17255
f:/home/common/PacifiCorp.
Anderson Testimony doc)

RECEIVED

JUN 18 4 39 PM '99

SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock	)))))	Docket No. 98-2035-04

DIRECT TESTIMONY AND EXHIBITS OF DR. RICHARD M. ANDERSON

ON BEHALF OF LARGE CUSTOMER GROUP

JUNE 18, 1999

TABLE OF CONTENTS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Richard M. Anderson, 39 W. Market Street, Suite 200, Salt Lake City, Utah 84101.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Energy Strategies, Inc. as a Senior Associate.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a Bachelor of Business Administration degree from the University of Texas-Austin and a Ph.D. in Economics from the University of Utah.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. I have approximately 16 years of work experience relating to the energy industry, with particular emphasis on electricity. Prior to my current employment I spent nine years as Director of the State of Utah's Energy Division. In my current position I am directly involved in issues relating to electric market restructuring, competitive procurement, market and strategic options analysis, and regulatory policy on behalf on a variety of clients in various western and southwestern states. I have participated in various proceedings before the Utah, Wyoming and Idaho Commissions and I currently represent a number of industrial entities in all three of those states in connection with the proposed PacifiCorp/ScottishPower merger.

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I am filing testimony on behalf of the Large Customer Group ("LCG").

I. INTRODUCTION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The primary purpose of my testimony is to discuss the benefits and associated risks to PacifiCorp customers of the proposed acquisition of PacifiCorp by ScottishPower. The extent to which the benefits and risks associated with this acquisition can be valued and the likelihood that they will occur are of critical importance in determining whether the proposed merger is in the "public interest". I will address whether the Applicants (ScottishPower and PacifiCorp) have demonstrated that the proposed merger is in the "public interest" and the extent to which that showing is supported by a reasonable assessment of benefits and costs.

Q. PLEASE DESCRIBE THE STANDARD BY WHICH YOU UNDERSTAND THE UTAH COMMISSION WILL REVIEW THIS APPLICATION.

A. Under Utah Code Ann. §§ 54-4-28 – 31, a utility must obtain Commission approval to sell its stock or utility assets or merge, combine or consolidate with another utility. The merger or acquisition contemplated by the Applicants can only be approved if the Applicants have made an adequate showing that the proposed transaction is consistent with the "public interest." In connection with the PacifiCorp/Utah Power merger, this Commission explained that "the necessary predicate for a determination that the proposed merger is 'in the public interest' is some net positive benefit to the public in this State." The Commission further explained that this determination should be made after giving consideration to "all" positive benefits and negative impacts of the merger, after "giving each its proper weight" so as to "determine whether on balance the merger is beneficial or detrimental to the public." (Order Re Standard of Approval for Merger, Case No. 87-035-27, issued November 20, 1987, at 2). As I interpret this "public interest" standard, the merger should be approved only upon a substantial showing that the quantifiable benefits of the merger clearly outweigh the potential detriments, costs and risks of the merger.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. Based on my review and analysis of the Applicants' filing, their responses to various data requests, and other public information available, it is my opinion that the Applicants have not demonstrated that the merger, as currently proposed, is in the public interest. The Applicants' filing does not guarantee that PacifiCorp customers will receive any significant benefits from the merger or the proposed actions of ScottishPower. The transaction as proposed could produce adverse impacts on Utah customers through increased economic risks. Moreover, post-merger pressures to recover costs and produce profits may put Utah consumers at risk of degradations in reliability.

The merger, as proposed by the Applicants, is essentially "conditioned" on customers underwriting in excess of $121 million in transition program investments. At this point, no determination has been made as to the need or cost effectiveness of such investments. Moreover, the customers' "willingness to pay" for such investments has not been shown. While the Applicants' contend that the transition program investments will be funded out of current budget projections and cost savings and will not result in upward pressure on rates, that contention is based upon unproven and non-guaranteed beliefs or expectations of the Applicants that they will improve operational efficiencies at PacifiCorp to a level sufficient to offset the investment expense. The argument is predicated on ScottishPower's claimed experiences in the United Kingdom (UK). The extent to which the results of the UK experiences are accurately stated or transferable to PacifiCorp remains highly uncertain.

As proposed, I believe that the merger has a skewed benefit/cost impact on customers. The costs are substantial, and have not been demonstrated as cost effective or necessary. The benefits, for the most part, remain unquantified and unguaranteed. As a result, unjustified economic risks may be placed on customers, creating a real potential for adverse impacts on the public interest. The merger proposal as currently presented should thus be denied. Before the proposal could be considered to be in the public interest, it would need to be changed or conditioned significantly in order to shift the risks of the merger from customers to shareholders.

Q. CAN YOU ELABORATE ON WHY YOU REACHED THIS CONCLUSION?

A. A number of issues that are critical to ensure that the Applicants' "promises" will be fulfilled have not been adequately addressed.

First, ScottishPower's contention that its experiences in the UK are fully transferable to PacifiCorp and will produce significant cost savings is questionable. The efficiencies that ScottishPower claims to have implemented at Manweb appear to be substantially overstated in that they include the results of reforms initiated by Manweb prior to the acquisition. In any event, it appears highly unlikely that PacifiCorp suffers from the same degree of inefficiency as either Manweb or Southern Water before they were acquired by ScottishPower. The potential for cost reductions at PacifiCorp may thus be of a much smaller magnitude. The burden of demonstrating that the Applicants can produce the savings necessary to support a favorable public interest finding by the Commission using the Manweb and Southern Water acquisitions as "models" has not been met.

Second, the risk of cost exposure to PacifiCorp's customers resulting from the proposed acquisition is substantial and is larger than any quantifiable potential benefits. Approximately ninety percent of the $135 million investment the Applicants are proposing to undertake in implementing their transition programs are "above the line" costs, that is, costs that the Applicants will propose to pass on to customers. These non-requested programs may cost customers $121.6 million for implementation and operation, with ScottishPower stockholders expected to contribute only $13.6 million. Under this proposal, ScottishPower stockholders would be exposed to only ten percent of the total cost of program implementation. This asymmetry of the economic risks, coupled with the unsubstantiated flow of benefits, could leave PacifiCorp's customers with a potentially significant economic burden.

Third, although the Applicants promise reliability improvements, the merger will also create tremendous cost-cutting pressures in order for ScottishPower to earn its desired return of and on the substantial investments associated with the merger. These significant cost-cutting pressures could result in reduced quality of service and reliability over time, despite ScottishPower's intentions and pledges to the contrary. The standards and guarantees offered by Applicants, while perhaps a reasonable starting point, do not adequately address the risks. Moreover, the promised guarantee payments and other proposed consequences of failures to achieve the reliability commitments are insignificant when compared to the economic risks that could be borne by PacifiCorp customers, particularly the larger customers, if reliability ultimately suffers. Once again, the risks that customers are asked to bear are not commensurate with any guaranteed level of benefits.

Fourth, the proposed transaction also injects risks stemming from international operations and multi-utility practices, to the potential economic detriment of PacifiCorp core retail electric customers. PacifiCorp's recent history has been characterized by a long and continuing string of unwise acquisitions and attempted acquisitions. Among other things, the lack of focus on the "core business" resulted in severe financial losses to the company. The result was a management overhaul in 1998 and a new corporate "refocus". That refocus on the core domestic retail electric business should be continued, rather than subjecting PacifiCorp and its customers to yet another round of aggressive international and multi-utility expansion.

Fifth, the proposal may impede potential customer benefits that might result from real diversification efficiencies available from a merger with another utility. In many other mergers and proposed mergers, service territories are being consolidated in order to produce real production, transmission, distribution and customer service synergies in addition to stand-alone benchmarking efficiencies being proposed by ScottishPower. ScottishPower's acquisition will not add significant value to the PacifiCorp business and may rather add complexities to the pledge to re-focus on its "core" business.

Q. IN YOUR OPINION HAS THERE BEEN AN AFFIRMATIVE CASE MADE BY THE APPLICANTS WHICH DEMONSTRATES THAT THIS MERGER APPLICATION MEETS THE PUBLIC INTEREST?

A. No. The Applicants have failed to make an affirmative showing that the merger satisfies the public interest standard. The PacifiCorp customers are exposed to significant rate and reliability risks, and the promised benefits are highly uncertain. The customers are being asked to underwrite major economic investments without any concomitant assurances of economic or other benefits.

II. APPLICANTS' "PROMISES"

Q. WHAT ARE THE APPLICANTS' STATED GOALS IN CONNECTION WITH THE PROPOSED MERGER?

A. The Applicants have announced numerous goals, such as providing "world class service", "world class performance" service that reflects the "best practices in the world", making PacifiCorp "best in its class" and bringing it into the "top 10" best performing electric utilities in the United States. Unfortunately, these stated goals are very general and have little meaning when examined closely. For example, in Witness O'Brien's direct testimony, page 6, lines 2 through 4, he states that "ScottishPower is fully committed to our goal for providing world class service". Yet, when Mr. O'Brien was asked to define the term and to provide the details of how PacifiCorp has or has not met "world class standards", his response was noncommittal. (Applicants' Response to WIEC, 1.4 a, b and c).

Q. WAS ANY EVIDENCE PRESENTED BY APPLICANTS AS TO WHAT CONSTITUTES "WORLD'S BEST PRACTICES"?

A. No. Witness O'Brien, in his direct testimony at page 5, lines 11 through 14 discusses the quest of the company to engage in "world's best practices" by stating:

> "Despite our decision to focus on our core electricity business, we remained convinced that our customers would be best served by a large, stable enterprise able to offer the most competitive prices while providing customer service and reliability that reflect the world's best practices".

However, when asked to define "world's best practices" in a discovery request, Mr. O'Brien was unable to respond in any meaningful way:

> "...the term 'world's best practices' is used in Mr. O'Brien's testimony in a general sense. As the term is used in only a general sense, PacifiCorp has no documents that specifically define or address the topic of the 'world's best practices'...PacifiCorp has no specific documents evaluating its performance as measured by 'world's best practices'...since the term is used in only a general sense in Mr. O'Brien's testimony and by itself does not provide a reasonable basis to evaluate utility performance." (WIEC discovery request 1.5, (numbers a, b and c)).

Q. WHAT IS YOUR CONCLUSION?

A. The Applicants have failed to present an affirmative case as to what goals they expect to achieve and the method by which they expect to achieve them. Indeed, it seems to be a moving target. While the overall objective of achieving "world class practices" at PacifiCorp is clearly meritorious, no means for defining or measuring such practices are provided. Thus, instead of providing a detailed map as to how new standards and objectives are to be obtained, we are given only general promises.

III. BENEFITS OF THE MERGER

A. CLAIMED BENEFITS

Q. DO THE APPLICANTS CONTEND THAT PACIFICORP CUSTOMERS WILL BENEFIT FROM THE PROPOSED MERGER?

A. Yes. The Applicants argue that PacifiCorp's current customers will realize substantial benefits from the proposed merger. The Applicants' presentation of promised benefits is divided into three main components:

1) $10 million in annual cost savings (beginning in 2003) resulting from reductions in duplicative costs at the corporate level;

2) $60 million in claimed annual economic benefits resulting from the promised service reliability enhancements (Richardson Utah Supplemental Exhibit AVR-2); and

3) Other benefits that by the Applicants' admission cannot be quantified, but which they believe will materialize as a result of unspecified programs to be implemented by Scottish Power.

Q. WHAT REASONS ARE GIVEN BY THE APPLICANTS AS TO WHY ECONOMIC BENEFITS WILL ULTIMATELY MATERIALIZE?

A. The primary bases for the Applicants' contentions lie in two primary sources. The first is a "high-level" benchmarking exercise. The second is ScottishPower's experience in the UK, particularly with the 1995 acquisition of the Manweb electric distribution company.

1) $10 MILLION IN CORPORATE COST REDUCTIONS

Q. DO THE APPLICANTS PROVIDE A DETAILED EXPLANATION OF HOW THEY WILL REDUCE CORPORATE OVERHEAD COSTS?

A. No. The Applicants' Direct Testimony explains only that the $10 million of annual savings will be generated through reductions in corporate overhead costs--basically through reductions in corporate staff employee levels. They have stated:

> "By the end of the third year following the closing of the transaction, ScottishPower expects to achieve approximately $15 million of annual cost savings in corporate costs which, when offset by $5 million of cost increases, will produce a net reduction of $10 million annually in corporate costs. ScottishPower will commit to reflecting this reduction in PacifiCorp's results of operations." (Direct Testimony of Robert D. Green, page 9, lines 20-24).

In discovery, the Applicants elaborated, without clarifying:

> ...No decision has been made as to where these savings will be made across the combined group. Similarly the $5 million estimate of cost increases reflects the recognition that there will be some increased costs to the remaining function after duplication has been eliminated." (Applicants' Response to Utah Division of Public Utilities Eighth Merger Data Request S8.9, Docket No. 98-2035-04).

Even accepting Applicants' calculation of this $10 million savings, they will not all benefit PacifiCorp's customers since the purported cost savings will presumably occur, and need to be shared, by both PacifiCorp and ScottishPower customers.

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPONENTS OF THE $10 MILLION "SAVINGS".

A. Applicants claim that $10 million in corporate cost savings will be achieved by consolidating a number of PacifiCorp corporate functions with ScottishPower. The specific functions that the Applicants propose to consolidate are identified in Applicants' Confidential Response to DPU S8.9.

Q. IS THE APPLICANTS' $10 MILLION "SAVINGS" ESTIMATE OVERSTATED?

A. Yes. The Applicants have erroneously assumed that the $10 million "savings" (even after considering the $15 million of "savings" netted against $5 million of costs) would be achieved without significant costs that generally accompany merging departments and reducing manpower. Applicants' $10 million "savings" assumption is clearly overstated, as demonstrated by recent manpower reduction experiences at PacifiCorp.

It is expensive to consolidate operations and reduce manpower in light of the one-time costs of early retirement packages, transfers, termination benefits and employee separation packages. For example, in PacifiCorp's January 1998 personnel downsizings, 759 people were terminated. As a result of that downsizing, PacifiCorp took a $123.4 million pre-tax charge in 1998. (PacifiCorp's SEC Form 10-K, 1998, page 31). Corporate downsizings are definitely not "costless" as assumed in the Applicants' $10 million "savings" contention. Rather, a downsizing would produce significant early-year cost impacts that do not appear to have been recognized in Applicants' calculations.

Q. IS IT VALID FOR THE APPLICANTS TO ASSUME THAT ALL OF THE CORPORATE COST "SAVINGS" WOULD BE ATTRIBUTABLE TO RETAIL ELECTRIC CUSTOMERS?

A. No. The cost savings may or may not occur in areas of "allowable expenses" in a rate case. The Applicants mistakenly assume that cost-reductions in all of these corporate functions would benefit retail electric customers. Some of the proposed consolidations, including the one with the greatest purported "confidential" savings, may not involve recoverable expenses in revenue requirements determinations by PacifiCorp's various state regulators.

Q. AFTER THE APPLICANTS' DIRECT TESTIMONY AND DATA RESPONSES WERE FILED, DID THEIR CONCEPT OF THE $10 MILLION "SAVINGS" CHANGE?

A. Yes, it apparently did. In Applicants' Oregon rebuttal testimony, they appear to have moved from basing the $10 million on actual cost savings from consolidating functions between PacifiCorp and ScottishPower to more of a "surrogate" savings "guarantee" of $10 million. As described by Mr. Green:

> "...the promised $10 million net reduction is permanent and guaranteed whether or not we actually achieve it, and I am providing a methodology whereby this net reduction can be tracked and verified." (Green Oregon Rebuttal, page 4, lines 11-13)
>
> "In any event, our commitment is to reflect a $10 million reduction in PacifiCorp's cost of service for ratemaking purposes. Cost areas that are disallowed are not part of that calculation and do not diminish the $10 million reduction." (Green Oregon Rebuttal, page 5, lines 13-16)

Q. HOW DO THE APPLICANTS PROPOSE TO GUARANTEE THIS $10 MILLION IN "SAVINGS"?

A. Mr. Green promised to provide to the Oregon Commission a corporate cost allocation proposal by June 18, 1999 to be used to "verify" the $10 million corporate cost reduction:

> "We will use PacifiCorp's 1999 budgeted corporate costs as a baseline and use that figure, after adjusting for inflation (using the GDP Price Index), as a benchmark. At the end of three years following completion of the transaction, the amount of PacifiCorp's corporate costs will in no event be greater than this benchmark less $10 million. If we achieve corporate cost savings greater than $10 million, this additional reduction in corporate

> cost savings will be captured for customers. In other words, we will reflect in PacifiCorp's cost of service for ratemaking purposes the lower of (1) the benchmark less $10 million, or (2) the actual corporate costs. We will track the corporate cost savings in this manner for the next five years, although the savings will continue in perpetuity. Moreover, the $10 million in annual savings to which we are committed will not be affected by currency exchange risk." (Green Oregon Rebuttal, page 4, lines 16-26)

After I have had a chance to further analyze this proposal (assuming it is also presented in Utah), I may have further comments on this issue.

Q. WHEN ALL IS SAID AND DONE, IS THIS $10 MILLION OF "SAVINGS" SIGNIFICANT?

A. Not really. The $10 million in projected annual savings for companies of the combined size of PacifiCorp and ScottishPower is relatively small. With combined ScottishPower and PacifiCorp annual revenues of $5.2 billion, $10 million in promised annual savings becomes almost inconsequential. In my view, this diminutive level of promised savings is insufficient to satisfy the "public interest" standard, particularly in light of potential ratepayer risks.

Q. MR. RICHARDSON HAS TESTIFIED THAT THIS $10 MILLION CORPORATE "SAVINGS" WOULD BE "WORTH ABOUT $100 MILLION ON A NET PRESENT VALUE BASIS". (SUPPLEMENTAL PAGE 1, LINE 15). HOW WAS THIS FIGURE DETERMINED?

A. In responding to LCG Request 1.5, Applicants provided the derivation of the $100 million net present value ("NPV") calculation:

> "These figures are approximate and are based on achievement of the $10 million cash savings in year three. The $10 million is then assumed to flow in perpetuity. A conservative discount rate of 9% has been used to allow the NPV calculation to be undertaken."

Q. DO YOU AGREE WITH THE APPLICANTS' $100 MILLION NPV CALCULATION?

A. No. The Applicants' determination of the $100 million net present value, results in a significant overstatement of the purported "savings", even assuming that $10 million in annual savings could be realized at all.

The Applicants' $100 million net present value "savings" calculation assumes a continuing stream of benefits in perpetuity. The Applicants' claimed "savings" would not be fully achieved until after more than 200 years. Such an extended time period cannot reasonably be used in estimating "benefits" to customers.

2) $60 MILLION IN RELIABILITY BENEFITS

ScottishPower Witness Alan Richardson, in his Supplemental Testimony, argues that he can quantify customer benefits stemming from promised system reliability enhancements:

> "[I]n the case of our promised improvement in system availability and momentary interruptions, there are techniques available which attempt to put dollar figures on the value to customers of not having their power interrupted. I have included as Exhibit SP__(AVR-2) one such study which attributes dollar values on these measures of improved service quality. That estimate, using a 1990 survey performed by the Bonneville Power Administration and the Electric Power Research Institute, suggests that the improvements in SAIDI and MAIFI to which we are committed produce approximately $60 million annually in value to our customers..." (Utah Supplemental Testimony of Alan V. Richardson, April 16, 1999, page 4, line 22 to page 5, line 4)

Mr. Richardson argues (Richardson Supplemental, p. 5, lines 4-5) that this $60 million in annual value stemming from improvements in network performance standards represents $600 million dollars in value to customers on a net present value basis. These claimed benefits are wholly unsubstantiated and illusory. Indeed, Mr. Richardson essentially acknowledges the weakness of his claims by admitting that parties "may debate the analytical techniques used in deriving these figures…." (Richardson Supplemental, page 5, lines 5 through 7).

The proper interpretation and application of survey techniques is very complicated and highly sensitive to the types and forms of techniques employed, timing, the audience, the interpretation of results, etc. To assume a value of $60 million based on a survey conducted almost a decade ago for a different utility serving different customers under very different market conditions is indefensible. No weight should be given to this weak attempt to quantify claimed benefits. Moreover, customers will largely be expected to pay for all of the system reliability enhancements. ScottishPower can hardly claim merger benefits stemming from system improvements funded by the customers. If these types of investments and enhancements are needed--which is certainly possible, although no showing to that effect has been made-- they should be done by PacifiCorp regardless of the proposed merger.

Q. **HAVE YOU REVIEWED THE WORKPAPERS SUPPORTING THE $60 MILLION CLAIM MADE IN MR. RICHARDSON'S SUPPLEMENTAL EXHIBIT—(AVR-2)?**

A. Yes, the figure is derived from two studies conducted in 1990 and 1995 by the Bonneville Power Administration and the Electric Power Research Institute. In both cases, a survey technique was employed to estimate the value of outage or interruptions on the system.

Q. **HAVE YOU REVIEWED THE WORKPAPERS SUPPORTING THE $600 MILLION NET PRESENT VALUE CLAIM MADE IN MR. RICHARDSON'S SUPPLEMENTAL EXHIBIT—(AVR-2)?**

A. Yes, I have. In responding to LCG Request 1.5, Applicants provided the derivation of the $600 million net present value "savings" calculation:

> "These figures are approximate and are based on a gradual 'ramp up' of the cash savings for the first five years. The $60 million is then assumed to flow in perpetuity. A conservative discount rate of 9% has been used to allow the NPV calculation to be undertaken."

Q. **DO YOU AGREE WITH APPLICANTS' CALCULATION OF THE $600 MILLION NET PRESENT VALUE?**

A. No. Similar to the Applicants' $100 million net present value savings claim, it would take more than 200 years to achieve a $600 million net present value. It is inappropriate for the Applicants to place a definitive value of $60 million on a survey conducted almost a decade ago under different market conditions and a different survey population; it is even less appropriate for the Applicants to assume that the claimed "benefits" would continue unabated for the next 200 years.

There are a number of errors involved in Applicants' determination of the $600 million net present value, resulting in a significant overstatement of the value, even assuming a $60 million annual value can be realized at all.

First, the applicants have assumed that the initial $60 million "savings" would be achieved on a costless basis despite the fact that they have recognized elsewhere in this proceeding that the proposed performance standards would initially cost customers $41.5 million for network investment, implementation and operation (Exhibit__ (RMA-1)). Applicants' have neglected to include up-front capital costs of $31.1 million and annual operating costs of $10.4 million in their net present value calculation.

Secondly, In the Applicants' $600 million calculation, "the $60 million annual "savings" is assumed to flow in perpetuity", eventually resulting in a $600 million net present value "savings" after 200 years. Such an extended time period should not be used in estimating "benefits" to customers.

Finally, the Applicants' assumed $60 million in annual savings is based on a particular assumed customer mix and electricity consumption characteristics. It would be incorrect to assume that the customer characteristics and mix upon which the survey was conducted would remain stable for the next 200 years.

3) OTHER UNQUANTIFIABLE BENEFITS

Mr. Richardson states that a portion of the benefits that customers are expected to experience are at this time unquantifiable:

> "Other benefits flowing to customers from the transaction, while capable of being quantified, do not lend themselves easily to being measured in dollar savings. However, these benefits are substantial and must be taken into account in any aggregation of customer benefits from the transaction." (Richardson Supplemental Testimony, April 16, 1999, page 3, lines 4-7).

Remarkably, after acknowledging that these "savings" cannot be measured in dollars, Mr. Richardson proceeds to state as a known fact that the benefits are a "substantial" portion of the benefit package customers will supposedly receive from the merger. Customers are thus left to ponder the value of a substantial portion of their promised benefits--benefits that, by ScottishPower's own admission, cannot be assigned a value and are thus likely to be ephemeral.

Q. ARE THE BENEFITS CREATED BY THE PROPOSED ACTIONS OF THE APPLICANTS UNCERTAIN?

A. Yes. There exists little certainty as to the source, value or actuality of any merger savings resulting from the merger. As acknowledged in the direct testimony of ScottishPower Witness Robert Green:

> "ScottishPower has, to date conducted only preliminary studies of potential areas for cost reduction and because those studies are preliminary they are insufficient to base any opinion or commitment to specific cost savings that would be forthcoming immediately from this merger". (at page 5, lines 18-21).

Similar statements of the Applicants' inability to quantify cost reductions or equivalent benefits to customers are found in the direct testimony of a number of witnesses, including Richardson (Supplemental, p 5, lines 13-16), O'Brien (Direct, p 8, line 6), and MacRitchie (Direct, p 13, lines 1-7). The uncertainty of future benefits arising from the proposed merger stems from at least two separate areas.

The first area of uncertainty stems from the difficulty in identifying the source of cost savings that may occur in future years. Identifying cost reductions or benefits attributable to actions of ScottishPower as compared to cost reductions or benefits created through PacifiCorp's 1998 "Refocus Program" and other PacifiCorp process re-engineering programs in progress before the merger agreement was announced will prove very difficult, if not impossible.

The second area of uncertainty lies in the general inability of ScottishPower to identify specific actions they will undertake as part of their efficiency improvement program, coupled with its inability to quantify the value of any such actions. Witness MacRitchie admits in his direct testimony (Direct, page 13, lines 1-3) that, because of the high level benchmarking used in identifying PacifiCorp as a utility in which substantial cost savings were likely, the specifics of how such cost savings can be developed have yet to be addressed.

B. ESTIMATION OF BENEFITS

1) MANWEB COST REDUCTION "MODEL"

Q. WITH REGARD TO MANWEB, WHAT EVIDENCE DO THE APPLICANTS PRESENT THAT DEMONSTRATES THEIR ABILITY TO ENACT THE TYPE OF COST REDUCTIONS AND PERFORMANCE STANDARDS THEY HOPE TO INTRODUCE AT PACIFICORP?

A. Witness Richardson, in his direct testimony at page 5, lines 2-5, discusses specific key improvements he claims occurred at Manweb after its acquisition by ScottishPower. In addition, Witness Richardson's supplemental testimony, pages 9 through 16, discusses the ScottishPower experience in transforming Manweb. Richardson concludes that

> "The Manweb experience provides a proven track record that substantiates our commitment here to produce cost savings." (Page 9, lines 10-11)

At page 10, lines 20-22, Mr. Richardson attempts to quantify the cost savings reflected in his Figure 1 that "ScottishPower was able to achieve in its transformation of Manweb":

> "Since 1993/94, the year before we acquired Manweb, its business operating costs have been reduced by over 55%, from £176 million to £78 million in 1997/98..." (Supplemental Testimony of Alan Richardson, page 10, lines 20-22)

In a similar manner, Mr. Richardson's Figure 3 at page 13 compares Manweb manpower levels using a comparison of "1993/94" pre-merger levels with manpower data after the merger.

Q. DO YOU BELIEVE THAT MR. RICHARDSON'S FIGURE 3 PROPERLY REFLECTS THE ACTUAL MANPOWER SAVINGS ATTRIBUTABLE TO SCOTTISHPOWER'S MANAGEMENT OF MANWEB?

A. No. Mr. Richardson's Figure 3 comparisons do not correctly characterize the manpower savings achieved as a result of ScottishPower's acquisition. The underlying assumptions of his comparison result in distortions, leading to a significant overstatement of the manpower reductions attributable to the ScottishPower merger.

Mr. Richardson's Figure 3 "merger savings" compares manpower levels from an incorrect and premature starting point that includes significant manpower reductions made by Manweb management prior to ScottishPower's acquisition. Mr. Richardson uses a "1993/94" base of comparison--April 1, 1993 to March 31, 1994--for business operating costs (Figure 1) and manpower (Figure 3). ScottishPower did not acquire control of Manweb until October, 1995 and did not complete its transition team planning until the end of 1995. Mr. Richardson is thus using a base for comparison that includes all of Manweb's independent activity for 18 months prior to the acquisition. To correctly measure the merger-related manpower savings at Manweb, manpower levels at the time of acquisition should be used, rather than data from 18 months before ScottishPower's October 1995 acquisition.

Prior to the acquisition by ScottishPower, Manweb management had implemented several programs that reduced manpower levels from 4,634 positions on March 31, 1994 to 3,353 positions on September 31, 1995--about one week before ScottishPower took control of Manweb on October 6, 1995. My testimony corrects Mr. Richardson's manpower comparisons using a more reasonable basis of September 31, 1995 employee levels to measure cost savings attributable to reductions in Manweb manpower after the acquisition.

Q. WHAT IMPACT SHOULD THE RECOGNITION OF SCOTTISHPOWER'S INCORRECT MANPOWER DATA HAVE ON THE COMMISSION'S EVALUATION OF THE PROPOSED PACIFICORP MERGER?

