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SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter Of The Application of	)	
PacificCorp and ScottishPower PLC	)	Docket No. 98-2035-04
for an Order Approving the Issuance	)	
of PacificCorp Common Stock	)	

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, INC.

DIRECT TESTIMONY
OF
CARL N. STOVER, JR.

June 17, 1999

TABLE OF CONTENTS

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OF
CARL N. STOVER, JR.

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carl N. Stover, Jr.; my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION WITH THE FIRM?

A. I am employed by C. H. Guernsey & Company, Engineers • Architects • Consultants. I am President and Chief Executive Officer of the firm. My consulting activities include rate and financial analysis on behalf of our clients before state and regulatory commissions. I am also involved in long range system planning and engineering feasibility studies related to power supply planning.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Electrical Engineering and a Master of Science degree in Industrial Engineering. I am a Registered Professional Engineer, licensed in the states of Oklahoma, Kansas, Colorado, Wyoming, Iowa, and Texas. I am a member of the Power Engineering Society and the Engineering Management Society of the Institute of Electrical and Electronics Engineers.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE STATE REGULATORY COMMISSIONS ON MATTERS RELATED TO COST OF SERVICE, RATE DESIGN, AND POWER SUPPLY PLANNING?

A. Yes. I have appeared before regulatory commissions in the states of Texas, Wyoming, Colorado, Oklahoma, Kansas, Utah, New Mexico, and Arkansas. Exhibit ____ (CNS-1) attached to this testimony is a summary of the retail rate proceedings in which I have been involved.

Q. HAVE YOU BEEN INVOLVED IN WHOLESALE RATE PROCEEDINGS?

A. Yes. I have been involved in a number of proceedings before state and federal regulatory agencies that involved cost of service and rate design issues related to wholesale rates. A summary of the wholesale rate proceedings in which I have participated can be found in Exhibit ____ (CNS-2).

Q. HAVE YOU BEEN INVOLVED IN GENERIC RATE PROCEEDINGS?

A. Yes. I have represented electric systems in generic hearings in the states of Texas and Colorado.

Q. HAVE YOU PUBLISHED OR PRESENTED PAPERS CONCERNING PLANNING, RATE DESIGN, COST OF SERVICE, ETC.?

A. Yes. Exhibit ____ (CNS-3) is a listing of my papers and presentations.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. Exhibit ____ (CNS-4) to Exhibit ____ (CNS-9) were prepared in support of my direct testimony.

Q. WERE THE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. WHOM DO YOU REPRESENT IN THIS PROCEEDING?

A. I am appearing on behalf of Deseret Generation & Transmission Co-operative, Inc. and its Member Systems ("Deseret").[1]

Q. PLEASE DESCRIBE DESERET.

A. Deseret is a wholesale electric generation and transmission cooperative that provides electric generation, transmission and related services to its six members: Bridger Valley Electric Association; Dixie-Escalante Rural Electric Association, Inc.; Flowell Electric Association, Inc.; Garkane Power Association, Inc.; Moon Lake Electric Association, Inc.; and Mount Wheeler Power, Inc. (collectively, "Members"), each of which is a rural electric cooperative that provides electric services at retail to its members/owners in the States of Utah, Wyoming, Arizona, Colorado and/or Nevada.

Deseret owns and operates the Bonanza Power Station, a coal-fired generating facility located near Vernal, Utah together with transmission facilities in various parts of Utah. Much of Deseret's power is transmitted for use by in-state utilities over PacifiCorp's transmission facilities. In addition, Deseret owns an interest in the Hunter II generating facility located in Emery County. PacifiCorp operates and maintains the Hunter II facility by contract with Deseret. Under the terms of the Hunter II Operating and Maintenance

[1] Bridger Valley Electric Association, Inc., Dixie-Escalante Rural Electric Association, Inc., Flowell Electric Association, Inc., Garkane Power Association, Inc., Moon Lake Electric Association, Inc., and Mount Wheeler Power, Inc.

Agreement, PacifiCorp passes certain costs on to Deseret related to the operation of Hunter II and to PacifiCorp's corporate expenses. These costs are, in turn, passed through to Deseret's members and to the consumers and ratepayers served by each of the Member Systems.

II. PURPOSE AND RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address two issues related to the proposed PacifiCorp and ScottishPower merger that will have an impact on Deseret:

1. The adverse impact that the proposed merger will have on customers in rural Utah in terms of reduced service reliability.
2. The adverse impact that the proposed merger will have on the allocation of cost to Deseret related to the Hunter II Operation and Maintenance Agreement with PacifiCorp. The increase in allocation of cost to Deseret will have a direct impact on the retail rates paid by rural customers in Utah. Unless particular care is taken in the allocation of merger related cost, Deseret will be allocated cost disproportionate to the benefits that the parties claim will exist.

My testimony will discuss why Deseret believes each issue is germane to this proceeding and the remedy proposed by Deseret.

Q. ARE OTHER PARTIES APPEARING ON BEHALF OF DESERET IN THIS PROCEEDING?

A. Yes. Mr. Carl R. Albrecht and Mr. R. Leon Bowler provide testimony specific to two of the Member systems.

Q. WHAT IS THE STANDARD BY WHICH YOU HAVE ADDRESSED EACH ISSUE?

A. The Commission's March 31 Memorandum stated that "All parties agree that the approval standard is net positive benefits." The Commission went on to say that they recognize that PacifiCorp's argument that the proper standard is not net positive benefits but rather what I would characterize as "no harm " to ratepayers. My testimony will consider both the "net positive benefit" test and the "no harm" test. In addition, I have evaluated the issues using a third test dealing with customer protection. The "customer protection" test is satisfied if PacifiCorp is willing to put in place mechanisms to protect the customer should the promised benefits not occur.

Q. IS THERE ANY PRECEDENT FOR PROPOSING CONDITIONS TO PROTECT THE CUSTOMER IF THE MERGER IS APPROVED?

A. Yes. The Federal Energy Regulatory Commission ("FERC") has stated that:

> "Rather than requiring estimates of somewhat amorphous net merger benefits and addressing whether the applicant has adequately substantiated those benefits, we will focus on ratepayer protection. Merger applicants should propose ratepayer protection mechanisms to assure that customers are protected if the expected benefits do not materialize. The applicant bears the burden of proof to demonstrate that the customer will be protected. This puts the risk that the benefits will not materialize where it belongs — on the applicants."[2]

III. CONCLUSIONS AND RECOMMENDATIONS

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[2] Order No. 592, *Policy Statement Establishing Factors the Commission Will Consider in Evaluating Whether a Proposed Merger is Consistent With the Public Interest*, FERC Stats. & Regs 31,044,61 Fed Reg 68595 (1996).

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. I do not believe that the Commission should approve the merger if the standard is a "net benefit" to the customer. PacifiCorp has not demonstrated that there will be net benefits to Deseret and the retail customers in rural Utah. I do not believe that the Commission should approve the merger if the standard is a "no harm" to Deseret and the retail customers in rural Utah. PacifiCorp has not demonstrated that Deseret and the retail customers in rural areas will not be harmed. Deseret is willing to support the merger if the PacifiCorp is willing to commit to the "customer protection" standard and to conditions that have been identified.

Q. WHAT ARE THE SPECIFIC CUSTOMER PROTECTION CONDITIONS THAT PACIFICORP MUST COMMIT TO?

A. Exhibit ____ (CNS-4) is an initial list of conditions PacifiCorp should agree to in order for the Commission to consider approval of the merger. This list is not intended to be all inclusive. The preferred approach is to expand the list to include issues and concerns raised by other parties. I think it is important that the Commission establish an inclusive list of customer protection requirements if the Commission approves the proposed merger.

Q. DO YOU BELIEVE THAT THE CUSTOMER PROTECTION CONDITIONS ARE REQUIRED EVEN IF THE COMMISSION FINDS THAT PACIFICORP SATISFIES THE NET BENEFIT AND NO HARM TEST?

A. Yes, definitely. Because absent such conditions, there are no safeguards for consumers. Both the net benefit test and the no harm test are criteria used by the regulator(s) as the basis for granting or denying merger applications. If expected outcomes don't develop, consumers will bear the risk. Customer protection conditions correct this inequity by putting the risk on the applicants.

Q. IS THE ALLOCATION OF RISK AN IMPORTANT ISSUE IN THIS PROCEEDING?

A. Yes. Based on my review of the proposal, the suggested benefits are very vague and ill-defined. The proposal places essentially all of the risk on the ratepayer. By conditioning the merger to include specific customer protection criteria, there is a more equitable assumption of risk.

IV. IMPACT ON RURAL UTAH

Q. WHAT IS THE ISSUE WITH REGARD TO THE IMPACT ON RURAL UTAH?

A. The customers in both the urban and rural areas of Utah should expect to be provided low cost reliable electric service. Portions of the Deseret system are not currently receiving reliable electric service from PacifiCorp. Based on information provided in this proceeding there is reason to conclude that service reliability in the rural areas will not improve, and in fact will become worse if the merger is approved.

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN PACIFICORP AND DESERET IN RELATION TO RELIABILITY OF SERVICE ISSUES.

A. Deseret's Member distribution cooperatives serve over 39,000 retail customers, predominantly rural, with approximately 26,000 residing in Utah. Over 25% of the total capacity and energy consumed by the Members' retail customers is delivered over PacifiCorp transmission and distribution facilities. Exhibit ____(CNS-5) is a list of the Members' wholesale delivery points. The list shows the delivery points directly connected to the PacifiCorp transmission and distribution system. For three of the systems, Dixie-Escalante Rural Electric Association, Inc., Flowell Electric Association, Inc., and Garkane Power Association, Inc., the PacifiCorp transmission facilities are particularly critical in providing reliable power supply service. In order to provide reliable electric service, it is necessary that PacifiCorp construct, operate and maintain adequate transmission facilities to serve the retail customer's load requirements.

Q. IS THE ISSUE OF SERVICE TO UTAH RURAL CUSTOMERS UNIQUE TO THE RETAIL CUSTOMERS SERVED BY DESERET AND THE MEMBER SYSTEMS?

A. No. PacifiCorp directly serves retail customers in rural areas as well, approximately 92,000 out of a total 612,000 served state-wide. In the aggregate, Deseret and PacifiCorp are responsible for approximately 118,000 rural consumers, which is roughly 18% of all retail electric consumers in the state (excluding retail customers served by the municipal owned electric systems). Questions of service reliability are equally important to retail customers served by the cooperatives and by PacifiCorp. The testimony of Mr. Albrecht will show that the rural reliability issues relate to both the Cooperative and PacifiCorp retail customers.

Q. YOU STATED EARLIER THAT PACIFICORP'S SERVICE TO PORTIONS OF THE DESERET SYSTEM IS NOT ADEQUATE. PLEASE EXPLAIN THE NATURE OF THE PROBLEMS.

A. The problems have been greatest in the southwest region of Deseret's system. A large proportion of PacifiCorp's existing transmission and distribution system in rural Utah is a radial system dating back to the 1940's. A radial transmission system is not as reliable as a looped transmission system. Over the past decade a combination of population growth associated with urbanization in the area and PacifiCorp's cutbacks in maintenance and improvements to the system has resulted in reduced service reliability. Two Member systems, Dixie-Escalante and Garkane Power Association, have been the most severely affected. Direct testimonies provided by Mr. Albrecht and Mr.Bowler explain the transmission service reliability in the southwestern portion of Utah.

Q. CAN YOU PROVIDE AN EXAMPLE OF SERVICE RELIABILITY CONCERNS?

A. Yes. Exhibit ____ (CNS-6) summarizes outages for Middleton and Pine Valley delivery points for the period 1995 through 1998, and a log of events corresponding to select outages. Outages at Middleton are associated with PacifiCorp's 138-kV transmission line from Cedar City to the Escalante Valley, while Pine Valley's problems relate to a 34.5-kV line from Cedar City. According to personnel at Dixie, several outages during this period were due to PacifiCorp's poor maintenance and failure to make capital improvements to upgrade facilities. The Exhibit shows 13 outages at Middleton between 1995 and 1998 ranging between 20 minutes to 5 hours 15 minutes in duration, with a median of 90 minutes. There were 11 outages at Pine Valley ranging between 10 minutes and 7 hours 30 minutes, with a median of 2 hours 30 minutes.

Q. IS THE IMPACT ON RETAIL CONSUMERS MEASURABLE?

A. Yes. Exhibit ___ (CNS-7) is a comparison of service interruptions for Dixie-Escalante as reported on RUS Form 7 and averages compiled by RUS. The comparison shows that Dixie's 5-year average (1993 - 1997) due to power supply interruptions is 1.89 hours per consumer, compared to 1.22 for Cooperatives in the Northwest and 0.98 for all Cooperatives for the same period. In other words, on average, Dixie's retail consumers have experienced power outages lasting 55% longer than the rural sector in the Northwest and 93% longer than the national average for rural electric service. In 1998 Dixie's power supply outage was 9.25 hours per consumer which results in a six-year average of 3.12 hours per consumer.

Q. CAN ALL OF THE POWER SUPPLY INTERRUPTIONS BE ATTRIBUTED TO UNSATISFACTORY RELIABILITY OF THE PACIFICORP TRANSMISSION SYSTEM?

A. No. The power supply outage statistics as reported by RUS reflect outage at the wholesale point of delivery. Outages at the wholesale point of delivery could be a result of either generation or transmission failures.

Q. IS THERE ANY WAY TO EVALUATE THE EXTENT TO WHICH THE OUTAGES FOR THE DIXIE-ESCALANTE SYSTEM ARE RELATED TO TRANSMISSION SERVICE RELIABILITY ISSUES?

A. Yes. One approach is to simply compare the outage data for Dixie-Escalante with the other Deseret Member systems. Deseret is the power supplier for all of the Member systems and the Members share a power supply resource that would include all of Deseret resources. Differences in outage between systems can therefore be related to transmission reliability.

Q. WHAT DO YOU CONCLUDE FROM REVIEWING THE DATA?

A. Exhibit ____ (CNS-7) shows power supply outage data for all of the Deseret Member systems. The five-year average outage due to power supply interruptions is:

Member System	*5-Yrs Ended 1997*	*6-Yrs Ended 1998*
BVEC	0.36	0.30
DEEA	1.89	3.12
FEA	1.60	1.33
GPA	1.27	1.06

MLEA	0.02	0.69
MWP	0.06	0.05

The Dixie-Escalante outage statistics are clearly very high compared to the other systems.

Q. CAN YOU PROVIDE EXAMPLES OF SERVICE RELIABILITY PROBLEMS FOR GARKANE?

A. Yes. Garkane has interconnect agreements with PacifiCorp at Panguitch and Hildale delivery points which allow the two utilities to pick up one another's load under outage or emergency conditions. Mr. Albrecht testified as to reductions in personnel and the extent to which PacifiCorp has not adequately maintained the 46 kV line from their Sigurd Substation to Garkane's Northern System delivery point in the Garkane 46 kV to 69 kV substation.

