell;
- have low load factors that encourage the companies to have extensive generation capacity relative to typical loads;
- do not have large hydroelectric generation; and
- had limited DSM activity during the sample period.

Table 5 summarizes key results of our unit cost comparisons to the SPP peer group. There are results for the cost, output quantity, and unit cost indexes. Results are presented for each of the three most recent years for which data are available for all companies. An average of these three years is also displayed.

For the average of the 2005-2007 period, we find that OG&E's cost was about 8% above the peer group norm. Its output index was, meanwhile, 41% above the peer group norm. OG&E's unit cost was 23% below the norm. This placed OG&E in a virtual tie for the best performance in the peer group sample. These results substantiate the findings of our econometric benchmarking results and suggest that OG&E has been a superior cost performer in recent years.



Table 5

O&M Unit Cost Index Results for OG&E, 2005-2007

Company	O&M Unit Cost - Percent Difference from Peer Group Norm			Average	Performance Rank
	2005	2006	2007		
Oklahoma Gas & Electric	-18.6%	-22.6%	-27.3%	-22.83%	2
Company	Output Quantity Index ¹ - Percent Difference from Peer Group Norm			Average	
	2005	2006	2007		
Oklahoma Gas & Electric	40.4%	40.4%	40.7%	40.50%	
Company	O&M Cost - Percent Difference from Peer Group Norm			Average	
	2005	2006	2007		
Oklahoma Gas & Electric	14.3%	8.6%	2.3%	8.41%	

¹ The output quantity index is a cost elasticity-weighted index of customer numbers and total delivery volumes. Elasticity estimates were drawn from the econometric cost model (Table 2).

APPENDIX

This section provides additional and more technical details of our benchmarking work. We first consider the form of the cost model and our econometric work. There follow discussions of the index-based approach to benchmarking.

A.1 Econometric Research

A.1.1 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, the double log and the translog. Here is a simple example of a linear cost model.

$$C = a_0 + a_1 \cdot N + a_2 \cdot W \quad [A1]$$

Cost is a function of the number of customers served (N) and the wage rate (W). Here is an analogous cost model of double log form.

$$\ln C = a_0 + a_1 \cdot \ln N + a_2 \cdot \ln W \quad [A2]$$

In this form, the value of each variable has been converted to its natural logarithm. It can be shown that this specification has the effect of making the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. 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.⁷

Here is an analogous model of translog form⁸

$$\begin{aligned} \ln C = & a_0 + a_1 \cdot \ln N + a_2 \cdot \ln W + a_3 \cdot \ln N \cdot \ln N \\ & + a_4 \cdot \ln W \cdot \ln W + a_5 \cdot \ln W \cdot \ln N \end{aligned} \quad [A3]$$

⁷ Cost elasticities are not constant in the linear model that is exemplified by equation A1.

⁸ The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N \cdot \ln N$ permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. The elasticity of cost with respect to the output variable may, for example, be lower for a small utility than for a large utility that has exhausted its opportunities to realize incremental scale economies. Interaction terms like $\ln W \cdot \ln N$ permit the elasticity of cost with respect to the business condition variable to depend on the labor price. When model data are mean scaled for convenience, the parameters of each first order term (the term that does not involve squares or interactions) is the elasticity of cost with respect to the basic variable at sample mean values of the business conditions.

The translog form is an example of a “flexible” functional form and is by some accounts the most reliable of several available alternatives. Flexible forms can accommodate a greater variety of possible relationships between cost and the business condition variables. They are especially useful in capturing differences between utilities in the realization of scale economies. A disadvantage of the translog form is that it involves many more variables than simpler forms such as the double log. As the number of variables increases, the precision of a model’s cost predictions falls. We have for this reason chosen to limit the translog treatment to the output variables of our model.

A.1.2 Estimation Procedure

Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables.

The error term in an econometric cost model is the difference between actual cost and the cost that is predicted by the model. It reflects imperfections in the development of the model. The imperfections may include any or all of the following: the mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the functional relationship. Error terms are a formal acknowledgement of the fact that the cost model is



unlikely to provide a full explanation of the variation in the costs of sampled utilities. It is customary to assume that error terms are random variables with probability distributions that are determined by additional coefficients, such as mean and variance.

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions that are 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 generalized least squares (“GLS”), is appropriate under assumptions of more complicated error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic in the sense that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Estimation procedures that address several of the error term issues that are routinely encountered in utility benchmarking are not readily available in commercial econometric software packages such as Gauss and Stata. They require, instead, the development of customized estimation programs.

In order to achieve a more efficient estimator, we corrected for autocorrelation and heteroskedasticity in the error terms of our model for OG&E using a custom in house regression procedure developed with Gauss software. Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimators (MLE).⁹ Our estimates thus possess all the highly desirable properties of MLEs.

Note, finally, that the model specification was determined using the data for all sampled companies, including OG&E. However, computation of model parameters and standard errors for the prediction required that the values for OG&E be dropped from the sample. The estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

⁹ See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

A.2 Unit Cost Indexes

A.2.1 Cost Indexes

The cost index for OG&E in each year t was defined by the formula

$$Cost\ Index_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{\overline{Cost}_t} \quad [A4]$$

where $\overline{Cost}_t$ is the mean value of cost for the peer group in year t .

A.2.2 Output Quantity Indexes

The output quantity index in each year t was defined by the formula

$$Output\ Quantity_{OG\&E,t} = \sum_i SE_i * \frac{Y_{OG\&E,i,t}}{\overline{Y}_{i,t}} \quad [A5]$$

Here,

$Y_{OG\&E,i,t}$ = Quantity of output i for OG&E

$\overline{Y}_{i,t}$ = Peer group mean of the quantity of output i .

SE_i = Share of output i in the sum of the econometric estimates of the cost

elasticities of the output quantities under sample mean business conditions.

In Table 2, the elasticities of cost with respect to the sales volume and the number of customers served were estimated to be .51 and .40 respectively. The corresponding elasticity-share weights for the output index were 56% and 44%, respectively.

A.2.3 Unit Cost Indexes

The unit cost index is the ratio of the cost index to the output quantity index.

$$Unit\ Cost_{OG\&E,t} = \frac{Cost_{OG\&E,t}}{Output\ Quantity_{OG\&E,t}} \quad [A6]$$

Then

$$Unit\ Cost_{OG\&E,t} = \left(\frac{Cost_{OG\&E,t}}{\overline{Cost}_t} \right) / \left(\sum_i SE_i * \frac{Y_{OG\&E,i,t}}{\overline{Y}_{i,t}} \right).$$



The percentage difference between the unit cost of OG&E and that of the peer group is then calculated using the formula $100 * (Unit\ Cost_{OG\&E} - 1)$.



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