A. Recognizing this overstatement of Manweb's merger-related manpower savings is important in that it casts doubt upon the actual savings that ScottishPower was able to achieve through the Manweb acquisition. This has import for claimed potential savings within the PacifiCorp system. As discussed below, ScottishPower's claimed experiences and cost savings from the Manweb merger are the linchpin of its contention that similar savings exist in PacifiCorp. My correction of ScottishPower's presentation shows significantly reduced manpower savings from the Manweb merger than purported by ScottishPower. If the savings at Manweb are substantially less than as claimed in the Applicants' filing, it cases doubt on ScottishPower's assertion that the proposed merger will lead to significant savings at PacifiCorp.

Q. **PLEASE EXPLAIN MR. RICHARDSON'S FIGURE 3.**

A. Figure 3 of Mr. Richardson's Supplemental Testimony is a bar chart illustrating Manweb's manpower levels from "1993/94" to "1997/98. My annotated version of Figure 3 showing year-to-year manpower reductions appears below:

MANWEB EMPLOYEE REDUCTIONS

Period Ending	Employees		Reduction
1993/943/31/94	4,634		
		)	219
1994/953/31/95	4,415		
		)	1,355
1995/963/31/96	3,060		
		)	147
1996/979/30/96	2,913		
		)	156
1997/983/31/97	2,757		
Total Reduction 93/94 – 97/98			1,877

(Richardson Supplemental Figure 3, page 13)

According to Mr. Richardson's Figure 3, Manweb employee levels were reduced by a total of 1,877 employees (4,634 – 2,757) over the 1993/94 – 1997/98 period.

Q. **WERE ALL OF THESE 1,877 EMPLOYEES IN MANWEB'S ELECTRIC DISTRIBUTION BUSINESS?**

A. No. ScottishPower's response to data requests shows the types of positions eliminated at Manweb between 1994 and 1997. I have prepared a table using the annual manpower data for Manweb for the terminal years shown in Mr. Richardson's Figure 3:

	1994	1997	Change	% of Total
Distribution	2,513	1,774	(739)	39.4%
Supply	650	498	(152)	8.1%
Corporate Services	396	88	(308)	16.4%
Contracting Services	414	314	(100)	5.3%
Retail-Appliances	661	83	(578)	30.8%
Total	4,634	2,757	(1,877)	100.0%

(Source: Applicants' Response to Wyoming CAS Eighth Data Request 231b)

Q WOULD IT BE FAIR TO SAY THAT SCOTTISHPOWER REDUCED MANWEB EMPLOYEE LEVELS BY 1,877 BETWEEN 1993/94 AND 1997/98?

A. No. In making such a claim, ScottishPower takes credit for manpower reduction at Manweb prior to ScottishPower's acquisition. A majority of the manpower reductions (and their associated cost savings) appear to have been initiated prior to ScottishPower acquiring Manweb in a hostile takeover on October 6, 1995. A more realistic characterization would be that ScottishPower inherited the benefits of the Manweb cost reduction programs initiated in 1994 and 1995 that had not yet been fully completed at the time of the takeover. According to my calculations, Manweb manpower at the time ScottishPower assumed control of the company on October 6, 1995 was approximately 3,353 positions segmented as follows, based on data as of September 30, 1995 (WIEC Data Request 2.3(a)):

Distribution	1,984
Supply	499
Corporate Services	283
Contracting Services	368
Retail-Appliances	190
Other	29
Total	3,353

A more accurate characterization of ScottishPower's manpower reductions at Manweb would start with the 3,353 total for September 30, 1995 and compare it with Mr. Richardson's March 31, 1997 staffing level of 2,757, resulting in total manpower reductions of 596 employees rather than the 1,877 reported in ScottishPower's Figure 3. Even the 596 figure is inflated because it includes employees not involved in Manweb's electric distribution and supply business. Taking those employees into account reduces actual manpower savings in Manweb's electric distribution and supply business to 211 employees.

Q. WHEN DID SCOTTISHPOWER FIRST INITIATE ITS MERGER WITH MANWEB?

A. ScottishPower reports that it initiated a bid for Manweb on July 24, 1995. ("Delivering Future Value", Charles Berry, Bates No. SP0369)

Q. COULD IT BE CHARACTERIZED AS A 'FRIENDLY MERGER'?

A. No. ScottishPower has characterized it as a "hostile bid" with "no leakage and no prior contact" with Manweb. Mr. Berry characterizes Manweb's defense in this hostile takeover as a "scorched earth defense" where "1,000 people left in September 1995". ("Delivering Future Value", Charles Berry, Bates No. SP0369) It was reported that Manweb rejected ScottishPower's bid because it had undervalued Manweb. (EnergyOnLine, September 8, 1995)

Q. WHEN DID SCOTTISHPOWER FINALIZE THE MERGER?

A. The Department of Trade and Industry cleared the merger bid on August 31, 1995. (CCNS Full Text News, August 31, 1995) ScottishPower reports that it took control of the company on October 6, 1995 with transition team conclusions made in December 1995. ("Delivering Future Value", Charles Berry, Bates No. SP0369)

Q. DID SCOTTISHPOWER START COST-CUTTING MEASURES IMMEDIATELY UPON ACQUIRING MANWEB ON OCTOBER 6, 1995?

A. Apparently not. Since Mr. Berry indicated that transition team conclusions were not finalized until December 1995, significant manpower adjustments presumably could not have been prudently considered until early 1996. ("Delivering Future Value", Charles Berry, Bates No. SP0369) For purposes of any comparisons, the use of manpower levels for 12/31/95 may be more appropriate than those levels that existed at the time of the acquisition (October 6, 1995). Use of the December 31, 1995 cutoff date would further reduce the 211 figure discussed above.

Q. MR. RICHARDSON SET FORTH NINE "ACTIONS" THAT HE CLAIMS SCOTTISHPOWER IMPLEMENTED TO ACHIEVE EFFICIENCIES AND COST SAVINGS AT MANWEB (SUPPLEMENTAL TESTIMONY, PAGE 10, LINES 1-17). HAS SCOTTISHPOWER SHOWN THAT THESE "ACTIONS" ARE TRANSFERABLE TO PACIFICORP?

A. No. PacifiCorp was unable to verify that any of ScottishPower's nine efficiency and cost savings "actions" at Manweb would even be applicable to PacifiCorp, not to mention whether or not efficiencies would be achieved or costs saved:

> "PacifiCorp objects to this request on the grounds that it is overly broad and vague. The referenced actions in the Supplemental Testimony are broad categories of management actions that ScottishPower undertook to achieve efficiencies and cost savings at Manweb. As such, a response would require a complete analysis of all performance management efforts undertaken by PacifiCorp over the last several years. Even then, the output would not be a reliable guide to potential transition actions at PacifiCorp as this will be based on the specific conditions encountered at PacifiCorp, not those that were present at Manweb." (Applicants' Response to LCG 1.18)

Q. **DO THE MANPOWER REDUCTION OPPORTUNITIES AT MANWEB AT THE TIME OF THE SCOTTISHPOWER ACQUISITION MIRROR THOSE AT PACIFICORP TODAY?**

A. I do not believe so. The conditions at Manweb, particularly in the 1993-1994 timeframe used by ScottishPower, appear to be far different than the conditions that exist at PacifiCorp today. At the Utah Public Service Commission's Technical Conference on April 21, 1999 conducted in Salt Lake City, ScottishPower made available Mr. Charles Berry, Chief Executive Officer of Manweb. When asked the question "what condition was Manweb in at the time of the acquisition?" Mr. Berry referred to Manweb as being "high cost" with a "lack of focus."

While both Manweb and PacifiCorp appear to have been in the process of reducing personnel and instituting cost reductions programs at the times the ScottishPower acquisitions were launched, the opportunities for ScottishPower to consolidate operations at PacifiCorp, as was done at Manweb, appear very different. As Applicants conceded in response to the Wyoming CAS data request 2.3(a):

> "The opportunities for cost reductions are different in PacifiCorp, but definitely real. The Manweb situation involved the combination of two electric utilities operating in nearby geographic areas, and thus presented greater opportunities for cost savings by eliminating duplicative functions and combining electric operations. The PacifiCorp transaction process presents limited opportunity for savings achieved in this manner..." (Applicants' Response to Wyoming CAS 231.a)

Moreover, it is not clear that PacifiCorp could properly be characterized as "lacking focus" at the time of the acquisition. In announcing its 1998 "Refocus" effort, PacifiCorp made well known its intention to return to its "core business" of serving retail electricity customers in the western states. Manweb had apparently not made any such strides prior to ScottishPower's takeover in 1995. It had clearly not done so in the 1993-1994 timeframe used by ScottishPower.

In submitting its Business Plan to OFFER, the Office of Electricity Regulation in the UK, in December 1998, ScottishPower stated:

> "We have worked hard to reduce controllable operating costs whilst improving customer service and system performance...The majority of cost savings have been achieved through reductions in staffing levels (29% on March 1995). There is obviously a limit to which future staffing levels (hence future levels of controllable operating costs) can be further reduced." (Reviews of Public Electricity Suppliers 1998-2000 PES Business Plans Consultation Paper, December 1998, "Manweb-Overview").

Although ScottishPower has reduced manpower levels at Manweb since 1995, PacifiCorp has also made significant personnel cuts in the last few years. The practical limit to staffing reductions that was acknowledged by ScottishPower may well be reached much more quickly at PacifiCorp in light of its recent downsizing efforts. In 1998, PacifiCorp had two major early retirement programs, one announced in January 1998 and the other announced in October 1998, resulting in the elimination of 926 electric operations positions. (PacifiCorp's 1998 SEC Form 10-K at page 31)

Details of PacifiCorp's electric operations manpower levels in each of its service territories was provided by Applicants in response to a data request:

"Employment by State, PacifiCorp Electric Operations"

	1994	1995	1996	1997	1998
California	105	102	94	98	74
Idaho	234	222	201	195	180
Montana	84	76	68	60	0
Oregon	2,145	2,155	2,194	2,331	2,215
Utah	3,091	2,899	2,820	2,758	2,373
Washington	519	477	435	416	361
Wyoming	1,427	1,367	1,247	1,223	1,112
Other	1	1	2	5	4
Total	7,606	7,299	7,061	7,086	6,319

(Source: Applicants' Response to WIEC Data Request 2.16)

In addition to the significant reductions in electric operations personnel in 1998 shown in the above table, PacifiCorp's divestiture of a number of non-core businesses has produced even greater manpower reductions.

Q. DO OTHER OPPORTUNITIES FOR COST REDUCTIONS AT PACIFICORP MIRROR SIMILAR OPPORTUNITIES THAT EXISTED AT MANWEB AT THE TIME OF THE SCOTTISHPOWER ACQUISITION?

A. As explained above, many of the actions undertaken by ScottishPower at Manweb were unrelated to the distribution and supply segments of the business. Also, the opportunities for combining staff positions at Manweb and ScottishPower were much more apparent as compared to similar opportunities at PacifiCorp. Manweb's recently filed Business Plan provides general insight on how ScottishPower reduced Manweb's costs since acquiring it in 1995:

> "Management Initiatives: The operating costs, excluding Rates, Depreciation and NGC Exit Charges, have reduced in real terms by 24% over the last three years as a result of a focused and coordinated drive to improve efficiency and productivity following the acquisition, while increasing the quality of service provided:
>
> The initiatives following the acquisition were to:
>
> - Merge the management of duplicate support functions.
> - Align operating cost base of ScottishPower and Manweb by transfer of best practice and general efficiencies;
> - Reorganize Manweb Distribution Operations into three regions with supporting depots for the more rural operations;
> - Reduce Corporate Centre in size;
> - Reduce Customer Service call centres from three down to two.
>
> (Reviews of Public Electricity Suppliers 1998-2000 PES Business Plans Consultation Paper, December 1998, "Manweb-Section 2.1").

Recall that the elimination of the 'duplicate corporate overhead' has already been accounted for in the claimed $10 million in annual savings. No additional "duplicative support functions" have been claimed to exist. PacifiCorp has already reduced the number of its support centers and has reorganized its customer support services. If ScottishPower follows the Manweb model, as it contends in its filing, the areas in which cost savings may be enacted appear very limited when compared to those available at Manweb prior to 1995.

Q. **IS THERE COMPARATIVE DATA THAT WOULD INDICATE PACIFICORP IS A HIGH COST UTILITY AND A LIKELY CANDIDATE FOR THE EFFICIENCY ACTIONS PROPOSED BY SCOTTISHPOWER?**

A. There are undoubtedly inefficiencies and excess costs in PacifiCorp's operations that can and should be eliminated. However, PacifiCorp's average retail electricity rates, reflecting its underlying cost of operations, are relatively low when compared to many other U.S. utilities. In fact, the Edison Electric Institute's ranking of 185 investor owned utilities for the 12 months ending June 30, 1998, as shown in Exhibit ___ (RMA-2), listed PacifiCorp's rates among the lowest in the country. In that study, a higher numerical ranking indicated a lower comparative average retail rate. PacifiCorp's Utah territory ranked 142nd; the Wyoming-West territory ranked 167th, the Idaho territory ranked 179th and the Wyoming-East territory ranked 180th. This study suggests that PacifiCorp's rates are relatively low. Assuming that lower rates reflect reasonable costs of operations, PacifiCorp would appear to be a different utility than Manweb was in 1995. This is a critical distinction because it suggests that the base from which Scottish Power will begin its cost cutting and efficiency measures is very different than its starting point with Manweb.

Q. **WOULD YOU CONCLUDE THAT THE MANWEB EXPERIENCE DEMONSTRATES AVAILABLE COST REDUCTIONS AND IMPROVED SERVICE FOR PACIFICORP?**

A. No. The basis from which ScottishPower will attempt to achieve the goals it has generally described for PacifiCorp is very different than it was for Manweb. It would be unrepresentative to use Manweb as a case example of what can be achieved at PacifiCorp.

Q. WOULD YOU CONCLUDE THAT SCOTTISHPOWER'S EXPERIENCE WITH SOUTHERN WATER IS APPLICABLE TO COST REDUCTIONS AND IMPROVED SERVICE AT PACIFICORP?

A. No. Southern Water, like Manweb, was apparently an unfocused, over-manned government water utility that also had "diversified" into a number of non-core businesses:

> "Southern Water, at the time of acquisition in August 1996, had accumulated a portfolio of 20 enterprise businesses. The total fiscal 1996 turnover for these businesses was £134 million. Of this £73 million was internal and £61 million was external representing 14% of the Southern Water's total sales. There was little evidence of strategic direction other than an overall encouragement to grow external business. There had been almost no attempt to rationalize the portfolio into larger groupings, little in the way of business planning and no attempt to formulate an overall market or industry strategy. As a result, the inherited enterprise business portfolio lacked focus, had high overheads and gave rise to complex interfaces and a significant burden of internal transaction costs..." (ScottishPower 1997 SEC Form 20-F, page 24).

Unlike the Southern Water acquisition, where ScottishPower divested 13 subsidiaries of Southern Water for a total of £ 90 million (Financial Times, November 5, 1997), there appears to be relatively little for ScottishPower to clean up at PacifiCorp after the large number of major divestitures during the last year stemming from the 1998 PacifiCorp "Refocus":

> "The Company sold its wholly owned telecommunications subsidiary, Pacific Telecom, Inc. ("PTI"), on December 1, 1997...The Company sold Pacific Generation Company ("PGC") on November 5, 1997, and the natural gas gathering and processing assets of TPC on December 1, 1997. During May 1998, a majority of the real estate assets held by PFS were sold." (PacifiCorp's SEC Form 10-Q for the quarterly period ended September 30, 1998).
>
> "PacifiCorp expects, over the next 12 months, to divest all of its businesses other than its western U.S. electric business and Powercor, its Australian electricity distribution business, assuming reasonable values can be achieved. The most significant businesses include:
>
> - TPC Corporation, the company's U.S. natural gas storage and marketing business;
> - The eastern U.S. electricity trading business of PacifiCorp Power Marketing;

- EnergyWorks, the company's joint venture with Bechtel Enterprises;
- The company's energy development activities in Turkey and the Philippines; and
- The company's investment in the Hazelwood power station in Australia.

The company has recorded charges totaling $230 million pre-tax in its third quarter financial results for expected losses associated with its planned business divestitures." (October 23, 1998 press release, "PacifiCorp Reports Third Quarter 1998 Financial Results")

Q. **PLEASE COMMENT ON SCOTTISHPOWER'S CLAIMED MANPOWER REDUCTIONS AT SOUTHERN WATER.**

A. ScottishPower contends that it has made significant employee reductions at Southern Water since its takeover on August 6, 1996. For example, see ScottishPower's presentation to financial analysts dated June 1998 (Exhibit ___ (RMA-3)).

While the "manpower reductions" illustrated in ScottishPower's analysts' presentation may be accurate for Southern Water in total, they are also misleading. A recent ScottishPower data response shows that ScottishPower's manpower "reductions" claimed at Southern Water were almost entirely derived from the divestiture of 13 subsidiaries ("Enterprise Businesses") by ScottishPower after the merger. In fact, during the 1996-1998 period, employment at Southern Water Services actually increased by 202 employees:

	1996	1997	1998	Change 96-98
Southern Water Services	2,003	1,782	2,205	+202
Enterprise Businesses	1,859	1,650	52	-1,807
Headquarters	144	94	107	-37
Agency	350	300	145	+205
Total	4,356	3,826	2,509	-1,847

Source: Applicants' Response to LCG 1.17, Appendix F

Q. HAVE SOUTHERN WATER'S "TYPICAL HOUSEHOLD BILLS" DECREASED SINCE SCOTTISHPOWER'S ACQUISITION IN 1996?

A. No. According to the Applicants, the typical water and wastewater combined bill increased from £218.71 in 1996/97 to £266.06 in 1998/99 (Applicants' Response to LCG 1.17, Appendex G)

Q. HAS SCOTTISHPOWER INSTITUTED ITS "MULTI-UTILITY" PLAN AT SOUTHERN WATER?

A. Yes. ScottishPower instituted a natural gas sales program in February 1997 (ScottishPower Presentation to U.S. Analysts, July 1997, page SP0662), within six months of its acquisition and just shortly after the implementation of a detailed transition plan:

> "The take-over of Southern Water was completed at the beginning of August 1996. A detailed transition plan for reconstructing the Company was prepared, with implementation commencing in January 1997." (Applicants' Response to Utah LCG 17)
>
> ScottishPower's SEC Form 20-F for the fiscal year ended March 31, 1997 stated:
>
> "In addition, the first stage of opening the gas supply market to full competition (i.e., to premises with consumption under 2,500 therms per annum) has been completed by the introduction of 2 million gas customers to competition in the gas trial in the south of England. The group was able to take advantage of the fact that many of these customers reside in the area served by Southern Water and has rapidly established itself as one of the leading challengers to British Gas (Centrica) in this market, acquiring over 70,000 customers, approximately 8%, of the market in the Kent and Sussex areas. In addition, the gas trial provided the group with valuable experience in all aspects of operating in a competitive energy market." (page 19)
>
> "**Business Objectives**:...In addition, further growth will come from exploiting multi-utility sales opportunities in the area as evidenced by ScottishPower's participation in the gas trials in Kent and Sussex, a large part of Southern Water territory, where ScottishPower gained 8% of the gas market." (page 23)

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPLICABILITY OF SCOTTISHPOWER'S UK EXPERIENCES?

A. Those experiences do not appear to be transferable to PacifiCorp to any significant extent. The efficiency opportunities present in the UK acquisitions are simply not replicated in the PacifiCorp operations.

Q. HAVE YOU ANALYZED THE OTHER OPERATING COSTS IN A MANNER SIMILAR TO YOUR ANALYSIS OF MANPOWER?

A. No, I have not. I may have further comments on two other figures referenced in Mr. Richardson's supplemental testimony (Figure 1-Business Operating Costs and Figure 2-Net Capital Expenditures) after I have had a chance to more fully review the supporting workpapers.

2) BENCHMARKING

Q. HAVE THE APPLICANTS PRESENTED A DETAILED ASSESSMENT OF HOW THEY DETERMINED PACIFICORP TO BE A CANDIDATE FOR THEIR PROPOSED COST REDUCTION EFFORTS?

A. The Applicants state that their assessment of the potential for cost reductions at PacifiCorp was primarily based on "a high level preliminary benchmark study" (MacRitchie Direct, at page 2, lines 16-17). Witness MacRitchie states (at page 3, lines 19-22) that "the process to identify the potential efficiencies that can be undertaken at PacifiCorp has actually only begun." In fact, he states (at page 3, line 20-21) that "a significant amount of work still needs to be undertaken with PacifiCorp before we can assess the potential for efficiencies with any degree of certainty." Mr. MacRitchie also stated (at page 12, lines 24-25 and page 13, lines 1-3) that "ScottishPower intends to set up a full integration team and conduct an exhaustive survey of PacifiCorp operations but that has not been undertaken to date...." He also acknowledges (at page 13, lines 9-10) that "a significant amount of work and further investment still needs to be undertaken in conjunction with PacifiCorp before the positive affects of this effort will materialized."

Q. BASED UPON THE INFORMATION PRESENTED BY THE APPLICANTS, IS IT ACCURATE TO STATE THAT THE POTENTIAL FOR COST REDUCTIONS AT PACIFICORP IS HIGHLY UNCERTAIN?

A. Yes. Particularly beyond the projected $10 million in annual corporate overhead reductions promised by 2003, the potential for cost reductions at PacifiCorp remains highly uncertain and speculative. Indeed, ScottishPower essentially indicated as much in its own testimony, in that it failed to identify or present a detailed action plan that would delineate specific objectives and their expected values to customers.

Q. DIDN'T SCOTTISHPOWER IDENTIFY THE POTENTIAL FOR COST REDUCTIONS AT PACIFICORP THROUGH BENCHMARKING PACIFICORP AGAINST OTHER UTILITIES?

A. Not really. As discussed above, ScottishPower conducted a "high level" benchmarking assessment of PacifiCorp, comparing it to other utilities it considered to be similar in operating and geographic conditions. Witness MacRitchie in his exhibit (Ex.SP_AM-1) provides a comparison of non-production cost per customer for several utilities in 1996. In that exhibit, Mr. MacRitchie highlights Puget Sound Energy, New Century Energies, Sierra Pacific Power Company, PacifiCorp and Idaho Power Company as utilities with similar characteristics and operating conditions.

Q. WHAT DOES MR. MACRITCHIE CONTEND HIS EXHIBIT DEMONSTRATES?

A. Mr. MacRitchie's conclusion is that PacifiCorp has a higher non-production cost per customer than Puget Sound Energy, New Century Energies and Sierra Pacific Power Company. On the other hand, PacifiCorp has a lower non-production cost per customer than does Idaho Power.

Q. DO YOU BELIEVE MR. MACRITCHIE'S EXHIBIT AM-1 PROVIDES A REASONABLE BASIS TO CONCLUDE PACIFICORP HAS RELATIVELY HIGH COSTS?

A. No. The comparison between PacifiCorp and those highlighted in Mr. MacRitchie's Exhibit AM-1 is not a comparison of utilities with similar characteristics. Comparisons with the "top ten utilities" listed in Mr. MacRitchie's exhibit produce some very curious comparisons. For example:

- Utility number four, Citizens Electric had 6,211 customers in Lewisburg, Pennsylvania, and 16 employees in 1997.
- Utility number six, Northwestern Wisconsin Electric, had 10,796 customers, 57 full time employees and slightly more than $50,000 of annual transmission operation and maintenance expenses in 1996.
- Utility number ten, Superior Water Light and Power had slightly less than 14,000 customers and 54 employees in 1996, and was owned and operated by the Minnesota Power & Light Company. Minnesota Power & Light is not included in the study.

The stark differences among those three utilities alone create real questions about the meaningfulness of the "top ten" comparison made by ScottishPower.

Additionally, the top two utilities noted in the exhibit, Florida Power and Light and Florida Power Corporation, as well as the number five utility, San Diego Gas and Electric, and the number four utility, Consumer's Energy, are large urban utilities that have very little in common with PacifiCorp's operating conditions. Moreover, ScottishPower admits that it has yet to gauge PacifiCorp's performance against other utilities:

> "ScottishPower has not yet developed the portfolio of measures it will use to gauge PacifiCorp's performance against other IOUs..." (Applicants' Response to WIEC First Data Request 1.52(a)).

The use of the general benchmarking technique as applied to Mr. MacRitchie's exhibit and the quest to position PacifiCorp as a 'top ten utility' is illusory.

Q. **DOES THE BENCHMARKING TECHNIQUE USED BY SCOTTISHPOWER DIFFERENTIATE BETWEEN REGULATED AND NON-REGULATED COSTS?**

A. No. Mr. MacRitchie's testimony fails to inform the reader that the non-production costs he has highlighted include both wholesale and retail as well as regulated and non-regulated costs, including instances of one-time charges for significant corporate write-offs. In addition, this "benchmarking" does not recognize the "used and useful" or "test year" conventions utilized in revenue requirements proceedings at the state regulatory level. The benchmarking analysis thus has little value in determining similarly situated utilities that could be used as a basis for predicting cost reduction potential for

PacifiCorp's retail electric customers. The "costs" benchmarked may not even be the relevant costs to be studied as far as "benefits" accruing to those customers.

Q. **DID THE BENCHMARKING TECHNIQUE USED BY APPLICANTS IN COMPARING PACIFICORP TO OTHER UTILITIES RECOGNIZE THE SIGNIFICANT INVESTMENTS IN NEW EFFICIENCY PROGRAMS UNDERTAKEN BY PACIFICORP OVER THE LAST FEW YEARS?**

A. To an extent, yes. The significant investments made by PacifiCorp in customer information systems, customer call centers and the Business Systems Integration Project over the last several years would presumably be included in this cost comparison. Mr. MacRitchie's benchmarking testimony, however, does not recognize the cost of any process re-engineering that occurred in the benchmarking year nor any anticipated benefits of these long-term cost reduction efforts. Also, to the extent that the costs reflected in his exhibit are from 1996, they would not include the $30 million cost reduction activities highlighted in the "Refocus Program". Therefore, the costs stated in MacRitchie's testimony are suspect.

Q. **DOES THE HIGH LEVEL PRELIMINARY BENCHMARKING TECHNIQUE FURTHER INCREASE THE UNCERTAINTY OF THE PERCEIVED MERGER BENEFITS TO PACIFICORP'S CUSTOMERS ?**

A. Yes. The MacRitchie exhibit does not provide any kind of meaningful basis to gauge PacifiCorp's operating costs or realistic cost-cutting opportunities.

In addition, the Applicants' benchmarking analysis, which is calculated using the number of customers served, would be inherently biased against companies such as PacifiCorp that have extensive transmission investments and operating costs in serving wholesale loads. While Mr. MacRitchie's benchmarking treats transmission as "non-production cost" expense, in reality, much of the transmission costs for PacifiCorp are production-related. Moreover, using the number of customers to determine benchmarking costs instead of another unit of consumption, such as kilowatt-hours, distorts the comparisons. As reflected in my Exhibit ___ (RMA-4), by ranking Applicants' "top 10 utilities" by per-megawatt-hour unit operating costs rather than by customers, significant differences appear in the rankings.

Q. DO YOU BELIEVE THAT THE CONCLUSIONS DRAWN BY MR. MACRITCHIE ARE UNCERTAIN, IF NOT INACCURATE?

A. Yes. This is also supported by other studies by industry researchers that reach completely different conclusions about PacifiCorp's efficiency ranking compared to other utilities. For example, in a September 1, 1998 article in Public Utilities Fortnightly, (Exhibit ___ (RMA-5)) entitled the "Fortnightly 100", PacifiCorp's 1996 "efficiency score" tied for the number 8 position nationwide. A similar ranking in Public Utilities Fortnightly, (Exhibit ___ (RMA-6)) June 15, 1997, ranked PacifiCorp number 5 out of 94 electric utilities investigated.

Q. DOES THE APPLICANTS' GENERAL BENCHMARKING APPROACH INTRODUCE UNCERTAINTY AS TO THE PUBLIC INTEREST IMPACT OF THIS MERGER?

A. Yes. Even the Applicants acknowledge that this generalized benchmarking approach has significant analytical problems:

> "It is important to point out that benchmarking efforts alone do not precisely specify likely cost savings, as explained in Mr. MacRitchie's testimony. ScottishPower has found that the variances identified in benchmarking comparisons while directionally correct, can be inaccurate for a number of reasons:
>
> - Differences in overall operating environments for individual utilities may require investment in, and operation of, different systems such as underground high-voltage transmission facilities.
> - Differences in cost allocation procedures or accounting conventions regarding the capitalization or expensing of certain items has the potential to distort results; and
> - Yardstick comparisons, by their nature, are imprecise and can mask best or worst practices in specific areas. Drawing too great an inference about steps that should be taken to better manage the organization without knowing whether best practices are being employed in any or all areas could lead to erroneous recommendations.
>
> For these reasons *it is inappropriate to conclude from a yardstick comparison where potential savings exist*. Therefore, ScottishPower would not advocate the use of such a yardstick comparison to project savings over a ten-year period." (Applicants' Response to WIEC 1.118(b) *(Emphasis Added)*.

