Application of SAN DIEGO GAS & ELECTRIC COMPANY for authority to update its gas and electric revenue requirement and base rates effective January 1, 2008 (U 902-M).)

Application No. 06-12-___
Exhibit No.: (SDG&E-33) ___________

PREPARED DIRECT TESTIMONY
OF MARK NEWTON LOWRY, PH.D.
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECEMBER 2006

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TFP Research for San Diego Gas & Electric

Pacific Economics Group, LLC
Economic and Litigation Consulting

TFP Research for San Diego Gas & Electric

1 August 2006

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TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

1.1 Introduction

San Diego Gas & Electric ("SDG&E," "San Diego", or "the Company") is filing a general rate case ("GRC") in this proceeding. Since 1987, jurisdictional investor-owned energy utilities have been asked by California's Public Utilities Commission ("CPUC" or "the Commission") to report on total factor productivity ("TFP") trends in GRC proceedings.[1] In 2005, the Commission requested that San Diego and its affiliated company, Southern California Gas ("SoCalGas"), provide new productivity studies in its next GRC. The companies were specifically asked to provide productivity estimates that reflect good to excellent performance.

To comply with these mandates, SDG&E has retained Pacific Economics Group LLC ("PEG") to calculate the long-run TFP trends of the U.S. gas and electric power distribution industries. PEG, a California-based firm, is the world's leading provider of energy industry productivity studies. Senior author and project leader Mark Newton Lowry has testified for San Diego Gas and Electric, Southern California Gas Company, and several other utilities on his productivity work.

This document reports on our research. Following a brief summary of the study, Section 2 of the report provides an introduction to productivity measurement. Highlights of our TFP research for gas distribution are presented in Section 3. Highlights of our work for power distribution are presented in Section 4. Further details of the research, along with some information on the qualifications of the research team, are provided in the Appendix.

1.2 Summary of Research

1.2.1 TFP Indexes

A TFP index is the ratio of an output quantity index to an input quantity index. It is used to measure the efficiency with which firms convert production inputs into outputs. The growth rate in a TFP trend index is the difference between the growth rates of the output and

[1] D.86-12-095, p. 38.

input quantity indexes. The output quantity index summarizes trends in measures of the services provided. The input quantity index summarizes trends in the amounts of all inputs used in providing the services.

1.2.2 Sample

The research was based on data for substantially all U.S. investor-owned gas and electric power distributors of some size for which requisite data of good quality are available. The sample period was in each case 1994-2004. The end date is the most recent year for which data are currently available. Results were calculated for the national industry, the California industry, and SDG&E.

1.2.3 Indexing Results

Gas Distribution

We calculated the TFP trend of sampled utilities as providers of gas distribution services. Gas distribution was defined to include the transmission, storage, local gas delivery, customer account and information, and administrative and general services that utilities provided. The costs considered included labor and materials expenses and the costs of plant ownership. Costs of gas purchases were excluded.

The trend in the TFP of the national gas distribution industry was found to be 0.70% growth per annum. By way of comparison, the federal government's multifactor productivity index for the private business sector of the U.S. economy grew at a 1.39% average annual rate over the same period. The trend for the good and excellent cost performers in the sample was found to be slightly below the average trend for the sample. The trend in the TFP of California's sampled gas distributors was a more rapid 1.35% growth per annum. The trend in the TFP of San Diego's gas distribution operations was a 0.57% decline per annum.

Power Distribution

We also calculated the TFP trend of sampled utilities as providers of power distribution services. Power distribution was defined to include the local power delivery, customer account, sales, and information, and administrative and general services that the utilities provide. The costs considered included labor and materials expenses and the costs of plant ownership. The costs of power purchases were not included.

The trend in the TFP of the national power distribution industry was found to be 1.08% growth per annum. The trend in the TFP of the good and excellent cost performers in the sample was slightly above the sample average. The trend in the distribution TFP of the California industry was a considerably slower 0.24% growth per annum. The trend in the TFP of San Diego's power distribution operations was a -0.66% decline per annum.

2. An Introduction to TFP

2.1 TFP Indexes

A TFP index is the ratio of an output quantity index to an input quantity index.

$$TFP = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [1]$$

It is used to compare the efficiency with which firms convert inputs into outputs. Comparisons can potentially be made between firms at a point in time or for the same firm (or group of firms) at different points in time. The indexes we developed for this study measure the TFP trends of gas and electric power distributors.

The growth trend in a TFP trend index is the difference between the trends in the component output and input quantity indexes.

$$trend\ TFP = trend\ Output\ Quantities - trend\ Input\ Quantities. \qquad [2]$$

The output quantity index of an industry summarizes trends in the amounts of services it provides. The input quantity index summarizes trends in the amounts of labor, capital, and other production inputs used. TFP grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index.

2.2 Sources of TFP Growth

A TFP index captures the net effect of developments that can cause the unit cost of firms to grow more slowly than input prices. Rigorous research has shown that the sources of TFP growth are quite diverse. One source is technical change. The adoption of new technologies permits an industry to produce given output quantities with fewer inputs.

A second important determinant of TFP growth is the degree of capacity utilization. Producers in most industries find it uneconomical to match production capacity exactly to year–to-year demand shifts. The capacity utilization rates of industries therefore fluctuate. TFP grows (falls) when capacity utilization rises (falls) because output is changing more rapidly than capacity. The short run is a period so short that capacity does not adjust fully to demand shifts. The long run is a period long enough for capacity to adjust to secular demand trends. Capacity utilization thus has an influence chiefly on year to year TFP growth rather than the long run growth trend.

Economies of scale are a third important source of TFP growth. Scale economies are available to a firm when cost grows less rapidly than output in the longer run. Realization of scale economies slows unit cost growth and accelerates TFP growth. The ability to realize scale economies varies with the size and output growth of utilities. The smaller companies in an industry can typically realize scale economies when output grows. Larger companies may have exhausted potential economies of scale, and some may even operate at a scale where output growth causes diseconomies of scale that slow TFP growth. The potential for scale economies to accelerate productivity growth in a given industry therefore depends on the number of firms of each kind, their size, and the output growth that they are experiencing.

Economic theory suggests that, in addition to input prices and output quantities, miscellaneous other business conditions can drive the cost of production. Changes in these business conditions can affect TFP growth. For example, a change in a business condition that tends to raise unit cost will tend to slow TFP growth. In the power distribution business, for example, the additional business conditions that can affect growth include the degree of system undergrounding.

A fifth important source of TFP growth is X inefficiency. This is the degree to which individual companies operate at the maximum efficiency that existing technology allows. TFP will grow (decline) to the extent that X inefficiency diminishes (increases).

2.3 Adjusting Results for Poor Performers

In 2005, the Commission stated that

> in the next proceeding SoCalGas and SDG&E shall either propose an X factor adjusted to reflect good to excellent performance (by excluding poor performance from the request) or propose an appropriate stretch factor to offset mediocrity in the study group."[2]

SDG&E is not proposing in this proceeding a PBR plan with an X factor linked to TFP research. However, it has asked PEG to comply with the Commission's directive in our

[2] D. 05-03-023 p. 74.

study. We calculate TFP trends for the national energy distribution industries after removing the influence of mediocre and poor performers.

Econometric cost models are used in our studies to make this adjustment. These models provide output weights for our TFP indexes and are used to benchmark the performance of the companies in the samples used in model estimation. After ranking the companies on the basis of their performance, we compute the average TFP growth of the companies in the top two quartiles and compare it to the results for the sample as a whole. This is a good estimate of how the TFP growth of good to excellent performers typically differs from that for poor performers. Further details of our work to develop the econometric cost models appear in the Appendix.

3. Gas Distribution Research

This section presents an overview of our work to calculate the TFP trend of U.S. gas distributors. The discussions here and in Section 4, which addresses our power distribution research, are largely non-technical. Additional and more technical details of the work are provided in the Appendix.

3.1 Data

The primary source of data used in our gas distribution productivity research has changed over time. For the earliest years of the sample period, the primary source was *Uniform Statistical Reports* ("USRs"). Many gas utilities have filed these annual reports to the American Gas Association.