Q. DID DESERET OR MEMBER SYSTEMS REPORT RELIABILITY PROBLEMS TO THE PUBLIC SERVICE COMMISSION?

A. Yes. The examples cited above and others have been provided the Public Service Commission through data responses submitted by the Utah Rural Electric Association in connection with Docket No. 99-2035-01 investigating service quality complaints against PacifiCorp.

Q. HAS THE COMMISSION DEVELOPED ANY CONCLUSIONS WITH REGARD TO QUALITY OF SERVICE ISSUES IN THE RURAL AREAS?

A. Yes. In Docket No. 99-2035-01, the Division of Public Utilities report of an investigation dated June 11, 1999 included the following statement (Ref. Exhibit____(CNS-10):

> However, the Division does find indication that the quality of service and reliability may have declined for PacifiCorp's wholesale municipal and Cooperative customers who take wheeling and power supply electric service from PacifiCorp at the transmission level. (Ref. Page 2)

Q. DID THE COMMISSION HAVE ANY FINDINGS WITH REGARD TO THE COMMUNICATION AND COORDINATION BETWEEN PACIFICORP AND ITS WHOLESALE CUSTOMERS?

A. Yes.

> The Division also finds evidence of a lack of communication and coordination between PacifiCorp and its municipal and cooperative agency customers that appears to be serious enough to be affecting service quality and reliability. (Ref. Page 2)

Q. HAVE EXPENDITURES FOR TRANSMISSION AND HIGH LEVEL DISTRIBUTION FACILITIES IN UTAH BEEN ADEQUATE?

A. It is impossible to make that determination. PacifiCorp asserts it does not budget for repair and maintenance by state and the information is not available (see response to data request UIEC No. 2.4.). Transmission O&M costs for the last five years for the state of Utah were provided, however. Annual totals, excluding wheeling costs, were reported as follows:

Year	Expense ($000)
1998	$8,020 (preliminary)
1997	$9,452
1996	$9,180
1995	$9,342
1994	$8,732

The preliminary estimates for 1998 reflect the reduction in the expenditures for transmission O&M related activities. Given the comments in the testimony in support of the proposed merger, I can only conclude that the decrease that is shown from 1997 to 1998 will likely continue, given the commitment to reduce cost. Given the Commission's finding with regard to the historical inadequacy of service in rural areas, a further reduction in O&M costs can only exacerbate the situation.

Q. IS THERE ANY PARTICULAR TREND WITH REGARD TO INVESTMENT IN TRANSMISSION PLANT?

A. As a part of its Docket 99-2035-01 findings, the Commission stated:

> Transmission plant investment was $64.8 million in 1989 and increased to a high of $105 million in 1993. After 1993, transmission plant investment has declined steadily to its current level of $13.1 million, 80% below its 1990 level. (Ref. Page 6)

Q. IS THERE ANY DATA TO SUPPORT THE COMMENTS THAT PACIFICORP APPEARS TO BE REDUCING ITS STAFFING IN SUPPORT OF TRANSMISSION FACILITIES?

A. Yes. The Commission in its Docket 99-2035-01 findings stated that:

> Utah transmission distribution head count (only budgeted in 1995 through 1998 figures are available) deceased 13.5% over the last four years. (Ref. Page 10)

Q. SCOTTISHPOWER HAS INDICATED THAT THEY INTEND TO IMPROVE SERVICE RELIABILITY AS A PART OF THE MERGER PLANS. WHY DO YOU BELIEVE THAT SERVICE RELIABILITY WILL DETERIORATE AFTER THE MERGER?

A. ScottishPower has committed to performance standards which it claims will improve system reliability. Specifically, they are:

- On the five-year anniversary of completion of the transaction, reduce the System Average Interruption Duration Index (SAIDI) by 10%.

- On the five-year anniversary of completion of the transaction, reduce the System Average Interruption Frequency Index (SAIFI) by 10%.
- On the five-year anniversary of completion of the transaction, reduce the Momentary Average Interruption Index (MAIFI) by 5%.
- The 5 worst performing circuits in each state will be selected annually based on Circuit Performance Indicator (CPI), as calculated over a 3-year average and corrective measures will be taken within 2 years of implementation of the performance targets to reduce the CPI by 20% [for each circuit selected (response to data request DPU 10th, S10.1)].
- For power outages because of a fault or damage on the system, PacifiCorp will restore supplies on average to 80% of customers within 3 hours.
- For each of the standards not achieved at the end of the five-year period, ScottishPower will pay a penalty equal to $1.00 for every customer served by PacifiCorp in Utah.
- Specified terms and conditions relating to implementation.

From Deseret's perspective, there are several problems with these standards. First, the improvements in SAIDI, SAIFI, and MAIFI measurements will be based on the overall performance, broken down on a state-by-state basis. ScottishPower will make no distinction between urban and rural circuits in compiling SAIDI, SAIFI, and MAIFI data. (see response to data request DPU 7th P7.5.). Because of differences in population density, a separate accounting for rural and urban regions would provide a much more accurate measure of service reliability to ensure that the rural section is receiving service comparable to the urban counterpart.

Q. HAS SCOTTISHPOWER INDICATED WHY IT WILL NOT COMPILE DATA ON ANY LEVEL OTHER THAN FOR THE ENTIRE STATE?

A. Yes. ScottishPower claims that tracking on a basis lower than state-by-state would not be manageable (see response to data request DPU 7th, S7.1). Moreover, ScottishPower claims that due to uncertainty in the accuracy of historical statistics, it is inappropriate to define standard baselines at this time (see response to data request DPU 7th, S7.2). Consequently, it appears that existing baseline levels have not been established for setting targets for reduction by 2005 and that there is no intent to establish different standards to account for different conditions in the rural sector versus the urban areas. Although ScottishPower witness Alan Richardson indicates that ScottishPower will establish a benchmark "in consultation with regulators" (Richardson rebuttal, P. 3, L. 17), because there will be no comparable historical data to compare against, it will be difficult to accurately assess the results of service improvements against the status quo at the time the program was implemented.

Q. IN YOUR OPINION, IS SCOTTISHPOWER CORRECT IN ASSERTING THAT TRACKING ON A LOWER BASIS IS UNMANAGEABLE?

A. No. There may be several simple ways to divide between urban and rural. For example, one method is to assign the four counties Weber, Davis, Salt Lake, Utah as urban and the remainder of the state as rural. If ScottishPower is truly dedicated to improving customer service, then recognizing and responding to the differences of each segment — rural and urban — should be a priority. The Commission's own report of reliability shows the need to improve reliability in the rural areas.

Q. GIVEN THAT THE RURAL SECTOR HAS MUCH LOWER DENSITY THAN THE URBAN COUNTERPARTS, WILL THE URBAN CIRCUITS HAVE PRIORITY FOR IMPROVEMENTS IN ORDER TO IMPROVE SAIDI, SAIFI, AND MAIFI?

A. Yes. The formulas for these statistics result in indices on a per customer basis. PacifiCorp intends to identify the five worst circuits based on the SAIDI, SAIFI and MAIFI statistics. PacifiCorp will then commit to an improvement in the reliability statistics. However, because the number of customers on a rural circuit is typically less than the number of customers on an urban circuit, and because ScottishPower will focus on system upgrades and improvements in outage response times where the impact will be the greatest, it will favor the urban areas over the rural sector. In fact, ScottishPower will not specify the threshold levels for SAIDI, SAIFI, and MAIFI that will drive investments in particular territories (see response to data request DPU 7th, S7.28). Therefore, I conclude that promised improvements in these statistics are not indicators that service reliability in the rural area will improve.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE HOW THE URBAN AREA MAY BE FAVORED OVER THE RURAL?

A. Yes. For simplicity, assume an electric system has only four circuits, two in an urban setting and two rural, with the following characteristics:

Line #	***Circuit***	***# Cust.***	***# Circuit Int.***	***# Cust. Int. (N_i)***	***Restoration Time (r_i)***	***N_i x r_i***
1	Urban-1	500	2	1,000	10	10,000
2	Urban-1	500	3	1,500	30	45,000
3	Urban-2	1,000	5	5,000	15	75,000
4	Urban-2	1,000	8	8,000	45	360,000
5	Rural-1	10	2	20	10	200
6	Rural-1	10	3	30	30	900
7	Rural-2	100	5	500	15	7,500
8	Rural-2	100	8	800	45	36,000
9	Total	1,610(N_T)	36	16,850	200	534,600

Indexing for the entire area results in 10.5 SAIFI (N_i/N_T) and 332 SAIDI ($N_i r_i/N_T$). Working backward, it is obvious that nearly 10% improvement in the indices is easily achieved by simply focusing on Urban-2. For example, the targets can be met by reducing the number of interruptions on line 4 in the table above from 8 to 7 and the restoration time from 45 minutes to 43 minutes. The resulting indices would be 9.84 SAIFI and 295 SAIDI, and targets would be met without any improvement to the rural area. Although a simplistic model, the concept is conveyed. If ScottishPower intends to improve the reliability statistics, the focus will be in the urban and not the rural areas.

Q. PLEASE COMMENT ON THE REMAINING TWO PROPOSED STANDARDS.

A. ScottishPower proposes that within 2 years of implementation of the performance targets it will reduce the Circuit Performance Indicator (CPI) by 20% by correcting the 5 worst circuits identified annually. CPI is a weighted value comprised of MAIFI, SAIDI, SAIFI, number of lockouts, and load factor (Moir direct, p. 7, l. 26). Application of the factors to determine the CDI is not clear. In addition, although ScottishPower indicates," that this particular standard is not applied on a state-wide basis " and "will try to accommodate relevant and reasonable requests from the Division for other network data" (response to data request DPU 10th, S10.2), there is no assurance that all regions will receive equal attention. Finally, ScottishPower claims that for power outages because of a fault or damage on the system, it will restore supplies on average to 80% of customers within 3 hours. Again, these averages are not sector-specific. Consequently, Deseret and Member systems have no assurance that service to them will improve. In fact, they conclude that the emphasis on system-wide results will result in harm to the rural sector.

Q. WHAT OTHER EVIDENCE TO YOU HAVE TO SUBSTANTIATE YOUR CLAIM?

A. First, there is concern regarding ScottishPower's policy of categorizing expenditures on the basis of investment output, quoting from ScottishPower's response to OFFER's business plan questionnaire, "We have moved away from the traditional Electricity Supply Industry approach of routinely replacing assets on a 'like for like' basis, and have categorized expenditure on the basis of investment output.". ScottishPower explains by stating:

> For example our overhead lines are ranked by both condition and reliability. The subsequent investment will replace, to a stronger construction, those sections of the circuit supplying the most customers. Sections of the circuit supplying small customer numbers will typically be refurbished (response to data requst DPU 4th, S4.3)

The concern is that investments based on the number of customers will bias PacifiCorp's system improvements in favor of the urban areas. Second, there is concern that ScottishPower's dramatic cost-cutting targets will override any potential benefits that may appear to occur as a result of these performance standards.

Q. PLEASE EXPLAIN.

A. One of the stated reasons for the merger is to make PacifiCorp one of the leading utilities in the U.S. In direct testimony Mr. Andrew McRitchie, witness for ScottishPower, has provided a comparison of non-production cost per customer for U.S. Utilities and stated that the intent is to move PacifiCorp into the top ten. Currently, PacifiCorp's average costs are \$300 per customer and the target is \$200 or less, a minimum decrease of \$100 or 30%. ScottishPower does not delineate how it will reduce costs (see response to data request DPU 4th, S4.1). The rural area has already suffered as a result of restructuring following the PacifiCorp and UP&L merger. The Commission's conclusion after reviewing comments on service reliability clearly points out the deterioration of service reliability in the rural areas. Based on a review of testimony and discovery, it appears that Deseret and Member Systems will experience additional pressure, resulting in further deterioration of service.

Q. WHAT DO YOU MEAN BY ADDITIONAL PRESSURES THAT WILL RESULT IN FURTHER DETERIORATION OF SERVICE?

A. I have already described the concern regarding the application of the CPI criteria and the fact that the application as proposed by ScottishPower will be biased in favor of the urban areas will result in a decrease in reliability in the rural areas. I think there are even greater pressures involved that will result in a decrease in reliability of service. They primarily relate to the overall economics of the merger. The total cost of merging the systems consists of three components: the acquisition cost, the transaction cost, and the transition cost. The acquisition premium is approximately $1.6 billion based on stock prices at the time the merger was announced. Based on current prices, the premium is approximately $730 million.[3] The transaction cost has not been completely defined but is estimated to be approximately $250 million. The transition cost is approximately $135 million (see response to data request DPU 10th S10.9). Approximately $122 million of the transition cost will be charged to ratepayers. The point is that given these costs, and in particular the premium that ScottishPower is paying, there will be substantial pressure to reduce costs in order to provide expected return to the stockholder. Deseret is concerned that a reduction in cost will be translated into continued deterioration in service in the rural areas.

[3] As of June 16, 1999, *The Wall Street Journal* reports the closing share prices of PacifiCorp and ScottishPower ADS were $19 and $37, respectively. With the exchange rate of .58 ADS for one share of PacifiCorp, the value of the exchange is $21.46 per ScottishPower ADS. This represents a market premium of $2.46 per share above PacifiCorp's closing price on June 16, 1999. Considering that PacifiCorp has 297 million shares outstanding, the current premium of the acquisition is $731 million.

Q. IN YOUR OPINION, COULD PACIFICORP ACHIEVE THE SAME LEVEL OF SERVICE RELIABILITY PROPOSED IN THE PERFORMANCE STANDARDS WITHOUT THE MERGER?

A. Yes. I cannot identify any components of the proposed reliability standards which PacifiCorp could not offer independently today.

Q. BASED ON THESE CONCERNS SHOULD THE COMMISSION REJECT THE MERGER?

A. Yes. ScottishPower has not adequately demonstrated net benefits and has laid out a strategy that will assuredly harm the customer in the rural area. Therefore, the merger would fail based on both standards.

Q. ARE THERE OTHER CONCERNS ASSOCIATED WITH THE RELIABILITY ISSUE?

A. Yes. Because of the poor quality of transmission service provided by PacifiCorp, Deseret is placed in a noncompetitive position. For example, Dixie-Escalante provides retail service to customers in the St. George area. Other customers in the area are served by the municipal electric system owned and operated by St. George. Because of the transmission outages, the retail customers served by Dixie-Escalante experience poorer quality of service than the retail customers served by the municipal system.