Q. APPLICANTS HAVE RECENTLY PROPOSED IN OTHER STATES TO FILE A DETAILED "TRANSITION PLAN" WITHIN SIX MONTHS OF COMPLETING THE MERGER. WILL THIS REDUCE THE RISK TO PACIFICORP'S CUSTOMERS?

A. No. Mr. Richardson mistakenly believes that an after-the-fact quantification of merger costs and benefits will show that the merger is in the public interest:

> "Several parties desire greater specificity with regard to the mechanism and timing under which cost savings will be achieved and reflected in rates. We believe that the normal ratemaking process will allow this to happen; however, we now understand that the parties want a more specific commitment with respect to the timing and process...we will agree to develop and share our transition plan within six months after closing the merger, identifying the specific areas in which ScottishPower expects to achieve cost savings, the plan for achieving them, and the expected cost and benefits of such initiatives." (Richardson Oregon Rebuttal, page 4, lines 5-13)

Unfortunately, the Applicants have yet to commit to a mechanism that will recognize promised merger cost savings in present customer rates.

Q. WHAT IS YOUR CONCLUSION REGARDING THE BENCHMARKING EXERCISE USED BY SCOTTISHPOWER?

A. The exercise produces no meaningful results. Rather, it produces misleading implications regarding PacifiCorp's relative cost level. It is mistakenly used by the Applicants as a "signal" that costs are relatively high. In fact, that conclusion has not been supported.

3) PACIFICORP'S 1998 "REFOCUS PROGRAM"

Q. TO WHAT EXTENT HAVE THE APPLICANTS ADDRESSED HOW THEIR "MERGER SAVINGS" CLAIMS ARE RELATED TO PACIFICORP'S 1998 "REFOCUS PROGRAM"?

A. The Applicants failed to consider the effects of cost cutting and performance enhancements that PacifiCorp has undertaken in its 1998 "Refocus Program". According to a March 31, 1999 statement by Mr. Keith McKennon, (Chairman and CEO of PacifiCorp) the "Refocus Program" was successful in improving PacifiCorp's financial performance, reorienting its corporate focus and implementing a cost reduction program with changes designed to improve customer service. In that March 31, 1999 press release, (Exhibit ___ (RMA-7)), Chairman McKennon stated that the "Refocus Program" had implemented an overhead cost reduction program designed to save the company $30 million annually in pre-tax operating costs. It stated that PacifiCorp had also restructured its customer service and other operation functions to better address "customer need" as well as having divested a number of non-core businesses. Chairman McKennon stated that he was "encouraged by the early results of the renewed focus on the western U.S. business and that the results mean even better service to our customer".

In addition to the cost savings derived from the "Refocus Program", on May 11, 1999 PacifiCorp and its partners agreed to sell the 1,340 MW Centralia Washington power plant and its affiliated coalmine to TransAlta for $554 million. PacifiCorp had been the operator and 47.5% owner of the plant and 100% owner of the Centralia coal mine.

Q. HAVE THE APPLICANTS ADDRESSED ANY OF THE SPECIFICS OF THE "REFOCUS PROGRAM" AND THE SUCCESSES OUTLINED BY CHAIRMAN McKENNON?

A. The Applicants' filing does not address any of the specific actions undertaken by PacifiCorp under the auspices of the "Refocus Program". More importantly, it does not separate out the expected $30 million of overhead cost reductions or the significant divestiture of non-core businesses.

Q. DOES THIS ADD UNCERTAINTY TO THE MEASUREMENT OF ANY BENEFITS OF THE MERGER?

A. Yes. The results of the "Refocus Program" are just now beginning to materialize and should continue to unfold over a number of years. Attributing benefits to the merger as opposed to the "Refocus Program" will be difficult. Customers will risk underwriting ScottishPower's transition programs when, in the absence of such actions, they might reap benefits from the "Refocus Program" at no incremental cost.

4) PACIFICORP'S OTHER PRE-MERGER RE-ENGINEERING

Q. ARE THERE ANY OTHER NEW PACIFICORP PROGRAMS THAT MAY IMPACT EFFICIENCY IN THE NEW FUTURE?

A. Yes there are. Although I do not have specific costs and benefits of these programs, I am aware that PacifiCorp has been developing a number of new programs aimed at improving efficiencies. Several of them--a new distribution service monitoring system, an SAP system that replaces most finance, work management, materials management and human relations computer systems as well as major consolidations of distribution dispatch and accounting--have been featured in PacifiCorp's corporate newsletter "Network," including distribution automation, system mapping, a new SAP system, consolidation of accounting functions and distribution dispatch:

> "<u>Internet-based system helps pinpoint outages</u>:...Last month, PacifiCorp went 'live' with a new Internet-based operation visualization system (OVS). It delivers to the computer screens of field managers, dispatchers and employees an advanced data display capability to show where service interruptions have occurred right down to individual customers...The OVS can take advantage of the nearly $10 million investment we have made to transforming all our paper distribution maps to digital versions..."(May 4, 1998).

> "<u>D2000+ removes mystery from outages</u>:...D2000+ is up and running in Portland. It combines the best of available automation and computer technology into one complete system significantly improving response to customer outages and use of existing physical assets-power lines, transformers and substations. D-2000E is what we believe an electric utility would look like if it were built from scratch...Other utilities have implemented pieces of this technology, but we've tied them all together into one integrated system..." (September 7, 1998).

> "<u>Accounting consolidates/moves to Portland</u>: All accounting functions throughout the company have been consolidated into the controller's department. In addition...most employees in the accounting functions in Salt Lake City will be asked to relocate to Portland as part of a geographic consolidation. In 'benchmarking' with other companies, it became clear that the most effective and efficient way to provide accounting services is through geographic and functional centralization. We will eliminate duplications that were occurring, reduce overall costs and improve business unit support." (February 16, 1998).

> "Distribution dispatch begins move to SCC: The consolidation of region and system dispatching into the Salt Lake Control Center (SCC) took a major step June 10, as distribution dispatchers moved from the Salt Lake Service Center to the SCC...It's the first phase of a plan to combine three dispatch centers into one...The benefits of this consolidation include savings in operation and maintenance by combining three different computer systems into two located in SCC. Eventually, all the dispatching functions will be further consolidated to one computer system." (June 29, 1998).

> "<u>BSIP software demo gets good reviews</u>: Employees in Portland and Salt Lake City recently got a sneak preview of the horsepower of SAP, the software which the business systems integration project (BSIP) will install throughout the company beginning Sept. 1...SAP R/3 software will replace most finance, work management, materials management and human relations computer systems. Implementation will be completed company-wide by the end of 1999, and training begins in some areas this summer." (May 25, 1998).

Further elaboration on these programs can be found in Exhibit ___ (RMA-86). Based on this sampling of PacifiCorp re-engineering programs, ScottishPower has failed to show that PacifiCorp is unable to provide efficiency improvements acting alone, in the absence of a merger.

IV. <u>CUSTOMER RISKS RESULTING FROM THE PROPOSED MERGER</u>

A. <u>IDENTIFIED COSTS</u>

Q. WHAT COSTS HAVE THE APPLICANTS IDENTIFIED IN CONNECTION WITH THE MERGER?

A. Two types of cost have been identified in the Applicants' filing. First are the transaction costs--costs incurred by the merging utilities in conducting studies and transactions necessary to complete the merger application. The second area of costs are transition costs--costs to ScottishPower of implementing the programs and guarantees they have promised.

1) TRANSACTION COSTS

Q. WHAT IS THE APPLICANTS' ESTIMATION OF TRANSACTION COSTS?

A. ScottishPower has indicated that the transaction costs for this merger could be as high as $250 million (ScottishPower's response to Wyoming CAS Second Request Number 1). It acknowledged that "[f]inal costs of the transaction are unknown at this stage".

Q. HAS PACIFICORP INCURRED ANY TRANSACTION COSTS?

A. As of December 31, 1998, PacifiCorp had recorded $13 million in transaction costs, as identified in a response to an Oregon data request. (Applicants' Response to ICNU Data Request Number P1.38). It is not clear how much in additional transaction costs have been incurred by PacifiCorp in 1999. ScottishPower's "Circular to Shareholders" for its June 15, 1999 shareholder meeting provides additional information on acquisition costs:

> "In connection with the Merger, the Combined Group will incur fees and expenses of approximately £132 million (including stamp duty reserve tax) and the cost of redeeming PacifiCorp Preferred Stock of approximately £15 million. Share issue costs of approximately £65 million and the costs of redemption of PacifiCorp Preferred Stock of approximately £15 million will be incurred by PacifiCorp. Other costs, totaling approximately £68 million, relate principally to investment banking fees as well as legal, accounting and regulatory filing fees. These other costs have been taken into account in calculating goodwill in the Unaudited Pro Forma Statement of Net Assets. In total, these costs have been treated as resulting in additional debt of £147 million." (page 62)

Q. HOW HAVE THESE COSTS BEEN RECORDED TO DATE?

A. ScottishPower and PacifiCorp transaction costs have been charged to account 426. (Applicants' Response to UDPU Data Request Number P4.2).

Q. HAVE THE APPLICANTS PROPOSED THAT THESE COSTS BE ABSORBED BY CUSTOMERS?

A. Not yet. The Applicants have stated that account 426, is "a below the line account".

Q. DOES THAT MEAN CUSTOMERS HAVE NO RISKS RELATING TO TRANSACTION COSTS?

A. No. The Applicants have warned that they may attempt to recover transaction costs from customers under certain circumstances:

> "In the interest and expectation of a relatively simple and expeditious approval process, PacifiCorp intended not to seek recovery of its transaction costs from customers. However to the extent parties seek to cause the proposed transaction to be viewed in the same manner as a more typical utility merger, PacifiCorp reserves the right to urge a different approach to transaction cost recovery." (Applicants' Response to UDPU Data Request Number P1.4).

Apparently the Applicants are holding in reserve the option of attempting to shift transaction cost recovery to customers if intervenors or Commission staff attempt to add conditions to the merger approval.

Q. DO THESE LARGE TRANSACTION COSTS PLACE ADDITIONAL PRESSURE ON THE APPLICANTS TO PRODUCE COST SAVINGS?

A. Yes.

Q. ARE THERE OTHER SOURCES OF PRESSURE TO REDUCE COSTS THAT WILL RESULT FROM THE TRANSACTION?

A. Yes. It appears that a significant premium, estimated at times by some to be as high as $1.6 billion, could be paid by ScottishPower for the acquisition of PacifiCorp. This premium will exert additional pressure for significant cost reductions.

Q. THE APPLICANTS' ACTION PLAN INCLUDES SIGNIFICANT COST REDUCTIONS, GREATER INVESTMENT IN FACILITIES AND A SUBSTANTIAL DIVIDEND RETURN TO COMPANY STOCKHOLDERS. TO WHAT EXTENT DOES THIS THREE PART ACTION PLAN CREATE RISK FOR PACIFICORP'S CUSTOMERS?

A. In order to meet all of the above goals, the Applicants must ensure that cost reductions are large enough to sustain both planned investments and stockholder dividend returns. To the extent the cost reductions fail to provide such substantial savings, the company may not be able to meet its objectives.

Q. IF THE EFFICIENCY GAINS DO NOT PRODUCE THE KIND OF COST REDUCTIONS THAT SCOTTISHPOWER ANTICIPATES, WILL THAT IN TURN RESULT IN INCREASED RISK TO CUSTOMERS?

A. Yes, particularly to the extent the dual objectives of aggressive investments and dividends are in conflict with each other. There is a risk that necessary capital investments, maintenance and system improvements may not be undertaken, in order to meet the dividend objective. If aggressive cost reduction programs place greater operational risks on the system, the customers will be at risk of decreased reliability and higher long-term costs.

The Applicants have promised significant improvements in reliability. However, they will also face tremendous pressures to slash costs in dramatic ways. These pressures may well be inconsistent with the promised reliability enhancements. The result could be reduced reliability over time, despite ScottishPower's intentions to the contrary. The applicants have pledged to meet certain performance standards. While these standards contain some basic commitments that may be a worthwhile first step, they do not go nearly far enough in protecting customers from reliability risks. Moreover, the "guarantee" payments to be paid to customers and the charitable contributions proposed for failure to meet certain commitments are wholly inadequate to protect Utah customers from the reliability risks. For example, the promised $100 "guarantee" payment to a commercial or industrial customer if power is not restored within 24 hours is hardly a guarantee and is wholly inadequate, particularly in light of the tremendous economic penalties that will be borne by the Applicants' customers if reliability in fact suffers over time. These consequences, along with potential after-the-fact consequences that might be imposed by the Commission if PacifiCorp allows unacceptable degradations in service or reliability, are hardly of comfort to customers whose businesses may have suffered significant economic losses.

In light of the tremendous cost-cutting pressures and other economic risks associated with the merger, the Applicants' customers are again being asked to bear the risks of the Applicants' promises. The risks to customers are simply not commensurate with any guaranteed benefits to customers.

2) TRANSITION COSTS

Q. WHAT LEVEL OF TRANSITION COSTS DO THE APPLICANTS PROPOSE TO IMPLEMENT THE PROPOSED MERGER?

A. The Applicants have identified a number of programs or actions they intend to undertake once the merger is completed. The transition programs involve system performance standards, customer guarantees, environmental resources, community programs and educational commitment. The projected cost of the transition programs is $135 million.

Q. TO WHAT EXTENT ARE CUSTOMERS EXPOSED TO HIGHER RATES IF THE APPLICANTS' PROPOSED TRANSITION PROGRAMS FAIL TO CREATE SUBSTANTIAL COST SAVINGS?

Applicants' $135 million transition cost proposal is summarized in the previously referenced Exhibit ___ (RMA-1). That exhibit provides a categorical breakdown of the costs that Applicants propose to include as "above the line" items--costs that they believe should be the responsibility of customers--as well as "below the line" costs that they offer at the shareholders' expense.

Q. WITH REFERENCE TO EXHIBIT ___ (RMA- 1), WHAT IS THE BREAKOUT BETWEEN CAPITALIZED AND EXPENSED ITEMS PROPOSED BY SCOTTISHPOWER?

A. Exhibit ___ (RMA-1) illustrates that of the $135 million in proposed transition costs, $92 million are proposed as capitalized expenses, with $43.2 million in the form of expensed items. The Applicants suggest that the "below the line" commitment of stockholders should be roughly $13.6 million—about 10% of the total merger transition cost. The Applicants suggest that $121.6 million--90% of the costs--be absorbed by customers. The Applicants are thus basically proposing to "buy" the purported benefits of the merger with customer money in an effort to make the transaction appear to be in the public interest.

Q. CAN YOU PROVIDE A MORE DETAILED BREAKDOWN OF THESE TRANSITION COSTS AND WHO WILL PAY FOR THEM?

A.

Customer Guarantees:	Customers:	$14.1 million
	Stockholders:	$ 1.0 million

ScottishPower represents that the anticipated $1.0 million of non-performance penalties of its proposed Customer Guarantee program will be funded by stockholders "below the line":

> "The cost of payments to customers as a result of failure to meet customer guarantees will be borne by the company's shareholders, not its customers, i.e. they will be recorded 'below the line'." (Applicants' Response to Utah DPU 8th Request S8.4).

The Applicants' proposal, however, is that customers will pay more than $14 million to implement and operate the program. Exhibit ___ (RMA-1).

Performance Standards: **Customers: $41.5 million**
Stockholders: $ 0

Exhibit ___ (RMA-1) also shows that ScottishPower's proposed performance standards will cost customers $41.5 million for additional network investment, implementation and operation. Under the ScottishPower proposal, there would be no "below the line" participation by stockholders in funding such programs. The proposal exposes customers to a $41.5 million economic risk without any demonstration that such an expenditure will be cost effective. Again, the Applicants suggest spending millions of dollars of customers' money gearing-up for programs that have not been shown to be necessary. Moreover, the proposed "improvements" have not been requested by PacifiCorp customers.

Training: **Customers: $6.0 million**
Stockholders: $ 0

The Applicants suggest that training and open learning programs will cost customers approximately $6 million, with no contributions made by stockholders.

Renewable Resources: **Customers: $60.0 million**
Stockholders: $ 0.1 million

The pledge that ScottishPower has made to develop 50 MW of renewable generation would cost the customers $60 million with a $100,000 stockholder donation to the Bonneville Foundation. The Applicants' proposed 50 MW commitment to renewable generation is far beyond the resource needs as identified in PacifiCorp's RAMPP 5 report. The cost effectiveness of the proposal is thus unsubstantiated. In addition, the 50 MW "commitment" had three "strings" attached to it in Oregon that Applicants failed to disclose in its Utah testimony (Richardson Oregon Direct, page 14, lines 14-16): As testified by Mr. Richardson in Oregon:

> "PacifiCorp will develop an additional 50 MW of renewable resources...at an anticipated cost of approximately $60 million within five years after the approval of the transaction, on the following bases:
>
> - Extension of the system benefit charge and renewables incentive portion of the AFOR;
> - Increase in the Oregon AFOR cap on eligible renewable resources; and
> - Resources must pass the AFOR renewable resource cost-effectiveness standard."(Prefiled Oregon Direct Testimony of Alan Richardson, page 14, lines 14-21)

In the event the Oregon Public Utility Commission does not accept these additional constraints, the value of this renewable "commitment" to the other states would be in doubt.

Q. PLEASE SUMMARIZE THE APPLICANTS' TRANSITION COST PROPOSAL.

A. Applicants propose a $135 million package of transition costs, where 90% of those costs will be charged to PacifiCorp customers:

Total $135 Package:	**Customers:**	**$121.6 million**
	Stockholders:	**$ 13.6 million**

Q. WILL CUSTOMERS BENEFIT FROM THIS $135 MILLION PACKAGE?

A. That is not possible to predict at this point. The net benefits of the $135 million package will only be as real as the cost savings, efficiency gains and needed reliability enhancements that ScottishPower can create as a result. If the merged company has less of an efficiency window than ScottishPower officials currently believe, their ability to create cost savings sufficient to offset the proposed $121 million rate commitment will be lessened. Under such a scenario customers may suffer rate increases to pay for programs that were not necessary or of value to them. In any event, the promised "benefits" would not be a "result" of the merger. Rather, customers are asked to buy the potential benefits with customer money and at customer risk.

Q. THE APPLICANTS CLAIM THAT THEIR CUSTOMER GUARANTEE AND SERVICE STANDARDS REPRESENT A $55 MILLION PACKAGE OF BENEFITS TO THE CUSTOMERS. HOW WILL THE COST OF THESE PACKAGES BE PAID?

A. ScottishPower argues that the $55 million should not be viewed as incremental costs, but "will be achieved through efficiencies within the existing spending plans of PacifiCorp." (Utah Supplemental Testimony of Alan Richardson 4/16/99 at page 1, lines 18-21) The source and payment of these "costs" thus remain a mystery. If ScottishPower is simply reorganizing capital spending priorities or cutting capital budgets, such actions, if prudent, should be demanded of PacifiCorp in any event and they cannot be considered "benefits" of the merger. Once again, customers are asked to "purchase" their purported benefits. Moreover, customers must rely upon only a promise that higher rates will not result from the investments. To the extent that the projected efficiency savings do not materialize, customers are at risk.

Mr. Richardson has recently attempted to "finesse" the propriety of the $55 million package cost by claiming that it will not affect customers:

> "...I must clarify that the estimated $55 million will not cause PacifiCorp's overall capital and revenue budgets to increase, as discussed in my Supplemental Testimony at 7-8. Rather, ScottishPower will seek other efficiencies in capital and operating expenditures, make investments which lead to operational efficiencies, and modify capital projects in PacifiCorp's existing budget. This refocusing of investment will not have an impact on the rates of Oregon customers." (Richardson Oregon Rebuttal, page 10, lines 18-23)

This reasoning, however, is not valid. Assuming that ScottishPower were to make the stated modifications to reduce expenditures, but did not spend the $55 million for service improvements, PacifiCorp's customers would enjoy the benefits of a rate decrease, other things being equal. No matter how the Applicants' spin the characterization of the $55 million service improvements budget, in reality those costs are incremental.

Q. HOW WOULD YOU SUMMARIZE THE OVERALL APPROACH OF APPLICANTS AS TO TRANSITION COSTS?

A. What has been placed on the table is $135 million in planned investments for transition related costs associated with this merger. Of the $135 million, PacifiCorp proposes that 90% be borne by customers. There is no guarantee, and it has certainly not been demonstrated, that the investment can be repaid out of savings generated through efficiency measures. Customers will be asked to pay for the so-called benefits they are supposed to receive. Virtually all of the economic risk has thus been shifted to the customer. The only conclusion to be drawn is that there is a significant asymmetry in the allocation of risks and benefits of the proposed merger.

B. <u>OTHER POTENTIAL RISKS</u>

1) EXECUTIVE SEVERANCE PLAN

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE PROXY STATEMENT'S $7.0 MILLION "PACIFICORP EXECUTIVE SEVERANCE PLAN" AND INDICATE WHETHER THOSE COSTS ARE INCLUDED IN THE $135 MILLION OF TRANSITION COSTS THAT YOU HAVE BEEN DISCUSSING?

A. The May 6, 1999 PacifiCorp Proxy Statement describes the proposed "Executive Severance Plan" as follows:

> "The PacifiCorp Executive Severance Plan ("Executive Plan") provides severance benefits to terminated executives, including enhanced change-in-control benefits in the event of certain terminations during the 24- month period following a qualifying transaction, including the consummation of the merger. Twenty-six PacifiCorp executives are entitled to severance pay under the Executive Plan..." (PacifiCorp Proxy Statement, page 55).

To my knowledge, the Applicants have not identified these costs as part of the $135 million in transition costs and have not explained if they expect these costs to be "above-the-line" costs charged to customers or "below-the-line" costs absorbed by the stockholders. The release of the proxy statement followed the Applicants' direct and supplemental filings. An additional $7 million of uncertainty is thus added to the potential merger costs.

2) BONUS AND RETENTION PLANS

Q. THE PROXY STATEMENT (PAGE 57) ALSO IDENTIFIES PAYMENTS TO PACIFICORP'S DIRECTORS AND RETENTION AND BONUS INCENTIVES. PLEASE SUMMARIZE THESE PROGRAMS AND INDICATE WHETHER THESE COSTS ARE INCLUDED IN THE $135 MILLION.

A. The payments to PacifiCorp's directors are based on the following:

> "Non-employee directors of PacifiCorp have been granted restricted stock under a non-employee directors' stock compensation plan. Stock granted under this plan vests over the five-year plan following the grant or shorter period to retirement, and unvested shares are forfeited if the recipient ceases to be a director. PacifiCorp has agreed to pay each non-employee director $50,000 promptly following the date the director's unvested shares are forfeited following the completion of the merger." (Proxy Statement, page 57).

The PacifiCorp "Retention and Bonus Incentives" are described in the Proxy Statement as follows:

> "PacifiCorp has provided retention incentives to retain employees in key positions through completion of the merger...Therefore, some executive officers of PacifiCorp may receive bonuses or retention incentive awards. (Proxy Statement, page 57).

To my knowledge, the Applicants have not quantified these costs, have not designated them as components of the $135 million in transition costs and have not indicated whether they should be "above-the-line" costs charged to customers or "below-the-line" costs absorbed by the stockholders. This, too, creates additional uncertainty and risk.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THESE SEVERANCE, BONUS AND RETENTION PAYMENTS?

A. It appears that payments to some PacifiCorp officers could be substantial. The potential for these kinds of payments can create and distort incentives in a manner that is inconsistent with the best interests of customers--or even shareholders. The extent and magnitude of payments that may be made to various individuals if the merger is successful should be considered in evaluating the incentives and credibility of those individuals.

C. CONCLUSIONS REGARDING THE TRANSITION PROGRAMS

Q. THE APPLICANTS ARGUE THAT THEIR INABILITY TO QUANTIFY BENEFITS DOES NOT MEAN THAT THE CUSTOMERS WILL NOT BENEFIT AND THAT SAVINGS CAN BE CAPTURED IN TRADITIONAL RATEMAKING PROCEDURES. DO YOU AGREE WITH THIS CONTENTION?

A. Not necessarily. Under the traditional ratemaking process, regulatory lag is a reality. When the uncertain and illusive benefits that will purportedly result from the merger are added to normal complications of regulatory lag, traditional rate proceedings will be an inefficient means of capturing benefits.

Q. DO YOU BELIEVE THAT CUSTOMERS SHOULD RECEIVE SOME KIND OF GUARANTEE THAT THE BENEFITS OF THE PROPOSED EFFICIENCY MEASURES WILL MATERIALIZE?

A. Yes. The Applicants are asking the customers to bear significant risks associated with the merger based on their confidence that savings will ultimately result. The Applicants' actual level of confidence in the availability of substantial efficiency gains can be tested through specific rate reduction or rate cap commitments. An out-of-hand rejection of any rate guarantees suggests that the contemplated efficiencies are not nearly as certain as the Applicants suggest. As such, they cannot be relied upon in gauging purported benefits of the merger. The Applicants have presented a case in which the claimed benefits are highly uncertain and largely unprovable, either before or after the merger, and the economic risks to customers are substantial. Rate guarantees could provide a means for equalizing risks and benefits of the merger.

V. OPPORTUNITY COST OF THE PROPOSED MERGER

Q. WILL THIS MERGER PRODUCE THE TYPES OF SYNERGISTIC BENEFITS TYPICALLY ASSOCIATED WITH MERGERS?

A. No. ScottishPower admits that, because of the distance between the utilities and the lack of overlap in operating systems, there are few synergies between the two companies. Most mergers produce quantifiable economic benefits and significant synergistic effects for the benefit of customers. The proposed merger with ScottishPower not only does not produce these kinds of synergistic benefits, it may very well preclude a future merger with another utility that could produce these kinds of traditional benefits.

ScottishPower argues at considerable length that no significant synergies will result from the merger and that significant cost reductions thus cannot be guaranteed. Ironically, these arguments prove that ScottishPower is not a very good merger candidate. Real synergies can produce quantifiable benefits to customers, as demonstrated by several recent merger proposals involving other utilities, such as Portland General /Enron, Sierra Pacific Resources/Nevada Power, Western Resources/Kansas City Power and Light, American Electric Power/Central Southwest and Northern States Power/ New Century Energies.

A. OTHER AREAS OF RISK

Q. COULD OTHER ASPECTS OF THIS MERGER BESIDES THE LACK OF SYNERGIES RESULT IN FUTURE PROBLEMS FOR CUSTOMERS OF PACIFICORP?

A. Yes. ScottishPower has presented a corporate strategy to become an international multi-utility corporation. It has circulated among parties in this case a four-quadrant table (Exhibit ___ (RMA-9)) demonstrating its transformation from a UK electric company to a multi-utility entity in the UK, its intention to move into an international position in the electricity industry, and its plan from there to venture into the international multi-utility industry. PacifiCorp will thus serve as a base or a platform from which ScottishPower can pursue its strategic goal of becoming a multi-utility provider in an international setting.

Observers of PacifiCorp have already witnessed the risks of attempting to become an international multi-utility. PacifiCorp's failed international efforts left it financially weakened, leading to a significant change of management and the need for the "Refocus Program" to return it to its core business of serving its existing customer base in the western states. Having spent less than a year refocusing on its core business, this merger would send PacifiCorp back in the opposite direction by serving as the platform for multi-utility acquisitions. Whether PacifiCorp customers should again be subjected to risks inherent in these expansive strategic goals is highly questionable. PacifiCorp is once again at risk of losing its focus on its core electric utility operations to the detriment of customers.

In addition, the proposed merger will apparently be structured such that a holding company owned by ScottishPower will own all of the stock of PacifiCorp. As I understand it, in the future the holding company could be sold to another entity and could buy and sell other utilities without approval from this Commission. Moreover, it is far from clear to what extent this Commission may lose its current jurisdiction or control over intra-company transactions and cost allocations as a result of a holding company structure. The result may well be that this Commission could lose significant control that it can currently exercise over the dominant electric utility in this state and its parent.