USRs are unavailable for most sampled distributors for the latter years of the sample period. The development of a satisfactory sample therefore required us to obtain basic cost and quantity data from alternative sources including, most notably, reports to state regulators. These reports are fairly standardized since they often use as templates the Form 2 report that interstate gas pipeline companies file with the Federal Energy Regulatory Commission ("FERC"). Gas distribution operating data from these sources are also compiled by commercial venders such as Platts. We obtained 2004 operating data for this study from the Platts *GasDat* package.

Other sources of data were also used in the gas research, primarily for input price data. The supplemental data sources were Whitman, Requardt & Associates; R.S. Means and Associates; 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; Global Insight (formerly DRI-McGraw Hill); and the Energy Information Administration ("EIA") of the U.S. Department of Energy.

Our TFP trend calculations are based on quality data for 39 gas distributors. The sample includes most of the nation's larger distributors. Some of the sampled distributors provide gas transmission and/or storage services but all were involved more extensively in gas distribution.

The sampled distributors, grouped by region, are listed in Table 1. The regional coverage of sampled LDCs is somewhat uneven. For example, California distributors accounted for almost 30% of the customers in the sample but for only 15% of U.S. gas end users. In contrast, the South Central states accounted for only 2% of customers in the sample and for about 9% of end users nationally. We have made a correction for this imbalance that is discussed further below.

3.2 Index Details

3.2.1 Scope

The applicable total cost of gas distribution was calculated as applicable operation and maintenance ("O&M") expenses plus the cost of gas plant ownership. Applicable O&M expenses are defined as the total gas O&M expenses of the utility less any expenses for natural gas production and procurement, transmission services by others, and franchise fees. The operations corresponding to this definition of cost include gas transmission, storage, local delivery, account information, and other customer services, and administrative and general services of LDCs.

3.2.2 Output Quantity Index

The trend in the output quantity index was a weighted average of the trends in two quantity subindexes: total throughput and the number of customers served. The weights were based our estimate of the relative impact of these two quantity measures on gas distribution cost. This is a sensible output specification when TFP is computed chiefly to measure trends in operating efficiency. The econometric research used to develop these estimates of the relative cost impacts of different output measures is discussed further in the Appendix.

Table 1

SAMPLED GAS DISTRIBUTORS FOR TFP RESEARCH

Region	Company	Number of Customers (2004)	Percent Sample Total	Percent Continental US
Northeast				
	Boston Gas	587,513		
	Central Hudson Gas & Electric	69,081		
	Connecticut Natural Gas	151,127		
	Consolidated Edison of New York	1,041,458		
	Keyspan Energy Delivery	1,155,008		
	Niagara Mohawk	560,566		
	New Jersey Natural Gas	453,983		
	Nstar Gas	252,576		
	Orange and Rockland Utilities	123,577		
	PECO Energy	464,619		
	People's Natural Gas (PA)	355,134		
	Public Service Electric & Gas	1,693,048		
	Rochester Gas and Electric	293,334		
	Southern Connecticut Gas	170,817		
	Total	*7,371,841*	*21.5%*	
	EIA Regional Total	*14,210,646*		*20.7%*
Southeast				
	Atlanta Gas Light	1,532,615		
	Baltimore Gas & Electric	624,862		
	Public Service of North Carolina	390,824		
	Washington Gas Light	980,686		
	Total	*3,528,987*	*10.3%*	
	EIA Regional Total	*6,554,338*		*9.5%*
Midwest and Plains				
	Consumers Energy	1,690,874		
	East Ohio Gas	1,217,546		
	Illinois Power	414,015		
	Madison Gas and Electric	131,674		
	North Shore Gas	153,856		
	NICOR Gas	2,092,607		
	Peoples Gas Light & Coke	812,705		
	Wisconsin Gas	570,927		
	Wisconsin Power & Light	169,216		
	Total	*7,253,420*	*21.2%*	
	EIA Regional Total	*20,348,354*		*29.6%*
South Central				
	Alabama Gas	460,921		
	Louisville Gas and Electric	316,311		
	Total	*777,232*	*2.3%*	
	EIA Regional Total	*5,970,122*		*8.7%*
Texas				
	Atmos Mid-Tex (former TXU)	1,482,435		
	Total	*1,482,435*	*4.3%*	
	EIA Regional Total	*4,270,822*		*6.2%*
Southwest				
	Southwest Gas	1,526,462		
	Questar	777,555		
	Total	*2,304,017*	*6.7%*	
	EIA Regional Total	*4,679,222*		*6.8%*
Northwest				
	Cascade Natural Gas	217,336		
	Northwest Natural Gas	586,461		
	Puget Sound Energy	661,739		
	Total	*1,465,536*	*4.3%*	
	EIA Regional Total	*2,282,626*		*3.3%*
California				
	Pacific Gas & Electric	4,030,373		
	San Diego Gas & Electric	805,772		
	Southern California Gas	5,266,356		
	Total	*10,102,501*	*29.5%*	
	EIA Regional Total	*10,432,623*		*15.2%*
Total For Sample		34,285,969		
Industry Total *		68,748,753		
Percentage of US Total		49.9%		
Number of Sampled Firms		39		

* Source for US Total: US Energy Information Administration,*Natural Gas Annual 2004*

3.2.3 Input Quantity Index

The growth rate in each input quantity index was a weighted average of the growth rates in quantity subindexes for capital, labor, and other O&M inputs. The weights were based on the shares of these input classes in the industry's gas distribution cost. The cost of gas delivery labor was defined as O&M salaries and wages and pensions and other benefits. The cost of other O&M inputs was defined to be O&M expenses net of expenses for labor, gas production and procurement, transmission by others, and franchise fees. This residual input category includes the services of contract workers, insurance, real estate rentals, equipment leases, materials, and miscellaneous other goods and services. Each of the three input quantity measures was calculated as the ratio of a corresponding cost to an appropriate input price index.

The decomposition of capital cost into a price and a quantity is required for the accurate measurement of TFP trends in capital intensive industries such as energy distribution. We used a service price approach to capital cost measurement. Under this approach, the cost of capital is the product of a capital quantity index and an index of the price of capital services. This method has a solid basis in economics and is well established in the scholarly literature.

3.2.4 Regional Weightings

Due to the regional imbalances in the gas distributor sample discussed in Section 3.1 above, we calculated the annual growth rate in the national industry output and input quantity indexes as weighted averages of the growth rates in corresponding indexes for the following eight regions: Northeast, South Atlantic, North Central, South Central, Texas, Southwest, Northwest, and California. The weight for each region was its share in the total number of gas end users in the continental U.S. The end user data needed for this calculation were obtained from the EIA. Within each region, output and input quantity growth was calculated as cost share-weighted averages of the growth rates of the individual companies.

3.2.5 Sample Period

In choosing a sample period for a TFP study it is desirable that the period include the latest available data. In the present case this means a 2004 end date for the period. It is also desirable for the period to reflect the long run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. We chose 1994 as the start date for the study.

3.3 Index Results

Table 2 and Figure 1 report the 1994-2004 average annual growth rates in the gas distribution TFP and component output and input quantity indexes. Inspecting the results, it can be seen that the national industry registered 0.70% average annual growth. Output quantity growth averaging 1.28% annually outpaced input quantity growth averaging 0.57% annually. TFP growth in California's gas distribution industry averaged a more rapid 1.35% annual pace. The annual TFP growth of San Diego's gas operations declined by 0.57% annually. By way of comparison, the federal government's multifactor productivity index for the private business sector of the U.S. economy grew at a 1.39% average annual rate over a similar period.

Table 3 reports results of our effort to adjust for the TFP trend of the sample's mediocre and poor performers. We find that the average annual growth rate in the TFP indexes of all the companies in our econometric sample was 0.79%. This number differs a little from our national industry TFP trend because the samples for the two streams of work are modestly different, results are simply averaged rather than weighted to reflect the size and regions of the sampled utilities, and because certain volatile costs were excluded from the company-specific TFP indexes for this exercise to make them consistent with the benchmarking work.[3]

Inspecting the results, it can be seen that the companies in the top tier had costs that averaged 21% below the predictions of our econometric model. The average annual growth rates in the TFP indexes for these companies averaged only 0.52%. The companies in the second tier had costs that averaged 3.2% below the predictions of our econometric cost model. The average annual growth rate in the TFP indexes for these companies was only

[3] The excluded costs were taxes and expenses for pensions and other benefits.