Q. IS THE LOSS OF A RETAIL CUSTOMER IN THE ST. GEORGE AREA A SIGNIFICANT CONCERN FOR DIXIE-ESCALANTE?

A. Yes. The loss of any customer is a concern to a cooperative. However, the loss of customers in the higher density areas, such as a municipal area, is of even greater concern.

Q. WHAT CUSTOMER PROTECTION STANDARD DOES DESERET PROPOSE TO REMEDY THE SERVICE RELIABILITY ISSUE?

A. The following specific action items are required:

- Performance Standards — Separate the overall Performance Standards between the rural and urban regions of the state, offering the same improvements to the rural area as to the urban area. This will require separate tracking of indices and calculation of five worst performing circuits for rural area and five worst for urban area. Whatever level of improvement in indices (SAIDI, SAIFI, MAIFI) is ultimately selected in this proceeding should be applied to the rural area and the urban separately.

- Customer Guarantees — In addition to overall performance standards, ScottishPower has proposed specific Customer Guarantees to retail customers. ScottishPower should extend those same guarantees to the aggregated retail customers who receive service from PacifiCorp's wholesale customers through PacifiCorp's wholesale delivery points.

- Repairs/Upgrade to Middleton Delivery Point — PacifiCorp should commit to a four-phase program to improve service reliability at Middleton delivery point:
  1. Install automatic transfer backup switch at Middleton.
  2. Add a breaker on the 138-kV line at New Castle.
  3. Tie in to PacifiCorp's 345kV line at UAMP's Red Butte substation.
  4. Rebuild 19 miles of outdated 138 kV line between Red Butte substation and Middleton.

- Require PacifiCorp to enter into discussions with Deseret to evaluate the potential benefits of Deseret providing service in the rural areas presently served by PacifiCorp.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE FOR THE COMMISSION TO REQUIRE PACIFICORP TO EXTEND THE SAME GUARANTEES TO THE WHOLESALE CUSTOMERS THAT ARE PROVIDED TO THE RETAIL CUSTOMERS?

A. There are two reasons. First, the wholesale customers are dependent upon PacifiCorp's transmission facilities for providing reliable electric service to their retail customers. By its own admission, ScottishPower asserts that the proposed performance standards are system indices designed to address the overall performance and that the "customer guarantees have been introduced to address individual customers" (see response to data request DPU 7th, S7.3). Service reliability should be transparent, i.e. at the same level with the same guarantees and penalties regardless whether the recipient is a retail customer of PacifiCorp or of another utility: the common denominator is delivery. Both are equally dependent upon PacifiCorp's transmission facilities and both should receive comparable treatment.

The second reason relates to competition. As the industry deregulates and utilities vie for customers, it will be essential to remove barriers which may create unfair advantages. The situation between Dixie-Escalante and City of St. George is an excellent example. In a customer choice environment, Dixie would risk losing customers because of PacifiCorp's inadequate transmission service. Extending customer guarantees to retail consumers served through PacifiCorp's wholesale delivery points would help remedy this problem. At this point, I wish to reiterate that the customer guarantees would be limited to only the retail customers who are dependent upon PacifiCorp's delivery system, not all retail consumers of PacifiCorp's wholesale customers.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE FOR THE COMMISSION TO REQUIRE PACIFICORP TO SEGREGATE THE PERFORMANCE STANDARDS BETWEEN THE RURAL AND URBAN AREAS?

A. All consumers expect reliable electric service, regardless whether they live in the city or in the country. ScottishPower has proposed a program which it claims will improve reliability. However, the proposed process is flawed and will harm residents in the rural sector. By splitting the state between urban and rural residents and setting performance standards for each sector, PacifiCorp can more accurately track and respond to system needs.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE FOR THE COMMISSION TO REQUIRE PACIFICORP TO MAKE IMPROVEMENTS IN THE DIXIE-ESCALANTE AREA?

A. The MDD24 Middleton circuit ranks among PacifiCorp's five worst performing feeders for the southern system (see response to data request UPSC P2.1). This circuit is located at St. George, in the Dixie-Escalante service area, and has been a problem for a number of years. The Customer Service Standards report for the 3rd Quarter 1998 indicates 27 miles of line rebuilt beginning in 1998 as corrective action. However, management at Dixie reports that no improvements have been made. Although PacifiCorp has acknowledged that the line needs repair, the job seems to be continuously delayed. By including the upgrade as a condition of the merger, a significant factor in Dixie's problems regarding reliability will be resolved.

Q. IS THERE A CONCERN THAT EVEN THOUGH THE CIRCUIT MAY BE ON THE LIST OF WORSE CIRCUITS THAT NOTHING WILL BE DONE TO CORRECT THE SITUATION?

A. Yes. This is why it is important to require PacifiCorp to correct the service problem on Middleton immediately.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE FOR THE COMMISSION TO REQUIRE PACIFICORP TO ENTER INTO DISCUSSION WITH DESERET CONCERNING THE BENEFITS OF DESERET PROVIDING SERVICE IN THE RURAL AREAS?

A. I believe that it is appropriate because there are potential benefits to all parties. For example:

1. The cooperatives have an established presence in the rural areas and are better able to provide service in the rural areas. PacifiCorp has indicated that in order to offset

the $122 million transition cost, it will be necessary to realize greater efficiencies and reduce cost. As described by Mr. Albrecht and Mr. Bowler, service in the rural areas is already unsatisfactory; further staff and cost reductions will only make the service even worse. Because of the cooperatives presence and commitment to customers in the rural areas, service by the cooperatives would reverse the adverse trend. This will provide benefits to not only the rural retail customers served by the cooperatives, but also the rural retail customers served by PacifiCorp.

2. The rural areas are generally less profitable than urban areas for the investor owned utilities to serve. ScottishPower may be paying a substantial premium for the PacifiCorp assets, they will incur a transaction cost that may exceed $250 million, and they will incur a $135 million transition cost.

There will be enormous pressure on ScottishPower to maximize earnings and eliminate the least profitable service areas in order to satisfy the return objectives of the stockholders. If the least profitable areas were transferred to the Cooperatives, then the shareholders would benefit and there would be less pressure to reduce costs that would affect reliability in the urban areas.

Q. IF THE RURAL AREAS WERE SERVED BY THE COOPERATIVES DOES THIS MEAN THAT THERE COULD BE STRANDED GENERATION ASSETS BECAUSE THE LOAD SERVED FROM PACIFICORP GENERATION WOULD BE REDUCED?

A. No. The transfer of the rural areas to the cooperative could be conditioned on a transfer of power supply obligations if there is a concern about power supply issues. For example, the rural areas could be served by Deseret Member systems however, the power requirements could continue to be supplied by PacifiCorp. Deseret would simply enter into a contract to purchased the required wholesale power from PacifiCorp and Deseret would then deliver the power to the Member systems. The important point is that the transfer of service in the rural areas would only occur if it is in the best interest of the PacifiCorp retail customers, Deseret and the retail customers served by the Members, and the PacifiCorp stockholders.

V. HUNTER II A&G COST ALLOCATION

Q. WHAT IS THE ISSUE WITH REGARD TO THE HUNTER II A&G COST ALLOCATION?

A. The proposed merger will result in an increase in the A&G cost allocated to Deseret. Because of the increase in allocated cost, the proposed merger is not acceptable under either a net benefit or no harm standard. Therefore, the merger should not be approved.

Q. PLEASE EXPLAIN THE A&G COST ALLOCATION ISSUE.

A. Deseret is a party to an Ownership and Management Agreement dated October 24, 1980 with PacifiCorp. The agreement establishes the terms and conditions under which Deseret has an undivided interest in Hunter II generation unit and associated common facilities. As a part of that agreement, Deseret is allocated a portion of the PacifiCorp administrative and general expenses. Exhibit ____ (CNS-8) is a copy of Exhibit E to the Ownership and Management Agreement showing how administrative and general expense is allocated to Deseret. The process begins with the total O&M expense (Line 1). Fuel, purchased power, and A&G expense is then subtracted to establish an adjusted O&M (Line 6). The A&G allocation factor (Line 7) is equal to the A&G expense divided by the adjusted O&M (Line 5/Line 6).

The A&G allocated to Deseret is equal to the A&G allocation factor times the Deseret share of the Hunter O&M expense.

Q. PLEASE EXPLAIN WHY THERE WILL BE NO NET BENEFIT AND WHY DESERET WILL HARMED IF THE COMMISSION APPROVES THE MERGER.

A. The reason there is no benefit and in fact Deseret will be harmed by the merger is that the allocation of merger related cost does not track the allocation of merger related benefits. The transition cost associated with the merger are estimated to approximately $135 million. It appears that PacifiCorp intends to charge approximately $122 million to the ratepayers. PacifiCorp claims that benefits will exist that will offset the increase in cost. The benefits are reflected in increased efficiencies and increased service reliability. Even if we assume that the benefits as claimed can in fact be realized, the majority of the benefits will flow to the retail customers served from transmission and distribution facilities.

Q. WHY WILL THERE BE A MISMATCH BETWEEN THE ALLOCATION OF COST AND ALLOCATION OF BENEFITS?

A. A portion of the transition cost will be charged to A&G accounts. These costs will directly increase the A&G allocation factor ratio. The benefits, if they exist, will be reflected primarily in non-A&G accounts. Because of the nature of the services provided under the Hunter II contract, the benefits will not offset the increase in cost.

Q. ARE THERE OTHER REASONS WHY DESERET WILL BE HARMED IF THE MERGER IS APPROVED?

A. Yes. It is clear that ScottishPower intends to be very aggressive in a number of areas. Their stated objective is to expand their business opportunities particularly in non-regulated business environments. The Hunter II A&G allocation formula will potentially result in Desert customers paying for these business ventures while not realizing any economic benefit.

Another consideration is that whereas PacifiCorp does not intend to charge the transaction cost to rate payers as an "above the line" expense to Utah ratepayers, there is no such guarantee with regard to the allocation of A&G cost in the Hunter II Agreement. Inclusion of a any portion of the transaction cost as a part of the A&G expense for the purposes of the Hunter II allocation process will be harmful to Deseret and the retail customers.

Q. HAS THE A&G ALLOCATION FACTOR DEFINED BY THE HUNTER II AGREEMENT REFLECTED ANY TREND OVER THE LAST FEW YEARS?

A. Yes. Exhibit ____ (CNS-9) shows the A&G allocation factor for the period 1994 to 1998. During the initial period of the contract,. the factor was typically 30%. By 1998 the factor has increased to 41%. If the merger is approved, I would expect the allocation ratio to steadily increase. I would expect the allocation factor to steadily increase because of the increased allocation of cost to the A&G accounts.

Q. BASED ON THIS RESULT SHOULD THE COMMISSION REJECT THE MERGER?

A. Yes. There is clearly no net benefit and there is clearly harm to the customer. Therefore, the merger would fail based on both standards.

Q. WHY IS THIS AN ISSUE THAT THE COMMISSION SHOULD ADDRESS AS A PART OF THE MERGER PROCEEDING?

A. The Commission has authority over the approval or disapproval of the proposed merger. Approval of the merger has the impact on Deseret that I have described, i.e., there is no net benefit and it is in fact harmful. By disapproving the merger, the adverse impacts are avoided.

Q. WHAT REMEDY IS PROPOSED BY DESERET IF THE COMMISSION APPROVES THE MERGER?

A. The proposal is to fix the the A&G factor at a value equal to the average of G&A fators for the period 1994 to 1998. The average net A&G factor for this period is 34.2%. The development is shown on Exhibit ____ (CNS-8).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

ARKANSAS (Arkansas Public Service Commission)
Ozarks Electric Cooperative Corporation, Fayetteville (Docket 86-162-U)

COLORADO (Colorado Public Utilities Commission)
Delta-Montrose Electric Association, Delta
Empire Electric Association, Inc., Cortez
Gunnison County Electric Association, Inc., Gunnison
Holy Cross Electric Association, Inc., Glenwood Springs
Intermountain Rural Electric Association, Sedalia
La Plata Electric Association, Inc., Durango
Moon Lake Electric Association, Inc., Roosevelt, UT
Poudre Valley Rural Electric Association, Inc., Ft. Collins
San Isabel Electric Association, Inc., Pueblo
San Luis Valley Rural Electric Cooperative, Inc., Monte Vista
San Miguel Power Association, Inc., Nucla
United Power, Inc., Brighton
White River Electric Association, Inc., Meeker

ILLINOIS
Egyptian Electric Cooperative Association, Steeleville
Southeastern Illinois Electric Cooperative, Inc., Eldorado
Southern Illinois Electric Cooperative, Dongola

INDIANA (Indiana Public Service Commission)
Clark County Rural Electric Membership Corporation, Sellersburg

KANSAS (Kansas Corporation Commission)
Ark Valley Electric Cooperative Association, Inc., Hutchinson
C.&W. Rural Electric Cooperative Association, Inc., Clay Center
C.M.S. Electric Cooperative, Inc., Meade
D.S.&O. Rural Electric Cooperative Association, Inc., Solomon
Great Plains Electric Cooperative, Inc.
Lane-Scott Electric Cooperative, Inc., Dighton
Lyon County Electric Cooperative, Inc., Emporia
N.C.K. Electric Cooperative, Inc., Belleville
Ninnescah Rural Electric Cooperative Association, Inc., Pratt
Northwest Kansas Electric Cooperative Association, Inc., Bird City
Norton-Decatur Cooperative Electric Company, Inc., Norton
Sedgwick County Electric Cooperative Association, Inc., Cheney
Smoky Hill Electric Cooperative Association, Inc., Ellsworth
Sumner-Cowley Electric Cooperative, Inc., Wellington
Victory Electric Cooperative Association, Inc., Dodge City
Western Cooperative Electric Association, Inc., WaKeeney

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

LOUISIANA (Louisiana Public Service Commission)
Teche Electric Cooperative, Inc., et. al. (Docket U-19943)

NEBRASKA
McCook Public Power District, McCook
Nebraska Electric G&T Cooperative, Inc., Columbus
Panhandle Rural Electric Membership Corporation, Alliance
Twin Valleys Public Power District, Cambridge

OKLAHOMA (Oklahoma Corporation Commission)
Caddo Electric Cooperative, Binger
Canadian Valley Electric Cooperative, Seminole
Central Rural Electric Cooperative, Stillwater
Cimarron Electric Cooperative, Kingfisher
Cookson Hills Electric Cooperative, Inc., Stigler
Cotton Electric Cooperative, Walters
East Central Oklahoma Electric Cooperative, Inc., Okmulgee
Harmon Electric Association, Inc., Hollis
Indian Electric Cooperative, Inc., Cleveland
Kay Electric Cooperative, Blackwell
Kiwash Electric Cooperative, Inc., Cordell
Lake Region Electric Cooperative, Inc., Hulbert
Northeast Oklahoma Electric Cooperative, Inc., Vinita
Northfork Electric Cooperative, Sayre
Northwestern Electric Cooperative, Inc., Woodward
Oklahoma Electric Cooperative, Norman
Oklahoma Gas & Electric Company, Cause No. 29450
People's Electric Cooperative, Ada
Red River Valley Rural Electric Association, Marietta
Rural Electric Cooperative, Inc., Lindsay
Southwest Rural Electric Association, Inc., Tipton
Sun Oil vs. Arkansas Louisiana Gas Company
Verdigris Valley Electric Cooperative, Inc., Collinsville