B. INDUSTRY RESTRUCTURING

Q. **DO OTHER ISSUES ASSOCIATED WITH THIS MERGER HAVE POTENTIAL LONG-TERM IMPLICATIONS FOR CUSTOMERS THAT HAVE NOT BEEN ADEQUATELY EXPLAINED IN THE TESTIMONY OF THE APPLICANTS?**

A. Yes. For example, ScottishPower and PacifiCorp have steadfastly refused to discuss issues relating to electric restructuring in this docket. That silence is very troubling. Whatever one's views of electric restructuring, it is indisputably an issue of major import to all Utah customers. While we do not know when or how the various State Legislatures or the U.S. Congress will enact laws to facilitate industry restructuring, the fact that ScottishPower remains silent on the issue gives customers absolutely no information on ScottishPower's intentions or positions. For example, we do not know whether it will support or oppose reasonable restructuring efforts, its views on how or when restructuring should take place, its position on stranded costs or its view on other vital issues. Customers are being asked to take on a new partner with whom we are to march forward into the future with almost no information about what this partner thinks regarding what is arguably the most important issue confronting the industry and customers today.

C. ACQUISITION STRATEGY

Q. DO OTHER ISSUES RELATING TO THE FILING REMAIN UNCLEAR OR INADEQUATELY DISCUSSED AT THIS TIME?

A. Yes. A May 1, 1998 research report on ScottishPower by HSBC Securities reviewed ScottishPower's previous attempt at merging with Florida Progress, the holding company for Florida Power. Although the merger was not consummated, the analysts reported that the strategy of ScottishPower in that acquisition would likely serve as a model for future attempted acquisitions of U.S. utilities. The strategy centered on the following three components: increase debt on the combined balance sheet of the two companies; issuance of new equity; and divesting of non-network assets (such as generation assets). The relevant section of that report has been attached at Exhibit ___ (RMA-10).

Q. WHAT IS YOUR CONCLUSION REGARDING THE SCOTTISHPOWER ACQUISITION STRATEGY?

A. It is unclear at this time what that strategy entails. If the strategy is a replication of the one utilized in the attempt to acquire Florida Progress, the Applicants have not been forthright in their discussions of the issue.

1) FURTHER DIVESTITURES

Q. TO WHAT EXTENT IS THE "DIVESTITURE" STRATEGY LIKELY TO BE USED IN THE PACIFICORP MERGER?

A. It is unclear at this time. To the extent that ScottishPower hopes to offset the costs of the merger by divesting generation assets, or to the extent that ScottishPower wants to focus on the wires end of the business, divestiture may make sense.

Q. WOULD YOU OPPOSE SUCH DIVESTITURE?

A. Not necessarily. It might be a positive step for addressing market power issues. My concern, once again, is that we have inadequate information about the future intentions of ScottishPower. ScottishPower's failure to provide sufficient information to understand this important issue should concern both customers and regulators alike.

2) UNSECURED DEBT INCREASE TO $5 BILLION

Q. HAS SCOTTISHPOWER ATTEMPTED TO INCREASE PACIFICORP DEBT, AS SUGGESTED BY THE ANALYST'S REPORT?

A. Yes. PacifiCorp's May 16, 1999 Proxy Statement asks its preferred stockholders to authorize increasing the unsecured debt limit from $2.15 billion to $7.15 billion:

> "*Reasons for the Unsecured Debt Consent.* PacifiCorp is seeking the consent of the holders of the PacifiCorp preferred stock to issue up to $5 billion of unsecured indebtedness in addition to the amount permitted to be issued under the present unsecured debt limit. As of March 31, 1999, PacifiCorp had approximately $4.1 billion of indebtedness outstanding, of which approximately $1.2 billion was unsecured.
>
> As competition intensifies in the electric utility industry, as a result of regulatory, legislative and market developments, flexibility and cost structure will be even more crucial to success in the future... PacifiCorp believes that the unsecured debt consent is key to meeting the objectives of flexibility and favorable cost structure..." (Proxy Statement, page 136).

Q. WAS THIS PROPOSAL INCLUDED IN APPLICANTS' FILING WITH THIS COMMISSION?

A. No, it was not. Mr. Green's Exhibit__(RDG-2), the draft proxy statement, does not contain this proposal.

Q. IF APPROVED, COULD THIS SIGNIFICANT INCREASE IN UNSECURED DEBT SUBJECT PACIFICORP'S CUSTOMERS TO ADDITIONAL RISK?

A. Potentially. According to the Proxy Statement (page 136), at this time, PacifiCorp has total outstanding debt of $4.1 billion, of which, $1.2 billion is unsecured debt. Applicants' request to the Preferred Stockholders would provide a more than five-fold increase in unsecured debt. I may have further comments on Applicants' proposal after I have reviewed this in more detail.

Q. HAS PACIFICORP OFFERED TO PAY ITS PREFERRED STOCKHOLDERS TO VOTE IN FAVOR OF THE INCREASED UNSECURED DEBT LIMIT AND APPROVAL OF THE MERGER?

A. Yes, it has. As provided in the Proxy Statement:

> "Special Cash Payments: If, but only if, the merger is approved at the PacifiCorp annual meeting and all regulatory approvals for the merger required under the merger agreement have been obtained, PacifiCorp will make a special cash payment in the amount of $1.00 per share...to each holder of record of PacifiCorp preferred stock on the PacifiCorp record date that voted FOR the merger...
>
> In addition, if, but only if, the unsecured debt consent is approved, PacifiCorp will make a special cash payment in the amount of $1.00 per share...to each holder of PacifiCorp preferred stock on the PacifiCorp record date that voted FOR the unsecured debt consent." (Proxy Statement, pages 138-139).

Q. WILL SUCH PAYMENTS ADD TO THE COST OF THE MERGER?

A. Yes, they will.

3) INTRACOMPANY LOANS

Q. DOES THE APPLICANTS' AMENDED AGREEMENT AND PLAN OF MERGER CONTEMPLATE "INTRA-SCOTTISHPOWER" LOANS AMONG AND BETWEEN SCOTTISHPOWER BUSINESSES?

A. The filed amended agreement does not indicate whether any loans are planned between PacifiCorp and ScottishPower.

Q. ARE YOU AWARE OF ANY EXISTING LOANS BETWEEN SCOTTISHPOWER BUSINESSES?

A. Yes, I am. Manweb's monthly financial reports show that Manweb has consistently made "loans" within the ScottishPower family with an average outstanding monthly balance of £215.2 million for the April 1996 to March 1998 period (Applicants' Response to WIEC 2.3(a)). I do not have access to the necessary documents to ascertain the donors or benefactors of these intra-company loans.

Q. SHOULD PACIFICORP CUSTOMERS BE LOANING FUNDS TO OTHER SCOTTISHPOWER COMPANIES?

A. No. If it is ScottishPower's intention to use PacifiCorp cash flow as a partial funding mechanism for activities undertaken elsewhere in the ScottishPower family of businesses, PacifiCorp customers should be held harmless from any risks associated with such activities, including any foreign exchange risks. ScottishPower has made its intention to become an international multi-utility well known. To the extent that PacifiCorp customers are used as a funding mechanism for such actions, the economic risks to PacifiCorp customers inherent in this proposed merger increases.

4) THE SCOTTISHPOWER 'SPECIAL SHARE"

Q. MR. RICHARDSON REFERS TO THE SCOTTISHPOWER "SPECIAL SHARE" HELD BY THE UK GOVERNMENT (UTAH SUPPLEMENTAL TESTIMONY, PAGE 18). WHAT IS YOUR UNDERSTANDING ABOUT THE SPECIAL SHARE?

A. The "Special Share" apparently acts as a kind of UK "safety net" to ensure that no company can acquire a controlling interest in ScottishPower without consent of the UK government. Moreover, it is not clear what standard the U.K. Government would apply in exercising its rights under the Special Share. The Special Share was described in the Proxy Statement as follows:

> **The ScottishPower Special Share** The U.K. Government (through the Secretary of State for Scotland) holds a special rights non-voting redeemable preference share, which is redeemable at par (£1) only at the option of the Secretary of State for Scotland. The special share, which may only be held by the U.K. government, does not carry any rights to vote at general meetings, but does entitle the holder to receive notice of, attend and speak at general meetings. The articles specify matters, in particular the alteration of specified provisions of the articles including the provision relating to limitations which prevent a person from owning or having an interest in 15% or more of ScottishPower voting shares require the written consent of the holder of the special share. The U.K. government, as holder of the special share, does not have a right to appoint or nominate directors to the ScottishPower Board of Directors.

> If the holding company structure is adopted, the special share in ScottishPower will be cancelled and replaced by an equivalent special share in New ScottishPower, which will be issued to the Secretary of State for Scotland. The New ScottishPower special share will have the same rights as the special share in ScottishPower, together with additional consent rights specified in the articles, the purpose of which will be to ensure that no persons other than New ScottishPower will be able to own or have an interest in more than 15% in aggregate of the ScottishPower voting shares without the Secretary of State's consent." (PacifiCorp Proxy Statement, May 6, 1999, page 122)

Q. HOW MIGHT THE SPECIAL SHARE AFFECT FUTURE COST REDUCTION OPTIONS FOR PACIFICORP CUSTOMERS?

A. The "Special Share" could possibly prevent a future takeover of ScottishPower by a utility that could produce significant cost reductions.

V. CURRENT RISKS SURROUNDING SCOTTISHPOWER'S OPERATIONS AND GLOBAL STRATEGY

Q. SCOTTISHPOWER HAS EMERGED IN THE UK AS AN AGGRESSIVE MULTI-UTILITY INTENT ON MOVING INTO THE GLOBAL MARKET. ARE THERE RISKS ASSOCIATED WITH SCOTTISHPOWER'S STRATEGY?

A. A multitude of risks have begun to be recognized by regulators and the financial community surrounding the actions and strategies ScottishPower seems to be employing. Such risks include the following:

- Risks associated with current UK operations
- Earnings risks of:
  - Manweb
  - Southern Water
  - ScottishPower Transmission
- Capital expenditure program risks
- UK industry restructuring
- US expansion plan risks

A review of UK regulatory information indicates that ScottishPower's financial strength could well be on the downturn. Volatility in ScottishPower's UK earnings base could influence corporate decisions regarding PacifiCorp operations. A down-swing in the financial status of the UK operations, in light of ScottishPower's focus on meeting stockholders' dividend expectations, is likely to place additional pressure for cost reductions in the PacifiCorp system.

Q. YOU INDICATED THAT SCOTTISHPOWER IS LIKELY TO FACE NEW RISKS IN CONNECTION WITH ITS CURRENT EARNINGS. COULD YOU PLEASE EXPLAIN?

A. ScottishPower's earnings could decline over the foreseeable future due to increased UK regulation mandating revenue reductions in a number of ScottishPower's holdings.

In a Wyoming data response ScottishPower commented on these UK regulatory changes:

> "... [P]rice controls have become tighter at each review since privatization. In the case of generation, the allowed revenue from generation purchases for ScottishPower's domestic and small business customers reduced by 24% in real terms from an indexed price established at privatization in 1990 to a market based price in 1997/98. All this is clear evidence of tighter regulation." (ScottishPower's Response to WIEC 1.12(a)).

A May 21, 1999 news article characterized UK utilities at a "strategic crossroads":

> "Strategy and regulation issues will be to the fore when British power and water companies kick off their year to March industry reporting season next week. The sector is racing to secure new income streams, as tightening regulation restricts core business growth. Analysts expect some casualties along the way..." ("UK Utilities at a Strategic Crossroads", Reuters, May 21, 1999)

ScottishPower recognizes the tightening of regulation, but believes the effects on earnings and consequent risk to stockholders and customers may be "minimized" by operating more efficiently:

> "Since privatization of the UK electricity industry in 1990-91, the group has experienced tightening regulation. Revised price controls governing the group's electricity supply activities took effect from April 1, 1998 with a potential further review from April 1, 2000. Reviews of the price controls governing the group's transmission activities, distribution activities and water business are underway and new price controls take effect from April 1, 2000. In addition, wide-ranging changes to the framework of regulatory and industry structure is under discussion as a result of HM Government's Green Paper issued in 1998 and proposals by OFFER. Management believes that by

> operating efficient customer focused businesses regulatory risks are minimized." (ScottishPower's 1998 SEC Form 20-F, page 6).

ScottishPower, however, has not explained or quantified these more efficient operations or how they will "minimize" increased regulatory risks. Whether ScottishPower can provide sustained earnings growth under a long-term scenario of tighter UK regulation is being carefully monitored by investors:

> "ScottishPower Under Pressure: ScottishPower finance director Ian Russell will be fending off questions about the effect of ever-tightening regulation on the utility giant's income as he unveils its preliminary annual results next Thursday...analysts will be looking for reassurance that ScottishPower can protect its revenues in the face of efforts by water, gas and electricity regulators to reduce prices for consumers..." (<u>Accountancy Age</u>, April 29, 1999).

Q. ARE SIMILAR RISKS APPARENT IN SCOTTISHPOWER'S OTHER OPERATING COMPANIES?

A. Yes. On November 3, 1998, one month prior to the announcement of the PacifiCorp acquisition, Moody's Investor Service placed certain ScottishPower senior debt on review for possible downgrade because of the potential for a 20% rate reduction mandated by the UK water regulator ("OFWAT") for ScottishPower's Southern Water Company:

> "Moody's Investors Service Tuesday has placed the long-term senior debt ratings of Scottish Power plc ("Scottish Power" rates Aa2) and its wholly-owned subsidiary Southern Water Services Limited ("Southern Water" rated A1) on review for possible downgrade. The review is prompted by the prospect of significant reductions in regulated earnings, particularly at Southern Water, at a time when Scottish Power is considering international expansion... (<u>ScottishPower PLC Put On Downgrade Review By Moody's</u>, Dow Jones Newswires, November 3, 1998).

ScottishPower has criticized and resisted OFWAT'S proposed price decrease. Recent media reports indicate that Southern Water and OFWAT are not close to resolving their differences:

> "<u>Water Groups Defy Price Cut Demand</u>: Three of the UK's biggest water companies yesterday threw down the gauntlet in their battle with the water regulator, Ofwat, over the amount they can charge customers for the next five years. Only one, Thames Water, is proposing a cut in bills...

> ScottishPower, owner of Southern Water, brushed aside demands for a cut, proposing to raise bills 3.5 percent next year and 3 percent above inflation until 2005...The proposals are in stark contrast to demands for hefty price cuts from Ian Byatt, director-general of Ofwat, last October. In Southern's case, he wanted a 17.5 percent price cut next year.
>
> Nigel Hawkins, utilities analyst at Williams de Broe, said: 'There's a gap between the proposals of Ofwat and Thames Water, but with ScottishPower it's more like a chasm.' (The Independent, April 10, 1999)

As reported in The Scotsman on April 10, 1999:

> "ScottishPower was yesterday heading for a clash with the water regulator, Ian Byatt, countering his proposals for hefty price cuts at its Southern Water subsidiary with plans for a rise instead.
>
> ...Southern Water, bought by ScottishPower in 1996, has above average bills at an expected 273 in 1999-2000, against 245 across the UK, and was facing a 17.5 percent initial price cut.
>
> But ScottishPower argued yesterday that Government plans announced last month to force the water industry to spend an extra 8 billion overall for 2000-2005 on environmental improvements would now land Southern Water with a bill for an extra 500 million on top of the 1 billion it had already earmarked.
>
> ...However, more heated negotiations between ScottishPower, the other water companies and the regulators are expected in the next few months. Mr. Byatt is due to publish revised proposals in July, with a final decision in November." (The Scotsman, April 10, 1999).

Q. **DO SIMILAR REVENUE RISKS FACE MANWEB?**

A. Yes. The Manweb operations are also confronting the prospect of new price controls which will restrict current revenue:

> "Manweb, Scottish Power's Regional Electricity Co., also faces the possibility of significant tariff reductions. While the debt profile of the group-in the absence of any U.S. activity-is not expected to rise significantly, the pricing reviews will weaken cash flow from 2000 and impair debt protection measurements and financial flexibility." (ScottishPower PLC Put On Downgrade Review by Moody's, Dow Jones Newswires, November 3, 1998).

OFFER's intends to publish its final price control proposals on November 1999.

Q. WHAT ABOUT THE CURRENT RATES FOR SCOTTISHPOWER TRANSMISSION?

A. A similar situation exists with the rate structure currently in place at ScottishPower transmission. UK regulators are reviewing the current rate structure and will soon decide on new rates for the years 2000-2004. The decision by OFFER is expected in November of 1999.

Q. HAVE THESE INCREASED REVENUE RISKS RESULTED IN SCOTTISHPOWER REDUCING ITS CAPITAL INVESTMENT IN THE UK?

A. No. In fact, the opposite seems to be the case. ScottishPower has already obligated itself to fund significant UK capital improvements well into the future. OFFER's February 1999 Business Plan Review indicates that ScottishPower is anticipating significant increases in capital spending in the future:

> "...The companies' projected, real increases in the average annual level of gross capital expenditures for the five years from April 2000 to the average during the six years preceding April 2000 are 19 percent for Scottish Hydro-Electric and 67 percent for ScottishPower." ("Reviews of Public Electricity Suppliers 1998-2000: Business Plans for Transmission Businesses in Scotland—Consultation Paper", February 1999, Section 1.20).

Q. HAS THIS INCREASING RISK TO REVENUE HAD ANY IMPACT ON SCOTTISHPOWER'S GLOBAL STRATEGY?

A. Apparently so. Moody's Investors Service has raised a concern that ScottishPower's international expansion plans were primarily being used as an effort to prop-up its languishing earnings in the UK with the corresponding increase in financial risk:

> "In order to counter declining regulated earnings, the group has indicated it will pursue further business opportunities in the UK, as well as the possibility of a significant U.S. acquisition. Moody's review will focus on the group's appetite for increased financial risk in order to meet shareholder demands," the rating agency said." (ScottishPower PLC Put On Downgrade Review By Moody's, Dow Jones Newswires, November 3, 1998).

UK investors have expressed similar concerns about expansion in America and the ensuing risk:

> "Investors Fear Trend to Buy US Utilities: UK institutional investors have voiced concerns about a move by British utilities to buy their counterparts in the US. Complaints about the trend came a month after ScottishPower became the first non-US company to enter the...US electricity market with its...bid for PacifiCorp..." (Financial Times, January 13, 1999).

Q. IT APPEARS THAT SCOTTISHPOWER HAS INCREASING RISKS OF REVENUE DECLINE IN ITS UK OPERATIONS, HAS SIMULTANEOUSLY COMMITTED TO MAJOR CAPITAL EXPENDITURES IN THE UK, AND NOW IS PURSUING GLOBAL EXPANSION THAT INCLUDES PAYMENT OF A SUBSTANTIAL PREMIUM FOR PACIFICORP. HOW COULD THIS AFFECT CUSTOMERS IN THE PACIFICORP SYSTEM?

A. The increasing risks to revenue that ScottishPower is fighting in its UK operations will result in additional pressure for major cost reductions and revenue increases throughout the PacifiCorp system. Dramatic cost reductions could permit revenue to flow from the U.S. operations to help offset these growing financial risks. As discussed above, it is unclear whether such cost reductions are feasible without declines in quality of service and reliability.

VII. ADDRESSING MERGER RELATED RISKS IN OTHER RECENT U.S. MERGERS

Q. THERE HAVE BEEN SEVERAL ELECTRIC MERGERS IN THE U.S. DURING THE LAST FEW YEARS. HOW HAVE MERGER-RELATED RISKS BEEN ADDRESSED IN OTHER PROCEEDINGS?

A. Several mergers have been concluded or are currently being pursued among a number of U.S. electric companies. In most cases, merger approvals have been conditioned on commitments and conditions designed to protect customers from exposure to risks. Following is a brief discussion of summary of several recent mergers and certain accompanying conditions.

Sierra Pacific- Nevada Power (December 1998) – The Nevada Commission (Docket No. 98-7023) approved the merger but only after shifting the majority of economic risk to stockholders. The following language was included in the Commission order:

> "The Commission finds that the merger savings are estimates. Furthermore, when analyzed on a net present value basis, the Commission agrees with the UCA in that the benefit to cost ratios become uncomfortably low. .... Therefore, the Commission finds that the risk of actually realizing merger savings should be placed squarely on the Joint Applicants. (IIIA2).
>
> Given the uncertain benefits associated with this merger, the Commission finds that it is not appropriate to place on customers the risk that they will have to pay for merger costs without receiving merger benefits. Utility management designed the transaction, arranged the terms and incurred the costs."(IIIB2).

American Electric Power – Central and South West Corporation– In this eleven-state merger, the companies have proposed a rate freeze until the year 2005:

> "The merger will form the largest electric utility holding company in the United States, serving 4.6 million customers in the United States (11 states) and more than 4 million customers in the United Kingdom." (CSW Merger Update, parenthetical added).
>
> As a result of the settlement negotiations, AEP has pledged to establish performance standards to maintain or improve customer service and system reliability, to apply to join a federally-approved regional transmission grid organization, and to keep its base rates unchanged until 2005." (Dow Jones Newswires, April 26, 1999).
>
> "The Oklahoma Corporation Commission...signed a final order confirming its May 11 decision to approve the proposed merger...The final order also provides a partial settlement... Among the terms of the Oklahoma settlement, AEP and CSW have agreed to share net merger savings with customers of CSW's subsidiary Public Service Company of Oklahoma (PSO), as well as shareholders, effective with the merger closing; to not increase PSO's base rates above their current levels prior to Jan 1, 2003; to file to join a regional transmission organization by Dec. 31, 2001; and to implement additional quality-of-service standards for PSO." (PR Newswire, May 17, 1999)

Northern States Power – New Century Energies – A rate freeze is anticipated in Colorado:

> "If the deal is completed, the combined company would have 4.5 million electric and natural-gas customers in 12 states stretching from the Canadian to Mexican borders and revenue totaling $6.4 billion a year..." ("Northern States Power, New Century Agree to Merge in $4 Billion Stock Deal", The Wall Street Journal, March 26, 1999).
>
> Colorado regulators say a similar rate cut could emerge from this deal. 'We will review this merger to make sure the customers are not disadvantaged,' said Terry Bote, spokesman for the Colorado Public Utilities Commission. ("Merger Energizes Utility", Rocky Mountain News, March 26, 1999).

Western Resources – Kansas City Power & Light – In its direct case, the Missouri Commission staff opposed the proposed merger:

> "Missouri Public Service Commission staff have recommended against approval of a proposed merger involving Western Resources Inc. and Kansas City Power and Light Co. The Commission said in a statement issued Tuesday that staff had concluded in testimony that the merger in its present form is detrimental to the public interest and should be denied unless various conditions are accepted by the companies.
>
> 'The Companies' proposed regulatory plan for rate treatment of merger costs and savings, if adopted, will lead to Missouri customers receiving very little or no rate benefit', said staff account Mark Oligschlaeger in filed testimony." ("Missouri PSC Staff Oppose W. Resources/KCPL Merger", Reuters, April 27, 1999).

A stipulation was recently announced between Western Resources and the Kansas Corporation Commission Staff. One of the proposed recommendations for settlement was:

> "There will be an electric rate moratorium of four years beginning on the date the transaction closes." (Western Resources Press Release, May 6, 1999).

Q. IT WOULD APPEAR THAT THE MERGER APPROVAL ORDERS DISCUSSED ABOVE IMPOSED CONDITIONS AS A MEANS TO PROTECT CUSTOMERS' INTERESTS. DO YOU BELIEVE THAT SIMILAR CONDITIONS SHOULD BE ORDERED IN THIS MERGER APPLICATION?

A. As detailed above, I do not believe that the transaction as currently proposed by the Applicants is in the public interest. The benefits are speculative and uncertain and the risks are substantial. In my view, the proposed transaction cannot be considered in the public interest unless it is changed significantly, through mandatory or voluntary conditions, so as to effectively place all of the risks of the merger on the Applicants' shareholders.

VIII. MERGER CONDITIONS

Q. WHAT TYPES OR FORMS OF CONDITIONS WOULD YOU SUGGEST THIS COMMISSION CONSIDER IF IT APPROVES THE MERGER?

A. I have not yet been able to develop, nor have I seen, a complete set of merger conditions that I believe would be adequate to minimize risks to PacifiCorp's customers. It is possible that an adequate set of conditions could be developed, but it would be complicated. If the Commission wishes to develop a set of conditions, a good starting point would be conditions imposed by UK regulators in connection with this and previous acquisitions by ScottishPower, conditions agreed to by or imposed on the Applicants in other states in connection with this proposed merger, and conditions utilized in connection with other recent mergers. Among the areas that should be covered by conditions are the following:

1. ScottishPower should be forced to convert its claimed efficiencies and cost reductions into price stability or price reduction guarantees. A five-year period of such rate guarantees should be required, consistent with the five-year benefit flow that the Applicants have assured us will result from their actions.

2. ScottishPower should be required to adopt adequate "safety net" conditions to insulate PacifiCorp from acts and risks of its parent and affiliates, including the requirements imposed in connection with the Southern Water acquisition.

1. ScottishPower should be required to separate financings in order to ensure that investments are properly made for each of the acquired companies, including those required in ScottishPower's UK acquisitions.

2. ScottishPower should be required to follow strict "arms-length transaction" criteria between or among related companies, including "ring fence" conditions like those required by OFFER. ScottishPower should also be required to consent to continued jurisdiction and control by this Commission over affiliate transactions and cost allocations.

5. ScottishPower should be required to meet strict conditions before distributing PacifiCorp dividends, including requirements imposed by UK regulators:

> "OFFER has proposed that, before recommending or declaring any dividend or other distribution, the directors of a PES should certify to the DGES that the licensee is in compliance with the ring-fencing conditions of its PES license and that payment of the dividend or making the distribution would not result, either alone or when taken together with any other reasonably foreseeable circumstance, in a breach of such conditions." (February 11, 1999, OFFER, "Modifications to Public Electricity Supply Licenses Following Takeover; Response to Consultation by the Office of Electricity Regulation", page 8).

6. Stringent reliability conditions should be developed and imposed to ensure that PacifiCorp customers do not suffer degradations in quality of service or reliability as a result of the merger. Among other things, the consequences for failure to meet reliability requirements or guarantees should be commensurate with the potential economic harm to customers.

IX. CONCLUSION

Q. **PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE MERGER APPLICATION.**

A. The Applicants' filing fails to establish an affirmative case of demonstrable benefits of the proposed merger that equal or exceed economic risks or costs to PacifiCorp customers.

Efforts to recover acquisition premiums, transition costs and transaction costs, to shore up uncertain U.K. returns and to fund significant shareholder dividends will create tremendous pressure to slash personnel, maintenance and operating budgets and other costs, resulting in significant risks of reduced quality of service and reliability degradations over time, with the potential for staggering economic damages to PacifiCorp customers.

Expenses necessary to implement the Applicants' proposed transition program include $121.6 million in customer commitments to underwrite approximately 90% of the program package costs. In order to be rate neutral, the $121.6 million in expenses must ultimately be offset by equal or greater operational savings. The extent to which this degree of efficiency gains are available in the PacifiCorp system is uncertain and unsubstantiated. Neither the Applicants' claimed experiences with Manweb nor their "high level" benchmarking analysis produces meaningful or quantifiable results that can be used to support a finding of merger benefits. In essence, the Applicants propose to try to reduce PacifiCorp's costs by investing $121 million in customer funds. Beyond that, there are no guarantees, commitments, plans of action or affirmative showings that the proposed investments are needed or desirable or will produce the anticipated savings.