Table 2

PRODUCTIVITY RESULTS: GAS DISTRIBUTION

Year	**Output Quantity Index**			**Input Quantity Index**			**TFP Index**			**Private Business Sector US Economy**
	Industry	**California Aggregate**	**SDGE**	**Industry**	**California Aggregate**	**SDGE**	**Industry**	**California Aggregate**	**SDGE**	
1994	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	93.7
1995	1.019	0.999	1.008	1.002	1.004	1.014	1.016	0.995	0.994	93.5
1996	1.043	1.005	1.023	1.014	0.975	1.048	1.029	1.031	0.976	95.1
1997	1.061	1.023	1.041	1.008	0.943	1.080	1.053	1.084	0.964	96.0
1998	1.068	1.034	1.075	1.006	0.950	1.155	1.061	1.089	0.931	97.5
1999	1.084	1.044	1.093	1.017	0.930	1.115	1.066	1.123	0.980	98.7
2000	1.108	1.036	1.096	1.028	0.920	1.101	1.077	1.126	0.996	100.0
2001	1.119	1.083	1.141	1.027	0.921	1.166	1.089	1.175	0.978	100.2
2002	1.131	1.098	1.150	1.034	0.934	1.171	1.094	1.176	0.983	101.8
2003	1.132	1.082	1.142	1.045	0.955	1.263	1.084	1.133	0.905	104.7
2004	1.136	1.106	1.175	1.059	0.966	1.244	1.073	1.144	0.945	107.7
Average Annual Growth Rate **1994-2004**	**1.28%**	**1.01%**	**1.62%**	**0.57%**	**-0.34%**	**2.18%**	**0.70%**	**1.35%**	**-0.57%**	**1.39%**

FIGURE 1: TFP RESULTS FOR GAS DISTRIBUTION

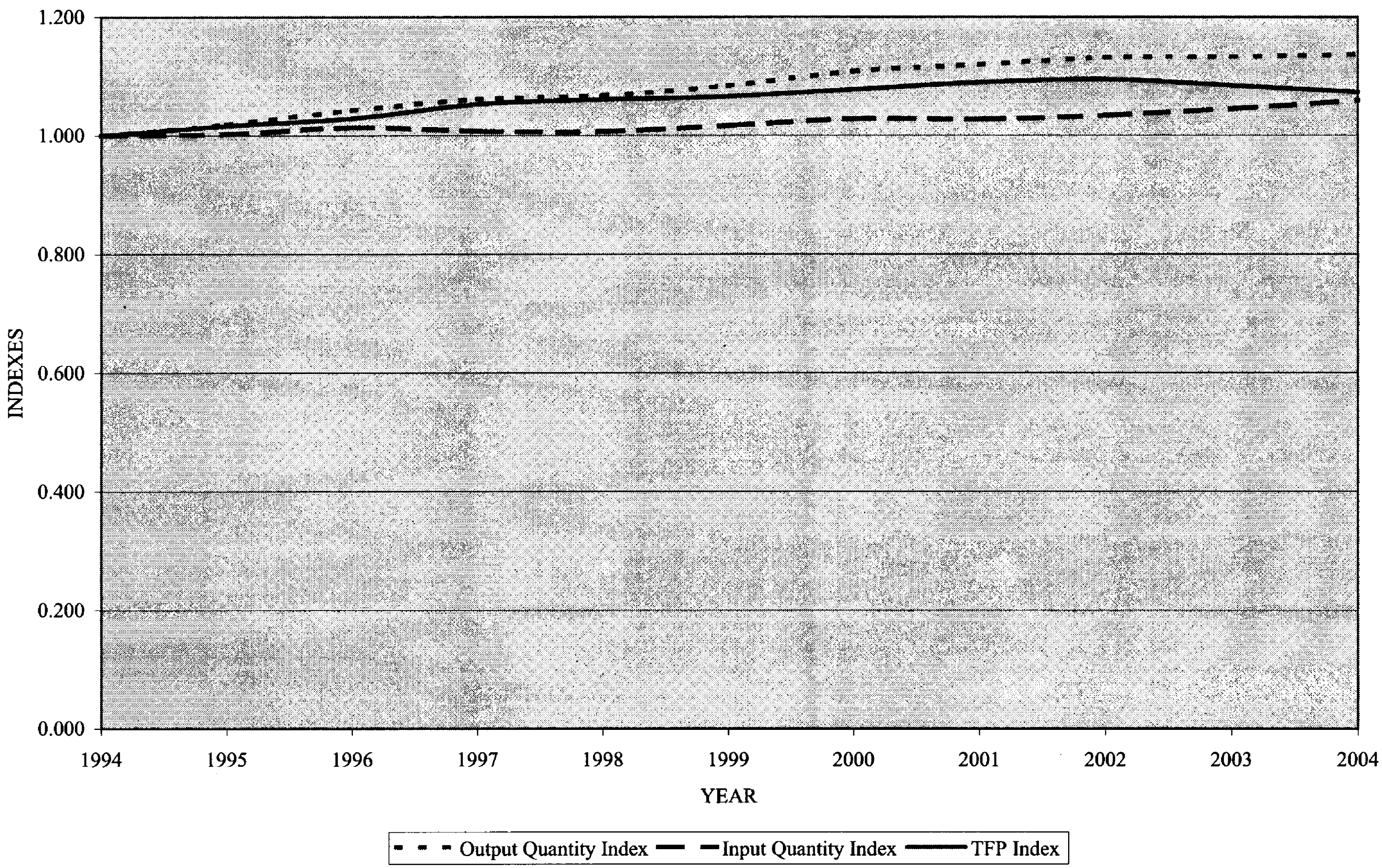

Table 3

TFP GROWTH RATE QUARTILES 1994-2004: U.S.GAS DISTRIBUTION

	Average Annual Growth TFP (%)	Benchmarking Results (Actual-Predicted Cost)
Quartile Range		
1st (highest)	3.2% to -1.6%	-35.0% to -11.6%
2nd	2.1% to -0.6%	-9.9% to 0.5%
3rd	2.2% to -0.1%	1.0% to 10.1%
4th (lowest)	1.6% to -2.1%	10.5% to 46.9%
1st and 2nd	3.2% to -1.6%	-35.0% to 0.5%
1st, 2nd and 3rd	3.2% to -1.6%	-35.0% to 10.1%
Quartile Average		
1st (highest)	0.52%	-21.4%
2nd	1.01%	-3.2%
3rd	1.13%	5.4%
4th (lowest)	0.52%	23.0%
1st and 2nd	0.76%	-12.3%
1st, 2nd and 3rd	0.88%	-6.8%
Sample Average	**0.79%**	**0.8%**

1.01%. The final step in our methodology was to compute results for the first and second quartiles combined. We found that the average TFP growth of these good and superior performers averaged 0.76%, slightly below the average TFP growth rate for benchmarked companies.

4. POWER DISTRIBUTION

This section presents an overview of our work to calculate the TFP trends of U.S. power distributors. Following a discussion of the data we consider some details of the index calculation. The section concludes with a presentation of key findings from our research.

4.1 Data

The primary source of the cost and quantity data used in the power distribution work 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.

FERC Form 1 data are processed by the Energy Information Administration ("EIA") of the U.S. Department of Energy. Selected Form 1 data were for many years published by the EIA and are now made available electronically.[4] These data have been gathered and processed by commercial vendors such as the Utility Data Institute (d/b/a Platts). FERC Form 1 data used in this study for years since 2001 were obtained directly from the electronic forms.