SOUTH DAKOTA
West Central Electric Cooperative, Inc., Murdo

TEXAS (Public Utility Commission of Texas)
B-K Electric Cooperative, Inc. (4701)
Bailey County Electric Cooperative Association (2915, 5003, 7900)
Bandera Electric Cooperative, Inc. (2786, 4279)
Bluebonnet Electric Cooperative, Inc. (266, 4070, 7415, 12126)
Cap Rock Electric Cooperative, Inc. (4749, 6778, 8283)
Central Texas Electric Cooperative, Inc. (3170, 6363, 7661, 10325, 12127)

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

Cherokee County Electric Cooperative Association (817)
City of Austin (6560 - in behalf of Bergstrom AFB
Coleman County Electric Cooperative, Inc. (4875, 13335)
Comanche County Electric Cooperative, Inc. (5272, 8272)
Concho Valley Electric Cooperative, Inc. (3550, 4797, 6540, 9056, 13334)
TEXAS (Continued)
Cooke County Electric Cooperative Association (9240)
Deaf Smith Electric Cooperative, Inc. (4481, 5019, 8354)
Deep East Texas Electric Cooperative, Inc. (3393, 6308)
Denton County Electric Cooperative, Inc. (3470, 4189, 5165, 9892)
Department of Defense (Bergstrom AFB v. City of Austin (6560)
DeWitt County Electric Cooperative, Inc. (667, 3702, 4919, 6618)
Dickens Electric Cooperative, Inc. (4299, 7556, 9563, 11513)
Erath County Electric Cooperative Association (4643, 8990)
Fannin County Electric Cooperative, Inc. (3747, 4940, 9992)
Farmers Electric Cooperative, Inc. (3780, 4422, 5259, 6475)
Fort Belknap Electric Cooperative, Inc. (4396, 6558, 9944)
Gate City Electric Cooperative, Inc. (4987)
Grayson-Collin Electric Cooperative, Inc. (3945, 6510)
Greenbelt Electric Cooperative, Inc. (5038, 9930, 10405)
Guadalupe Valley Electric Cooperative, Inc. (398, 3397, 4516, 6338, 7550)
Hamilton County Electric Cooperative Association (5971)
Hill County Electric Cooperative, Inc. (7154)
Houston Lighting and Power Company (5779 and 8425)
Hunt-Collin Electric Cooperative, Inc. (3091, 4750)
Jackson Electric Cooperative, Inc. (2753, 4710, 10561)
Johnson County Electric Cooperative, Inc. (4353, 4961, 8288, 11347)
Kaufman County Electric Cooperative, Inc. (3926, 5612, 8096)
Kimble Electric Cooperative, Inc. (2308)
Lamb County Electric Cooperative, Inc. (3270)
Lighthouse Electric Cooperative, Inc. (2995, 4612, 8097)
Limestone County Electric Cooperative, Inc. (3931)
Lone Wolf Electric Cooperative, Inc. (5878)
Lyntegar Electric Cooperative, Inc. (2988, 4564)
Magic Valley Electric Cooperative, Inc. (1991, 3212, 5477)
Medina Electric Cooperative, Inc. (4113, 11048)
Midwest Electric Cooperative, Inc. (2717, 3711, 6983)
Navarro County Electric Cooperative, Inc. (3116)
Navasota Valley Electric Cooperative, Inc. (7355)
New Era Electric Cooperative, Inc. (4625)
North Plains Electric Cooperative, Inc. (2934, 4958, 5214)
Nueces Electric Cooperative, Inc. (3936, 5203)
Pedernales Electric Cooperative, Inc. (2247, 3437, 5109)
Rayburn Country Electric Cooperative, Inc. (7361)

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

Rio Grande Electric Cooperative, Inc. (521, 3681)
Rita Blanca Electric Cooperative, Inc. (2527, 8422)
Rusk County Electric Cooperative, Inc. (3383)
San Bernard Electric Cooperative, Inc. (2699, 3692, 4534, 5467, 6218)
San Miguel Electric Cooperative, Inc. (4127, 5351)
South Plains Electric Cooperative, Inc. (2936, 4822, 6985)
Southwest Texas Electric Cooperative, Inc. (5335)
TEXAS (Continued)
Stamford Electric Cooperative, Inc. (4095, 8077)
Swisher Electric Cooperative, Inc. (3062, 6796)
Taylor Electric Cooperative, Inc. (3679, 5767, 9159)
Victoria County Electric Cooperative Company (770, 3949, 6680)
Wharton County Electric Cooperative, Inc. (4541, 6685)

UTAH (Utah Public Service Commission)
Empire Electric Association, Inc., Cortez, CO
Moon Lake Electric Association, Inc., Roosevelt

WYOMING (Wyoming Public Service Commission)
Big Horn Rural Electric Company (9076)
Bridger Valley Electric Association, Inc. (9447)
Carbon Power & Light, Inc. (9022)
Garland Power & Light, Inc. (9575)
Hot Springs Rural Electric Association, Inc. (9553, 10010-CR-89-2)
Niobrara Electric Association, Inc. (9572)
Riverton Valley Electric Association, Inc. (9451)
Sheridan-Johnson Rural Electrification Association (9392)
Shoshone River Power, Inc. (9656)
Wheatland Rural Electric Association (9574)
Wyrulec Company (9097)

MUNICIPAL UTILITY RATE ANALYSIS AND DESIGN
Altus, OK
Blackwell, OK
Braman, OK
Bryan, TX
Chanute, KS
Chathan, IL
Cody, WY
Cushing, OK
Fredericksburg, TX
(7661, Certification - Central Texas EC)
Lamar, MO v. Southwestern Power Admin.
Larned, KS
Oklahoma Municipal Power Authority, OK
Osborne, KS
Ponca City, OK
Raton, NM
Riverton, IL
Stillwater, OK
Torrington, WY
Vernon, TX
Wellington, KS

WHOLESALE ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

ARKANSAS (Arkansas Public Service Commission)	
Arkansas Electric Cooperative Corporation	Docket Nos. U-3071 and 83-023-U
COLORADO	
Tri-State G&T Association, Inc.	Docket No. 98A-511E
ILLINOIS	
Southern Illinois Power Cooperative	
IOWA	
Corn Belt Power Cooperative, Inc.	
Northwest Iowa Power Cooperative, Inc.	
LOUISIANA	
Cajun Electric Power Cooperative, Inc.	Docket No. U-17735
NEW MEXICO	
Plains Electric G&T Cooperative, Inc.	Merger with Tri-State G&T Assn.
NORTH CAROLINA	
North Carolina Electric Membership Corporation	
NORTH DAKOTA	
Basin Electric Cooperative, Inc.	
Central Power Electric Cooperative, Inc.	
SOUTH DAKOTA	
Rushmore Electric Power Cooperative, Inc.	
TEXAS (Public Utility Commission)	
Brazos Electric Cooperative, Inc.	Docket Nos. 4079, 8868, and 12757, 13100
Golden Spread Electric Cooperative, Inc.	Docket Nos. 14980, 16738
Lower Colorado River Authority	Docket Nos. 366, 1521, 2503, 3522, 3838, 6027, 7512, 8032, 8400, and 9427
South Texas Electric Cooperative, Inc.	Docket Nos. 4128, 5077, 5387, 5440, and 8952
Southwestern Electric Service Company	Docket No. 2817
Southwestern Public Service Company	Docket Nos. 4387 and 6055

WHOLESALE ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

Texas Electric Service Company	Docket Nos. 527, 1903, 2606, 3250, 4097 and 5200

TEXAS (Continued)

Texas Power & Light Company	Docket Nos. 3006, 3780 and 4321
Texas Utilities Electric Company	Docket Nos. 5640, 9300 and 13100
Texland Electric Cooperative, Inc.	Docket No. 3896
West Texas Utilities Company	Docket No. 4716

UTAH
Deseret G&T Cooperative, Inc.

FEDERAL POWER COMMISSION (Federal Energy Regulatory Commission)

Gulf States Utilities Company	Docket Nos. EL87-051 and ER88-477
Central and South West Services, Inc.	Docket No. ER84-031
Central Power & Light Company	Docket Nos. ER77-331, ER81-387 and ER86-721
El Paso Electric Company	Docket Nos. ER76-409, ER77-488, ER79-526, ER81-426, ER84-236 and ER86-368
Golden Spread Electric Cooperative, Inc.	Docket Nos. ER87-396, EL89-050 and EL95-24
Oklahoma Gas & Electric Company	Docket Nos. ER77-127, ER77-215 ER78-423, ER80-421, ER82-256 and ER84-541
Public Service Company Colorado	Docket Nos. ER76-381, ER76-687, ER78-507 and ER80-407
Public Service Company Oklahoma	Docket Nos. ER77-422, ER78-511 and ER82-545
Southwestern Public Service Co.	Docket Nos. ER84-604, ER85-477 and EL89-051
West Texas Utilities Company	Docket Nos. ER80-038, ER82-023, ER82-708, ER83-694, ER84-236, ER85-081, and ER87-065

WHOLESALE ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

TRANSMISSION WHEELING/INTERCONNECTION ANALYSIS

Central and South West Services, Inc.	Docket No. EL79-008 and ER82-545, et.al.
LCRA Wheeling Case before the Texas PUC	Docket No. 6995

POWER SUPPLY PLANNING

A. System Resource Planning:

Golden Spread Electric Cooperative, Inc.: Notice of Intent (PUCT Docket No. 13444)
Golden Spread Electric Cooperative, Inc.: Exempt Wholesale Generation Contract Certification (PUCT Docket No. 15100)

B. Long-Range Power Cost - 20-Year Forecast:

Golden Spread Electric Cooperative, Inc.	Southwestern Public Service Company
Kim-Wood Electric Cooperative, Inc.	Southwestern Public Service Company
Mid-Tex G&T Electric Cooperative, Inc.	West Texas Utilities Company and Brazos Electric Cooperative
Magic Valley Electric Coop., Inc./ Rio Grande Electric Cooperative, Inc.	South Texas Electric Coop., Inc./ Central Power & Light Company
Magic Valley Electric Cooperative, Inc.	City of Brownsville/Central Power & Light Co.

C. Other Power Supply Planning Projects:

Blackwell, OK
Golden Spread Electric Cooperative, Inc., TX
Joint Cities Agency (Ohio)
Magic Valley Electric Cooperative, Inc., TX
Raton, NM

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Planning; Lincoln, Nebraska; April 14-15, 1999.

"Rate Design in a Restructured Environment," NRECA's 1999 Management Internship Program; Lincoln, Nebraska; January 14-15, April 28-29, and May 13-14, 1999.

"Rate Design and the Changing Electric Industry," WREA Annual Meeting; Cheyenne, Wyoming; September 24, 1998.

"Rate Design and the Changing Electric Industry," CFC's Annual Meeting; Colorado Springs, Colorado; July 3, 1998.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Program; Lincoln, Nebraska, May 20-21, 1998.

"Rate Issues and Strategy for the Changing Utility Industry," NRECA's Management Internship Program; Lincoln, Nebr., January 7-8, April 9-10, April 30-May 1, 1998.

"Identifying Revenues and Costs Associated with Marketing Solutions," NRECA's Strategic Marketing Planning for Management Conference; Lincoln, Nebr., June 4, 1997.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Program; Lincoln, Nebraska, April 10-11, 1997.

"Rate Issues and Strategy for the Changing Utility Industry," NRECA's Management Internship Program; Lincoln, Nebr., January 9-10, April 23-24, and May 8-9, 1997.

"Application of Market-Based Rates in a Competitive Utility Industry," presented to NRECA's Tech Advantage '97 Annual Meeting; Las Vegas, Nevada; March 15, 1997.

"Preparing for the Future Cooperative Electric Service in Texas," presented to Texas Electric Cooperatives' Managers' Conference; Austin, Texas; December 5, 1996.

"Industry Restructuring Implications for Cooperatives," presented to Texas Electric Cooperatives' Government Relations Committee; Austin, Texas; July 1, 1996.

"Identifying Revenues and Costs Associated with Marketing Solutions," NRECA's Strategic Marketing Planning for Management Conference; Lincoln, Nebr., June 3-7, 1996.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; April 3-4 and July 24-25, 1996.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Power Supply Issues in the U.S. and Abroad - Increasing Competition and Deregulation," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rates and Related Issues," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 15-16, March 4-5, and April 15-16, 1996.

"The Economics of Serving Large Loads," Electric Cooperatives of South Carolina's Competitive Strategies Workshop, Columbia, S.C., August 15-16, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA's Summer School; New Orleans, La., June 30-August 1, and Hilton Head, S.C., July 18-19, 1995.

"Evolving Cooperative Structures," CFC's Cooperative Financing Forum; Chicago, Ill.; July 11, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 20-21, 1995.

"Takeover Workshop," Texas Electric Cooperatives, Inc.; Lubbock and Cleburne, Texas; April 6-7, 1995.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; April 4-5 and May 9, 1995.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 22-23, 1995.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 9, April 24, and May 8, 1995.

"Competing for Retail Loads," NRECA's 1994 G&T Legal Seminar; New Orleans, La., November 10, 1994.

"The Power in the Partnership: Changing the Co-Op Power Supply," TEC 54th Annual Meeting; Fort Worth, Texas, August 2, 1994.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 14-15, 1994.

"Competing in the '90s and Beyond," 1994 NRECA G&T Rates Conference; San Antonio, Texas; June 5-8, 1994.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Implementation of Demand-Side Component of IRP," Georgia EMC in coordination with NRECA; Ga., April 27, 1994.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; March 29-30, 1994

"The Transmission Access Revolution," Special G&T Director's Update Program for Brazos Electric Power Cooperative, DFW Airport Marriott Hotel, Texas; March 21-22, 1994.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 9-10, 1994.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 17, April 22, and May 16, 1994

"Buy-Out and Refinancing of REA Loans: Factors to Consider in Evaluation Analysis," Texas Electric Cooperatives, Inc.; Austin, Texas; December 3, 1993.

"Transmission Access Revolution," NRECA's 1993 G&T Director's Update Conference; Nashville, Tenn.; December 2, 1993.

"Update on Current Issues — Texas RECs and PUCT," Texas Electric Cooperatives, Inc.; Austin, Texas; November 15, 1993.