The merger proposal produces an unfair and asymmetrical benefit/cost equation. Benefits to customers are highly uncertain, speculative and incapable of quantification. Customer risks are apparent. To avoid customer exposure to these risks, the application should be denied or significantly altered through voluntary or mandatory conditions designed to insulate customers from both rate and reliability risks. If the Applicants' shareholders desire to proceed with this merger despite the absence of demonstrable benefits to PacifiCorp customers, they and they alone should bear all significant risks of the merger. Customers should be held harmless. Meaningful rate/cost-reduction guarantees, financial assurances, reliability conditions and other meaningful protections should be required

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was mailed, postage prepaid, this 18th day of June, 1999, to the following:

Edward Hunter
John Eriksson
STOEL RIVES
201 South Main Street, Suite 1100
Salt Lake City, UT 84111

Brian W. Burnett
CALLISTER NEBEKER & MCCULLOUGH
10 East South Temple, #800
Salt Lake City, UT 84133

Michael Ginsberg
ASSISTANT ATTORNEY GENERAL
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111

Douglas C. Tingey
ASSISTANT ATTORNEY GENERAL
Committee of Consumer Services
160 East 300 South, 5th Floor
Salt Lake City, UT 84111

Daniel Moquin
ASSISTANT ATTORNEY GENERAL
1594 West North Temple, Suite 300
Salt Lake City, UT 84116

F. Robert Reeder
William J. Evans
PARSONS BEHLE & LATIMER
201 South Main Street, Suite 1800
P.O. Box 45898
Salt Lake City, UT 84145-0898

Stephen R. Randle
RANDLE DEAMER ZARR ROMRELL & LEE
139 East South Temple, Suite 330
Salt Lake City, UT 84111

Peter J. Mattheis
Matthew J. Jones
BRICKFIELD BURCHETTE & RITTS
1025 Thomas Jefferson Street, N.W.
800 West Tower
Washington, D.C. 20007

Eric Blank
Land and Water Fund of the Rockies
2260 Baseline Rd., Suite 200
Boulder, CO 80302

Matthew F. McNulty, III
VANCOTT BAGLEY CORNWALL & MCARTHY
50 South Main Street, Suite 1600
P.O. Box 45340
Salt Lake City, UT 84145

Lee R. Brown
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, UT 84116

Bill Thomas Peters
David W. Scofield
PARSONS DAVIES KINGHORN & PETERS
185 South State Street, Suite 700
Salt Lake City, UT 84111

Dr. Charles E. Johnson
The Three Parties
1338 Foothill Blvd., Suite 134
Salt Lake City, UT 84108

Steven W. Allred
Salt Lake City Law Department
451 S. State, Suite 505
Salt Lake City, UT 84111

Roger O. Tew
60 South 600 East, Suite 200
Salt Lake City, UT 84102

Paul T. Morris
3600 Constitution Blvd.
West Valley City, UT 84119

Toni Tibbitts

RMA_ Exhibit 1

ScottishPower's Estimate of Cost of Merger Commitments

	Above-the-line		Below-the-line		Total		Ratepayer's Share	
	Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed
Customer Guarantees								
Implementation/Set-up	$900,000	$0	$0	$0	$900,000	$0	100.00%	
Operating Costs	$0	$13,200,000	$0	$0	$0	$13,200,000		100.00%
Provision for Customer Payments	$0	$0	$0	$1,000,000	$0	$1,000,000		0.00%
Total-Customer Guarantees	$900,000	$13,200,000	$0	$1,000,000	$900,000	$14,200,000	100.00%	92.96%
Performance Standards								
Additional Network Investment	$27,500,000	$0	$0	$0	$27,500,000	$0	100.00%	
Implementation/Set-up	$3,600,000	$0	$0	$0	$3,600,000	$0	100.00%	
Operating Costs	$0	$10,400,000	$0	$0	$0	$10,400,000		100.00%
Total-Performance Standards	$31,100,000	$10,400,000	$0	$0	$31,100,000	$10,400,000	100.00%	100.00%
Training/Open Learning Initiatives								
Development Cost		$3,000,000	$0	$0	$0	$3,000,000		100.00%
Operating Cost		$3,000,000	$0	$0	$0	$3,000,000		100.00%
Total-Training/Open Learning	$0	$6,000,000	$0	$0	$0	$6,000,000		100.00%
PacifiCorp Foundation Contribution	$0	$0	$0	$5,000,000	$0	$5,000,000		0.00%
Customer Care Initiatives	$0	$0	$0	$7,500,000	$0	$7,500,000		0.00%

ScottishPower's Estimate of Cost of Merger Commitments

	Above-the-line		Below-the-line		Total		Ratepayer's Share	
	Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed
Environmental Commitments								
Bonneville Foundation				$100,000	$0	$100,000		0.00%
Renewable Generation	$60,000,000				$60,000,000	$0	100.00%	
Total-Environmental	$60,000,000	$0	$0	$100,000	$60,000,000	$100,000	100.00%	0.00%
Total Merger "Commitments"	$92,000,000	$29,600,000	$0	$13,600,000	$92,000,000	$43,200,000	68.05%	31.95%
					$135,200,000			

	Percentage Contribution	Total Capital & Expense
Above-the-line	89.94%	$121,600,000
Below-the-line	10.06%	$13,600,000
Total	100.00%	$135,200,000

Source: Applicants' Response to Oregon Staff Request SP34 and Wyoming CAS 5.154.
Applicants' Response to LCG Request 1.29.

RMA__Exhibit 2

WYOMING

20000-EA-98-141

PACIFICORP

APRIL 9, 1999

WIEC DATA REQUEST
ATTACHMENT RESPONSE O'BRIEN 28b

Rankings

July 1, 1998

Printed in the United States of America

Table of Contents

****

* Typical electric bills within each service classification are *
* ranked from high to low. Thus, the highest bill within a *
* service classification for any demand and/or usage level will *
* receive a ranking of 1, the next highest 2, etc. *

****

Edison Electric Institute
Average revenue in cents/kWh ranked, INCLUDING INTERNATIONAL RATES

Ranking of 185 utilities total retail average revenue for the 12 months ending June 30, 1998

185	ESKOM	SA	2.24
184	Manitoba Hydro	CN	3.28
183	Hydro-Quebec	CN	3.41
182	Idaho Power Company	NV	3.58
181	Idaho Power Company	ID	3.61
180	PacifiCorp	WY	3.71
179	PacifiCorp	ID	3.76
178	AmerenUE	IL	3.79
177	Wisconsin Electric Power Company	MI	3.82
176	Monongahela Power Company	OH	3.91
175	AEP (Kentucky Power Rate Area)	KY	4.00
174	Kentucky Utilities Company	KY	4.03
173	OG&E Electric Services	AR	4.05
172	Minnesota Power Company	MN	4.09
171	Idaho Power Company	OR	4.12
170	Wisconsin Public Service Corporation	MI	4.14
169	Washington Water Power Company	ID	4.25
168	AEP (Ohio Power Rate Area)	OH	4.26
167	PacifiCorp - Wyoming West	WY	4.32
166	AEP (Kingsport Power Rate Area)	TN	4.35
165	Cheyenne Light, Fuel & Power Company	WY	4.37
164	Southwestern Public Service Company	TX	4.41
163	PacifiCorp	MT	4.44
162	South Beloit Water, Gas & Electric Company	IL	4.45
161	Wisconsin Public Service Corporation	WI	4.47
160	PacifiCorp	WA	4.52
159	Edmonton Power	CN	4.53
158	Southwestern Electric Power Company	TX	4.55
157	Empire District Electric Company	AR	4.61
156	Public Service Company of Oklahoma	OK	4.63
155	AEP (Appalachian Power Rate Area)	WV	4.64
154	AEP (Appalachian Power Rate Area)	VA	4.66
153	Southern Indiana Gas & Electric Company	IN	4.70
152	AEP (Wheeling Power Rate Area)	WV	4.72
151	Washington Water Power Company	WA	4.77
150	PSI Energy, Inc.	IN	4.82
149	Duke Power Company	SC	4.84
148	Old Dominion Power Company	VA	4.85
147	Southwestern Electric Power Company	AR	4.88
146	Interstate Power Company	IL	4.90
145	Southwestern Public Service Company	NM	4.91
144	Portland General Electric Company	OR	4.97
143	Potomac Edison Company	MD	4.98
142	PacifiCorp	UT	4.99
141	Transalta Utilities	CN	5.02
140	Wisconsin Power & Light Company	WI	5.03
139	Otter Tail Power Company	MN	5.04
138	KEPCO	KO	5.05
137	PacifiCorp	OR	5.08
136	West Penn Power Company	PA	5.11
135	KPL Company	KS	5.12
134	Entergy Gulf States, Inc.	TX	5.16
133	St. Joseph Light & Power Company	MO	5.27
132	Northern States Power Company (Minnesota	ND	5.30
131	Monongahela Power Company	WV	5.30
130	Southwestern Public Service Company	OK	5.34
129	Black Hills Power & Light Company	MT	5.36
128	Public Service Company of Colorado	CO	5.38
127	Nova Scotia Power, Inc.	CN	5.39
126	Montana Power Company	MT	5.41
125	Alabama Power Company	AL	5.42
124	Union Light, Heat and Power	KY	5.43
123	Southwestern Electric Power Company	LA	5.44
122	Edison Sault Electric Company	MI	5.45
121	OG&E Electric Services	OK	5.48
120	Indianapolis Power & Light Company	IN	5.49
119	Nevada Power Company	NV	5.49
118	Interstate Power Company	IA	5.50
117	Otter Tail Power Company	ND	5.51
116	Otter Tail Power Company	SD	5.60
115	Empire District Electric Company	KS	5.62
114	Kansas City Power & Light Company	MO	5.62
113	Northern States Power Company (Wisconsin)	WI	5.62
112	Madison Gas & Electric Company	WI	5.67
111	Entergy Louisiana, Inc.	LA	5.68
110	Entergy Gulf States, Inc.	LA	5.70
109	AEP (Indiana Michigan Power)	IN	5.72
108	Duke Power Company	NC	5.73
107	Empire District Electric Company	MO	5.73
106	Puget Sound Power & Light Company	WA	5.77
105	Wisconsin Electric Power Company	WI	5.79
104	North Carolina Power	NC	5.80
103	Montana-Dakota Utilites Company	MT	5.81
102	Empire District Electric Company	OK	5.83
101	Potomac Edison Company	VA	5.85
100	Potomac Edison Company	WV	5.87
99	Central Illinois Light Company	IL	5.87
98	IES Utilities, Inc.	IA	5.88
97	Northern States Power Company (Minnesota)	MN	5.90
96	West Texas Utilities Company	TX	5.92
95	Carolina Power & Light Company	SC	5.97
94	Northern States Power Company (Minnesota)	SD	5.99
93	AmerenUE	MO	6.00
92	Central Louisiana Electric Company	LA	6.03
91	Houston Lighting & Power Company	TX	6.06
90	Black Hills Power & Light Company	WY	6.07
89	Northern States Power Company (Wisconsin)	MI	6.11
88	Georgia Power Company	GA	6.13
87	MidAmerican Energy	IL	6.21
86	Central Power & Light Company	TX	6.25
85	Virginia Power	VA	6.26
84	Cincinnati Gas & Electric Company	OH	6.26
83	Savannah Electric & Power Company	GA	6.31
82	Southwestern Public Service Company	KS	6.33
81	Montana-Dakota Utilities Company	WY	6.35
80	AEP - Indiana Michigan	MI	6.36
79	MidAmerican Energy	IA	6.36
78	Carolina Power & Light Company	NC	6.37
77	AEP (Columbus Southern Power Rate Area)	OH	6.39
76	Sierra Pacific Power Company	NV	6.41
75	Montana-Dakota Utilities Company	ND	6.43
74	KG&E Company	KS	6.54
73	Central Illinois Public Service Company	IL	6.55
72	TU Electric	TX	6.55
71	Northern Indiana Public Service Company	IN	6.59
70	Upper Peninsula Power Company	MI	6.62
69	Tampa Electric Company	FL	6.66
68	Entergy New Orleans, Inc.	LA	6.67
67	Dayton Power & Light Company	OH	6.67
66	Interstate Power Company	MN	6.82
65	Consumers Energy	MI	6.84
64	Black Hills Power & Light Company	SD	6.86
63	Nantahala Power & Light Company	NC	6.87
62	Entergy Arkansas, Inc.	AR	6.97
61	Kansas City Power & Light Company	KS	6.98
60	Pennsylvania Electric Company	PA	7.06
59	Baltimore Gas & Electric Company	MD	7.10
58	Florida Power Corporation	FL	7.11
57	Entergy Mississippi, Inc.	MS	7.12
56	Florida Power & Light Company	FL	7.15
55	Northwestern Wisconsin Electric Company	WI	7.19
54	Potomac Electric Power Company	MD	7.20
53	PacifiCorp	CA	7.23
52	Pennsylvania Power & Light Company	PA	7.29
51	Potomac Electric Power Company	DC	7.54
50	Detroit Edison Company	MI	7.60
49	Metropolitan Edison Company	PA	7.61
48	COPEL-Companhia Paranaense de Energia	BR	7.80

Edison Electric Institute

Average revenue in cents/kWh ranked, INCLUDING INTERNATIONAL RATES

Ranking of 185 utilities total retail average revenue for the 12 months ending June 30, 1998

47	Union Fenosa	SP	7.9
46	PNM	NM	7.9
45	Arizona Public Service Company	AZ	8.0
44	Montana-Dakota Utilities Company	SD	8.1
43	Tucson Electric Power Company	AZ	8.2
42	UGI Utilities, Inc. (Electric Utilities Division)	PA	8.2
41	El Paso Electric Company	TX	8.2
40	Commonwealth Edison Company	IL	8.3
39	Niagara Mohawk Power Corporation	NY	8.4
38	Duquesne Light Company	PA	8.4
37	Iberdrola	SP	8.5
36	Central Hudson Gas & Electric Corporation	NY	8.5
35	El Paso Electric Company	TX	8.8
34	Green Mountain Power Company	VT	8.9
33	Public Service Electric & Gas Company	NJ	9.2
32	San Diego Gas & Electric Company	CA	9.5
31	Western Massachusetts Electric Company	MA	9.5
30	PECO Energy	PA	9.6
29	Central Maine Power Company	ME	9.65
28	Pacific Gas & Electric Company	CA	9.67
27	Southern California Edison	CA	9.75
26	Blackstone Valley Electric Company	RI	9.81
25	Rochester Gas & Electric Corporation	NY	9.82
24	Concord Electric Company	NH	9.90
23	Bangor Hydro-Electric Company	ME	10.00
22	Eastern Edison Company	MA	10.16
21	Maine Public Service Company	ME	10.16
20	Exeter & Hampton Electric Company	NH	10.24
19	Connecticut Light & Power Company	CT	10.42
18	Hawaiian Electric Company	HI	10.66
17	Fitchburg Gas & Electric Light Company	MA	10.83
16	GPU Energy	NJ	10.88
15	Boston Edison Company	MA	11.00
14	Central Vermont Public Service Corporation	VT	11.13
13	Newport Electric Corporation	RI	11.17
12	United Illuminating Company	CT	11.54
11	Commonwealth Electric Company	MA	11.65
10	Public Service Company of New Hampshire	NH	12.12
9	Chubu Electric Power Co., Inc.	JP	13.29
8	MarketSpan	NY	13.50
7	Maui Electric Company (Maui)	HI	13.68
6	Consolidated Edison Company of New York	NY	13.98
5	Barbados Light & Power Co., Ltd.	BA	14.48
4	Hawaii Electric Light Company	HI	17.49
3	Maui Electric Company (Molokai)	HI	18.45
2	Maui Electric Company (Lanai)	HI	18.72
1	Bermuda Electric Light Co., Ltd.	BE	22.69

RMA__Exhibit 3

ScottishPower

DELIVERING VALUE

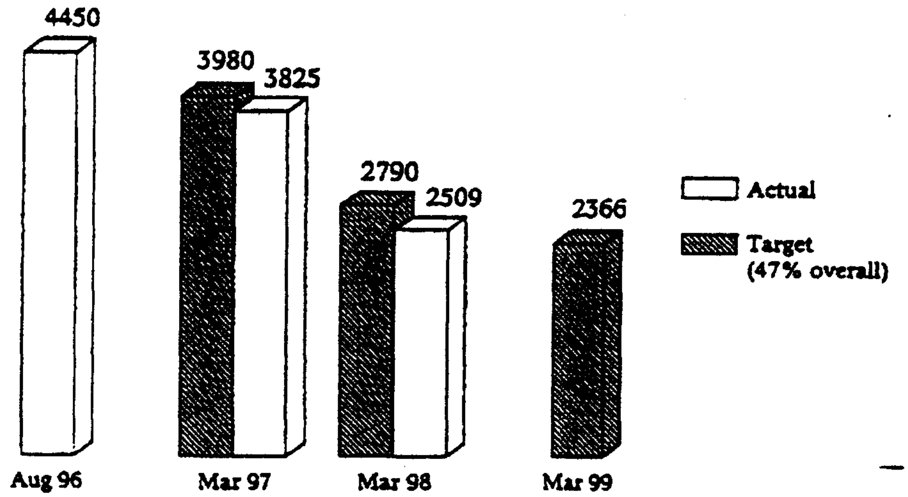
June 1998

Notes

SP0150

TRANSITION PLAN

Manpower Reduction

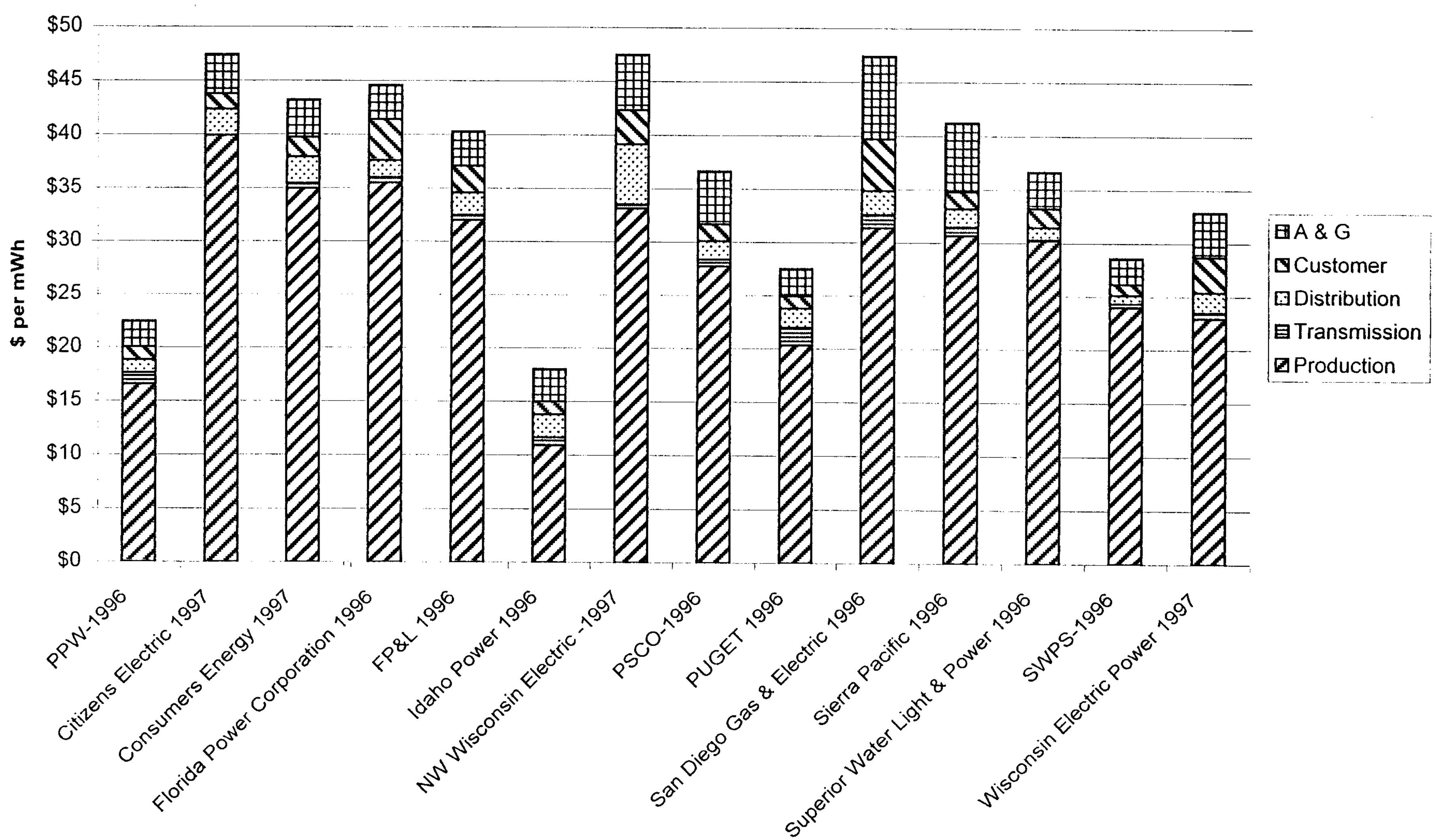


Notes

SP0268

RMA__Exhibit 4

Operations and Maintenance Expenses



Operations and Maintenance Expenses

Category: / Ferc accounts:		Production 500 - 557	Transmission 560 - 573	Distribution 580 - 598	Customer 901 - 916	A & G 920 - 935	TOTAL
Company:							
PPW-1996		$ 1,241,365,514	$ 78,625,174	$ 91,163,912	$ 91,421,874	$ 180,620,970	$ 1,683,197,444
	$ / mWh	$ 16.5641	$ 1.0491	$ 1.2164	$ 1.2199	$ 2.4101	$ 22.4597
Citizens Electric 1997		$ 6,541,335		$ 400,250	$ 234,159	$ 599,241	$ 7,774,985
	$ / mWh	$ 39.9115	$ -	$ 2.4421	$ 1.4287	$ 3.6562	$ 47.4385
Consumers Energy 1997		$ 1,324,101,129	$ 19,814,594	$ 92,838,272	$ 68,519,102	$ 132,281,254	$ 1,637,554,351
	$ / mWh	$ 34.9545	$ 0.5231	$ 2.4508	$ 1.8088	$ 3.4920	$ 43.2292
Florida Power Corporation 1996		$ 1,189,709,690	$ 16,543,311	$ 53,009,811	$ 127,274,621	$ 106,900,780	$ 1,493,438,213
	$ / mWh	$ 35.5216	$ 0.4939	$ 1.5827	$ 3.8001	$ 3.1918	$ 44.5902
FP&L 1996		$ 2,586,908,939	$ 39,224,778	$ 168,362,963	$ 204,033,967	$ 259,621,513	$ 3,258,152,160
	$ / mWh	$ 32.0172	$ 0.4855	$ 2.0838	$ 2.5253	$ 3.2132	$ 40.3250
Idaho Power 1996		$ 182,072,817	$ 12,162,296	$ 35,885,406	$ 20,317,552	$ 50,472,900	$ 300,910,971
	$ / mWh	$ 10.9057	$ 0.7285	$ 2.1494	$ 1.2170	$ 3.0232	$ 18.0238
NW Wisconsin Electric -1997		$ 4,777,290	$ 53,020	$ 811,250	$ 456,775	$ 749,034	$ 6,847,369
	$ / mWh	$ 33.1558	$ 0.3680	$ 5.6303	$ 3.1702	$ 5.1985	$ 47.5228
PSCO-1996		$ 694,519,018	$ 16,044,609	$ 43,041,438	$ 39,619,286	$ 125,118,521	$ 918,342,872
	$ / mWh	$ 27.7448	$ 0.6410	$ 1.7194	$ 1.5827	$ 4.9983	$ 36.6862
PUGET 1996		$ 506,463,260	$ 40,519,702	$ 45,613,758	$ 29,070,982	$ 65,386,820	$ 687,054,522
	$ / mWh	$ 20.3095	$ 1.6249	$ 1.8291	$ 1.1658	$ 2.6221	$ 27.5513
San Diego Gas & Electric 1996		$ 543,129,573	$ 21,713,954	$ 38,778,939	$ 83,790,339	$ 133,707,837	$ 821,120,642
	$ / mWh	$ 31.3843	$ 1.2547	$ 2.2408	$ 4.8418	$ 7.7262	$ 47.4479
Sierra Pacific 1996		$ 245,280,526	$ 6,685,708	$ 13,708,401	$ 12,693,345	$ 51,630,791	$ 329,998,771
	$ / mWh	$ 30.6752	$ 0.8361	$ 1.7144	$ 1.5875	$ 6.4570	$ 41.2702
Superior Water Light & Power 1996		$ 16,533,162	$ 43,087	$ 634,964	$ 953,652	$ 1,902,574	$ 20,067,439
	$ / mWh	$ 30.2488	$ 0.0788	$ 1.1617	$ 1.7448	$ 3.4809	$ 36.7151
SWPS-1996		$ 505,952,816	$ 7,776,457	$ 17,199,327	$ 22,216,468	$ 52,173,172	$ 605,318,240
	$ / mWh	$ 23.9412	$ 0.3680	$ 0.8139	$ 1.0513	$ 2.4688	$ 28.6431
Wisconsin Electric Power 1997		$ 634,130,823	$ 15,143,154	$ 53,339,739	$ 92,146,722	$ 117,251,452	$ 912,011,890
	$ / mWh	$ 22.9160	$ 0.5472	$ 1.9276	$ 3.3300	$ 4.2372	$ 32.9580

Electric Plant in Service - Total

Category Ferc accounts:	Intangible 301 - 303	Production 310 - 346	Transmission 350 - 359	Distribution 360 - 373	General 389 - 398	TOTAL
Company:						
Pacificorp 1996	$ 215,481,195	$ 4,659,166,788	$ 2,069,194,366	$ 3,029,739,091	$ 1,129,000,451	$ 11,102,581,891
Florida Power 1996	$ 77,463,819	$ 2,715,512,061	$ 831,323,915	$ 1,986,961,573	$ 334,170,925	$ 5,945,432,293
Florida Power / Light 1996	$ 181,019,828	$ 7,711,633,398	$ 2,091,675,481	$ 5,350,008,474	$ 896,363,716	$ 16,230,700,897
Idaho Power 1996	$ 6,929,536	$ 1,323,090,245	$ 371,123,084	$ 688,231,670	$ 148,644,481	$ 2,538,019,016
PSCo. 1996	$ 12,411,143	$ 1,628,984,651	$ 551,984,915	$ 1,601,743,188	$ 37,974,287	$ 3,833,098,184
Puget Sound 1996	$ 50,714,395	$ 926,705,837	$ 535,661,135	$ 1,634,462,888	$ 236,972,129	$ 3,384,516,384
Sierra Pacific 1996	$ 2,786,598	$ 516,240,654	$ 328,475,188	$ 589,357,168	$ 57,953,210	$ 1,494,812,818

Electric Plant in Service - Unit Costs

($ / mWh)

Category Ferc accounts:	Intangible 301 - 303	Production 310 - 346	Transmission 350 - 359	Distribution 360 - 373	General 389 - 398	TOTAL
Company:						
Pacificorp 1996	$ 2.8753	$ 62.1693	$ 27.6102	$ 40.4272	$ 15.0648	$ 148.1467
Florida Power 1996	$ 2.3129	$ 81.0781	$ 24.8212	$ 59.3255	$ 9.9775	$ 177.5152
Florida Power / Light 1996	$ 2.2404	$ 95.4441	$ 25.8879	$ 66.2151	$ 11.0940	$ 200.8816
Idaho Power 1996	$ 0.4151	$ 79.2497	$ 22.2293	$ 41.2233	$ 8.9034	$ 152.0208
PSCo. 1996	$ 0.4958	$ 65.0750	$ 22.0508	$ 63.9868	$ 1.5170	$ 153.1254
Puget Sound 1996	$ 2.0337	$ 37.1615	$ 21.4804	$ 65.5430	$ 9.5027	$ 135.7213
Sierra Pacific 1996	$ 0.3485	$ 64.5620	$ 41.0797	$ 73.7060	$ 7.2477	$ 186.9439

RMA__Exhibit 5

The Fortnightly 100

Which Utility Ranks The Highest?

Despite what one may think, the industry isn't showing strong signs of improved efficiency.

By Janice Forrester, M. Sami Khawaja, Hossein Haeri, and Michael Carter

IT TAKES LABOR, FUEL, OPERATING CASH AND INVESTMENT capital to produce and deliver electric power. Which utilities have managed to use these resources optimally to produce and sell kilowatt-hours? How do these utilities compare with each other? Is there room for improvement?

And what about financial success? Does efficiency, as measured by a ratio of inputs to outputs, serve as a reliable predictor of market-to-book ratios or merger premiums?

Some of these questions are answerable; others not. Yet a simple observation of the range of utility expenses on the four basic inputs—fuel, capital, labor and O&M—can provide a window of which company we might choose to label as "most efficient." This method also allows a less-efficient utility to identify "peer" companies higher up on the ladder, to mark as examples to emulate.

Economists have wrestled with these questions for a long time. Several ways to provide an answer have been proposed and used, from the simple back-of-the-envelope method to complex multi-equation econometric models. The questions and the tools are becoming increasingly relevant in today's utility markets. To stay competitive in a restructured environment, utilities are searching for ways to understand productive efficiency better, to cut costs and to ensure survival in the 21st century.

Using historical data for 140 holding companies in the United States, we analyzed the relative efficiency of the top 100 using Data Envelopment Analysis (DEA), an approach for measurement of operational efficiencies and identification of "peers" to be used as best benchmarks.[1]

Economic theory of productive efficiency is based on the comparative analysis of the best-in-class producers vis-à-vis all others. The criterion for determining the "best" producers refers to the ability to produce maximum output given a specific level of input, or conversely, the ability to use the least amount of input to produce a specific level of output. DEA is a linear programming technique first introduced in the early 1980s by Charnes, Cooper and Rhodes. It has since been used in various applications ranging from healthcare to banking to retail. *Fortune* magazine stated that DEA is a tool every manager must have if his business is to remain competitive. We used static and dynamic DEA methods to measure annual operational efficiencies of holding companies as well as their respective improvements over time.[1]

Striving for Efficiency

Increases in productivity may prove the key to competitive advantage of any economic enterprise. Yet few take the necessary steps to actually measure it. The measurement of productivity by economists, for the most part, is based on comparisons between inputs and outputs. The complexity ranges from Robert Solow's econometric production functions to the Jorgenson Divisia index to simple ratios of output to input (for example, MWh per employee).