Data were considered for inclusion in the sample from all major U.S. investor-owned power distributors that filed the Form 1 in 2004 and that, together with any important predecessor companies, have requisite data that are credible and available continuously since the mid 1960s. Data from 77 companies met these standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the TFP trend of U.S. power distributors. The included companies are listed in Table 4.[5] It can be seen that all regions of the U.S. are well-represented.

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[4] This publication series, which has been suspended, had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

[5] The sample for the TFP trend work includes some companies that were excluded from the sample for the econometric cost research. These companies were deemed to have satisfactory cost and output quantity data despite some flaws in the data for one or more of the additional business condition variables that appear in the cost model.

Table 4

SAMPLED POWER DISTRIBUTORS FOR TFP TREND RESEARCH

Alabama Power	Mississippi Power
Ameren UE	Mount Carmel Public Utility
Appalachian Power	Nevada Power
Arizona Public Service	Northern Indiana Public Serivce
Atlantic City Electric	Northern States Power
Avista	Ohio Edison
Baltimore Gas & Electric	Ohio Power
Bangor Hydro Electric	Oklahoma Gas and Electric
Black Hills Power	Orange and Rockland Utilities
Boston Edison	Otter Tail Power
Carolina Power & Light	Pacific Gas & Electric
Central Hudson Gas & Light	PacifiCorp
Central Illinois Light	Potomac Edison
Central Maine Power	Potomac Electric Power
Central Power & Light	PSI Energy
Central Vermont Public Service	Public Service of Colorado
Cincinnati Gas & Electric	Public Service of New Hampshire
CLECO	Public Service of Oklahoma
Cleveland Electric Illuminating	Public Service Electric & Gas
Columbus Southern Power	Rochester Gas and Electric
Duke Energy	San Diego Gas & Electric
Edison Sault Electric	South Carolina Electric & Gas
El Paso Electric	Southern California Edison
Empire District Electric	Southern Indiana Gas & Electric
Entergy New Orleans	Southwestern Electric Power
Florida Power & Light	Southwestern Public Service
Florida Power	Tampa Electric
Green Mountain Power	Texas Utilities Electric
Hawaiian Electric	Texas-New Mexico Power
Idaho Power	Toledo Edison
Kansas City Power & Light	Tucson Electric Power
Kansas Gas and Electric	Union Light Heat & Power
Kentucky Power	United Illuminating
Kentucky Utilities	Virginia Electric & Power
Kingsport Power	West Penn Power
Louisville Gas and Electric	Western Massachusetts Electric
Madison Gas and Electric	Wisconsin Electric Power
Maine Public Service	Wisconsin Power and Light
	Wisconsin Public Service

Number of Companies: 77

Other sources of data were also accessed in the research. These were used primarily to measure input prices. As in the gas distribution work, they included Global Insight; Whitman, Requardt & Associates; the Bureau of Economic Analysis, the Bureau of Labor Statistics, and the Energy Information Administration.

4.2 Index Details

4.2.1 Scope

The indexes calculated in this study measured the TFP trends of the sampled utilities as power distributors. The applicable services included the local power delivery and customer account, sales, and customer information services that the utilities provided.[6] The corresponding total cost of these services comprised operation and maintenance ("O&M") expenses and the cost of plant ownership. Cost was defined to include shares of a utility's administrative and general ("A&G") expenses and costs of general plant ownership. The study used a service price approach to capital cost measurement that was substantially the same as that used in the gas distribution work.

4.2.2 Output Quantity Index

The growth rate of the output quantity index was a weighted average of the number of customers served and the retail delivery volume. As in the gas research, the weights assigned to these quantity measures reflected estimates of their relative impacts on cost. The estimates were drawn from an econometric total power distribution cost function that was developed for this project and described further in the Appendix.

4.2.3 Input Quantity Index

The growth rate in each input quantity index was a weighted average of the growth rates in quantity subindexes for distribution plant, general plant, labor, and other O&M inputs. The weights were based on the shares of these input classes in total power distribution cost as we have defined it.

[6] The term "distribution" in the Uniform System of Accounts corresponds most closely to local delivery service as discussed here.

4.2.4 TFP

Given the better regional coverage of the power distribution sample, results for the national industry and the California aggregate were obtained as cost share-weighted averages of the results for the individual utilities and no supplemental regional weighting was undertaken.

4.2.5 Sample Period

The sample period for the power distribution research was 1994-2004. 2004 is the latest for which data are currently available.

4.3 Index Results

Table 5 and Figure 2 report the 1994-2004 average annual growth rates in the power distribution TFP and component output and input quantity indexes. The results indicate that the annual growth trend in the TFP of the national industry was 1.08%. Output quantity growth averaging 1.71% annually outpaced input quantity growth averaging 0.63% annually. The TFP growth of California's power distribution industry was much slower and averaged only 0.24% annually. The TFP index for SDG&E's power distribution operations averaged a 0.66% decline annually.

Table 6 reports results of our effort to adjust for the TFP trend of the sample's mediocre and poor performers using results from our econometric model. We find that the average annual growth rate in the TFP indexes of the companies in our econometric sample was 1.11%, very close to our calculated national industry trend. The companies in the top tier had cost that averaged 20.3% below the predictions of the econometric cost model. The average annual growth rate in the TFP indexes for these companies was 0.88%. The companies in the second tier had performance appraisals that averaged 6.5% below the cost model predictions. The average annual growth rate in the TFP indexes for these companies was 1.43%. The final step was to compute results for the first and second quartiles combined. We found that the average TFP growth of these good and superior performers was 1.15%, a bit above the average TFP growth rate for the sample.

Table 5

PRODUCTIVITY RESULTS: POWER DISTRIBUTION

Year	Output Quantity Index			Input Quantity Index			TFP Index			Private Business Sector US Economy
	Industry	CA Aggregate	SDGE	Industry	CA Aggregate	SDGE	Industry	CA Aggregate	SDGE	
1994	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	93.7
1995	1.020	1.007	1.009	0.996	0.962	1.014	1.024	1.047	0.995	93.5
1996	1.039	1.024	1.032	1.011	0.987	1.045	1.028	1.037	0.988	95.1
1997	1.057	1.047	1.059	1.009	0.983	1.024	1.048	1.066	1.034	96.0
1998	1.080	1.051	1.054	1.035	1.021	1.137	1.044	1.029	0.927	97.5
1999	1.098	1.066	1.075	1.044	0.999	1.072	1.051	1.067	1.003	98.7
2000	1.123	1.093	1.097	1.051	1.041	1.081	1.069	1.050	1.014	100.0
2001	1.133	1.097	1.118	1.053	1.036	1.152	1.075	1.058	0.970	100.2
2002	1.148	1.101	1.136	1.053	1.062	1.180	1.091	1.037	0.963	101.8
2003	1.167	1.129	1.163	1.069	1.117	1.289	1.092	1.011	0.902	104.7
2004	1.187	1.158	1.202	1.065	1.130	1.284	1.115	1.025	0.936	107.7
Average Annual Growth Rate **1994-2004**	**1.71%**	**1.47%**	**1.84%**	**0.63%**	**1.22%**	**2.50%**	**1.08%**	**0.24%**	**-0.66%**	**1.39%**