"Coordination of IRP and Marketing Strategy with G&T Wholesale Rate Design," NRECA's G&T Rates & G&T Marketing Conference; Lexington, Ky.; June 8, 1993.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; April 27-28, 1993.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 14-15, April 14-15 and May 10, 1993

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 10-11, June 30-July 1, and September 29-30, 1993.

"Rates as a Marketing Tool," NRECA's G&T Marketing Seminar; Denver, Colo.; September 10, 1992.

"The Co-Op Power Picture in Texas," TEC's 52nd Annual Meeting; Houston, Texas; July 28, 1992.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 3-4, June 3-4, and November 18-19, 1992.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 9-10 and May 5-6, 1992.

Rate Training Course presented for members of Bangladesh REB coordinated through NRECA; Oklahoma City, Okla.; October 28-November 8, 1991.

"Ratemaking Activities for Rural Electric Cooperatives," TEC's Seminar on Electric Cooperatives; Austin, Texas; October 18, 1991.

"Rate Analysis: Determination of Revenue Requirements," NRECA's Accounting and Finance Conference; Albuquerque, N. Mex.; August 18-21, 1991.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Work-shop; Lincoln, Nebr.; May 1-2, June 25-26, and November 6-7, 1991.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 17-18 and May 8-9, 1991.

"Development of a Rate Strategy for the Cooperative System," 1991 Rural Electric Expo for NRECA; New Orleans, La.; February 2-3, 1991.

"Innovative Rate Forms," 1991 NRECA Engineering and Operations Conference; New Orleans, La.; January 31, 1991.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 9-10, 1991.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Work-shop; Lincoln, Nebr.; October 3-4, 1990.

"Making Sense of Your System's Rate Structure," NRECA 1990 Member Services Communication Conference; Charlotte, N.C.; July 31, 1990.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 18 and May 11, 1990.

"Cost of Service Major Points," TEC Accounting Association Annual Meeting; San Antonio, Texas; April 20, 1990.

"Rate Design for Large Power Service and Options for Marketing and Incentive Rates," TEC Engineering Association; Austin, Texas; September 27, 1989.

"Service to Large Industrial Customers," NRECA's Rural Electric Management Council; Fargo, N. Dak.; May 17, 1989.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 24-25 and May 15-16, 1989.

"Revenue Requirements and Cost of Service Considerations at the PUC," TEC Engineering Association; Austin, Texas; April 28, 1988.

"Course 495.3 - Rate Issues and Philosophies," NRECA's Management Internship Program; University of Nebraska, Lincoln; April and May, 1988.

"Course 495.3 - Rate Issues and Philosophies," 1987 Wisconsin Electric Cooperative Association; Wisconsin Rapids, Wis.; December 1-3, 1987.

"Marketing: Distribution Benefits Through Sale of Surplus Power and Jointly Designed Marketing Rates," 1987 NRECA Engineering and Operations Conference; Denver, Colo.; November 20, 1987.

"Cost Bases for Incentive Rates Applicable to Industrial Loads," 1987 Conference on Industrial Energy Technology; Houston, Texas; September 16-17, 1987.

"Considerations in Cooperative Consolidations," with Martin Lowery at NRECA's 1987 Accounting and Finance Conference; Lexington, Ky.; September 9, 1987.

"Rates to Attract Attractive Loads," Association of Louisiana Electric Cooperatives, in coordination with AHP Systems, Inc.; Baton Rouge, La.; July 1-2, 1987.

"Course 495.3 - Rate Issues and Philosophies," NRECA's 1987 Summer School; Lake of the Ozarks, Mo.; July 20-22; and Williamsburg, Va.; August 13-15, 1987.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 24-25 and May 15-16, 1987.

"Rates to Attract Attractive Loads," Wisconsin Electric Cooperative Association in Coordination with AHP Systems, Inc.; Stephens Point, Wis.; February 12, 1987.

"Rate Design for Attracting and Maintaining Loads," NRECA's Management Internship Program; Lincoln, Nebr.; October 1, 1986.

"Rate Seminar," Indiana Statewide Association of REC, Inc., (Co-Presenter: David Hedberg); Indianapolis, Ind.; September 25, 1986.

"Preconference Workshop: Basic Issues in Rate Design," NRECA's 1986 National Accounting and Finance Conference; Tampa, Fla.; September 9, 1986.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Course 495.2 - Rate Issues and Philosophies," NRECA's 1986 Summer Schools; Myrtle Beach, S.C.; Nashville, Tenn.; and Taos, N. Mex.; July 1986.

"Cost of Service and Rate Design Issues Affecting Industrial Customers in Retail Rate Proceedings," Public Utility Commission of Texas 1986 Industrial Energy Technology Conference; Houston, Texas; June 1986.

"The Importance of the Impact of Rates," NRECA's Management Services Conference -- Preparing Now to Prevent a Takeover or Sellout; Denver, Colo.; April 17-18, 1986; and New Orleans, La.; May 14-15, 1986.

"Energy Cost for Industrial Customers," (Co-Author: M.K. Moore) ACEC Research & Management Foundation's Industrial Energy Management Forum; Tempe, Ariz., March 26, 1986.

"Analysis of Financial and Operating Ratios," REA National Conference; San Antonio, Texas; July 10, 1985.

"Coordination of Wholesale/Retail Rate Design for Effective Marketing Strategy," NRECA's National Marketing Conference; Kansas City, Mo., June 5, 1985.

"Development of Rate Schedules for an Electric Utility," CAST/CSEE/NRECA Workshop; Kunming, Republic of China; May 14-19, 1984.

"Development of a Rate Analysis," NRECA Management Quarterly; Washington, D.C.; Volume 24, No. 3; Summer 1983.

"Cost Allocation Considerations for Rural Distribution Systems," NARUC Biennial Regulatory Information Conference; Columbus, Ohio; October 19, 1978.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Transactions on Industry Application; Volume 1A-13, No. 2; 1977.

"Design of Irrigation Rates Under Load Management Program," (Co-Authors: S.P. Patwardhan and B.E. Smith), presented at IEEE Rural Power Conference; Kansas City, Mo.; May 16, 1977.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Rural Electric Power Conference; Omaha, Nebr.; April 1975.

"A Financial Forecasting Model for Rural Electric Distribution Systems," IEEE PES Summer Power Meeting and Energy Resources Conference; Anaheim, Calif.; July 1974.

"A Planning Model for the Analysis of Long Range Distribution System Design Alternatives," IEEE PES Summer Meeting and EHV/UHV Conference; Vancouver, Canada; July 1973.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Transmission Substation Control Using On-Site Computer Directed Simulation and Closed Loop Control," (Co-Author: H.E. Michel).

"The Development of Design Objectives for Electric Utility Rate Schedules," Master's Thesis; University of Oklahoma, Norman; 1969.

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, INC.

CONSUMER PROTECTION CONDITIONS

1. Separate the overall performance standards between the rural and urban regions of the State, offering the same improvements to the rural area as to the urban area. This will require a separate tracking of indices and a calculation of the five worst performing circuits for the rural area and the five worst for the urban area.

2. Extend the same customer guarantees as offered to the PacifiCorp retail customers to the retail customer served by the Cooperatives through PacifiCorp wholesale delivery points.

3. Commit to a four-phase program to improve service reliability at Middleton delivery point. Items include (a) install automatic transfer backup switch at Middleton, (b) add a breaker on the 138-kV line at New Castle, (c) tie in PacifiCorp's 345-kV line at Red Butte Substation, (d) rebuild 19 miles of outdated 138-kV line between Red Butte Substation and Middleton.

4. Require PacifiCorp to enter into discussions with Deseret to evaluate potential benefits of Deseret's providing service in the rural areas presently served by PacifiCorp.

5. Establish a fixed A&G allocation factor applicable to the Hunter II ownership and management agreement at a value of 34.24% (net).

Deseret Generation & Transmission Cooperative

Points of Delivery by Member System

Member	Delivery Point	Nominal Delivery - kV	PacifiCorp System
Bridger Valley Elec. Assoc., Inc.	Flaming Gorge	69	
	Sweetwater (Blacksfork)	230	yes
Dixie-Escalante Rural Elec. Assoc., Inc.	New Castle	138	yes
	St. George	69	yes
	Littlefield	69	
Flowell Elec. Assoc., Inc.	Meadow "Fillmore"	46	yes
Garkane Power Assoc., Inc.	Sigurd	69	yes
	Glen Canyon	138	
Moon Lake Elec. Assoc., Inc.	Upalco	138	
	- Fort Duchesne	138	
	- Cove	138	
	- Clay Basin	138	
	Vernal	138	
	Rangley	138	
	- CO2	138	
	- California	138	
	- Bonanza Plant	138	
	- Colorado C-a Oil Shale	138	
	- Deserado	138	
	Flaming Gorge	25	
Mt. Wheeler Power, Inc. *	Gonder/Machacek	230	

* Mt Wheeler deliveries of CRSP are received at Sigurd and moved to Gonder via Sigurd/Gonder line which is owned by PacifiCorp and Sierra Pacific.

Source Side Outages
Middleton Circuit

Date of Outage	Time of Outage	Total Time of Outage	Num. Customers Affected	Outage Location	Person Reporting
			1998		
06/18/98	03:00 A.M.	5hr 15 min	5500	138kV from W. Cedar	Sam/Andy
06/16/98	07:00 P.M.	1 hr	5500	138kV from W. Cedar	Sam/Stella
03/29/98	05.30 A.M.	1 hr 30 min	5500	138kv from W. Cedar	Jeff
			1997		
07/07/97	02:30 P.M.	20 min	5500	138kV from W. Cedar	Crew
			1996		
10/31/96	04:00 A.M.	2 hr	5500	138kV from W. Cedar	Robert
10/28/96	01:00 A.M.	1 hr 30 min	5500	138kV from W. Cedar	Kelly
10/13/96	11:15 P.M.	2 hr	5500	138kV from W. Cedar	Kelly
09/01/96	04:30 A.M.	1hr 30 min	5500	138kV from W. Cedar	Robert
08/10/96	05:00 A.M.	1 hr 30 min	5500	138kV from W. Cedar	Robert
07/02/96	06:30 P.M.	45 min	5500	138kV from W. Cedar	Jeff
06/23/96	06:00 A.M.	2 hr	5500	138kV from W. Cedar	Sam
05/22/96	09:50 A.M.	1 hr	5500	138kV from W. Cedar	Sam
			1995		
10/21/95	01:30 A.M.	1 hr	5500	138kV from W. Cedar	Robert

Source Side Outages
Pinto/Pine Valley

Date of Outage	Time of Outage	Total Time of Outage	Num. Customers Affected	Outage Location	Person Reporting
		1998			
04/24/98	01:00 A.M.	7 hr 30 min	300	34.5kV Pinto tap	Sam
		1997			
02/02/97	01:42 P.M.	3 hr	350	34.5kv Pinto tap	Sam
		1996			
09/09/96	05:10 A.M.	2 hr	300	34.5kV Pinto tap	Sam
08/14/96	06:00 A.M.	2hr	440	34.5kv Pinto tap	Sam
07/16/96	01:30 A.M.	3 hr 30 min	300	34.5 Pinto tap	Kelly
01/31/96	01:30 P.M.	4 hr 30 min	350	34.5 Pinto tap	Sam
01/17/96	12:30 P.M.	2 hr	350	34.5 Pinto tap	Sam
		1995			
08/22/95	07:00 A.M.	3 hr	350	34.5 Pinto tap	Jeff
08/21/95	07:00 P.M.	2 hr 30 min	350	34.5 Pinto tap	Sam
01/24/95	10:00 P.M.	2 hr	350	34.5 Pinto tap	Sam
01/16/95	02:00 P.M.	10 min	350	34.5 Pinto tap	Sam

SOURCE SIDE OUTAGE REPORT FOR 1998

March 29

5:30 A.M. Power went off feeding Dixie system. Jeff contacted UP&L dispatch. UP&L was aware of the outage. Their breaker in the Middleton Substation had a non essential alarm communicating through their SCADA system. The breaker developed a leak with the SF6 gas due to the sudden change in temperature. They refilled the breaker with the SF6 gas and energized DEREA. We couldn't be fed through UAMPS due to the maintenance St. George City was doing. UP&L has changed the alarm to read essential for the future.

7:00 A.M. Power was restored. The outage lasted approximately 1 ½ hours.

June 16

7:00 P.M. Power went off. Stella contacted UP&L dispatch. They were aware of the outage. DEREA had a 69 kV pole blow down in the 80 mph wind storm in the Dixie Springs area. Pacific Corp also had poles blow down during this time that fed from Middleton to their LaVerkin service area. The feed was routed out of Middleton due to maintance being done on their Transmission line south of Cedar City. Our QC1 breaker opened and isolated us from Pacific Corp. The breaker in the Middleton sub did not operate thus creating the outage which opened upstream in the west Cedar sub. Since this time UP&L has changed out the relay in their west Cedar sub.

8:00 P.M. The power was restored. The outage lasted approximately 1 hour.

June 18

3:00 A.M. Power went off.

3:30 A.M. Public notified Andy, and he contacted UP&L dispatch. UP&L was aware of the outage and said they were working on the problem. They did not know if the fault was in their west Cedar sub or on the line feeding the Escalante Valley.

3:45 A.M. UP&L tried to energize the line, but it would not hold. UP&L dispatched a crew to the Enterprise sub.

5:00 A.M. Power was restored in Beryl and Dixie and stayed on for around ½ hour before shutting off again.

6:00 A.M. UP&L crew opened the Enterprise sub which restored power to the Escalante valley. Ladel called Tom Bytheway of UP&L to have him coordinate with UAMPS to restore power through their system to our Dixie area.

7:00 A.M. Tom Bytheway called Ladel back and said they were there in the Middleton sub ready but were trying to find Phil Solomon of St. George City. Tom said their hands were tied and that maybe we should contact Wayne McArthur of St. George City to put pressure on him to energize our system. Jumpers in the Middleton sub tying Pacific Corp and UAMPS lines together were taken down by St. George City crews approximately 6 months ago while working on PT's in the sub. They claimed Pacific Corp wanted to reconnect the jumpers, but they were never placed back. During the outage the jumpers had to be reconnected and the air brake switched closed. Bird nests in the switch caused arching that had to be cleaned out before it could be closed.

8:45 A.M. Power was restored, with a total outage of approximately 5 hours and 15 minutes.