Productive efficiency can be measured in terms of input-conserving or output-increasing orientation. Choice

The Fortnightly Five

Most Efficient Utilities

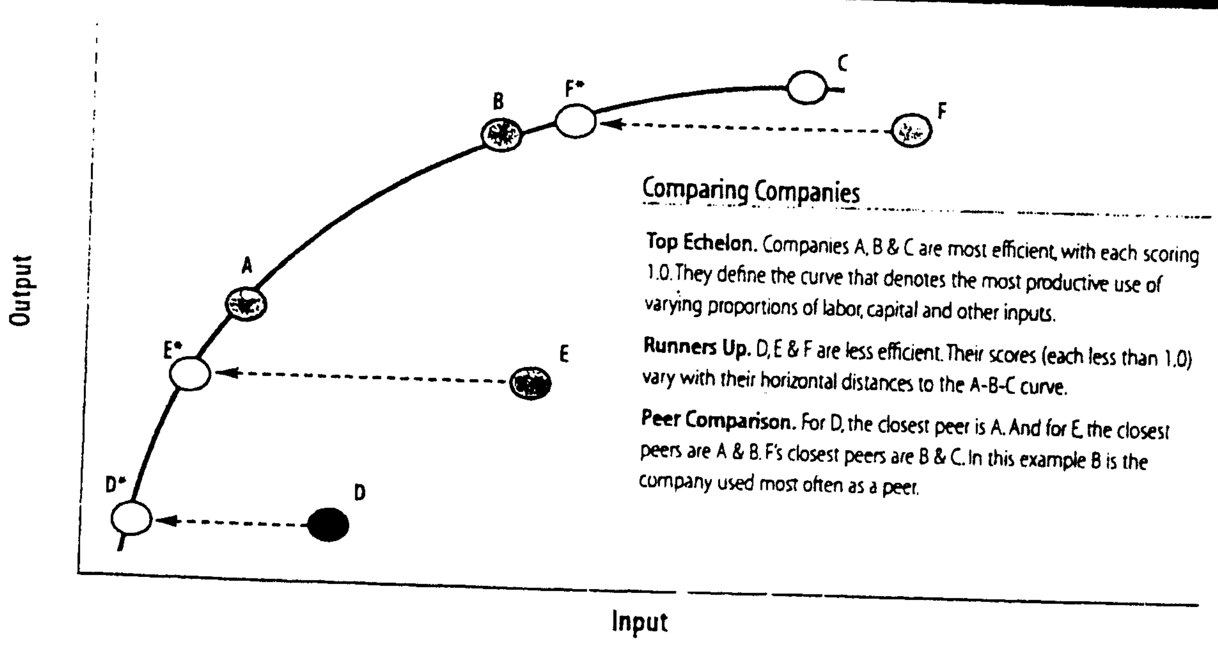
1. Idaho Power Co.
2. Ohio Valley Electric Corp.
3. Montana Power Co.
4. American Electric Power Co.
5. MidAmerican Energy Holdings Co., and Washington Water Power Co. (a tie)

Fortnightly's Most Improved

Greatest Productivity Gain

1. Upper Peninsula Energy Corp.
2. Ameren Corp.
3. Northwestern Wisconsin Electric
4. American Electric Power Co.
5. North Central Power

Figure 1: DEA Efficiency Estimation



of orientation in most cases won't impact efficiency ratings significantly and will identify the same efficient utility companies. Since holding companies are more likely to have control over input usage than over demand for output, we chose to use an input-oriented analysis. In this study, we examine each holding company as a productive unit that converts inputs to outputs. We refer to each such entity as a Decision-Making-Unit (DMU).

Traditionally, research on technical efficiency has relied on one of two approaches: 1) a parametric approach using econometric tools or, 2) a non-parametric approach using linear programming techniques, such as DEA. Econometric methods involve estimating a production function based, on average, on how various inputs are used by a group of similar producers. These techniques require that certain statistical assumptions be satisfied (e.g., that there should exist no significant relationship among various independent variables or inputs) and some knowledge of the functional form. On the other hand, DEA, being nonparametric, requires no such assumptions. DEA also optimizes each company individually (by benchmarking it against its closest peers), whereas traditional statistical methods rely on averages.

Table 1: Ranking of Utilities Based on 1996 Efficiency Score

Ranking	Holding Company	Returns to Scale*	Efficiency Score	No. of Times Used as Peer	Holding Company Code For Efficient Peers	Two Closest Peers
1	Idaho Power Co.	CRS	1	55	IPC	na#
2	Ohio Valley Electric Corp.	CRS	1	54	OVEC	na
3	Montana Power Co.	CRS	1	30	MPC	na
4	American Electric Power Co. Inc.	DRS	1	24	AEP	na
5	MidAmerican Energy Holdings Co.	CRS	1	12	MAEHC	na
5	Washington Water Power Co.	CRS	1	12	WWP	na
6	Central & South West Corp.	DRS	1	9	CSWP	na
6	LG&E Energy Corp.	CRS	1	9	LG&E	na
7	Western Resources Inc.	DRS	1	7	WRI	na
7	North Central Power Co. Inc.	CRS	1	7	NCPC	na
8	Duke Energy Corp.	DRS	1	6	Duke	na
8	PacifiCorp	DRS	1	6	PacifiCorp	na
9	Upper Peninsula Energy Corp.	CRS	1	5	UPEC	na
10	PG&E Corp.	DRS	1	3	PG&E	na
11	Ameren Corp.	CRS	1	2	Ameren	na
12	Texas Utilities Co.	DRS	1	1	TU	na
12	SIGCORP Inc.	CRS	1	1	SIGCORP	na
13	FPL Group Inc.	DRS	1	0	FPL	na
13	The Southern Company	DRS	1	0	Southern	na
20	Entergy Corp.	DRS	0.9974	na	na	TU, AEP
21	IPALCO Enterprises Inc.	DRS	0.9888	na	na	LG&E, WRI
22	Wisconsin Energy Corp.	DRS	0.9722	na	na	IPC, OVEC
23	Northern States Power Co.	DRS	0.9470	na	na	IPC, Duke

*For definition, see note 5. #Efficient firms have no peers.

The DEA Method

Using historical production data, DEA measures how efficiently a producing unit converts inputs to output. DEA uses mathematical optimization to construct a piecewise convex production frontier based on the most efficient companies. Companies that form the production frontier are considered efficient and receive a score of 1; all other companies receive an efficiency score between 0 and 1 based on distance from the production frontier.[3]

Figure 1 is a graphical presentation of a simple one-input, one-output DEA production frontier. DMUs A, B, and C form the efficient production frontier (most efficient). Given their input levels, they are able to produce more output relative to any other DMU. All three receive an efficiency score of 1.0. D, E, and F are less efficient (fall below the efficient frontier). D, E, and F could move closer to the efficient frontier by using less input for the current level of output or increase their output given the existing inputs by using, for example, better technology. These DMUs thus can move from their current positions (D, E, and F) to the closest efficient position (D', E', and F'). Based on similarities in the input and output mix, DEA identifies efficient peers for each of the inefficient units. For example, unit D may end up with unit A as the peer against which it is compared and its efficiency score (the horizontal distance to the production frontier, DD') is computed. Similarly, unit E's peers maybe utilities A and B, and F's may be B and C.

To assess changes in technical efficiency over time, we use the Malmquist productivity index. Overall change in productivity consists of not only the change in efficiency, but also change in technology. The advantage of the Malmquist productivity index is that it is comprised of these two distinct elements. For ease of interpretation, we use the natural log of the Malmquist index, thereby reporting change in productivity as a percent increase or decrease.

Table 1 (cont.): Ranking of Utilities Based on 1996 Efficiency Score

Ranking	Holding Company	Returns to Scale	Efficiency Score	No. of Times Used as Peer	Holding Company Code For Efficient Peers	Two Closest Peers
24	Allegheny Energy Inc.	DRS	0.9299	na	na	OVEC, AEP
25	Black Hills Corp.	DRS	0.9202	na	na	WWP, OVEC
26	WPS Resources Corp.	CRS	0.9185	na	na	OVEC, WWP
27	KU Energy Corp.	DRS	0.9139	na	na	LG&E, OVEC
28	FirstEnergy Corp.	DRS	0.9071	na	na	OVEC, AEP
29	DPL Inc.	DRS	0.8949	na	na	LG&E, OVEC
30	Unicom Corp.	DRS	0.8949	na	na	Duke, AEP
31	Cilcorp Inc.	CRS	0.8857	na	na	SIGCORP, LG&E
32	ESELco Inc.	DRS	0.8771	na	na	NCPC, UPEC
33	Cinergy Corp.	DRS	0.8710	na	na	IPC, Duke
34	Carolina Power & Light Co.	DRS	0.8708	na	na	IPC, AEP
35	Illinova Corp.	DRS	0.8653	na	na	OVEC, IPC
36	IES Industries Inc.	DRS	0.8639	na	na	MAEHC
37	PECO Energy Co.	DRS	0.8600	na	na	IPC, PacifiCorp
38	Central Vermont Public Service Corp.	DRS	0.8575	na	na	NCPC, MPC
39	GPU Inc.	DRS	0.8545	na	na	IPC, OVEC
40	Central Maine Power Co.	CRS	0.8262	na	na	IPC, WWP
41	DTE Energy Co.	DRS	0.8173	na	na	IPC, CSWP
42	TECO Energy Inc.	DRS	0.7989	na	na	LG&E, CSWP

For each inefficient company, it is possible to calculate individual target values for labor, capital, operation and maintenance and fuel. The target values represent realistic goals for operating at peak efficiency with respect to identified peers. These are the changes necessary to move the company to an optimal position on the efficient production frontier. As written earlier, the production frontier, or "best" practice, is based on the observed performance of other utilities. Therefore, optimal performance in terms of allocation of inputs and resources is also measured in relative terms. Targets and goals set in this manner are, therefore, realistic and obtainable. In this article we present the target values results aggregated across all the utilities used in the study. We show, on average, how the inefficient utilities have "misallocated" their resources with respect to the various inputs.

Just the Facts

Data were obtained from POWERdat ©1998 Version 2.01, a Resource Data International Inc. database. Original data sources included the Federal Energy Regulatory Commission Form 1 and the U.S. Securities and Exchange Commission 10-K and 10-Q reports for holding companies and utility operations. The data set included 140 holding companies from 1990 to 1996.

Output was defined as total physical production in megawatt-hours produced and sold to all sectors (Schedule 14). Purchased power was removed from total MWh sales.[4] Input variables consisted of labor cost, O&M expenses (excluding depreciation), pensions and benefits, total outlays for all fuels (Schedule 14), and capital (book value of total electric plant, including production, transmission and distribution). All data were converted to 1996 dollars using the producer price index.

Table 1 lists the top 100 utilities in terms of achieved efficiency in 1996.

Table 1 (cont.): Ranking of Utilities Based on 1996 Efficiency Score

Ranking	Holding Company	Returns to Scale	Efficiency Score	No. of Times Used as Peer	Holding Company Code For Efficient Peers	Two Closest Peers
43	SCANA Corp.	DRS	0.7958	na	na	WRI, OVEC
44	Kansas City Power & Light Co.	DRS	0.7946	na	na	IPC, OVEC
45	Houston Industries Inc.	DRS	0.7488	na	na	WRI, CSWP
46	Baltimore Gas & Electric Co.	DRS	0.7413	na	na	IPC, AEP
47	Enron Corp.	CRS	0.7380	na	na	IPC, WWP
48	CMS Energy Corp.	DRS	0.7331	na	na	OVEC, IPC
49	WPL Holdings Inc.	CRS	0.7204	na	na	OVEC, IPC
50	New Century Energies Inc.	DRS	0.7199	na	na	WRI, OVEC
51	OGE Energy Corp.	DRS	0.7146	na	na	OVEC, IPC
52	Minnesota Power & Light Co.	CRS	0.7108	na	na	WWP, OVEC
53	DQE Inc.	CRS	0.7077	na	na	OVEC, IPC
54	Northwestern Public Service Co.	DRS	0.7004	na	na	IPC, OVEC
55	NIPSCO Industries Inc.	CRS	0.6727	na	na	LG&E, OVEC
56	Public Service Enterprise Group Inc.	DRS	0.6632	na	na	IPC, AEP
57	Pinnacle West Capital Corp.	DRS	0.6561	na	na	IPC, OVEC
58	Madison Gas & Electric Co.	DRS	0.6495	na	na	IPC, MPC
59	UniSource Energy Corp.	CRS	0.6268	na	na	LG&E, OVEC
60	Empire District Electric Co.	CRS	0.6259	na	na	MPC, OVEC
61	Edison International	DRS	0.6207	na	na	PacifiCorp, PG&E

Nineteen utilities were classified as efficient (efficiency score = 1). The inefficient utilities received a score between 0 and 1 indicating the proportionate amount of inputs they should be using. That is, an efficiency score of 0.8 would indicate that the utility is underutilizing its input resources by about 20 percent. Table 1 also lists the DEA-selected peers identified by "Holding Company Code." The efficient utilities will not have a peer since there are no other utilities that can produce as much output using less input. For the inefficient utilities, we provided the peers to which they were compared; the companies that produced proportionally the same output using less input. The peer utilities are selected based on the same mix of inputs. It is understood that the DEA-selected peers may differ with respect to production conditions such as fuel mix, geography or customer base. Identifying peers based on these factors would require a case-by-case analysis of all the utilities in the study.

The list of top performers includes a wide mix of utilities in terms of size (from North Central Power to Southern Co.) and geographic location. Table 1 shows the specific conditions of scale economies under which we believe the utility is operating (i.e., constant, decreasing, or variable returns to scale—CRS, DRS or VRS, respectively).

Further ranking of the 19 efficient utilities is possible through DEA. The analysis creates a ranking of the DMUs on the efficient frontier based on the number of instances that they have been designated in DEA as peers. From an analytical point of view, this increases the confidence in the assessment concerning the operational efficiencies of these utilities. For example, Southern Co. received an efficiency score of 1, but was never used as a peer. This indicates that Southern, although efficient, was not influential in determining the efficiency of the other companies (i.e., no companies matched the criteria for comparison with Southern Co.). Furthermore, this indicates that Southern was found to be efficient, at least partially, due to its uniqueness. Idaho Power, on the hand, also received an efficiency score of 1 and was used as a peer for 55 different utilities. (Idaho Power received an efficiency score of 1.0 even when placed with 55 similar utilities, a more convincing accomplishment.)

Table 2 shows the gains/losses in productivity for the top 100 holding companies utilities for each year between 1990

Figure 2: Application of Individual Inputs

Percent of underuse by the least-efficient utilities.

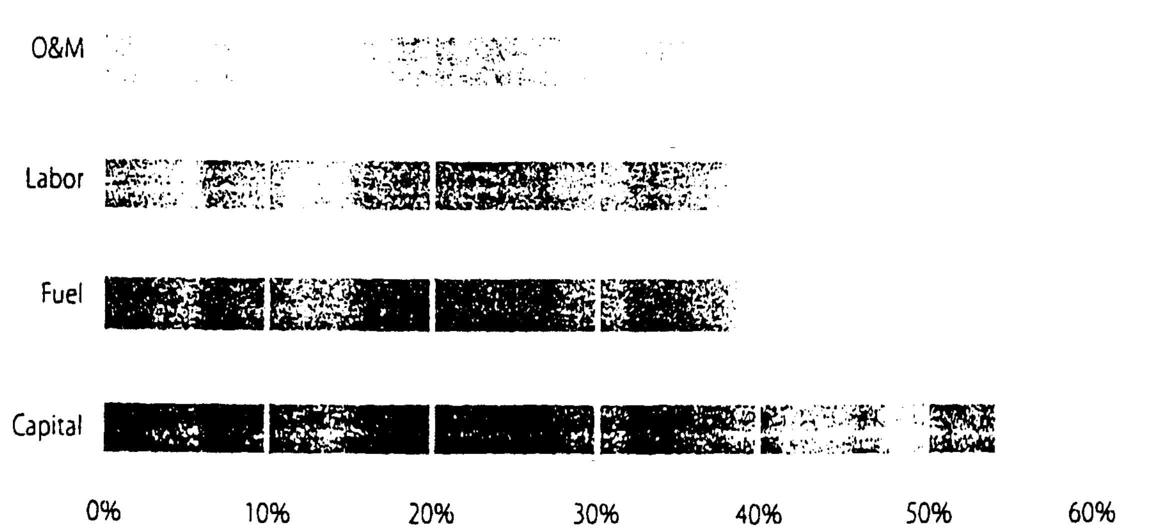


Table 1 (cont.): Ranking of Utilities Based on 1996 Efficiency Score

Ranking	Holding Company	Returns to Scale	Efficiency Score	No. of Times Used as Peer	Holding Company Code For Most Efficient Peers	Two Closest Peers
62	Rochester Gas & Electric Corp.	CRS	0.6183	na	na	MPC, OVEC
63	El Paso Electric Co.	CRS	0.5992	na	na	IPC, OVEC
64	PSC of New Mexico	CRS	0.5962	na	na	OVEC, IPC
65	Florida Progress Corp.	DRS	0.5771	na	na	OVEC, IPC
66	Niagara Mohawk Power Corp.	DRS	0.5620	na	na	IPC, PG&E
67	New York State Electric & Gas Corp.	DRS	0.5618	na	na	IPC, OVEC
68	MDU Resources Group Inc.	CRS	0.5560	na	na	MPC, IPC
69	Bangor Hydro-Electric Co.	DRS	0.5316	na	na	UPEC, NCPC
70	Delmarva Power & Light Co.	DRS	0.5291	na	na	OVEC, WWP
71	UtiliCorp United Inc.	CRS	0.5083	na	na	IPC, WWP
72	Otter Tail Power Co.	DRS	0.5021	na	na	IPC, WWP
73	Potomac Electric Power Co.	DRS	0.4986	na	na	OVEC, IPC
74	Interstate Power Co.	DRS	0.4892	na	na	OVEC, MPC
75	Northwestern Wisconsin Electric Co.	DRS	0.4641	na	na	NCPC, UPEC
76	Alaska Electric Light & Power Co.	DRS	0.4544	na	na	NCPC, UPEC
77	New England Electric System	DRS	0.4410	na	na	OVEC, IPC
78	UGI Corp.	DRS	0.4341	na	na	MPC, OVEC
79	Nevada Power Co.	CRS	0.4292	na	na	IPC, OVEC
80	Atlantic Energy Inc. (NJ)	CRS	0.4258	na	na	MPC, OVEC
81	Boston Edison Co.	CRS	0.4178	na	na	MPC, OVEC
82	United Illuminating Co.	CRS	0.3972	na	na	MPC, OVEC
83	Enova Corp.	CRS	0.3895	na	na	MPC, OVEC
84	Central Hudson Gas & Electric Corp.	CRS	0.3647	na	na	IPC, MPC
85	Northeast Utilities	DRS	0.3636	na	na	IPC, OVEC
86	Green Mountain Power Corp.	DRS	0.3585	na	na	NCPC, UPEC
87	Sierra Pacific Resources	CRS	0.3443	na	na	IPC, OVEC
88	TNP Enterprises Inc.	CRS	0.3186	na	na	MPC, OVEC
89	Long Island Lighting Co.	CRS	0.2767	na	na	MPC, OVEC
90	Unitil Corp.	DRS	0.2733	na	na	MPC, OVEC
91	Commonwealth Energy System	CRS	0.2617	na	na	MPC, OVEC
92	Consolidated Edison Inc.	DRS	0.2561	na	na	IPC, PacifiCorp
93	Hawaiian Electric Industries Inc.	CRS	0.2539	na	na	OVEC, MPC
94	Orange & Rockland Utilities Inc.	CRS	0.2466	na	na	IPC, MAEHC
95	Citizens Utilities Co.	DRS	0.1666	na	na	MPC, OVEC
96	Eastern Utilities Associates	CRS	0.1054	na	na	MPC, OVEC
97	Maine Public Service Co.	CRS	0.0718	na	na	NCPC, IPC
98	Citizens Electric Co.	VRS	0.0000	na	na	MPC, OVEC
99	Mount Carmel Public Utility Co.	VRS	0.0000	na	na	MPC
100	Vermont Electric Power Co. Inc.	VRS	0.0000	na	na	MPC

RMA__Exhibit 6

Competitive Efficiency:

By Hossein Haeri, M. Sami Khawaja and Matei Perussi

Do mergers and "critical mass" really make a difference? The answer, it seems, is yes.

To become more competitive, U.S. electric utilities have embarked on a quest in recent years to improve operational efficiency and factor productivity. The question is: Are utilities making progress? And, which companies have gained a competitive edge? Which have not?

Industry analysts have long argued that given the structure of the markets they serve and their cost-based, rate-setting procedures, electric utilities tend toward monopolistic behavior. Consequently, they are prone to wasteful applications of resources, especially overcapitalization. Without proper incentives, the argument went, utility managers have little motivation to cut costs or improve efficiency. As Hicks has argued, they would be more likely to exploit their market power by not bothering to approach maximum efficiency. "The best of monopoly profits," Hicks suggests, "is a quiet life."

These arguments, however, are waning quickly as the bang and clatter of competition disturbs the utility manager's "quiet life." Prompted by the discipline imposed by competitive markets and the demands of incentive regulation, utilities are paying increasing attention to the economic fundamentals of electricity production and delivery.

An examination of efficiency improvements at U.S. utilities, as measured by megawatt-hours per employee, reveals a modest increase (0.5 percent per year) between 1990 and 1995, mostly after 1993. This has led to moderately lower average system rates *(see Figure 1)*. Variable expenses have declined in nearly all categories of operation and maintenance, fuel and labor. Price stability in the oil markets and better procurement practices also have helped control fuel input costs. In fact, labor productivity has shown steady annual improvements of more than 6 percent per annum, increasing from 4,670 MWh per employee (1990) to 6,420 MWh per employee (1995).

We have estimated the operational efficiencies for 94 U.S. electric utilities from 1990 to 1995 using conventional statistical techniques. As might be expected, the patterns that emerge appear to show some link between operational performance and geographic location. Also, to lend credence to the current "merger mania," we found that size of operation (and the fact of the merger itself) does appear to act as a significant determinant of overall efficiency.

Measures and Models

One measure of operational efficiency is productivity—the ratio of outputs to inputs. Productivity among firms can vary due to several factors, however, such as differences in production technologies, environments in which production takes place and efficiencies of the production processes. A firm is efficient if it cannot increase its output without adding more inputs; or, conversely, if it cannot decrease the quantity of its inputs without reducing its output.

Productive efficiency has two components: technical and allocative. The technical component marks the ability to produce as much output as possible with available inputs, or using as little input as possible to produce the same level of output. The allocative component tracks the ability to combine inputs and outputs in optimal proportions under prevailing prices. In other words, it is the flexibility to adjust the mix of inputs as their prices change. Here, we measure overall operational efficiency without breaking it into components.[1]

[1]Several econometric techniques have been developed for obtaining the measurement of each component. The computational procedures, however, are complex and inexact.

A Ranking of U.S. Electric Utilities

Methods for measuring efficiency can be divided into two families, each comprising several specific techniques. One group of measurement techniques relies on mathematical programming. Using observed outputs and inputs for a group of firms, the algorithm calculates a measure of how efficient each firm is in converting inputs into outputs. This calculation is done by constructing a production "frontier" and measuring each firm's distance from it.[2] The other family is econometric. This family involves applying regression techniques to calibrate a production function that compiles information on inputs, outputs and other production characteristics of a group of firms over one or more periods. Each firm's efficiency is measured by comparing it with other firms in the group.

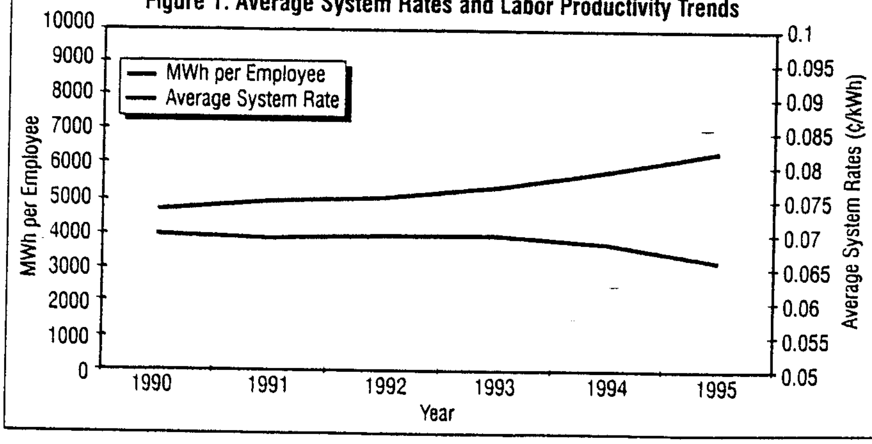
In general, efficiency is almost always measured in relative terms, comparing one firm with another firm or with an industry average (benchmarking). A firm can also be compared with itself at different times (trend analysis), or its performance can be evaluated against its goals (goal or "gap" analysis). The difference between efficiency levels under the operationally best possible resource allocation and the actual resource allocation is the degree of x-inefficiency—the familiar concept introduced by Harvey Leibenstein in 1966.

Our Approach

Utilities use technology to transform capital, labor, energy and materials into electricity. The physical relationship between the amounts of each input and electricity produced can be expressed as a production function. In our analysis, we used a simple formulation of the production function known as the Cobb-Douglas. Under this formulation, output, measured in MWh, depends on capital, labor, fuels and materials used by utilities. A load factor variable was included to account for idle capacity. A trend variable was used to capture the time-varying effect of technology.[3]

Except for the Producer Price Index, which came from the Bureau of Labor Statistics, all other data came from Edison Electric Institute's Uniform Statistical Reports. Data were gathered on each variable from 1990 through 1995. We chose the holding company as the analysis unit rather

Figure 1. Average System Rates and Labor Productivity Trends



[2]One study employing this technique was published in *Public Utilities Fortnightly*. (See, "The Efficient Utility: Labor, Capital, & Profit," by D. Thomas Taylor and Russell G. Thompson, Sept. 1, 1995, p. 25.) That study used Data Envelopment Analysis, a mathematical programming technique, to estimate relative efficiencies of 13 investor-owned utilities. Some of that study's flaws and certain weaknesses of its methodology were later noted by Matthew Morey and L. Dean Hiebert. (See, "Measuring Utility Efficiency: A New Frontier" [letter to editor], *Public Utilities Fortnightly*, Jan. 1, 1996, p. 7.)

[3]The estimated equation was formulated as:

$$Ln(Y_{it}) = \sum_i \alpha_i + \sum_j \beta_j Ln(X_{ijt}) + LF_{it} + \epsilon_{it}$$

where $Ln(Y_{it})$ is the natural logarithm of total output in megawatt hours, $Ln(X_{ijt})$ is natural logarithm of a set of j inputs (labor, capital, fuel and material), LF is the load factor, and T is a trend variable with values of 1 to 6 representing each year of data from 1990 to 1995. Index i refers to utilities, and index t refers to time periods.

ϵ_{it} is an error term representing two elements: statistical noise (v_{it}) and inefficiency (u_i): $\epsilon_{it} = v_{it} + u_i$). The decomposition of the error term into its two components may be done in several ways. The *fixed effects* approach assumes differences in the efficiency of different utilities are captured in their respective intercepts by the term (α_i) in the above equation. That is, had all utilities used the same amount of each input, all differences in output levels would be represented in the intercept.

In estimating the efficiency level associated with each utility, the most efficient utility would be defined as the one with largest intercept. In other words, the most efficient utility represents 100-percent efficiency, and all other utilities are compared to it.