FIGURE 2: TFP RESULTS FOR POWER DISTRIBUTION

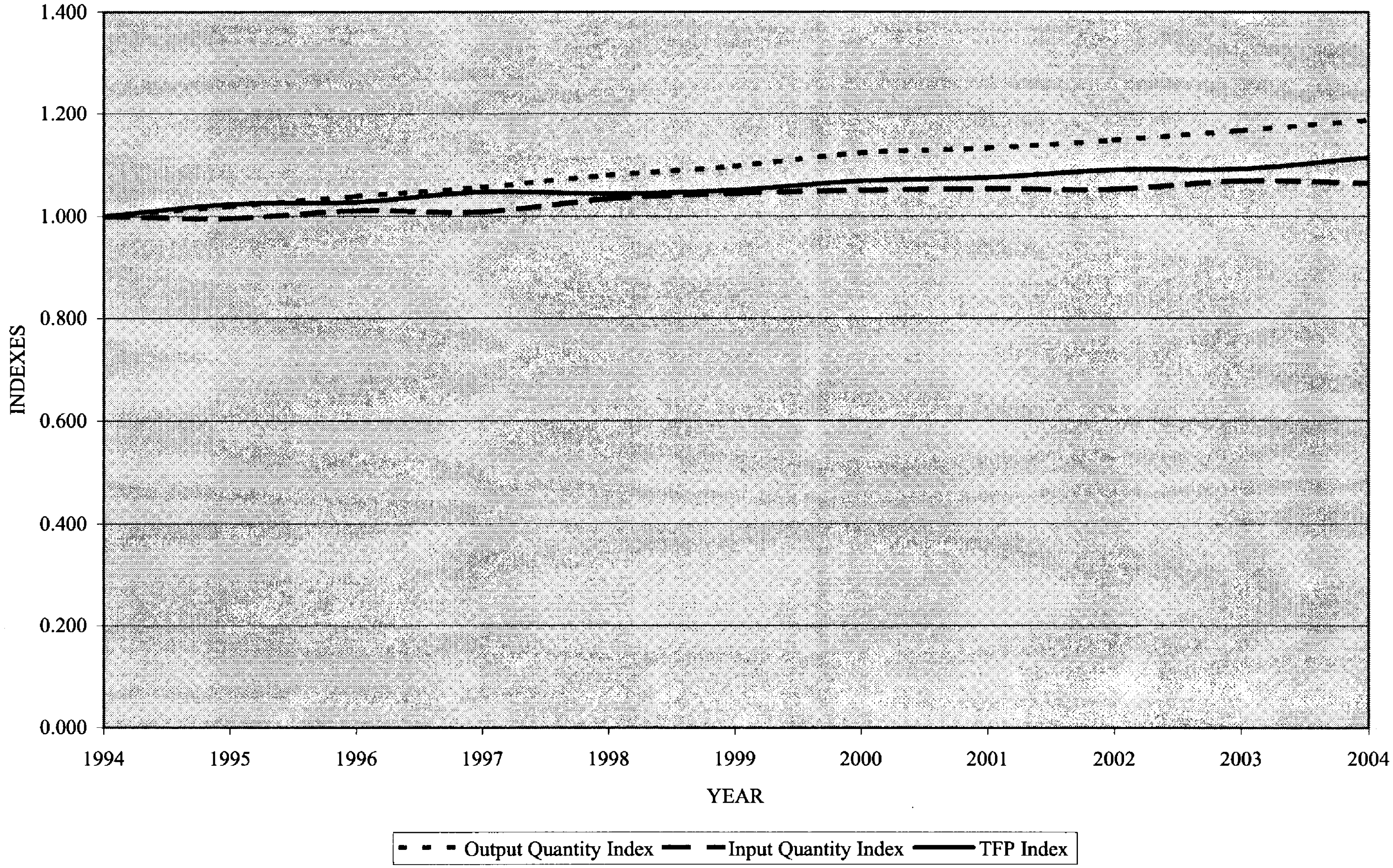

Table 6

TFP GROWTH RATE QUARTILES 1994-2004: U.S. POWER DISTRIBUTION

	Average Annual Growth TFP (%)	Benchmarking Results (Actual-Predicted Cost)
Quartile Range		
1st (highest)	2.71% to -0.72%	-33.90% to -12.60%
2nd	3.30% to 0.07%	-12.40% to 1.50%
3rd	3.00% to -0.66%	2.20% to 11.70%
4th (lowest)	2.65% to -1.59%	12.30% to 35.70%
1st and 2nd	3.30% to -0.72%	-33.90% to 1.50%
1st, 2nd and 3rd	3.30% to -0.72%	-33.90% to 10.10%
Quartile Average		
1st (highest)	0.88%	-20.31%
2nd	1.43%	-6.52%
3rd	1.25%	6.24%
4th (lowest)	0.90%	20.54%
1st and 2nd	**1.15%**	**-13.41%**
1st, 2nd and 3rd	1.18%	-6.86%
Sample Average	**1.11%**	**-0.01%**

APPENDIX

This Appendix contains additional details of our TFP research for San Diego Gas & Electric. Section A.1 addresses the output quantity indexes and Section A.2 the input quantity indexes, including the calculation of capital cost. Section A.3 addresses our method for calculating TFP growth rates and trends. Sections A.4-A.6 discuss the econometric cost research. The qualifications of the authors are discussed in A.7.

A.1 Output Quantity Indexes

The growth rates of the output quantity indexes were defined by formulas. As noted in Section 3.2, these formulas involved subindexes measuring growth in various dimensions of utility workload. Major decisions in the design of such indexes include their form and the choice of output categories and quantity subindexes.

A.1.1 Index Form

The growth rate in the output quantity for each region was determined by the following general formula.

$$\ln\left(\text{Output Quantities}_t \big/ \text{Output Quantities}_{t-1}\right) = \Sigma_i \ (SE_i) \cdot \ln\left(Y_{i,t} \big/ Y_{i,t-1}\right). \qquad \text{[A-1]}$$

Here in each year t,

$Output\ Quantities_t$ = Output quantity index

$Y_{i,t}$ = Aggregate measure of output i for companies in the region.

SE_i = Share of output measure i in the sum of our estimates of the corresponding cost elasticities.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the output quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years.[7]

[7] In the case of power distribution only one region --- the nation --- was considered, as noted above.

The weight for each output quantity measure was its share in the sum of our econometric estimates of the corresponding cost elasticity estimates for the measures. In the gas distribution index, the weights for customers and throughput were 85% and 15%, respectively. In the power distribution index, the weights for customers and the retail delivery volume were 50% and 50%, respectively.

A.1.2 Detailed Results

Detailed output quantity results for gas distribution can be found in Table A-1. It can be seen that the number of customers grew at a 1.58% average annual rate during the sample period. The delivery volume fell by an average of 0.26% annually. The gas distribution industry thus experienced a considerable decline in volume per customer.

Comparable results for power distribution can be found in Table A-2. It can be seen that the number of customers grew at a 1.55% average annual rate, very similar to the finding for gas. However, the retail power delivery volume was quite different from its gas counterpart, growing by an average of 1.87% annually. The power distribution industry thus experienced a small increase in volume per customer.

A.2 Input Quantity Indexes

The growth rates of the input quantity indexes were defined by formulas. As noted in Section 3.2, these formulas involved subindexes measuring growth in the amounts of various inputs used. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

A.2.1 Index Form

The input quantity index for each company included in the TFP research was of Törnqvist form.[8] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\mathit{Input\ Quantities}_t \middle/ \mathit{Input\ Quantities}_{t-1} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(X_{j,t} \middle/ X_{j,t-1} \right). \quad \text{[A-2]}$$

Here in each year t,

[8] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

Table A-1

OUTPUT QUANTITY INDEXES: GAS DISTRIBTUION

Year	**Output Quantity Index**	**Customer Numbers Subindex**	**Volumes Delivered Subindex**
1994	1.000	1.000	1.000
1995	1.019	1.020	1.015
1996	1.043	1.039	1.065
1997	1.061	1.059	1.072
1998	1.068	1.076	1.019
1999	1.084	1.095	1.022
2000	1.108	1.114	1.075
2001	1.119	1.136	1.031
2002	1.131	1.145	1.057
2003	1.132	1.155	1.013
2004	1.136	1.168	0.974
Average Annual Growth Rate **1994-2004**	**1.28%**	**1.55%**	**-0.26%**

Table A-2

OUTPUT QUANTITY INDEXES: POWER DISTRIBTUION

Year	Output Quantity Index	Customer Numbers Subindex	Volumes Delivered Subindex
1994	1.000	1.000	1.000
1995	1.020	1.015	1.025
1996	1.039	1.028	1.050
1997	1.057	1.046	1.068
1998	1.080	1.062	1.098
1999	1.098	1.080	1.116
2000	1.123	1.098	1.149
2001	1.133	1.117	1.149
2002	1.148	1.133	1.164
2003	1.167	1.151	1.183
2004	1.187	1.168	1.206
Average Annual Growth Rate **1994-2004**	**1.71%**	**1.55%**	**1.87%**

Input Quantities$_t$	= Input quantity index
$X_{j,t}$	= Quantity subindex for input category *j*
$S_{j,t}$	= Share of input category *j* in applicable total cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of the distributor during these years are the weights. The input quantity trend for each region considered was a cost share-weighted average of the growth rates of the companies in that region.