OUTAGE REPORT FOR MAY 22, 1996

9:45 P.M.	Power went off. We checked our transmission breakers and determined that the fault was on Pacificorp. We gathered our official UP&L/UAMPS switching procedures from the office.
10:15 P.M.	Contacted UP&L dispatcher Gary Clayton at 1-800-385-3338 and requested they implement switching procedure UAMP - 02a.02. They did not have copies of any switching procedures and didn't know how to proceed. We requested that they open their switch 66A to remove us from their line. After lengthy explanation of the location of their switch 66A, they stated that they would send a man to open their switch.
10:30 P.M.	Contacted St. George dispatcher Alan at 634-5836. Requested that they close their switches 225 & 353 as per switching procedure 02a.02. They said that all their men were busy but would try to send a man to close their switches.
10:40 P.M.	Called St. George to verify status. They had found the switching procedure but would not implement the procedure without request direct from UP&L.
10:45 P.M.	Called UP&L. They stated that they wanted to try their line again before implementing the switching procedure.
10:55 P.M.	UP&L successfully energized line to Newcastle.
11:00 P.M.	Called UP&L. They are trying to energize line from Newcastle south. They expected switching to take 15 to 20 minutes.
11:10 P.M.	Called UP&L. Line did not hold south of Newcastle. They are trying to energize Middleton from Gateway.
11:25 P.M.	Called UP&L. They could not hold Middleton line from Gateway. They agree to now implement switching procedure with UAMPS. Called St. George. They are waiting to hear from UP&L before implementing switching procedures.
11:40 P.M.	Called St. George. They are still waiting for UP&L to decide what they want to do. UP&L has no switching procedures. Call from Vernon in Beryl. He is watching the loads for when we come on line.
11:45 P.M.	Called UP&L. They want to implement a procedure to tie onto UAMPS that brings all their customers on line. They are requesting that St. George implement procedure 03a.02.

11:55 P.M.	Called St. George. They are still waiting for UP&L to decide what they want to do. Called UP&L. They are trying to energize another section of line. Will take 15 minutes.
12:15 A.M.	Called UP&L. They have requested UAMPS procedure 03a.02 switching at Red Butte/Central substation.
12:40 A.M.	Called St. George. Phil Solomon has canceled 03a.02 because it would put faulted line onto 345kV line. Has started to pickup Middleton out of St. George.
1:05 A.M.	Call from UP&L requesting verification of visual opens per switching with St George. We informed them that we had visual opens on our transmission breaker as well as all of our distribution breakers.
1:25 A.M.	Called UP&L. They expect to be back on in 10 minutes.
1:40 A.M.	Called St. George. All lines were busy. Called UP&L. They give the O.K. to energize at 1:45 A.M. Our men dispersed to close lines, but there was no power at Quail Creek Switchyard.
2:00 A.M.	Called UP&L. Their breaker is open at Middleton. They retry it and it won't hold. Call from St. George. They see blinks from Middleton breaker and want to know if it is us picking up load. Called UP&L. Inform them of their air break switch in Washington to sectionalize their line to get us back on.
2:05 A.M.	Called St. George to request that they be ready to close us in at Red Cliff Switchrack in case UP&L's line can't hold. Our crews are patrolling our transmission line to make sure it's not our problem.
2:20 A.M.	Called UP&L. Their man is working on outage in Ivins before he will try his air break switch in Washington.
2:30 A.M.	Called UP&L. Their man is still in Middleton working on their other outage. Will try air break switch in Washington when he has Ivins back on.
2:45 A.M.	Our crew reports we have power at Quail Creek Switchyard. Called UP&L and requested permission to close load.
2:50 A.M.	Called St. George to request permission to bring loads on line. Clear to close loads.

2:55 A.M.	No air pressure in QC1 to close breaker. Called UP&L to request that they open their breaker 66 in Middleton to allow us to close bypass switches. They have to open breaker manually because their SCADA is down with this alternate power feed.
3:10 A.M.	We receive notice that UP&L's breaker 66 is open, we closed bypass on QC1, UP&L reclosed breaker 66. We started to restore power to customers.
3:20 A.M.	All customers should be restored to power.
3:25 A.M.	QC1 closed, opened bypass switches. Called UP&L to notify them of return to normal configuration.

DESERET G&T MEMBER SYSTEM
SUMMARY OF POWER SUPPLY OUTAGE - AVG HOURS PER CONSUMER

	1993	1994	1995	1996	1997	1998	1997 ending 5 year Average	6 year Average
Bridger Valley Elec Assn (Wyoming - 9)	0.03	0.00	0.12	0.57	1.09	0.00	0.36	0.30
Dixie-Escalante Rural Elec Assn (Utah-20)	0.00	5.31	1.30	2.48	0.37	9.25	1.89	3.12
Flowell Electric Assn (Utah-11)	0.00	0.00	4.00	4.00	0.00	0.00	1.60	1.33
Garkane Power Assn (Utah-6)	2.77	2.46	0.59	0.55	0.00	0.00	1.27	1.06
Moon Lake Elec Assn (Utah-8)	0.00	0.02	0.00	0.09	0.00	4.00	0.02	0.69
Mount Wheeler Power ((Nevada - 19)	0.00	0.13	0.15	0.00	0.00	0.00	0.06	0.05

	5-Yr Avg Power Supplier
Northwest	1.22
Northeast	1.07
Southwest	1.00
Southeast	0.70
National	0.98

Source: RUS Form 7 year end report

Exhibit E
to
Ownership and Management
Agreement

ILLUSTRATION OF CALCULATION OF ADMINISTRATIVE AND GENERAL EXPENSES

YEAR 1979

UTAH POWER & LIGHT COMPANY ELECTRIC OPERATIONS ONLY

		$
1.	Total UP&L Operation & Maintenance Expense	289,027,580
2.	Less:	
3.	Fuel Expense	143,795,268
4.	Purchased & Interchange Power Expense	30,307,755
5.	Administrative & General Expense	29,657,313
6.	Total	85,267,244

7. Percent A&G of O&M (ex A&G) = $\frac{29,657,313}{85,267,244}$ = 34.8%

8. A&G Expense Paid By Deseret:

9. Hunter Unit No. 2 0&M (excluding fuel) x 34.8%

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, INC.

HUNTER II OPERATING & MAINTENANCE AGREEMENT
SUMMARY OF A&G ALLOCATION FACTOR

	1994	1995	1996	1997	1998	Avg.
Net	30.20%	30.40%	34.20%	35.80%	40.60%	34.24%
Gross	31.30%	31.60%	35.20%	36.80%	41.50%	35.24%

Gross includes insurance. Insurance is billed separately.

Exhibit ____ (CNS - 10)

DEPARTMENT OF COMMERCE

Michael O. Leavitt
Governor
Douglas C. Borba
Executive Director
Ric Campbell
Division Director

DIVISION OF PUBLIC UTILITIES
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Phone (801) 530-7622
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MEMORANDUM

June 15, 1999

TO: **UTAH PUBLIC SERVICE COMMISSION**

FROM: UTAH DIVISION OF PUBLIC UTILITIES
Ric Campbell, Director RC by LEA
Lowell E. Alt, Manager - Energy Section LEA
Mark V. Flandro, Utility Rate Analyst MVF
Neal Townsend, Utility Rate Analyst NT

RE: **DOCKET NO. 99-2035-01, INVESTIGATION OF PACIFICORP'S SYSTEM RELIABILITY AND QUALITY OF SERVICE IN UTAH. TRANSMITTAL OF DIVISION'S REPORT OF INVESTIGATION.**

Attached please find the Division's Report of Investigation in Docket No 99-2035-01, In The Matter of Service Quality Complaints Against PacifiCorp and PacifiCorp's Service Quality Performance Since the 1988 Merger of UP&L and PP&L, dated June 11 1999.

C: Douglas C. Borba, Executive Director
D. Douglas Larson, PacifiCorp
Tim Hunter, Stoel Rives LLP
Brian D. Cook, Kaysville City
Douglas O. Hunter, UAMPS
G. Richard Judd, UMPA
Michael F. Peterson, UREA
Kenneth L. Bullock, ULCT
David Crabtree, DG&T
Roger J. Ball, CCS
Mike Ginsberg, DPU AG

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Service Quality Complaints Against PacifiCorp and PacifiCorp's Service Quality Performance Since the1988 Merger of UP&L and PP&L	))))	**Docket No. 99-2035-01** Division of Public Utilities Report of Investigation June 11, 1999

On January 15, 1999, the Utah Public Service Commission(PSC) opened Docket No. 99-2035-01 to investigate quality of service and reliability complaints against PacifiCorp received from the Utah League of Cities and Towns (ULCT) on January 13, 1999 (see Attachment 1) and included previous complaints contained in October 23, 1998 letters from Kaysville City and Utah Associated Municipal Power Systems (UAMPS) that were made during the course of the 1998 PacifiCorp rate case (see Attachments 2 and 3). On April 15, 1999, the PSC expanded the scope of this investigation asking the Division to investigate PacifiCorp's quality of service and reliability performance in its entire Utah service territory from the 1989 merger through 1998.

The Division requested input for this investigation through data requests from seven parties: ULCT, Kaysville City, UAMPS, Utah Municipal Power Agency (UMPA), Utah Rural Electric Association (UREA), Deseret Generation and Transmission Cooperative (DG&T) and PacifiCorp (or Company). Responses were received from all but ULCT and DG&T. The Division did not make any attempt to gather additional service quality and reliability information from PacifiCorp's large number of retail customers for this study, but relied upon updated complaint history information and service indicator reports traditionally used by regulators to measure this type of performance.

This short term investigation looked at generation, transmission and distribution reliability and quality of service information but focuses primarily on transmission and distribution data. The Division has attempted to identify trends in PacifiCorp's quality of service and reliability performance since the Utah Power/Pacific Power merger. This report includes information as follows:

- Executive summary
- Comments of parties regarding maintenance of the grid
- Maintenance and capital dollar expenditure trends
- PSC complaint trends
- Service complaints directly to PacifiCorp
- Comments and data concerning service restoration capabilities and trends, staffing, skills, training, service restoration, responsiveness to outages, etc.

- Trends in service indicators
- Specific problem facilities
- Infrastructure impact on economic development
- Generation/transmission problems affecting PacifiCorp's retail customers
- Transmission and wheeling contracts
- Tree trimming expenditures and policies
- FERC issues
- Equipment and technological advances affecting reliability
- Inter-Company communication and coordination
- 1989-1998 quality of service/reliability trends
- Investigation findings

In the text of this report, the Division has included some direct quotes from the data responses of parties (for emphasis, the Division has italicized portions of these quotes). The complete data responses from parties are Attachments No's 4 through 11. A considerable number of comments were prepared by the parties so the Division invites the Commission to scan these Attachments to get the full impact of positions of the parties in this Docket. In Attachment No. 11, PacifiCorp responds line-by-line to the other four party's data responses and claims.

Executive Summary

The Division finds no clear indication that PacifiCorp's quality of service and reliability to its *retail* customers in Utah has declined or changed significantly since the 1988 merger between Utah Power and Pacific Power. However, the Division does find indications that quality of service and reliability may have declined for PacifiCorp's *wholesale* municipal and cooperative customers who take wheeling and power supply electric service from PacifiCorp at the transmission level. The Division also finds evidence of a lack of communication and coordination between PacifiCorp and its municipal and cooperative agency customers that appears to be serious enough to be affecting service quality and reliability.

A more detailed list of the Division's findings in this investigation is found as the last section of this report under "Investigation Findings."

The Division report follows:

Comments of Parties Regarding Maintenance of the Grid

Following are a few sample comments of parties indicating their perception of a lack of capital and maintenance dollars being made available for transmission grid maintenance, repair and capital upgrade:

UREA

- "*Dixie Escalante REA has experienced several unnecessary outages due to PacifiCorp's lack of adequate maintenance and capital improvements to its transmission system.* Most of the current problems have occurred in the St. George area where PacifiCorp supplies transmission over a 138 kV transmission line from Cedar City to the Escalante Valley and on to St. George.

  Dixie Escalante has met on several occasions with PacifiCorp to inform them of the severity of the problem and to request that improvements be made to this portion of their system. However, no progress has resulted from the meetings. *Our assumption, based on these discussions, is PacifiCorp has been unwilling to supply the necessary budget allocations for adequate maintenance and capital upgrades to minimize the outage problems in this area.*" UREA 1.1, page 2

- "Through [UREA Member Cooperatives'] discussions with PacifiCorp employees in contact with UREA member system employees, *there appears to be some frustration on the part of PacifiCorp employees for the drastic cuts in maintenance budgets which have flowed down to them from corporate offices of PacifiCorp.*" UREA 1.12, page 3

Kaysville City

- "*Lack of money to upgrade and maintain was the reason for delay of service improvements stated by various company [PacifiCorp] employees.*" Kaysville City 1.4, page 2

- "Kaysville City believes that the employees of PacifiCorp are competent, *but lack the resources to respond in an adequate manner.*" Kaysville City 1.13, page 4

UMPA

- "*UMPA has noted multiple problems with both maintenance and capital expenditures for several years with PacifiCorp's system in Utah*". UMPA 1.1, page 1

- "As to the transmission that serves Nephi from the Mona Substation, and then on to Levan, *the only maintenance it receives is when it breaks down. There is no apparent routine maintenance or system upgrades.*" UMPA 1.2, page 5

- "PacifiCorp initiated certain measures to improve reliability of its 46 KV line into Ephriam, including construction of the Jerusalem Substation in October 1993. However, Manti continued to experience low-voltage problems and frequent outages. When UMPA approached PacifiCorp, indicating that the improvements made were not adequate to remedy the problem, *PacifiCorp indicated that it did not have the money to make additional improvements at that time.*" UMPA 1.5, page 7

- "... *However, subsequent to the execution of that 1996* [Sidebar Letter] *Agreement, PacifiCorp has indicated to UMPA that it still lacks the financial capability to make adequate improvements on that system. This is the second time that PacifiCorp's Utah Central Division people had requested that UMPA talk directly to PacifiCorp Portland because Utah Central had been told there was no funding available for this type of maintenance. Utah Central suggested that UMPA should be willing to pay for half the cost of those improvements. UMPA was unwilling to pay for such costs, since they are simply costs of maintaining the existing system, which costs are already included in the tariff. UMPA has not requested that PacifiCorp upgrade the system, but rather that it only maintain its system in accordance with Prudent Utility Practices.* As stated in question UMPA1.1 above, Manti continues to experience reliability and maintenance problems to this date."

  UMPA 1.5, page 7

UAMPS

- "... Since the UP&L/PacifiCorp merger and Order 888, PacifiCorp's management left to its own devices, with no protective restrictions from FERC or our Public Service Commission has made a wholly rational decision to redirect capital investment to projects where it believed they would earn a higher rate of return for shareholders. *PacifiCorp made investments overseas and created unregulated subsidiaries in power marketing and energy services. These investment decisions did not turn out as anticipated, and PacifiCorp made little or no investment in its existing transmission system.*

  This type of lack of capital investment funding is an example of what may well happen in the entire electric utility industry. UAMPS raised this issue in FERC's mega-NOPR docket that resulted in Order 888. Redirection of capital investment was an unanticipated fallout of the "functional unbundling" the FERC imposed with Order 888. *UAMPS believes there will be further deterioration of the transmission and distribution systems as capital investment is redirected to "higher return" or "deregulated" areas of the industry.* Separating the operations of generation and transmission makes the generation market competitive in the short run, but management makes capital investment decisions and as long as there is a possibility of earning higher returns in power marketing and generation, there will be little or no investment in the "regulated" transmission and distribution functions of the industry.