Table 1. Relative Efficiency Rankings for 94 Electric Utilities

Rank	Utility	Relative Efficiency	Relative Efficiency Change from '90 to '95
1	American Electric Power Co.	100.00%	1.62%
2	Washington Water Power Co.	99.99%	–2.26%
3	Southwestern Public Svc. Co.	99.53%	2.33%
4	Allegheny Power System	99.36%	–2.02%
5	PacifiCorp	99.21%	0.96%
6	Idaho Power Co.	99.17%	1.41%
7	Kentucky Utilities Co.	98.50%	4.11%
8	Portland General Electric Co.	97.50%	–0.74%
9	Puget Sound Power & Light Co.	97.41%	–0.89%
10	Minnesota Power	96.84%	0.89%
11	Southern Co.	96.67%	1.11%
12	Northern States Power Co.	96.54%	0.80%
13	Montana Power Co.	96.50%	–0.79%
14	Louisville Gas and Electric Co.	96.11%	1.59%
15	Cincinnati Gas & Electric Co., Cinergy Corp. *	95.94%	4.38%
16	Union Electric Co.	95.93%	5.65%
17	Central and Southwest Corp.	95.76%	2.41%
18	Texas Utilities Co.	95.72%	1.92%
19	Duke Power Co.	95.06%	3.22%
20	Ipalco Enterprises	95.03%	2.27%
21	Kansas Power and Light Co., Western Resources *	94.55%	1.70%
22	Oklahoma Gas and Electric Co.	94.53%	1.32%
23	So. Indiana Gas & Electric Co.	94.44%	2.01%
24	Houston Lighting & Power Co.	94.29%	2.21%
25	Scana Corp.	93.68%	1.16%
26	Entergy Corp.	93.67%	0.98%
27	Virginia Electric and Power Co.	93.50%	2.50%
28	Wisconsin Power and Light Co.	93.44%	2.44%
29	Iowa Power, Midwest Power, MidAmerican *	93.38%	5.71%
30	Dayton Power and Light Co.	93.05%	2.08%
31	Carolina Power & Light Co.	92.91%	2.32%
32	Wisconsin Public Service Corp.	92.81%	3.31%
33	Empire District Electric Co.	92.65%	0.68%
34	Kansas City Power & Light Co.	92.51%	8.31%
35	Public Service Co. of Colorado	92.48%	1.53%
36	Gulf States Utilities Co.	92.39%	4.22%
37	Pennsylvania Pwr. & Light Co.	92.33%	2.84%
38	Cipsco, Central Illinois Public Service	*92.32%	9.05%
39	Potomac Electric Power Co.	92.06%	–0.27%
40	Interstate Power Co.	91.90%	0.98%
41	Illinois Power Co.	91.87%	8.34%
42	Florida Power Corp.	91.66%	0.81%
43	Iowa-Illinois Gas & Electric Co.	91.59%	1.48%
44	Consumers Power Co.	91.57%	0.90%
45	Nevada Power Co.	91.51%	–0.18%
46	Otter Tail Power Co.	91.50%	4.50%
47	Detroit Edison Co.	91.25%	2.93%
48	Tampa Electric Co.	91.10%	–0.58%

than the operating company. Mergers during the data period were aggregated into single holding-company level. The analysis began with the complete database for all EEI member utilities. Only utilities with complete data for all variables in all six years were kept. This criterion left 94 observations for use in the analysis.

Output was measured as total physical production in MWh sold to all accounts (Schedule 14). Input variables were capital, labor, fuel, operating expenses and load factors. Fuel inputs were total outlays for all fuels in real dollars (Schedule 14). Operating expenses were the sum of all expense accounts and included operation, maintenance, depreciation, depletion, amortization and property losses, excluding local taxes (Schedule 2). Annual load factors were obtained from Schedule 17. All monetary variables were expressed in real terms, deflated by the PPI.

Leaders and Laggards

The statistical results from calibrating the production function showed that all included variables affected output and, together, explained more than 99 percent of its variations.[4] Estimated efficiency rankings and percentage changes in overall relative efficiency from 1990 to 1995 for the 94 companies are listed in Table 1. From 1990 to 1995, American Electric Power, Washington Water Power, and Southwestern Public Service Co., followed narrowly by Allegheny Power and PacifiCorp, led other utilities in the group in average efficiency.

Bangor Hydro-Electric Co., Upper Peninsula Energy, and Maine Public Service Co. scored the lowest, lagging the leaders

[4] The data, estimation results and summary statistical properties in SAS output format are available from the authors by request.

Rank	Utility	Relative Efficiency	Relative Efficiency Change from '90 to '95
49	Commonwealth Edison Co.	91.01%	2.83%
50	Ohio Edison Co.	90.95%	1.77%
51	Baltimore Gas and Electric Co.	90.74%	6.79%
52	Central Illinois Light Co.	90.64%	3.21%
53	Central Louisiana Electric Co.	90.57%	2.32%
54	Delmarva Power & Light Co.	90.41%	4.35%
55	NIPSCO Industries	90.10%	3.98%
56	St. Joseph Light & Power Co.	89.71%	4.25%
57	Utilicorp United	89.65%	3.45%
58	Iowa Electric Light & Power Co., IES Utilities*	89.04%	12.13%
59	New York State Electric & Gas Corp.	88.83%	1.35%
60	Philadelphia Electric Co., PECO Energy Co. *	88.75%	6.73%
61	General Public Utilities Corp.	88.60%	0.98%
62	Public Svc. Enterprise Group	88.42%	1.32%
63	Arizona Public Service Co.	88.27%	1.73%
64	Niagara Mohawk Power Corp.	87.75%	0.52%
65	MDU Resources Group	87.23%	1.34%
66	Centerior Energy Corp.	86.86%	5.50%
67	Duquesne Light Co.	86.84%	4.30%
68	Pacific Gas and Electric Co.	86.77%	–0.67%
69	Sierra Pacific Power Co.	86.71%	0.32%
70	Northwestern Public Svc. Co.	86.33%	5.90%
71	Public Svc. Co. of New Mexico	86.26%	9.38%

Rank	Utility	Relative Efficiency	Relative Efficiency Change from '90 to '95
72	Cent. Hudson Gas & Elec. Corp.	85.98%	0.61%
73	Tucson Electric Power Co.	85.82%	6.44%
74	So. California Edison Co.	85.78%	1.37%
75	El Paso Electric Co.	85.77%	4.87%
76	New England Electric System	85.45%	0.45%
77	Commonwealth Energy System	85.25%	5.02%
78	San Diego Gas & Electric Co.	85.22%	1.54%
79	Green Mountain Power Corp.	85.18%	–2.17%
80	Northeast Utilities	85.13%	3.38%
81	Rochester Gas & Electric Corp.	84.99%	1.37%
82	Black Hills Corp.	84.90%	0.67%
83	Long Island Lighting Co.	84.60%	–3.68%
84	Cent. Vermont Public Svc. Corp.	84.30%	4.73%
85	United Illuminating Co.	83.88%	3.54%
86	Orange and Rockland Utilities	83.41%	7.63%
87	Consolidated Edison Co. of New York	83.25%	3.25%
88	Boston Edison Co.	82.97%	1.75%
89	Central Maine Power Co.	82.87%	2.08%
90	Hawaiian Electric Co.	81.31%	–1.78%
91	Eastern Utilities Associates	80.85%	5.42%
92	Maine Public Service Co.	80.08%	0.83%
93	Upper Peninsula Energy Corp.	78.44%	1.39%
94	Bangor Hydro-Electric Co.	78.32%	–1.29%
	Average Efficiency	**90.49%**	**2.47%**

**Companies merged.*

nearly 22 percent. In interpreting the figures, it should be noted these are normalized scores and represent relative rankings rather than absolute efficiencies. In other words, scores of 100 and 99 for AEP and PacifiCorp, respectively, should not be construed as the actual operational efficiencies for the two utilities. Instead, the figures mean that over the five-year period, Idaho Power has been, on average, 1 percent more efficient than PacifiCorp.

Comparing the top three performers with the bottom three, marked differences emerge between the groups regarding location and size, as measured in MWh sales. The differences in rates are most striking. During the five years of the analysis period, the average system rates for the bottom three utilities were almost exactly double the average rates of the top three. The best performers are much larger than the worst, and are concentrated in the Northwest. Marked differences between the two groups are apparent in several important dimensions, including labor productivity, average operating expenses and, especially, percentage of purchased power.

Six of the 10 top performers are in the Pacific Northwest; eight of the 10 bottom performers come from the Northeast. The data show that, compared with the top three utilities, on average, the bottom three utilities lag in sales per employee by nearly a 3-to-1 margin, and purchase a far greater portion of their power from outside sources. The bottom group also has slightly higher proportions of residential customers. No apparent differences emerge between the two groups regarding wages (*Table* 2).

Close examination of utility efficiency scores reveal several important patterns, as shown in Table 3. Size of the operation is a significant determinant of efficiency and matters considerably in overall

Table 2. Comparison of Top and Bottom Performers

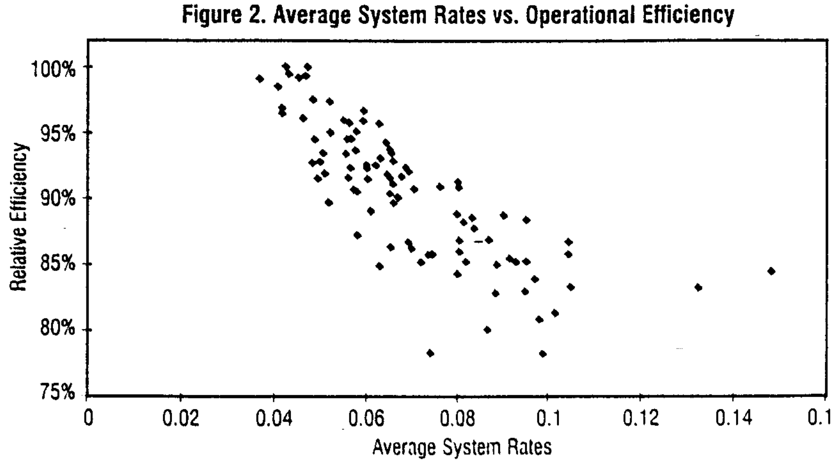
Variable	Top 3 companies			Bottom 3 companies		
	AEP	Washington Water Power	Southwestern Public Service	Maine Public Service	Upper Peninsula Energy Corp.	Bangor Hydro Electric Co.
Total Sales (MWh)	116,196,875	10,558,467	19,084,259	664,623	808,215	1,725,870
% Residential Sales	24%	29%	13%	26%	31%	30%
% Industrial Sales	36%	15%	39%	20%	28%	51%
Average System Rate	0.05	0.04	0.04	0.09	0.07	0.10
Salary per employee	45,755	48,301	43,412	37,006	46,468	40,278
Total Sales (MWh)/Employee	6,408	10,335	9,403	3,675	1,495	3,469
Plant in Service ($1000s)/MWh	0.16	0.14	0.12	0.12	0.20	0.16
Percent Purchased Power	4%	42%	2%	84%	81%	81%
Operating Expense ($1000s)/MWh	0.03	0.03	0.03	0.07	0.06	0.08
Load Factor	0.63	0.60	0.63	0.64	0.71	0.76

rankings. It shows a strong relationship with efficiencies due to economies of scale. The results suggest as much as a 5-percent difference in efficiency between utilities in the largest group and those in the smallest group.

Contributions of economies of scale to efficiency are also apparent when we consider company structure (individual operating company vs. holding company). For example, holding companies show slightly higher efficiencies than individual operating companies. More important, five of the six holding companies resulting from mergers during 1990-1995 show above-average efficiency gains. The one-half of the utilities in the sample that are combined operations show slightly higher efficiencies, resulting possibly from economies of joint production.

Northwest utilities lead in overall efficiency. Southeastern, Southern and North-Central utilities follow the Northwest by a high 5-percent margin. A utility's reliance on nuclear generation, measured as nuclear fuel outlays, also shows a strong negative correlation with efficiency; the higher the share of nuclear fuel costs, the lower the operational efficiency. Inversely, we find a strong relationship between operational efficiency and the share of hydroelectric power in a utility's generation mix.

Figure 2. Average System Rates vs. Operational Efficiency



The Incentive to Improve

The efficiency by which a utility uses its resources directly influences its profitability. In fact, increased productivity may be the most important determining factor in a utility's operations for both regulated and competitive markets. Judging by current trends, there is little doubt that those functions of electric utilities that remain regulated will be subject to incentive ratemaking in one form or another. In all forms of incentive regulation, retained earnings are largely decided based on their specific factor productivities (partial incentive mechanisms) or overall efficiency gains (price cap formulas). It seems, therefore, reasonable to expect utilities will have every incentive to improve their efficiency by closely monitoring operations and controlling costs.

Efficiency also bears directly on price, determining the utility's ability to compete in commodity markets. Our study suggests a close association between

Table 3. Comparison of Efficiency by Various Categories

Variable	Category	Number of utilities in category	Average Efficiency
Size (Average MWh)	Small = Quartile 1	23	86.7%
	Medium= Quartile 2	24	90.8%
	Large = Quartile 3	23	92.0%
	Very Large = Quartile 4	24	92.4%
Region	Northwest	4	98.5%
	West	16	89.6%
	North-central	21	92.2%
	Central / Midwest	9	90.5%
	South / Southeast	13	93.9%
	East / Northeast	31	87.3%
Nuclear fuel:	0%	39	91.1%
Percent of total fuel cost	1-10%	23	91.0%
	10-20%	19	89.7%
	20-30%	7	88.6%
	30-40%	5	89.0%
	over 40%	1	88.7%
Purchase Power -	<25 %	52	92.3%
% of total sales	25-50%	32	89.6%
	50-75%	5	86.8%
	over 75%	5	81.3%
Utility with gas sales	Yes	47	90.7%
	No	47	90.3%
Percent Industrial	0-20%	22	89.1%
	20-40%	60	91.0%
	over 40%	12	90.0%
Holding Company	Yes	30	91.6%
	No	64	90.0%
Hydro electric % of sales	0	39	90.0%
	0-10%	47	91.0%
	over 10%	8	90.0%

efficiency rankings and average system rates for utilities in the sample (Figure 2). In fact, the results suggest efficiency scores account for more than 60 percent of the variations in average system rates.

As John Kenneth Galbraith has said, "Things that are measured tend to improve." Operational efficiency has never been more important for electric utilities than it is today, as they embark on the new era of retail access and competition. As competition intensifies, market pressures will inevitably force prices toward marginal costs, leading to shrinking margins and a greater demand for operational efficiency. Productive efficiency will emerge as the survival condition in a competitive environment. ▼

Hossein Haeri, M. Sami Khawaja and Matei Perussi and are economists in the Portland, Ore., offices of Barakat & Chamberlin Inc., a consulting firm that provides technical and strategic services to the utilities industry.

RMA__Exhibit 7

March 31, 1999

PacifiCorp Makes Early Progress on Refocused Strategy

PORTLAND, Ore. - Keith McKennon, Chairman and Chief Executive Officer of PacifiCorp (NYSE: PPW), told investors and securities analysts today that the company has made good progress toward implementing a strategic refocus on its western electricity business.

"We have moved quickly to execute our new strategy, and I am pleased with the progress we have made so far," McKennon said in remarks prepared for today's conference call with analysts and investors.

"We still have a long way to go toward fully implementing our strategy and improving our financial performance, but the early returns are good," McKennon said.

Last October, PacifiCorp announced it would focus on its electricity business in the western United States and divest all of its other business activities except Powercor in Australia.

In confirming the company's progress, McKennon pointed to sales of non-core businesses, implementation of a cost reduction program and changes designed to improve customer service.

Specifically, the company has:

- Closed its eastern U.S. electricity trading business.
- Sold TPC Corporation, the company's natural gas storage and marketing subsidiary, for $132.5 million plus an additional payment for working capital.
- Sold EnergyWorks, the company's joint venture with Bechtel, for $50 million.
- Ended its business development activities in Turkey.
- Implemented an overhead cost reduction program designed to save the company $30 million annually in pre-tax operating costs.
- Restructured its customer service and other operations functions to better address customer needs.

The company reported Tuesday earnings of $0.22 per share in the fourth quarter of 1998 and $1.01 per share for the full year 1998, excluding a series of special charges and other adjustments. Including the charges and adjustments, the company reported a 1998 loss on common stock of $55 million, or $0.19 per share.

"While 1998 was a very disappointing year financially for PacifiCorp, I am pleased that our recurring earnings for the fourth quarter -- the first reporting period following the implementation of our new strategy -- were in line with expectations," McKennon said.

McKennon also indicated that PacifiCorp's proposed merger with ScottishPower is progressing as the company expected. "While it is still early in the approval process, we are just where we expected to be at this stage," McKennon said.

The company expects shareholder voting to commence in mid-1999, with completion of the regulatory approval process occurring sometime this fall.

"I am encouraged by the early results of the renewed focus on our western U.S. business," McKennon said. "Our employees deserve a lot of credit for the progress.

Many people are working harder than ever to deliver good results for our shareholders and ever-better service to our customers."

PacifiCorp serves 1.5 million electricity customers in Oregon, Utah, Wyoming, Washington, Idaho and California. It has one of the most extensive transmission systems in the U.S. and owns 8,300 megawatts of low-cost thermal and hydroelectric generation. PacifiCorp also serves 550,000 electricity customers in the Australian states of Victoria and New South Wales.

For further information
Scott Hibbs, for investors, (503) 813-7222
Angela Hult (503) 813-7234
Scott Hibbs (503) 813-7222

RMA__Exhibit 8

CAS Data Request PC 159:

Please list and summarize in brief detail all significant programs, procedures, or other efforts that have been incorporated or otherwise "rolled out" by PacifiCorp on a permanent or trial basis to improve maintenance practices, customer service practices, and facility investment practices for transmission, distribution, and customer service facilities (Descriptions may be limited to those efforts that were implemented on or considered for a system-wide application). Please describe the objectives of each effort, the results of each effort, and the costs to implement (actual or estimated as applicable). Information provided shall be for efforts undertaken within the past 7 years. (EB)

Response to CAS Data Request PC 159:

Principal programs are as follows:

Description	**Objective**	**Results**	**Implementation Costs**
Customer Service Information System (CSS)	Develop and implement a system wide, Y2K compliant customer information system to replace legacy systems	System was developed and deployed commencing in 1996.	$72.7 million
Establish business centers in Portland and Salt Lake	Improved customer service through extended hours of operation, economies of scale, and reduced costs	Centers were established and staffed in 1996 and 1997. Local customer counters closed throughout 1996 and 1997. Customers can now call PacifiCorp on outages or business matters 24 hours/day	$22.2 million

20000-EA-98-141/PacifiCorp
April 29, 1999
CAS Data Request PC 159

Description	**Objective**	**Results**	**Implementation Costs**
Distribution Management System (DMS)	Respond to customer outage incidents by processing "trouble tickets" that are initiated by customers through Business Centers and electronically forwarded to appropriate dispatchers located throughout the service territory.	System was developed and deployed at staged intervals during 1997. Numerous enhancements were made during 1998. The system has not implemented any significant functional changes for several months. Processes approximately 300,000 "trouble tickets" per year.	$2.5 million
Operations Visualization System (OVS)	Give operating managers and Business Centers employee's information access to outage restoration events by combining maps, circuitry and customer "trouble ticket" data in a web-reporting tool.	System was developed and deployed the beginning of 1998. Added functionality was incorporated in a later release towards the end of 1998. Another release is slated for mid-1999. Approximately 300 users access the system at various times during outage events and normal day-to-day activities.	$350,000
Facilities Management	Increase the life of electric facilities, improve system reliability, and meet National Electric Safety Code.	The program includes several major components: pole test & treat, safety inspection, detail facility inspection, tree trimming,	$19.4 million per year over the last 5 years.

RMA__Exhibit 9

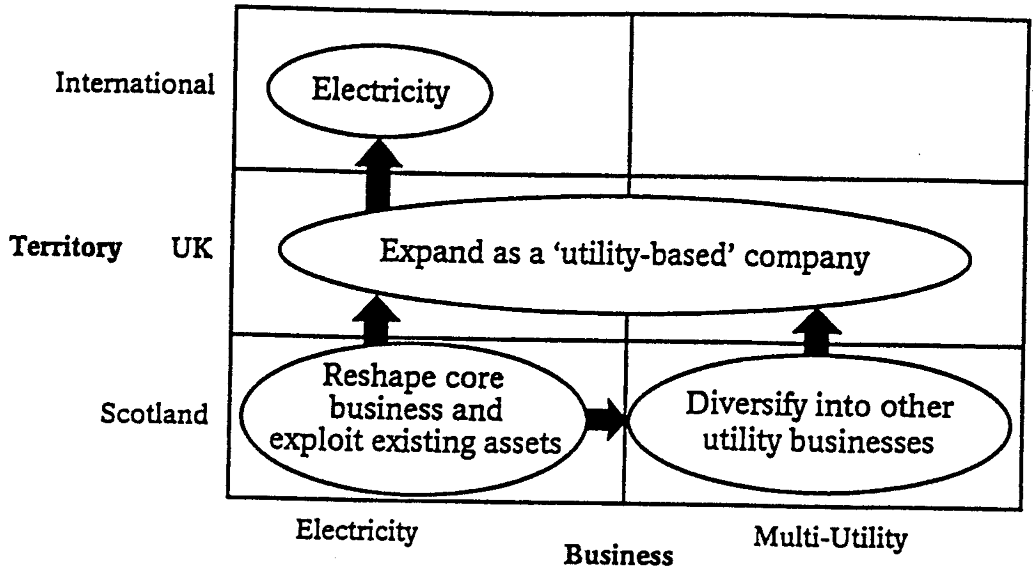
ScottishPower

Analysts
Presentation
June 1998

Prepared for
competition

SP0149

STRATEGY FOR BUILDING BUSINESSES



Creating Value - Building Businesses

Notes

SP0154

RMA__Exhibit 10

ScottishPower

Value added

- Value sensitivity to extreme price reviews – 555p to 659p
- 7.8% EPS growth to 2002 despite price reviews
- EVA of £267m from acquisitions

SP5559

US Acquisition

- The next stage of ScottishPower's strategy is to expand into overseas electricity markets. Recently it announced that it had terminated discussions with Florida Progress, a vertically integrated US utility with a market cap of around $4bn (£2.5bn), because it would not be able to derive sufficient shareholder value from the acquisition.
- ScottishPower would aim to derive value from a US utility in much the same way as it has done so with Manweb and Southern Water, via increasing the financial efficiency of the balance sheet; exploiting organic growth opportunities; and improving the operating efficiency of the target company where appropriate.
- We estimate that the acquisition cost of Florida Progress would have been in the range of $4.8 - 5.0bn (£3.0bn - £3.1bn) representing a 20 - 30% premium over the company's market cap. ScottishPower could have financed this via selling off Florida Progress' generation for around $1bn (c.£0.6bn) and fuel transportation business for around $1bn (c.£0.6bn); increasing net debt by around $2.4bn (£1.5bn); and placing equity in the US market $400 - 600m (£250 - 375m).
- We expect that ScottishPower will continue with its stated strategy to expand into overseas electricity markets and expect it to seek out another US partner. We expect that the next target will be characterised by having undervalued generation, a benign regulatory environment and strong management.

ScottishPower has been consistent in stating its strategy. Initially it aimed to expand in the UK as a utility based company. This was achieved by the acquisition of Manweb in 1995. The company then wished to diversify into other utility businesses within the UK. This was achieved with the acquisition of Southern Water in 1996 and the development of a gas supply business. The company now provides a utility service to 1 in 5 homes in the UK and has direct access to another 9m customers via marketing alliances with the AA and Union Energy.

Whilst the UK business is growing, the company is starting to pursue the next stage its stated strategy which is to expand into overseas electricity markets. The obvious geographic area to focus this expansion on is the US and ScottishPower has already been active identifying opportunities. On 24 April 1998 ScottishPower announced that it had terminated discussions with Florida Progress, a US utility, which would have led to a combination of the businesses. The company stated that during the due diligence process it became apparent that an acquisition would not result in the creation of sufficient shareholder value.

Florida Progress

Florida Progress has a market capitalisation of around $4bn (£2.5bn), net assets of $4.3bn and annual sales of around $2.3bn. In 1996 it produced net

US Acquisition

income of $252m and is based in St. Petersburg, Florida. The company has three divisions:

- Energy Solutions - customer service and marketing. The company's service area covers 20,000 square miles which contains 4.5m customers. The company serves 1.3m customers.
- Energy Delivery - the transmission and distribution business. The company has the second largest transmission network in Florida (4,600 circuit km) and around 30,000 circuit km of distribution lines; and
- Energy Supply - power generation from the company's 7,341MW of capacity including coal, gas, oil and nuclear plant.

The attractions of Florida Progress to ScottishPower would have been the capacity to cut costs in the core networks business and the particular market and regulatory environment in which Florida Progress operated.

- The regulatory regime is relatively benign. The company's average retail tariff (7.1 cents kWh) is equal to the national average and the company is allowed by the regulator (the Florida Commission) to earn a 12% return on equity.
- The company also benefits from relatively high unit growth - customer growth has averaged 2.6% for the past five years and sales were estimated to grow by 3.7% p.a. out to 2000.
- As with the rest of the US the electricity sector is being liberalised, however, the geographic location and peninsular shape will reduce the level of competition from out of state power sources.

A superficial disadvantage relative to some other utilities which Florida Progress does have is that it owns a nuclear station. The 860MW Crystal River Unit No. 3 represents about 20% of Florida Power's system capacity. During 1993 - 1995 it achieved a 90% load factor. However, it was then shut down for an extended period for maintenance and to resolve design issues related to back up safety systems. The station is now back on line and performing well, however, legislation in the US makes it difficult for non-US citizens to control nuclear assets. We believe that ScottishPower has had discussions with the Nuclear Regulatory Commission (NRC) and has found a way to circumvent this problem. As such, the company does have the capability of acquiring a utility which has a nuclear asset. This is an important fact, given that the majority of US utilities tend to have one or more nuclear reactors.

Financing an Acquisition

Although it is clear that ScottishPower is not now going to acquire Florida Progress, it does provide an excellent example of how ScottishPower might finance a subsequent acquisition in the US.

Florida Progress has a $4bn (£2.5bn) market cap and we would estimate that an acquirer would have to pay a 20 - 25% premium to the market. This would result in an acquisition cost to ScottishPower of $4.8 - 5.0bn (£3.0 -

US Acquisition

3.1bn). The most likely way that ScottishPower would have financed such a transaction would be via:

- the sale of assets could realise over $2bn (£1.2bn);
- we estimate that the combined balance sheet could have taken another $2.6bn (£1.5bn) of debt without breaching interest cover of 3x; and
- equity placing in the US market, assuming the above around $400 - 600m (£250 - 375m) would have had to be raised.

ScottishPower is essentially a networks business. It has derived value from its acquisitions of Manweb and Southern Water by exploiting its core network skills to radically improve operating efficiency. As such it may have decided to sell the non-network parts of Florida Progress' business, namely its generation assets and a subsidiary, Electric Fuels, which is an energy and transportation company.

Given the difficulty in selling in nuclear plant in the US we assume a zero value for Crystal River Unit No. 3, but estimate that at least $1bn (£0.6bn) could have been raised by selling the company's generation business. Electric Fuels owns or operates: 4,000 railcars, 45 trains, 700 river barges and 30 river two boats. Via joint ventures the business also has five ocean going tugs and one third of a large bulk products terminal on the Mississippi River south of New Orleans. The business also has control of around 170m tonnes of coal reserves and its mining operation produced 3.7m tonnes in 1996. Again we would estimate that this business could be sold for at least $1bn (£0.6bn).

We estimate that in 1997/8 ScottishPower will have interest cover of 5.2x (operating profit of £790m and a net interest charge of £152m). Florida Progress also has 5.6x interest cover (operating profit of $482m and a net interest charge of $86m). Once the integration and any asset sales were complete it is likely that there would be headroom to take on further debt without breaching a combined interest cover of 3.2x. We assume that the combined entity could take on around $2.4bn (£1.5bn) of additional debt (precise figures would be dependent upon what assets were sold and what debt was apportioned to those assets) which would result in gearing on the combined balance sheet of 170 - 180% after capitalising goodwill.

The third method of financing is likely to have involved equity. Given that it would have been a US acquisition the most likely form of equity issue would have been a placing in the US. Assuming that the company would have raised around $4.4bn (£2.7bn) via asset sales and raising balance sheet debt, the equity placing would have had to have raised the additional $400 - 800m (£250 - 500m). Given that the company is looking at making a US acquisition we believe the most likely form of equity issue is either a placing in the US market or as part of the consideration for the acquisition. There is already a strong appetite for ScottishPower equity in the US, 10% of the equity is owned by US institutions, and it is likely that a US acquisition would augment this appetite. We believe it is very unlikely that the company would seek to issue new equity in the UK market.

Selection Criteria

Although ScottishPower has terminated discussions with what was presumably its first target, the company's strategy remains the same and it is likely that it will try to acquire another US utility. When identifying other potential targets, there are four key criteria which are likely to be used:

- size - any acquisition must be "bankable" thus the target is unlikely to have a market cap in excess of $5bn;
- undervalued generation - the sale of the New England assets in the US demonstrated that marketeers were willing to place a higher value on generating plant than utilities;
- benign regulatory environment - enables value from increased operational efficiency to be retained; and
- good operational management - given that ScottishPower is based in the UK it would want to ensure that there is a strong and dependable management team in the US business.