A.2.2 Input Quantity Subindexes

Each quantity subindex for labor was calculated as the ratio of salary and wage expenses to a labor price index. The labor price variables used in this study were constructed by PEG using data from multiple sources. Occupational Employment Survey ("OES") data for 2004 were used to construct average wage rates that correspond to each distributor's service territory. The wage levels were calculated as a weighted average of the OES pay level for each job category using weights that correspond to the national industry. Values for other years were calculated by adjusting the 2004 level for changes in employment cost trends. For this purpose, we used the Employment Cost Index ("ECI") computed by the BLS for the electric, gas, and sanitary sector of the economy. Regional labor price trends were obtained by adjusting the national trend using the ECIs that the BLS uses to track general price inflation in different regions of the country.

Each quantity subindex for other O&M inputs was calculated as the ratio of the expenses for other O&M inputs to a non-labor O&M price index. The growth rate in this price index is a weighted average of the growth rates in Global Insight indexes of trends in the prices of non-labor O&M inputs used by energy utilities. The weights reflect the cost shares of SDG&E in 2003. The quantity subindexes for capital are discussed in Section A.2 below.

The general approach to quantity trend measurement used in this study relies on the theoretical result that the growth rate in the cost of any class of inputs *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. In that event,

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j. \qquad [A\text{-}3]$$

A.2.3 Detailed Results

Detailed input quantity results for gas distribution can be found in Table A-3. It can be seen that the quantity of capital had a 1.39% average annual growth rate. The quantity of labor services fell by 3.77% annually, while the quantity of other O&M inputs grew by 2.65% annually.

Detailed input quantity results for power distribution can be found in Table A-4. It can be seen that the quantity of distribution plant had a 1.21% annual growth rate, whereas the quantity of general plant declined by 1.44% annually. The quantity of labor services fell by 2.17% annually, whereas the quantity of other O&M inputs rose by 1.47% annually on average.

Results for both industries reflect some substitution of capital and outsourced services for utility labor. They may also reflect the movement of some labor services to affiliates of reporting utilities. This increases reported non-labor expenses relative to labor expenses.

A.2.4 Capital Cost

A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[9] It facilitates the use of benchmarking of cost data for utilities with different plant vintages.

In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,t-1}$).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [A\text{-}4]$$

[9] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

Table A-3

INPUT QUANTITY INDEXES: GAS DISTRIBUTION

Year	Input Quantity Index	Labor Subindex	Non-Labor O&M Subindex	Capital Subindex
1994	1.000	1.000	1.000	1.000
1995	1.002	0.925	1.054	1.021
1996	1.014	0.912	1.083	1.038
1997	1.008	0.881	1.031	1.053
1998	1.006	0.815	1.051	1.067
1999	1.017	0.782	1.102	1.078
2000	1.028	0.735	1.215	1.093
2001	1.027	0.671	1.265	1.106
2002	1.034	0.723	1.181	1.120
2003	1.045	0.727	1.192	1.135
2004	1.059	0.686	1.304	1.150
Average Annual Growth Rate **1994-2004**	**0.57%**	**-3.77%**	**2.65%**	**1.39%**

Table A-4

INPUT QUANTITY INDEXES: POWER DISTRIBUTION

Year	Input Quantity Index	Labor Subindex	Non-Labor O&M Subindex	Capital Subindex - Distribution	Capital Subindex - General
1994	1.000	1.000	1.000	1.000	1.000
1995	0.996	0.968	0.968	1.012	1.017
1996	1.011	0.958	1.021	1.024	1.014
1997	1.009	0.903	1.041	1.032	0.979
1998	1.035	0.904	1.133	1.047	0.984
1999	1.044	0.905	1.150	1.058	0.982
2000	1.051	0.881	1.162	1.073	0.952
2001	1.053	0.844	1.163	1.087	0.968
2002	1.053	0.811	1.167	1.098	0.925
2003	1.069	0.827	1.200	1.111	0.908
2004	1.065	0.805	1.158	1.129	0.866
Average Annual Growth Rate **1994-2004**	**0.63%**	**-2.17%**	**1.47%**	**1.21%**	**-1.44%**

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market.

In our gas distribution research there is only one category of plant. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering. In constructing capital quantity indexes for gas we took 1983 as the benchmark or starting year. Our calculations of the capital cost and quantity in that year are based on the net value of plant as reported in the USRs. The capital quantity index in the base year is the current (replacement) net plant value in that year. We calculated this by dividing the net plant (book) value by an average of the values of a construction cost index for a period ending in the benchmark year. The construction cost index (WKA_t) was the regional Handy-Whitman index of gas utility construction costs for the relevant region.[10]

In our power distribution research there are two plant categories: power distribution plant and general plant. The power distribution plant data from FERC Form 1 include the value of plant for local delivery and metering. In constructing capital quantity indexes, we took 1964 as the benchmark year. Our calculations of the capital cost and quantity in that year are based on the net value of plant as reported in the FERC Form 1. We calculated the value of the capital quantity index in the benchmark year using the same general method as for gas distribution and the relevant regional Handy Whitman indexes of trends in electric utility construction costs.

For both industries, the following general formula was used to compute subsequent values of the capital quantity index:

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad \text{[A-5]}$$

Here, the parameter d is the economic depreciation rate and $VI_{j,t}$ is the value of gross additions to utility plant. The economic depreciation rate was calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category was derived from

[10] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

data reported by the BEA. A special adjustment was made to the capital quantity index for general plant to reflect reported transfers and adjustments.

The general formula for the capital service price indexes used in the study is:

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A-6]$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility. In this formula, r_t is the opportunity cost of plant ownership per dollar of plant value. As a proxy for this, we calculated the user cost of capital for the U.S. economy using data in the National Income and Product Accounts (NIPA). This variable reflects returns on equity as well as bond yields. The NIPA accounts are published by the BEA in its *Survey of Current Business* series.

A.3 TFP Growth Rates and Trends

The annual growth rate in each regional TFP index is given by the formula

$$\ln\left(\frac{TFP_t}{TFP_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A-7]$$

The long run trend in each TFP index was calculated as its average annual growth rate over the sample period.

A.4 Econometric Cost Research

In this study, econometric cost models were used to provide weights for the output quantity indexes and to adjust TFP trend estimates for the impact of average and poor performers. We discuss in this Appendix section our general approach to econometric cost model development. In the following two sections we present some details of our work for gas and electric power distribution.

A.4.1 Cost Models

A cost model is a set of one or more equations that represent the relationship between cost and external business conditions. Business conditions are defined as aspects of a company's operating environment that affect its activities but cannot be controlled. Models can in principle be developed to explain total cost or important cost subsets such as O&M expenses. In this study, total cost models were developed to support the TFP research.

Economic theory can be used to guide cost model development. According to theory, the minimum total cost of a firm is a function of the amount of work that it performs and the prices it pays for capital, labor, and other production inputs. The amount of work it performs can be multidimensional and may require several variables for effective measurement. Theory also provides guidance regarding the nature of the relationship between these business conditions and cost. For example, it predicts that a firm's cost will typically be higher the higher are input prices and the greater is the amount of work performed.

A.4.2 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

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t} \qquad \text{[A-12]}$$

Here, for each firm h in year t, cost is a function of the number of customers served ($N_{h,t}$), the prevailing wage rate ($W_{h,t}$), and an error term ($e_{h,t}$). Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t}\,. \qquad \text{[A-13]}$$

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes 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* across every value that the cost and business condition variables might assume.

A more sophisticated translog functional form was employed in our econometric research for Sempra.[11] This very flexible function is common in econometric cost research, and by some accounts the most reliable of several available flexible forms.[12] Here is an analogous cost function of translog form.

$$\begin{aligned}\ln C_{h,t} &= a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + 1/2 \cdot a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ &\quad + 1/2 \cdot a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} + e_{h,t}\end{aligned} \qquad \text{[A-14]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. 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 differ at different values of the variable. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable.