The options for regulators and legislators is to either impose mandatory investment levels and performance standards or to mandate divestiture of transmission services and, possibly distribution services, into separate, independent companies. In a vertically integrated industry, the investment dollar will always follow the higher return and, since transmission and distribution will always be regulated as natural monopolies generation and power marketing will receive investment dollars at the expense of the transmission and distribution systems." UAMPS 1.8, Pages 6 & 7

PacifiCorp

- *"FERC tariffs and individual wheeling contracts provide only a small portion, 9.5 percent, of the company's transmission revenue requirement. There is no reason to believe that wheeling revenues under FERC jurisdiction are insufficient to support a reasonable proportion of the expenditures needed for maintenance and repair for service reliability in Utah. The majority of the transmission revenue requirement comes from retail tariffs approved by state commissions. To the* UMPA 1.5, page 7 *extent that jurisdictional prices recover the allocated shares of revenue requirements, the costs of necessary maintenance, repair and replacement of the transmission system are recovered."*

  PacifiCorp 1.6

Maintenance and Capital Dollar Trends

The Division performed several analyses to attempt to evaluate the trends in both capital and maintenance expenditures since the merger of Pacific Power & Light and Utah Power & Light in 1989. First, as a readily available proxy for PacifiCorp's capital expenditures, the Division evaluated the annual change in average gross plant in service for the total company. It should be noted that this annual change in gross plant in service includes both capital plant additions as well as retirements. However, for this high level analysis, the Division believes this annual change serves to identify trends in capital plant investment. Second, maintenance expenditures were evaluated for PacifiCorp's total company steam generation plant, hydro generation plant, and transmission plant, while the distribution plant was limited to the Utah jurisdiction. Both the change in average gross plant in service and maintenance expenses in each year have been adjusted to constant 1998 dollars to facilitate a trend analysis. These adjustments were made using price deflators from the United States Bureau of Economic Analysis. Finally, the Division evaluated maintenance expenses as a percentage of average gross plant in service.

Capital Investment

Exhibit 1.1 shows the annual change in average plant in service, the proxy for capital investment, in constant 1998 dollars. The annual change has been placed in the latter year, e.g. the change between 1989 and 1990 is shown in 1990.

Significant investment was made in *steam plant* in the early 1990s before returning to a more consistent level in 1994. Investment in 1989 was $43.5 million before reaching a high of $324 million in 1992. Investment trended downward to a low of $32.1 million in 1996 before increasing to its 1998 level of $52 million, a nineteen (19) percent increase over 1990 levels. The high levels in the early 1990s correspond with PacifiCorp's acquisition of the Cholla, Craig, and Hayden steam plants in 1991 and 1992.

Annual *hydro plant* investment has remained fairly consistent throughout the period. Investment increased from $8.5 million in 1989 to a high of $20.2 million in 1993 before trending downward to its current level of $8.7 million, a three (3) percent increase from 1989.

Other plant investment remained insignificant (below $100,000) until 1996 when it increased to roughly $60 million for two years before declining to its current level of $12 million. The increase coincided with PacifiCorp's entering a contract for the Hermiston gas-fired cogeneration plant in 1996.

Transmission plant investment was $64.8 million in 1990 and increased to a high of $105 million in 1993. After 1993, transmission investment has declined steadily to its current level of $13.1 million, eighty (80) percent below its 1990 level.

The investment in the Utah *distribution plant* has shown a fairly steady and consistent upward trend. This increase is not surprising given the growth of PacifiCorp's Utah service territory. In 1990, investment was $14.5 million and has increased to its current level of $68.4 million.

Maintenance Expenditures

Exhibit 1.2 shows the *steam and hydro* total maintenance expenses in constant 1998 dollars. In real dollar terms, steam maintenance expenses have increased by about twenty-five (25) percent from $75.5 to $94.7 million between 1989 and 1990. However, these expenses have remained relatively constant since 1992. In contrast, hydro generation has increased by one hundred thirteen (113) percent from $3.6 to $7.6 million between 1989 and 1998.

The *transmission* system expenses are shown in Exhibit 1.3. In real dollar terms, these expenses have increased twelve (12) percent from $8.7 to $9.7 million dollars between 1989 and 1998. However, with the exception of the high $12.1 million 1997 figure, the transmission

Distribution maintenance expenses within Utah are shown in Exhibit 1.4. Again in real dollar terms, these expenses have increased seventeen (17) percent from $15.5 to $18.1 million between 1989 and 1998. It should be noted that these expenses dropped in 1990 to $ 12.9 million before trending upward to the 1998 level. These results are not surprising given the growth in the company's distribution system and loads during the 1990s.

The Division also calculated maintenance expenses as a percent of average gross plant in service. Nominal dollars were used for both maintenance expense and average gross plant in service in this calculation. Exhibit 1.5 shows the results of this calculation since 1989 as well as a linear regression line fitted to each set of data. Steam and distribution expenses clearly decline as a percentage of average rate base. Transmission maintenance expenses show a modest decline. Interestingly, hydro plant has shows a definite upward trend. There may be a number of reasons which may explain these trends. First, as noted earlier, steam, transmission, and distribution plant have all increased in recent years. To the extent this plant investment involved new plant, it would be reasonable to assume substantial maintenance would not initially be required. Second, the Company may be more efficiently managing its maintenance resources spending less to maintain its system. Third, the Company may be cutting its maintenance expenses in certain areas to fund expenses in other areas. These are just several possibilities and there are undoubtedly others reasons for the trends shown in the exhibit.

The data used in this section's exhibits is included in Exhibit 1.6. For maintenance expenses, subcategories are included under each function that shows the breakdown of the total maintenance expenses. "Other Generation Plant" and "General Plant" maintenance expenses are included in this data but are not discussed above. The data includes nominal dollar maintenance expenses, average gross plant in service and related annual change calculations, constant dollar maintenance expenses, maintenance expenses as a percent of average gross plant in service, and the price deflators used to adjust figures to constant 1998 dollars.

PSC Complaint Trends

Since 1972, the Division has been tracking rates of Utah customer complaints made to the Utah Public Service Commission for PacifiCorp, Questar Gas and US West. For PacifiCorp and Questar Gas an index is calculated showing the number of complaints per 1000 customers using the number of complaints and the average number of customers the utility has in any calendar year. This basic data for 1972 through 1998 is shown below:

	PACIFICORP			QUESTAR GAS		
Year	# Cmpl	Cust	PC	# Cmpl	Cust	QGC
1972	102	268200	0.38	94	257600	0.36
1973	135	281643	0.48	111	269500	0.41
1974	238	292817	0.81	132	280600	0.47
1975	514	305078	1.68	222	292800	0.76

Year	# Cmpl	Cust	PC	# Cmpl	Cust	QGC
1972	102	268200	0.38	94	257600	0.36
1973	135	281643	0.48	111	269500	0.41
1974	238	292817	0.81	132	280600	0.47
1975	514	305078	1.68	222	292800	0.76
1976	338	319696	1.06	240	305156	0.79
1977	338	335260	1.01	241	320964	0.75
1978	358	355451	1.01	292	338100	0.86
1979	341	371992	0.92	302	356200	0.85
1980	357	384831	0.93	360	370448	0.97
1981	291	395950	0.73	371	382191	0.97
1982	409	413463	0.99	816	390226	2.09
1983	467	421197	1.11	1122	398197	2.82
1984	585	432264	1.35	1255	408378	3.07
1985	446	443894	1.00	825	421060	1.96
1986	533	457487	1.17	733	430990	1.70
1987	585	466533	1.25	715	440623	1.62
1988	494	470693	1.05	546	446640	1.22
1989	410	478391	0.86	488	479512	1.02
1990	373	486735	0.77	468	473793	0.99
1991	335	495855	0.68	457	485653	0.94
1992	374	506270	0.74	390	498548	0.78
1993	329	518914	0.63	268	515896	0.52
1994	336	533951	0.63	196	536236	0.37
1995	391	549929	0.71	153	556391	0.28
1996	282	568529	0.49	217	578998	0.37
1997	337	591799	0.57	158	603800	0.26
1998	471	612034	0.77	193	625353	0.31

Example: For PacifiCorp in 1998 there were 471 PSC complaints received and recorded. The average number of PacifiCorp customers in Utah during 1998 was 612,034. Calculating the number of complaints per 1000 customers yields an index or complaint rate of 0.77 complaints per 1000 customers for that year.

Exhibit 2.1 of this report shows this same information graphically over this 27 year period. These complaint numbers reflect all types of complaints including billing, collections, customer service, damage claims, meter problems, line extension, rate increases, outages, shut offs, etc., to name a few. The Division's review of PacifiCorp's performance for the 1989 through 1998 years shows this complaint rate ranging from a low of 0.49 in 1996 to a high of 0.86 in 1989. Higher complaint rates existed for the seven years (1982-1988) preceding the merger. Since the merger PacifiCorp's complaint rates per 1000 customers have trended slightly down and somewhat level, with a slight upward trend occurring in 1997 and 1998. For comparison purposes, we have included the performance of Questar Gas over this same 27 year period.

Service Complaints Directly to PacifiCorp

PacifiCorp utilizes an 800 number for customers to call in electric service complaints directly to its complaint section in its Regulatory Group here in Utah. PacifiCorp only has Utah customer complaint annual numbers for 1996, 1997 and 1998. PacifiCorp's data show that they received the following numbers of complaints in those three years:

1996 - 323 complaints
1997 - 319 complaints
1998 - 481 complaints

This compares to 282, 337 and 471 for these same years, respectively, for PSC received complaints. It is difficult to say there is a trend with just three numbers other than to observe that PacifiCorp's direct 800 number complaint quantities have turned upward in 1998 just as the PSC received complaints have done. The Division draws no conclusion as to quality of service and reliability trends since the merger relative to PacifiCorp's 800 line telephone complaint quantities.

Trends in Staffing, Skills, Training, Service Restoration, Responsiveness, etc. & Comments

PacifiCorp provided the following information regarding staffing levels:

PacifiCorp Electric Operations Employment
All Position Classifications

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Total Company	8366	7692	7495	7500	7656	7606	7299	7061	7086	6319
Utah	3701	3261	3088	3052	3088	3091	2899	2820	2758	2373
*Utah T&D Operations (Budgeted Positions)							834	798	794	722
*Utah Generation	n/a	743	787	793	795	792	703	658	640	592

* Corporate Staff not included

Notes:
Utah T&D Ops. – Actuals not available, budget information only available for 1995-

Transmission and distribution personnel may perform many types of work and are not specifically assigned to a maintenance job classification. Similarly, employees are not assigned to just the transmission or the distribution system and may do work on both. The information provided above is for personnel doing all types of work and is not limited to maintenance only.

Reductions in numbers of operations employees reflect an overall shift toward greater use of contract personnel and increased efficiency.

Abnormal system events generally do not affect employment levels. Temporary work requirements are generally filled by contractors." PC 1.3 DR1

PacifiCorp's data response shows that the total number of employees in the Company went from 8366 in 1989 to 6319 in 1998 reducing in number by 24.5%. Utah employee headcount went from 3701 to 2373 during the same period with a reduction of 35.9%. Utah generation employee numbers went form 743 in 1990 (no 1989 data) to 592 in 1998, or a 20.3% reduction. Utah transmission and distribution headcount (only budgeted 1995 through 1998 figures available) decreased 13.3% over the last four years.

PacifiCorp points out several things. They indicate that the above information (employee numbers) is for personnel doing all types of work and is not limited to maintenance functions only. They also indicate that the reduced headcount reflects increased efficiency by the Company and the greater use of outside contract personnel.

Addressing concerns regarding urban vs rural staffing and overall employee experience, PacifiCorp responded as follows:

"Staffing levels in urban and rural areas are adjusted by management to meet the requirements of construction, operation, maintenance, and outage restoration. Such requirements are met by a balance of employee and contract resources. PacifiCorp currently employs 26 contract crews for maintenance, construction, and outage restoration.

While some journeyman linemen including servicemen and troublemen left the Company through the early retirement program, the overall skill level of the remaining maintenance and emergency outage workforce has not been diminished by the early retirement. The maintenance and emergency outage response functions of retired employees have been assumed by a combination of replacement employees and cross training of other qualified employees to more efficiently perform those functions." PC1.4a DR1

" . . . Regardless of years of service, all journeymen lineman employed by the company (or used as contractors) are fully trained and qualified to perform construction, maintenance and emergency outage functions.

Average years of service is not readily available for personnel by year from 1989 through 1994. The chart below indicates the average years of service for skilled maintenance technicians from 1995 through 1998:

1995:	20.75
1996:	21.70
1997:	22.77
1998:	23.46

However, we do not necessarily consider years of service to be a valid indication of the ability of our workforce to adequately perform maintenance and emergency outage functions. All employees, regardless of tenure, are fully trained and qualified to perform their respective functions.

Annual expenditures for maintenance training for transmission and distribution employees are not separately tracked and not available." PC1.4a DR1

PacifiCorp provided the following information on service restoration:

Outage Customer Restores by percentage

		1998	1997	1996	1995	1994
Oregon	within 3 hours	78.28%	90.61%	84.16%	83.50%	83.66%
	within 24 hours	99.91%	99.91%	99.81%	98.60%	99.99%
Washington	within 3 hours	73.73%	83.92%	49.14%	83.66%	82.73%
	within 24 hours	100.00%	100.00%	88.95%	99.99%	100.00%
Wyoming	within 3 hours	95.93%	97.33%	93.93%	86.66%	91.97%
	within 24 hours	100.00%	99.99%	100.00%	99.99%	98.25%
Idaho	within 3 hours	94.49%	93.54%	91.52%	94.73%	71.48%
	within 24 hours	100.00%	99.99%	99.99%	100.00%	100.00%
Utah	within 3 hours	92.33%	95.10%	94.19%	96.03%	96.36%
	within 24 hours	99.99%	99.99%	100.00%	99.99%	99.99%
California	within 3 hours	82.67%	85.19%	92.00%	73.27%	81.06%
	within 24 hours	100.00%	99.98%	100.00%	99.98%	100.00%

This data indicates that Utah's restoration results over the last five years are among the highest.