We believe that there are a number of US utilities which meet this criteria and as such the search for an alternative to Florida Progress should not be too difficult. The only area of doubt is the gap in expectations between what the US utility thinks it is worth and what ScottishPower would be willing to pay to ensure that shareholder value is enhanced.

SP5599

17227

RECEIVED

JUN 18 4 17 PM '99

UTAH PUBLIC
SERVICE COMMISSION

STATE OF UTAH
BEFORE THE
PUBLIC SERVICE COMMISSION

DOCKET NO. 98-2035-04

APPLICATION OF
PACIFICORP AND SCOTTISHPOWER PLC
FOR AN ORDER APPROVING THE ISSUANCE OF
PACIFICORP COMMON STOCK

DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF
NUCOR STEEL

June 18, 1999

STATE OF UTAH
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP AND SCOTTISHPOWER PLC FOR AN ORDER APPROVING THE ISSUANCE OF PACIFICORP COMMON STOCK	))))	**DOCKET NO. 98-2035-04**

DIRECT TESTIMONY
DR. DENNIS W. GOINS
ON BEHALF OF
NUCOR STEEL

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I was employed as a staff economist by the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in regulated markets. For example, I have conducted detailed analyses of cost of service, rate design, and power supply and fuel transaction issues; developed product pricing strategies to respond to market conditions and competitive pressures; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients participating in electric utility restructuring proceedings in New Jersey, New York, South Carolina, and Virginia, and have been involved in several cases before the Federal Energy Regulatory Commission involving such issues as utility mergers, market power, and transmission access and pricing.

I have filed testimony and reports in more than 90 proceedings before state and federal agencies as an expert in utility planning and operating practices, competitive market issues, regulatory policy, cost of service, and rate design. These agencies include the Federal Energy Regulatory Commission, the United States Court of Federal Claims, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Arkansas, Georgia, Illinois, Louisiana, Maine, Massachusetts, Minnesota, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. I have previously assisted clients in cases before the Utah Public Service Commission involving Utah Power (Docket Nos. 89-039-10, 85-035-01, 84-035-01) and Mountain Fuel Supply (Docket No. 93-057-01). In addition, I participated in the merger case before FERC involving Pacific Power & Light and Utah Power & Light (Docket No. EC88-2-007).

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of Nucor Steel, a division of Nucor Corporation. Nucor owns and operates a steel mill in Plymouth, Utah, which is served by PacifiCorp (doing business as Utah Power) under a special contract approved by this Commission.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to review and evaluate the proposed merger between PacifiCorp and ScottishPower plc ("Applicants") and determine whether the merger as filed with the Commission meets the "public interest" standard under which the Commission evaluates utility mergers. In conducting my review and evaluation, I relied primarily on documents filed by the Applicants, including their responses to discovery requests in this case and in concurrent merger-related proceedings in other regulatory jurisdictions. In addition, I relied on such merger-related materials as those found on PacifiCorp's Web site.

CONCLUSIONS

Q. WHAT HAVE YOU CONCLUDED ABOUT THE PROPOSED MERGER?

A. On the basis of my review and evaluation, I have concluded that:

1. The merger should be approved only if it is in the public interest, defined as producing "positive benefits" in which ratepayers share.
2. Quantifiable merger savings are relatively meager—about $10 million annually in reduced corporate costs. Although ScottishPower has identified other potential cost-saving areas, it cannot quantify such savings in a meaningful way that would ensure benefit to ratepayers.
3. ScottishPower has identified several post-merger service quality improvements it hopes to effect, and proposed service quality standards that

will result in penalty payments if the standards are not met. These identified service quality improvements and standards could be adopted and implemented by the Commission and PacifiCorp absent the merger. That is, the service quality improvements and standards are not a benefit unique to the merger. Moreover, the proposed penalty payments to commercial and industrial customers are insignificant—far less than estimated outage costs for these customers.

4. ScottishPower has made no guarantee that it will not attempt to recover from ratepayers the large acquisition premium (up to $1.6 billion) that it is paying for PacifiCorp.
5. The acquisition premium's magnitude may put significant pressure on ScottishPower to raise rates or sell existing valuable generation and transmission assets.
6. ScottishPower has not proposed specific methods for sharing with ratepayers the merger's alleged benefits—for example, a rate reduction corresponding to a reasonable sharing of potential savings.
7. ScottishPower's proposal to develop an additional 50 MW of renewable resources is inconsistent with PacifiCorp's integrated resource plan and is not beneficial to ratepayers.

RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE PROPOSED MERGER?

A. I recommend that the Commission reject the proposed merger as filed since it does not meet the public interest standard. However, if it approves the merger, the Commission should impose conditions that will ensure ratepayers receive significant merger-related benefits. Specifically, the Commission should:

1. Prohibit recovery of the merger acquisition premium in base rates unless ScottishPower demonstrates with reasonable certainty that quantified merger-related benefits equal or exceed the acquisition premium it is paying for PacifiCorp.
2. Impose an immediate across-the-board base rate reduction applicable to non-special contract customers and a post-reduction 5-year rate freeze applicable to all customers. The magnitude of the rate reduction should reflect a reasonable sharing of merger-related cost savings between ratepayers and ScottishPower. Existing contracts with industrial customers should be extended (at the customer's option) to coincide with the 5-year rate freeze to ensure that all PacifiCorp customers receive the rate freeze's protection and benefit. If the Commission elects not to freeze special contract customers' rates for 5 years, then they should be allowed to choose their electricity supplier when their contracts expire subject to rules and guidelines set by the Commission.
3. Require ScottishPower to forego any generation- and transmission-related stranded cost recovery on existing domestic plant and equipment.
4. Require ScottishPower to file a plan for immediate retail access in Utah if it initiates sales of existing PacifiCorp domestic generation and/or transmission assets (excluding assets currently planned for divestiture) to a third party.
5. Increase the proposed reliability penalty payments to commercial and industrial customers to enhance ScottishPower's incentive to achieve the proposed reliability improvements.
6. Require ScottishPower to absorb any costs associated with developing resources that do not meet standards established in PacifiCorp's existing resource planning process.

PUBLIC INTEREST STANDARD

Q. PLEASE DESCRIBE THE PUBLIC INTEREST STANDARD AGAINST WHICH THE MERGER SHOULD BE EVALUATED.

A. The Utah Code states that "[n]o utility shall combine, merge nor consolidate with another public utility engaged in the same general line of business in this state, without the consent and approval of the Public Utilities Commission, which shall be granted only after investigation and hearing and finding that such proposed merger, consolidation or combination is in the public interest."[1] In a 1987 order addressing the standard for approving proposed electric utility mergers, the Commission adopted the "positive benefits" standard for determining whether a merger is in the public interest. Under this standard, the applicants have the burden to demonstrate that "on balance the merger as proposed will result in benefits not otherwise enjoyed,"[2] implying that a merger must result in tangible benefits that could not be realized absent the merger.

In its final order approving the Utah Power & Light/PacifiCorp merger, the Commission applied the positive benefits test to a number of issues.[3] The Commission found that the merger applicants had not adequately quantified benefits in selected areas.[4] Moreover, because of the lack of benefit quantification in certain areas and concerns regarding such issues as local control, the Commission imposed a number of conditions on the merger. The Commission concluded that the merger, subject to the stated conditions, was "in the public interest because the expected benefits of the merger to the Utah jurisdiction outweigh[ed] the costs and detriments associated with it."[5]

---

[1] Utah Code § 54-4-28.
[2] 90 PUR 4th at 555 (Utah P.S.C. 1987).
[3] 97 PUR 4th at 79, 98-116 (Utah P.S.C. 1988).
[4] 97 PUR 4th at 101.
[5] 97 PUR 4th at 125.

Q. DOES THE PUBLIC INTEREST STANDARD REQUIRE APPLICANTS TO DEMONSTRATE BENEFITS THAT COULD NOT BE ACHIEVED ABSENT THE MERGER?

A. Yes. As I stated earlier, merger applicants must demonstrate that "on balance the merger as proposed will result in benefits not otherwise enjoyed."

Q. DOES THE PUBLIC INTEREST STANDARD REQUIRE THAT MERGER-RELATED COSTS AND BENEFITS BE QUANTIFIED?

A. Yes. On the basis of my interpretation of the Commission's prior orders discussed earlier, I believe that reasonable estimates of a merger's costs and benefits must be used to determine whether a merger is in the public interest. Pre-approval quantification of merger benefits provides assurance that a merger is in the public interest, establishes the post-merger framework for determining whether benefits are being achieved, and eliminates reliance on promises and unsupported claims.

ALLEGED MERGER BENEFITS

Q. HAVE THE APPLICANTS ASSERTED THAT BENEFITS WILL RESULT FROM THE MERGER?

A. Yes. ScottishPower has identified numerous qualitative and quantitative benefits allegedly attributable to the merger.[6] These alleged benefits include:

- Net $10 million annual reduction in corporate costs achieved by the end of the third year following completion of the merger.
- Network performance improvements measured by benchmark standards accompanied by failure-to-achieve penalties. Specifically, over the next five years ScottishPower plans to improve system availability (measured by

[6] Alan V. Richardson, supplemental testimony, Ex. SP_(AVR-1).

SAIDI[7]) and system reliability (measured by SAIFI[8]) by 10 percent, and to reduce momentary interruptions (measured by MAIFI[9]) by 5 percent.

- Customer service performance improvements measured by benchmark standards accompanied by failure-to-achieve penalties.
- Pledge to develop an additional 50 MW of renewable resources costing approximately $60 million.

Q. HAS SCOTTISHPOWER QUANTIFIED THE MERGER'S ANNUAL COST SAVINGS?

A. No. With the exception of the $10 million net annual reduction in corporate cost, ScottishPower has not quantified annual cost savings from the various initiatives it proposes to undertake when the merger is completed. ScottishPower has provided information concerning the value of reliability measured by customers' outage costs, and also claims that its proposed network system improvements measured by SAIDI and MAIFI create about $60 million in annual benefits to ratepayers.[10]

Q. DO YOU AGREE WITH THE APPLICANTS' ESTIMATED MERGER BENEFITS?

A. No. I am not at this time taking a position regarding the estimated $10 million net annual reduction in corporate costs, although at least part of these benefits would likely occur absent the merger under PacifiCorp's new focused effort to reduce operating costs and overhead.

I have serious concerns regarding ScottishPower's $60-million estimate of annual benefits from network system improvements. Some monetary benefit to customers will occur if reliability increases. However, the key issue is whether the cost of reliability improvements exceeds the value that customers place on such incremental

[7] System Average Interruption Duration Index.
[8] System Average Interruption Frequency Index.
[9] Momentary Average Interruption Frequency Index.
[10] Alan V. Richardson, supplemental testimony, page 19 and Ex. SP_(AVR-2).

improvements. ScottishPower has neither quantified the cost of meeting the incremental reliability improvements, nor demonstrated that customer benefits outweigh such cost. For example, ScottishPower's estimation technique is similar to asking a customer to pay $150 for a computer power supply backup system and still incur four momentary interruptions each year. The customer would not accept such a deal, and neither should Utah ratepayers unless and until ScottishPower provides a benefit-cost analysis of its proposed network system improvements.

Q. ARE SIGNIFICANT MERGER-RELATED COST SAVINGS ACHIEVABLE IN THE NEAR-TERM?

A. No. Witness Robert D. Green addressed this issue succinctly.

> This transaction presents *very limited opportunities for achieving immediate cost savings*. Unlike most other U.S. utility mergers, there are *no significant, redundant corporate operations* to be eliminated, *nor are there synergies* to be obtained in combining operating systems. Over time, however, the improvement in operating performance achieved by ScottishPower will lead to cost savings resulting in rates lower than they would have been without the transaction.[11] (emphasis added)

Q. ARE THE UNQUANTIFIED MERGER BENEFITS SUFFICIENT FOR THE MERGER TO MEET THE PUBLIC INTEREST STANDARD?

A. No. ScottishPower is unable to quantify the vast majority of alleged merger benefits. While I do not doubt ScottishPower's sincerity in believing the merger will produce the alleged benefits, the Commission and Utah's ratepayers should rely on more than mere statements and promises that the benefits will be achieved. More importantly, if the Commission determines that PacifiCorp's customer service is currently inadequate, the Commission can impose additional customer-service standards backed up by its ratemaking and regulatory authority regardless whether the merger occurs. In my opinion, the Commission should consider the unquantified merger benefits in its public interest deliberations only if it:

[11] Robert D. Green, direct testimony, page 4.

- Accepts that ScottishPower's claimed corporate turnaround capabilities can effectively and efficiently be transferred to PacifiCorp
- Determines that PacifiCorp's current management is incapable of remedying any identified service quality deficiencies in the near future.

MERGER-RELATED COSTS AND RISKS

Q. DOES THE MERGER IMPOSE ANY COSTS AND RISKS FOR PACIFICORP'S CUSTOMERS?

A. Yes. Certain aspects of the proposed merger may pressure ScottishPower to seek rate increases in PacifiCorp's regulatory jurisdictions and/or impose cost reductions leading to deterioration in service quality and reliability. Whether the risk of price increases and/or lower service quality and reliability is offset by merger benefits is unknown since ScottishPower has not quantified merger-related benefits. Moreover, Utah customers face these merger-related risks without a guaranteed share of any achieved merger-related cost savings. Finally, the merger precludes PacifiCorp's merger with a domestic utility with which it may have more obvious corporate synergies.

Rate Increase Pressure

Q. WILL THE MERGER INCREASE PRESSURE TO RAISE PRICES?

A. Yes. Two merger-related factors—speculative cost savings and the large acquisition premium—may ultimately force ScottishPower to seek base rate increases in PacifiCorp's regulatory jurisdictions.[12] One of ScottishPower's objectives appears to be pushing PacifiCorp's earned return up to the regulatory ceiling, in large part by capturing merger-related cost savings for shareholders. If the claimed cost savings do not materialize, then ScottishPower's most readily available options to meet this

[12] These two factors ignore others—for example, cost of investments to improve service, transaction costs, promised dividends, and transition costs—that may pressure ScottishPower to seek rate increases.

objective are base rate increases from PacifiCorp's customers and/or cost reductions that may lead to deterioration in service quality and reliability.[13]

Q. WHAT IS THE SIZE OF THE ACQUISITION PREMIUM?

A. According to information presented in the Utah and Oregon merger-related cases, the acquisition premium ranges from $1.3 billion[14] to $1.6 billion.[15] (The estimated premium depends on the stock prices used.) Regardless of the precise acquisition premium value, we can conclude that ScottishPower paid a significant premium for PacifiCorp.

Q. HOW WILL THE ACQUISITION PREMIUM BE TREATED FOR RATEMAKING PURPOSES?

A. ScottishPower apparently plans to reflect the acquisition premium in PacifiCorp's future base rates. That is, we can reasonably assume that ScottishPower will try to earn a return on and return of the acquisition premium through rates. For example, ScottishPower says::

> ...Scottish Power does not separate the premium [from the purchase price], and will seek a return on its total investment. ScottishPower intends to earn a return on the transaction price by ensuring that PacifiCorp consistently earns its permitted rate of return.[16]

If projected costs savings are not realized or realized much slower than expected, ScottishPower will be pressured to try and recover the acquisition premium through a base rate increase. Alternatively, ScottishPower may elect to reduce expenditures on system performance improvements and cut back on basic maintenance expenses, resulting in poorer quality and less reliable service.

---

[13] Another option is asset divestiture—particularly valuable generation and transmission assets. The only currently planned divestitures are those previously announced by PacifiCorp.

[14] Oregon Public Service Commission, Docket No. 98-2035-04, ScottishPower's response to UIEC Merger Data Request No. 11.7.

[15] Oregon Public Utility Commission, Docket No. UM 918, John S. Thornton, Jr., direct testimony, page 4.

[16] Oregon Public Service Commission, Docket No. 98-2035-04, ScottishPower's response to UIEC Merger Data Request No. 14.3.

Q. IS IT REALISTIC TO BELIEVE THAT SCOTTISHPOWER WOULD REDUCE SERVICE QUALITY AND RELIABILITY SIMPLY TO RECOVER THE ACQUISITION PREMIUM?

A. Yes. ScottishPower's primary objective is (and should be) to protect and enhance the value of its shareholders' investment. If it becomes necessary to cut budgets below levels necessary to make PacifiCorp a "top-10 utility" to meet ScottishPower's earning goals and to recoup the acquisition premium, then we should reasonably expect that ScottishPower will make such cuts.[17]

Uncertain Benefits

Q. ARE UTAH RATEPAYERS GUARANTEED A SHARE OF THE MERGER'S BENEFITS?

A. No. ScottishPower indicates that merger-related cost savings will mitigate pressure for rate increases. However, in addition to being unable to quantify most of the merger's alleged benefits, ScottishPower makes no affirmative proposal to share realized merger benefits immediately or in the near-term with Utah ratepayers via a base rate reduction. For example, witness Robert D. Green says that "[w]ithout any firm assurances that such cost savings are available, it would be premature to reflect these hoped-for cost reductions in rates."[18]

Q. ARE UTAH RATEPAYERS PROTECTED IF THE APPLICANTS FAIL TO ACHIEVE THE ALLEGED MERGER BENEFITS?

A. No. Post-merger regulatory protection cannot undo a merger and its ill effects. Moreover, as I discussed earlier, the merger puts significant pressure on ScottishPower to raise rates and/or cut operating and maintenance budgets below acceptable levels if its management and operating initiatives do not reduce costs and increase earnings as planned. Although ScottishPower has agreed to some modest

[17] A recent coach trip on most major airlines should sufficiently demonstrate that companies can and will reduce service quality if necessary to enhance shareholder returns.
[18] Robert D. Green, direct testimony, page 5.

penalties if it fails to achieve the promised network and customer service performance improvements, the proposed penalties are not adequate compensation for merger-related risks imposed on ratepayers.

Q. CAN THE MERGER BE UNDONE IF THE CLAIMED MERGER BENEFITS ARE NOT ACHIEVED?

A. I do not know the legal answer. However, from a practical standpoint, the answer is no. Once the merger is completed, an intense regulatory game of "estimate the benefits" will ensue, even though reasonable techniques to quantify the merger's benefits may never be found. At the end of the transition for system improvements and thereafter, we may find that customers are no better off (and possibly worse off) than they would have been if PacifiCorp had remained an independent company. The risk of not achieving the alleged merger benefits is simply unacceptable.

Q. ARE THE APPLICANTS' CLAIMS REGARDING THE CORPORATE TURNAROUND AND RELATED COST SAVINGS AT MANWEB DIRECTLY APPLICABLE TO PACIFICORP?

A. No. ScottishPower does not identify similar cost and operating conditions at Manweb that are directly applicable to PacifiCorp. We are simply asked to believe that ScottishPower can replicate at PacifiCorp its alleged management turnaround at Manweb.

Q. SHOULD WE RELY ON THE APPLICANTS' COST-SAVING CLAIMS AS AN OFFSET TO THE MERGER'S RISKS?

A. No. ScottishPower used a benchmarking to estimate potential cost savings arising from making PacifiCorp a "top-10 utility." Specifically, ScottishPower estimated that PacifiCorp's average non-production cost per customer is about \$100 higher than the "top 10" domestic utilities.[19] Reducing PacifiCorp's non-production cost per customer by \$100 implies around \$130 million annual savings (assuming

[19] Andrew MacRitchie, direct testimony, Ex. SP_(AM-1).

PacifiCorp serves 1.3 million customers). If ScottishPower believes it can achieve such significant reductions in PacifiCorp's non-production operating costs, then it should commit to sharing these savings with Utah ratepayers. Because ScottishPower has made no such commitment, the Commission should assume that ScottishPower's faith in the savings estimate is not as strong as its public statements. A famous president said that we should "trust, but verify." This statement is particularly applicable to ScottishPower's claims regarding cost savings.

RENEWABLE RESOURCE PROPOSAL

Q. DO THE APPLICANTS CLAIM THAT THE MERGER PRODUCES SIGNIFICANT ENVIRONMENTAL BENEFITS?

A. Yes. One of the major claimed benefits is a commitment to spend up to $60 million to develop 50 MW of additional renewable resources.

Q. SHOULD THIS COMMITMENT BE CONSIDERED A MERGER BENEFIT?

A. No. First, if investment in additional renewable resources is needed, PacifiCorp can undertake such investment absent the merger—that is, ScottishPower is not needed to ensure that such resources are developed. Second, 50 MW of additional renewable resources may be unneeded. PacifiCorp's recent Resource and Market Planning Program analysis (RAMPP-5, December 1997) indicates that gas-fired resources—not renewable resources—are its least-cost supply-side option, and that no new resources are needed for several years.

RATEPAYER SAFEGUARDS

Q. SHOULD THE COMMISSION APPROVE THE MERGER AS FILED?

A. No. The merger as filed is plainly not in the public interest. The merger creates no significant, quantitative benefits. Moreover, even alleged qualitative benefits (that cannot be measured) are uncertain, and could possibly be achieved absent the merger. In addition, the merger imposes risks of future rate increases and/or deterioration in service quality and reliability.

Q. IF THE COMMISSION APPROVES THE MERGER, SHOULD IT IMPOSE CONDITIONS TO PROTECT RATEPAYERS?

A. Yes. The Commission should impose conditions to:

- Provide assurance that the merger's alleged benefits are achieved
- Ensure that ratepayers share in achieved merger benefits
- Insulate ratepayers from potential merger-related risks.

Q. WHAT CONDITIONS SHOULD THE COMMISSION IMPOSE ON THE PROPOSED MERGER?

A. The Commission should:

1. Prohibit recovery of the merger acquisition premium in base rates unless ScottishPower demonstrates with reasonable certainty that quantified merger-related benefits equal or exceed the acquisition premium it is paying for PacifiCorp.
2. Impose an immediate across-the-board base rate reduction applicable to non-special contract customers and a post-reduction 5-year rate freeze applicable to all customers.
3. Require ScottishPower to forego any generation- and transmission-related stranded cost recovery on existing domestic plant and equipment.
4. Require ScottishPower to file a plan for immediate retail access in Utah if it initiates sales of PacifiCorp's existing domestic generation and/or transmission assets (excluding assets currently planned for divestiture) to a third party.
5. Increase the proposed reliability penalty payments to commercial and industrial customers to enhance ScottishPower's incentive to achieve the proposed reliability improvements.

6. Require ScottishPower to absorb any costs associated with developing resources that do not meet standards established in PacifiCorp's existing resource planning process.

Acquisition Premium Recovery

Q. WHY SHOULD THE COMMISSION PROHIBIT RECOVERY OF THE ACQUISITION PREMIUM IN BASE RATES?

A. As I noted earlier, ScottishPower's takeover precludes PacifiCorp's merger with a domestic utility with which it may have more obvious corporate synergies that create significant—and measurable—benefits. Because of uncertainty about the proposed merger's benefits, ratepayers should be protected from paying a premium for a company that already serves them.

Rate Reduction

Q. WHY IS AN IMMEDIATE BASE RATE REDUCTION NECESSARY IF THE COMMISSION APPROVES THE MERGER?

A. A rate reduction is necessary to protect non-special contract customers from merger-related risks, and to put meaning behind ScottishPower's numerous, and generally unsupported claims of merger benefits. If ScottishPower has faith in its estimates of merger-related cost savings, then it should back up that faith by sharing some of the cost savings with ratepayers now. In addition, the 5-year rate freeze for all customers is necessary to protect ratepayers from a post-reduction (or post-contract) series of rate increases. A base rate reduction and 5-year rate freeze would ensure that customers receive some tangible, positive benefit from the merger.

Q. WHAT PERCENTAGE RATE REDUCTION SHOULD BE IMPLEMENTED IF THE COMMISSION APPROVES THE MERGER?

A. I am not recommending a specific percentage reduction at this time. The magnitude of the rate reduction should reflect a reasonable sharing of merger-related cost savings between ratepayers and ScottishPower. If the parties cannot agree on a settlement rate cut, then the Commission should reduce rates enough to mitigate merger-related risks, but not enough to impair PacifiCorp's financial viability.

Q. SHOULD THE RATE REDUCTION APPLY TO ALL CUSTOMERS?

A. No. The rate reduction should apply only to non-special contract customers, although all customers—including special contract customers—should be covered by the 5-year rate freeze.

Q. HOW SHOULD SPECIAL CONTRACT CUSTOMERS BE TREATED UNDER THE 5-YEAR RATE FREEZE?

A. Existing contracts with industrial customers should be extended (at the customer's option) to coincide with the 5-year rate freeze to ensure that they—like tariff customers—receive some tangible, positive benefit from the merger. If the Commission elects not to freeze special contract customers' rates for 5 years, then they should be allowed to choose their electricity supplier when their contracts expire subject to rules and guidelines set by the Commission.

Stranded Cost Recovery and Asset Divestiture

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING STRANDED COST RECOVERY?

A. Stranded cost typically reflects the difference between the market value and embedded cost of a utility asset.[20] In making its bid for PacifiCorp, ScottishPower has explicitly valued PacifiCorp's assets and compensated investors responsible for creating those assets. I view ScottishPower's bid for PacifiCorp much as a third-party's bid for divested utility assets occurring today in states with retail access. The basic rule for such purchases is *caveat emptor*—let the buyer beware. ScottishPower

[20] My recommendation addresses only stranded costs associated with generation and transmission assets. I am making no recommendation in this case regarding potential stranded costs associated with distribution and general plant assets, regulatory assets, or above-market contracts with nonutility generators (NUGs).

Renewable Resources

Q. SHOULD THE APPLICANTS ASSUME COST-RECOVERY RISKS FOR RESOURCES THAT DO NOT MEET COST AND EFFICIENCY STANDARDS REFLECTED IN EXISTING RESOURCE PLANS?

A. Yes. In particular, ratepayers should not bear cost responsibility for ScottishPower's proposed 50-MW increment in renewable resources unless such resources meet these standards.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF UTAH
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
PACIFICORP AND SCOTTISHPOWER PLC	)	**DOCKET NO. 98-2035-04**
FOR AN ORDER APPROVING THE ISSUANCE	)	
OF PACIFICORP COMMON STOCK	)	

AFFIDAVIT
OF
DENNIS W. GOINS

County of Fairfax

:ss

State of Virginia

Dr. Dennis W. Goins, having been sworn in due form of law, on oath, deposes and says that the foregoing testimony was prepared by him or under his supervision and that the information contained therein is true and correct to the best of his knowledge, information, and belief.

Dennis W Goins

Dennis W. Goins
Affiant

Subscribed and sworn before me this 17th day of the month of June, 1999.

Notarial Seal

Notary Public

My commission expires: June 14, 2004

CERTIFICATE OF SERVICE

I hereby certify that on this 18th day of June, 1999, I caused via federal express or mail, first class, postage prepaid, a true and correct copy of the foregoing **DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF NUCOR STEEL** to:

Michael Ginsberg
Assistant Attorney General
Utah Division of Public Utilities
160 East 300 South
Salt Lake City, UT 84111

Doug Tingey
Assistant Attorney General
160 East 300 South
Salt Lake City, UT 84111

Lee R. Brown
Vice President, Contracts, Human Resources,
Public & Government Affairs
238 North 2200 West
Salt Lake City, UT 84116

Stephen R. Randle
Randle, Deamer, Zarr, Romrell & Lee, P.C.
139 East South Temple, Suite 330
Salt Lake City, UT 84111-1004

Daniel Moquin
Assistant Attorney General
1594 West North Temple, Suite 300
Salt Lake City, UT 84116

Eric Blank
Land and Water Fund of the Rockies
2260 Baseline, Suite 200
Boulder, CO 80302

Edward A. Hunter
Stoel, Rives, Boley, Jones & Grey
201 South Main Street, #1100
Salt Lake City, UT 84111

Brian Burnett
Callister, Nebeker & McCullough
10 East South Temple, #800
Salt Lake City, UT 84133

F. Robert Reeder
William J. Evans
Parsons Behle & Latimer
201 South Main Street, Suite 180
P.O. Box 45898
Salt Lake City, UT 84145-0898

Dr. Charles E. Johnson
The Three Parties
1339 Foothill Boulevard, Suite 134
Salt Lake City, UT 84108

Gary Dodge
Parr, Waddoups, Brown, Gee & Loveless
185 South State Street, Suite 1300
Salt Lake City, UT 84111-1536

Bill Thomas Peters
David W. Scofield
Parsons, Davies, Kinghorn & Peters, P.C.
185 South State Street, Suite 700
Salt Lake City, UT 84111