The general form of the total cost function used in our study is captured by the following formula:

$$\begin{aligned}\ln C &= \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \alpha_j \ln W_j + \sum_\ell \alpha_\ell \ln Z_\ell + \alpha_t T \\ &+ \frac{1}{2}\left[\sum_i \sum_m \gamma_{im} \ln Y_i \ln Y_m + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\ &+ \sum_i \sum_j \gamma_{ij} \ln Y_i \ln W_j + \varepsilon.\end{aligned} \qquad \text{[A-15]}$$

Here, Y_i denotes one of several variables that quantify output and W_j denotes one of several input prices. The *Z*'s denote the additional business conditions, *T* is a trend variable, and ε denotes the error term. Note that in order to preserve degrees of freedom and thereby to permit the recognition of additional business conditions we did not translog the Z variables. This practice is common in econometric cost research.

Cost theory requires a well-behaved cost function to be linearly homogeneous in input prices. This implies the following three sets of restrictions:

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[11] 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.

[12] See Guilkey (1983), et. al.

$$\sum_{j=1}^{J} \frac{\partial \ln C}{\partial \ln W_j} = 1 \qquad [A\text{-}16]$$

$$\sum_{i}^{M} \frac{\partial^2 \ln C}{\partial \ln Y_i \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots,J \qquad [A\text{-}17]$$

$$\sum_{n=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_j \partial \ln W_n} = 0 \qquad \forall j = 1,\ldots,J \qquad [A\text{-}18]$$

These conditions were imposed prior to model estimation.

Estimation of the parameters of an equation like [A-15] is now possible but this approach does not utilize all of the information available in helping to explain the factors that determine cost. Better parameter estimates can be obtained by augmenting the cost equation with some of the cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j,* can be written as:

$$SC_j = \alpha_j + \sum_i \gamma_{ij} \ln Y_i + \sum_n \gamma_{jn} \ln W_n. \qquad [A\text{-}19]$$

The parameters in this equation also appear in the cost model. Thus, information about cost shares can be used to sharpen estimates of cost model parameters.

A.4.3 Estimating Model Parameters

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data on the dependent and explanatory variables.[13] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. The sample used in model estimation can be a time series (consisting of data over several years for a single firm), a cross section (consisting of one observation for each of several firms), or a panel data set that pools time series data for several companies. In this study we have employed panel data in an effort to enhance model precision.

Numerous statistical methods have been established for estimating parameters of economic models. The desirability of each method depends on the assumptions that are made about the probability distribution of the error term. The assumptions under which the best known estimation procedure, ordinary least squares, is ideal often do not hold in statistical cost research.

[13] The estimation of model parameters in this type of model is sometimes called regression.

In this study, we employed a variant of an estimation procedure first proposed by Zellner (1962)[14]. If there exists a contemporaneous correlation between the error terms in a system of regression equations, more efficient estimates of their parameters can be obtained using a Feasible Generalized Least Squares (FGLS) approach. To achieve an even better estimator, we corrected as well for heteroscedasticity in the error terms. Since we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators (MLE).[15] Our estimates thus possess all the highly desirable properties of MLEs.

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[16] The choice of which equation to drop does not affect the benchmarking results.

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. 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. Once such variables have been removed, the model is re-estimated. An econometric model in which business condition variables are selected in this manner is not a "black box" that confounds earnest attempts at appraisal.

A.4.4 Cost Model Predictions

A cost model fitted with econometric parameter estimates obtained in the fashion just described may be called an econometric cost model. We can use such a model to predict each company's cost, for each year of the sample period, given values of the variables that measure the business conditions that the company faced. The difference

[14] See Zellner, A. (1962)

[15] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[16] This equation can be estimated indirectly if desired from the estimates of the parameters remaining in the model.

between the actual and predicted cost for a company is a measure of its cost management efficiency. We used such comparisons in the computation of the frontier TFP trend.

A.5 Gas Distribution Cost Model

A.5.1 Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. There are two output quantity variables in our model: the number of retail customers and total throughput. We expect cost to be higher the higher are the values of each of these workload measures.

A.5.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, we have specified input price variables for capital, labor, and other O&M inputs. We expect cost to be higher the higher are the values of all of these variables.

A.5.3 Other Explanatory Variables

Four additional business condition variables are included in the cost model. One is the percentage of distribution main not made of cast iron. This is calculated from American Gas Association data. Cast iron steel pipes were common in gas system construction in the early days of the industry. They are more heavily used in the older distribution systems found in the northeast. Greater use of cast iron typically involves a combination of higher maintenance and higher capital replacement costs. A higher value for this variable means that a company owns fewer cast iron mains. Hence, we would expect the sign for this variable's parameter to be negative.

A second additional business condition variable in this model is the number of power distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into power distribution. Such diversification will typically lower cost due to the realization of scope economies. The extent of diversification is greater the greater is the value of the variable. We would therefore expect the value of this variable's parameter to be negative.

A third additional business condition is a binary variable that equals one if a company serves a densely settled urban core. Gas service is generally more costly in urban cores due in part the greater cost of installing mains and services and to the greater difficulty of performing O&M tasks. Accordingly, we expect the parameter of this variable to have a positive sign.

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

A.5.4 Estimation Results

Estimation results for the gas distribution cost model are reported in Table A-5. The parameter values for the additional business conditions and for the first order terms of the translogged variables are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. 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* ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The critical value was 1.645. The *t* ratios were used in model specification. The output quantities and input prices (which were translogged in model specification) were required to have first order terms with statistically significant parameters. The other variables (which were not translogged) were also required to have statistically significant parameters.

Examining the results in Table A-5, it can be seen that all of the key cost function parameter estimates were statistically significant. Moreover, all were plausible as to sign and magnitude. With regard to the first order terms of the translogged variables, cost was

Table A-5

ECONOMETRIC COST MODEL FOR GAS DISTRIBUTION

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number Customers
V = Total Throughput
NIM = % Non-Iron Dx Miles
NE = Number of Electric Customers
UD = Urban Core Dummy

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC
WL	0.197	73.77	NIM	-0.519	-14.32
LL	-0.132	-5.03			
LK	-0.011	-0.53	NE	-0.010	-10.30
LN	-0.007	-1.05			
LV	0.000	-0.03	UD	0.115	7.87
WK	0.592	193.68	Trend	-0.008	-4.13
KK	0.133	6.17			
KN	0.002	0.26	Constant	12.339	552.94
KV	-0.003	-0.41			
N	0.736	21.54	System Rbar-Squared	0.977	
NN	-0.020	-0.25			
NV	0.028	0.35	Number of Obsevations	444	
V	0.131	3.92			
VV	-0.041	-0.48			

found to be higher the higher were the input prices and the two output quantities. At the sample mean, a 1% rise in the number of customers raised cost by 0.74%. A 1% rise in throughput raised cost by about 0.13%. The number of customers served was thus the dominant output-related cost driver.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was about 0.59%. This was almost three times the estimated elasticity of the price of labor. This comparison reflects the capital intensiveness of the gas distribution business.

The estimates of the parameters of the other business conditions were also sensible.

- Cost was lower the greater was the percentage of distribution mains not made with cast iron and bare steel.
- Cost was lower the greater were the number of electric customers served.
- Cost was higher for distributors that served a core urban area
- Cost shifted downward over time by 0.8% annually for reasons not otherwise explained in the model

The table also reports the system 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 0.977, suggesting that the explanatory power of the model was high.

A.6 Power Distribution Cost Model

A.6.1 Business Condition Variables

Output Quantities and Input Prices

There are two output quantity variables in our cost model for power distribution: the number of retail customers and the retail power delivery volume. We have specified input price variables for capital, labor, and other O&M inputs.[17] We expect cost to be higher the higher are the values of all these variables. The parameter estimates corresponding to these variables should all be positive.

[17] As in the gas model, the price of other O&M inputs does not appear explicitly in this model.

Other Business Conditions

Ten other business condition variables are included in the power distribution cost model. One is the miles of distribution line. This is the best available proxy of the distances over which local deliveries are made.[18] This size-related variable is an especially important driver of power distribution cost and has therefore been translogged.[19] The source of our line mile data is a directory that is currently entitled *Directory of Electric Power Producers and Distributors*. This was for many years an annual publication of the Utility Data Institute (d/b/a Platts). We expect cost to be higher the greater are the line miles of a distributor so that the parameter for this variable should be positive.

A second business condition variable added to the model is the percentage of the total reported value of distribution plant that involves assets that are not underground. This variable is calculated from FERC Form 1 data. We use it to measure the extent of system undergrounding. Undergrounded plant provides a higher quality service than overhead plant but involves markedly higher capital costs that tend to be only partially offset by lower operating costs. The extent of undergrounding varies greatly across America's distribution systems. Generally speaking, undergrounding is greater in urban areas and where state and local governments encourage it.

A third business condition variable added to the model is the number of customers that the utility provides with natural gas distribution services. This variable was calculated chiefly from FERC Form 2 data. It is intended to capture the extent to which the company has diversified into gas distribution. Such diversification will typically lower the cost of power distribution due to the realization of scope economies.

A fourth business condition variable added to the model is a measure of system age. The measure of age that we use for this purpose is the estimated percentage of customers served in a given year that have been added in the last twenty years. This variable is calculated from FERC Form 1 data. We expect a younger system to involve lower O&M expenses and higher capital cost. The net effect of system age on *total* cost cannot be predicted and may vary by industry.

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[18] Due in part to missing values, some of the line mile observations in the sample required some estimation and/or interpolation.

[19] Treatment of line miles as an output variable in the TFP research would unfortunately result in the loss of numerous companies due to a shortage of quality data.

A fifth business condition variable added to the model is a measure of service territory forestation. This variable was calculated using U.S. Forest Service data. We expect the cost of power distribution to be higher the greater is forestation. We would therefore expect this variable to have a positive parameter estimate.

A sixth business condition that has been added to the model is the percentage of power deliveries that are made to residential and commercial customers. These customers typically have more peaked loads and rely on the distributor for more services than do the larger volume customers. We therefore expect the relationship between cost and this variable to be positive. The variable was calculated using FERC Form 1 and Form EIA 861 data.

A seventh business condition variable that has been added to the model is a binary ("dummy") variable that indicates whether the service territory of a given utility is highly non-contiguous. A value of one indicates that the service territory of a utility is non-contiguous while a value of zero indicates a contiguous service territory. We expect that it is more costly to serve a non-contiguous service territory and thus expect a positive parameter estimate.

Generation and transmission O&M expense is the eighth additional business condition variable. This variable captures the extent of vertical integration of a given utility, which tends to reduce cost as a result of scope economies. We expect the variable to have a negative parameter estimate.

A binary variable for retail competition is the ninth business condition variable. This variable has a value of 1 for utilities that have retail access customers. We expect the parameter of this variable to have a positive sign that reflects the higher cost of customer services.

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. It captures the net effect on cost of diverse developments that include technological change. Accordingly, we expect the parameter of this variable to have a negative sign.

A.6.2 Model Estimation Results

Estimation results for the power distribution cost model are reported in Table A-6.

Table A-6

ECONOMETRIC COST MODEL FOR POWER DISTRIBUTION

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number Customers
V = Total Throughput
M = Distribution Line Miles
OH = % Plant Overhead
NG = Number of Gas Customers
Nadd20 = Twenty Year Customer Growth
TF = % Territory Forested
VRC = % Deliveries Residential and Commerical
NC = Non-Contiguous Service Territory
TXGX = O&M Expenses for Transmission and Generation
CD= Competiton Dummy

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC
WL	0.167	117.55	OH	-0.711	-13.46
LL	-0.074	-4.78	OHM	-0.337	-5.54
LK	0.006	0.53			
LN	0.019	3.66	NG	-0.007	-9.04
LV	-0.039	-9.04			
LM	0.002	0.60	Nadd20	-0.039	-2.81
WK	0.549	266.27	TF	0.064	12.25
KK	0.059	3.30	TFM	0.064	12.96
KN	-0.058	-8.68			
KV	0.092	15.11	VRC	0.281	8.31
KM	-0.017	-3.37			
			NC	0.012	5.76
N	0.410	15.77			
NN	0.730	7.05	TXGX	-0.020	-2.93
NV	-0.595	-6.24			
NM	-0.142	-2.43	CD	0.005	2.50
V	0.406	19.05	Trend	-0.017	-16.56
VV	1.009	11.22			
VM	-0.368	-7.83	Constant	19.290	1217.52
M	0.199	12.11			
MM	0.461	7.54	System Rbar-Squared	0.985	
			Number of Obsevations	979	

It can be seen that the cost function parameter estimates were generally plausible in sign and magnitude. With regard to the first order terms of the translogged variables, cost was found to be higher the higher were input prices, output quantities, and the miles of distribution line. At the sample mean, a 1% increase in the number of customers was estimated to raise cost by 0.41%. A 1% hike in the delivery volume was estimated to raise cost by 0.41% as well.

Turning to the results for the input prices, it can be seen that a 1% increase in the price of capital was estimated to raise cost by 0.55%. This is more than three times the cost elasticity of the price of labor. These estimates reflect the capital intensiveness of the power distribution business.[20]

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

- Total distribution cost was greater the greater were line miles.
- Cost was lower the greater was the extent of system overheading.
- Cost was lower the greater was the number of gas distribution customers served.
- Cost was higher the higher was the extent of service territory forestation.
- Cost was lower the younger was system age.
- Cost was higher the higher was the percentage of total retail deliveries made to residential and smaller-volume business customers.
- Cost was higher for utilities with non-contiguous service areas.
- Cost was lower the greater was the diversification into generation and transmission.
- Cost was higher for utilities that operated under retail competition.

The estimate of the trend variable parameters suggests that cost fell by 1.7% annually for reasons other than the trends in the other business condition variables. This exceeds the TFP trend due in part to the fact that some of the larger utilities in the sample encountered diseconomies of scale during the sample period.

The system R^2 statistic for the model was 0.985.

[20] Recall also that expenses for pensions and other benefits were excluded from cost in the benchmark work.

• A.7 PEG Qualifications

A.7.1 Pacific Economics Group

Pacific Economics Group (PEG) is an economic consulting firm with practices in the fields of utility regulation and civil litigation. Our home office is in Pasadena, CA. The chief satellite office is based in Madison, Wisconsin. Five principals of the company are PhD economists and three are current or former faculty members at respected universities. Founding partner Charles Cicchetti holds the Jeffrey Miller Chair of Government and the Economy at the University of Southern California. He was previously chair of Wisconsin's Public Service Commission and an economics professor at the University of Wisconsin. Founding partner Jeff Dubin is an economics professor at Cal Tech.

PEG is a leading provider of energy utility performance measurement and PBR services. Our personnel have over 30 man years of experience in these areas. This work has required a thorough understanding of the energy industry and the science of performance measurement.

A.7.2 Mark Newton Lowry

Senior author Mark Newton Lowry is the managing partner in PEG's Madison office and directs our North American practice in the areas of performance based ratemaking ("PBR") and utility performance measurement. His specific duties include the supervision of performance research, the design of PBR plans, and expert witness testimony. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin-Madison.

Over the years he has prepared numerous utility performance studies and developed many PBR plans. He has testified or filed commentary 14 times on statistical benchmarking, and more than 20 times on industry productivity trends and other PBR issues. The venues for this testimony have included California, Hawaii, Kentucky, Maine, Massachusetts, Oklahoma, New York, Quebec and British Columbia. His practice has extended beyond our shores to include projects in Asia, Australia, Europe, and Latin America. Dr. Lowry is multilingual and can advise clients in French and Spanish as well as English.

Before joining PEG, Dr. Lowry worked for several years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of the company's Regulatory Strategy practice. In total, he has over 16 years of consulting experience in the areas of performance measurement and PBR.

His career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and advanced empirical methods in market analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances.

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