Sample comments of parties regarding staffing, skills, training, service restoration, responsiveness, etc.:

UREA

- "*Since the UP&L/PP&L merger, PacifiCorp appears to have reduced staff levels and closed numerous rural offices throughout the state leaving a limited number of field personnel to cover large service areas. This reduction has resulted in a slower response time to outages and ultimate restoration of service for utilities taking delivery from PacifiCorp.* Moreover, the decline in local service has resulted in some PacifiCorp customers approaching neighboring rural electric cooperatives about the possibility of receiving service from them."

  UREA 1.9, page 3

UMPA

- "*In talking with, and observing PacifiCorp crews since the merger of UP&L and PP&L, we have found their maintenance program for substations and related equipment has changed. Crews have been reduced therefore the amount and sometimes the quality of maintenance performed is not what it has been in the past.*"

  UMPA 1.5, page 8

- At the Bonnett Geothermal Powerplant near Cove Fort, Utah, we have encountered a variety of maintenance problems relating to PacifiCorp's system in the area. UMPA has found that local PacifiCorp maintenance crews have been responsive, *but have had difficulty locating specific structures on their own system. Response to maintenance problems reported to PacifiCorp's corporate customer service department, on the other hand, has been quite poor.*"

  UMPA 1.9, page 10

UAMPS

- "*PacifiCorp has reduced the number of service centers in the state and has centralized customer service to a telephone operation in Portland. Customer* *service located exclusively in Portland creates predictable response time problems for both emergencies and normal repair problems.* A good example of this type of problem occurred when Oak City contacted PacifiCorp about service problems in 1996, *they were asked for Oak City's address and social security number in order to identify Oak City's location.* UAMPS 1.13, page 8

Trends in Service Indicators

PacifiCorp provided the Division with historical service indicator data from 1990 to 1998 for the twenty-two (22) districts that comprise UP&L's service territory within the State of Utah as well as for the State as a whole. The data included the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI), and the momentary average interruption frequency index (MAIFI). The Division also calculated a fourth performance measure, the customer average interruption duration index (CAIDI), by simply dividing SAIDI by SAIFI. Each index has five categories. These five categories are:

1. Extreme Storm	Outages caused by natural events claimed to be outside the control of the Company.
2. Pre-arranged	Scheduled outages planned by the Company for construction or maintenance with reasonable advance notice to customers.
3. Transmission	Outages on lines or circuits, regardless of voltage, with no end-use customers directly connected, but that causes outages on *other* circuits with customers.
4. All Other	Outages *not* categorized as extreme storms, pre-arranged, or transmission.
5. Total	The sum of extreme storms, pre-arranged, transmission, and all other outage categories.

The Division has focused its analysis on the "All Other" category of outages because this category is considered to be, at least to some extent, within the control of the Company.

Each of the four service measures is discussed below, but a word of caution regarding the data must be made before any conclusions are drawn from this data. First, the data provided by PacifiCorp contained two instances of negative numbers. For these service indicators, negative numbers are not theoretically possible, thus negative numbers would indicate data inaccuracies. Second, in at least one instance, the data from PacifiCorp conflicted with data provided by Scottish Power in Docket 98-2035-04 by a factor of ten, raising additional questions about data accuracy. Third, Scottish Power conducted a one month audit that revealed eighty (80) percent of that months outage data was not input into PacifiCorp's outage reporting system. Finally, Scottish Power has indicated its skepticism regarding the accuracy of this data and, based on its experience, intends to inflate these historical numbers initially by twenty (20) or thirty (30) percent when establishing performance standards. In addition, Scottish Power maintains that after better data collection techniques are implemented, this historical data may be inflated a second time to provide a more accurate representation of PacifiCorp's historical reliability.

The Division evaluated each of the four service indicators by simply comparing 1998 to 1990 "All Other" data to determine if customers in each district are better off, the same, or worse off in 1998 than they were in 1990 immediately following the UP&L and PP&L merger. The Division recognizes that using these service indicators is just one way of evaluating the impact of that merger on customers. Also, this comparison approach ignores the data in the years between 1990 and 1998, data that provides a more complete picture of service reliability since the merger. While the Division believes 1990 and 1998 are the most relevant years to analyze, the data for each year from 1990 to 1998 is readily available from the Division. Following this 1990 to 1998 comparative analysis, the Division also compares the overall state of Utah figures with each year's worst performing district for each service indicator.

System Average Interruption Duration Index

SAIDI measures the *average* outage duration time, minutes in this case, that a typical customer within a district or the state experiences in a given year. Table 1 below indicates districts with worse (greater by 10% or more), same (within +/- 10 %), or better (less by 10 % or more) performance when comparing 1998 and 1990 "All Other" SAIDI data.

Table 1

COMPARISON OF "ALL OTHER" SAIDI DATA (avg minutes/customer)

DISTRICT	1990 SAIDI	1998 SAIDI	STATUS
Metro	40.4	98.8	Worse
Park City	118.4	114.4	Same
Lake	161.4	96.5	Better
Cottonwood	84.5	83.0	Same
SouthValley	30.2	121.0	Worse
Valley West	67.0	75.0	Worse
Tooele	25.7	33.5	Worse
American Fork	52.5	68.3	Worse

Timp	9.4	39.7	Worse
Nebo	21.7	59.0	Worse
Canyonlands	6.6	56.1	Worse
Carbon	20.3	34.7	Worse
Castledale	32.6	30.9	Same
Ashley	9.8	1.9	Better
Salina	126.0	72.4	Better
Delta	27.3	196.8	Worse
Milford	90.5	150.0	Worse
Cedar City	64.7	149.3	Worse
Ogden	98.1	122.0	Worse
Layton	116.1	126.3	Same
Tremonton	113.8	100.4	Better
Smithfield	56.3	95.0	Worse

Fourteen (14) districts have a worse SAIDI, four (4) have roughly the same SAIDI, and four(4) have a better SAIDI.

System Average Interruption Duration Index

SAIFI measures the *average* number of times that a typical customer within a district or the state has a service interruption. Table 2 below indicates districts with worse (greater by 10% or more), same (within +/- 10 %), or better (less by 10 % or more) performance when comparing 1998 and 1990 "All Other" SAIFI data.

Table 2

COMPARISON OF "ALL OTHER" SAIFI DATA (avg # interruption/customer)

DISTRICT	1990 SAIFI	1998 SAIFI	STATUS
Metro	0.92	0.93	Same
Park City	0.89	0.85	Same
Lake	1.97	1.09	Better
Cottonwood	1.09	1.02	Same
SouthValley	0.65	1.23	Worse
Valley West	1.12	1.10	Same
Tooele	0.31	0.81	Worse
American Fork	0.45	0.70	Worse
Timp	0.14	0.64	Worse

Nebo	0.28	0.52	Worse
Canyonlands	0.06	0.29	Worse
Carbon	0.30	0.13	Better
Castledale	0.55	0.27	Better
Ashley	0.05	0.20	Worse
Salina	0.26	0.74	Worse
Delta	0.23	0.33	Worse
Milford	0.60	2.14	Worse
Cedar City	0.56	1.00	Worse
Ogden	1.23	1.29	Same
Layton	1.54	1.24	Better
Tremonton	0.95	1.06	Worse
Smithfield	0.80	0.82	Same

Twelve (12) districts have a worse SAIFI, six (6) have roughly the same SAIFI, and four(4) have a better SAIFI.

Momentary Average Interruption Frequency Index

MAIFI measures the *average* number of times that a typical customer within a district or the state experiences a momentary service interruption. A momentary interruption is defined as an outage lasting less than five minutes, usually caused by a temporary fault that can be reset by an automatic recloser or feeder circuit breaker. Table 3 below indicates districts with worse (greater by 10% or more), same (within +/- 10 %), or better (less by 10 % or more) performance when comparing 1998 and 1990 "All Other" MAIFI data.

Table 3

COMPARISON OF "ALL OTHER" MAIFI DATA (avg # momentary interruption/customer)

DISTRICT	1990 MAIFI	1998 MAIFI	STATUS
Metro	4.18	7.64	Worse
Park City	0.68	6.68	Worse
Lake	7.85	10.79	Worse
Cottonwood	7.44	7.84	Same
SouthValley	15.46	13.14	Better
Valley West	5.18	6.83	Worse
Tooele	20.05	14.92	Better
American Fork	0.69	6.38	Worse

Timp	0.00	3.93	Worse
Nebo	0.10	1.25	Worse
Canyonlands	0.25	4.82	Worse
Carbon	0.18	3.57	Worse
Castledale	1.04	6.06	Worse
Ashley	0.00	0.20	Worse
Salina	0.03	6.24	Worse
Delta	0.01	6.27	Worse
Milford	0.02	4.17	Worse
Cedar City	1.11	10.79	Worse
Ogden	3.72	11.07	Worse
Layton	3.10	13.91	Worse
Tremonton	1.17	7.09	Worse
Smithfield	0.19	6.49	Worse

Nineteen (19) districts have a worse MAIFI, one (1) has roughly the same MAIFI, and two(2) have a better MAIFI.

Customer Average Interruption Duration Index

CAIDI measures the *average* outage duration time, minutes in this case, per interruption within a district or the state in a given year. CAIDI is calculated by dividing SAIDI by SAIFI. Despite similarities in acronyms, CAIDI and SAIDI are different measures and are not comparable to each other. Table 4 below indicates districts with worse (greater by 10% or more), same (within +/- 10 %), or better (less by 10 % or more) performance when comparing 1998 and 1990 "All Other" CAIDI data.

Table 4

COMPARISON OF "ALL OTHER" CAIDI DATA (avg # minutes / interruption)

DISTRICT	1990 CAIDI	1998 CAIDI	STATUS
Metro	44.1	106.3	Worse
Park City	133.7	134.9	Same
Lake	81.9	89.0	Same
Cottonwood	77.9	81.4	Same
SouthValley	46.6	98.1	Worse
Valley West	60.1	68.1	Worse
Tooele	83.8	41.6	Better

American Fork	117.7	97.6	Better
Timp	68.3	62.5	Same
Nebo	76.5	113.2	Worse
Canyonlands	120.0	192.1	Worse
Carbon	68.3	263.2	Worse
Castledale	59.3	112.8	Worse
Ashley	192.9	9.6	Better
Salina	482.8	98.5	Better
Delta	117.6	603.7	Worse
Milford	151.6	70.1	Better
Cedar City	114.5	148.8	Worse
Ogden	79.6	95.0	Worse
Layton	75.5	101.9	Worse
Tremonton	119.9	94.8	Better
Smithfield	70.2	116.5	Worse

Twelve (12) districts have a worse CAIDI, four (4) have roughly the same CAIDI, and six (6) have a better CAIDI..

<u>State Of Utah vs Worst District</u>

Exhibits 3.1 through 3.4 contains four graphs showing the overall state service indicator figures, one for each indicator, for both the "All Other" and "Total" data categories. On each graph, the Division has plotted each year's worst district "All Other" data to provide an indication of how the worst district compares to the overall state figures. Two observations can be made from these exhibits. First, the "All Other" category comprises the majority of the outage data. In general, the "All Other" category tracks very closely with the "Total" category which, as previously noted, includes all outage categories. Secondly, the worst performing districts generally have significantly higher service indicator values than the overall state data.

Regarding service outages PacifiCorp says:

"Regarding responsiveness and service, the frequency and duration of outages fluctuates from year to year, but show no clear trend." PC1.4a DR1

<u>Specific Problem Facilities</u>

This short term investigation brought forth numerous examples of what parties represent are problems with PacifiCorp's transmission grid in Utah. PacifiCorp appears to be aware of most of these areas and provided its own listing of problem areas that they already know about and those it says it is working on to improve. The Division recommends that the Commission read through the attachments to this study (data responses of the parties, Attachments 4 through 11) for many specific examples of problem facilities. We also recommend that the Commission review PacifiCorp's June 2, 1999 data response (see Attachment 11) which gives PacifiCorp's response to claims of problem facilities by the complainants.

In its initial data response, PacifiCorp says the following about its transmission facilities:

- "PacifiCorp's approach to developing and maintaining its transmission facilities in Utah seeks to achieve a reasonable balance between service quality and cost while keeping the company's transmission system in compliance with National Electric Safety Code requirements. As with any transmission system, opportunities for improvement will always exist – perfect reliability would be unachievable without excessive and unreasonable expenditures and the resulting rate impact. PacifiCorp seeks to meet the challenges posed by events like extreme weather and fires as well as high and fluctuating load growth in areas of Utah while finding the right balance between service quality and cost. Please see Response to PC1.8 for a brief description of the planning process PacifiCorp follows in this regard.

  Within this context, PacifiCorp is not aware that any of its transmission facilities in Utah fail to meet National Electric Safety Code requirements due to lack of funding for necessary maintenance, repair or replacement. That is not to say that the Company does not continuously seek to improve its facilities and service within the constraints of reasonable cost. Indeed, PacifiCorp expects that its merger with ScottishPower will bring to bear ScottishPower's considerable expertise and experience in managing power delivery systems to improve quality of service."

  PacifiCorp PC1.6

Infrastructure Impact on Economic Development

Complainants is this Docket have indicated that poor reliability and quality of service pose serious impediments to economic growth. Most parties were asked to respond to the following data request: "Is [your organization] aware of any specific examples and information where problems with PacifiCorp's electric grid system has had a negative impact on economic growth in Utah?" One example was submitted.

UREA

- "Economic Development in Dixie Escalante's service territory has been negatively impacted due to perceived reliability problems with Dixie Escalante's system. However, the root cause for the bulk of these reliability issues rests with PacifiCorp's delivery into the Dixie system." UREA 1.8, page3

UREA explained that when Dixie's power goes off on its side of the river in St. George due to a PacifiCorp wheeling line failure, the St. George municipal customers on their side of the river observe or hear about these outages. Dixie maintains that these outages occur more often in its service area than in the municipal system, so when new customers come to St. George they are told by residents to avoid locating in Dixie's service area if they want reliable electric service. Dixie maintains this causes it to lose customer growth and revenues. (No hard evidence was provided to the Division to support this claim).

Generation/Transmission Problems Affecting PacifiCorp's Retail Customers

Some complainants in this Docket implied that if the wheeling and power supply wholesale customers of PacifiCorp were experiencing quality of service and reliability problems due to PacifiCorp's transmission grid inadequacies and that these problems affected municipal and cooperative retail customers, then there most likely are retail customers of PacifiCorp suffering this same lack of quality service.

In data requests, parties in this Docket were asked: "Is [your organization] aware of any areas of the State of Utah where generation or transmission systems are affecting the quality of service or reliability for PacifiCorp's retail electric service customers? Please identify these."

The Division received the following responses:

UREA

- "As mentioned in the response to question 1.5, Garkane Power Association would rely on the PacifiCorp 46 kV transmission line from Sevier to Panguitch in the event of a problem to Garkane's normal feed from hydro sources near Boulder, Utah and Glen Canyon Dam. Nevertheless, this transmission line also serves rural PacifiCorp customers along highway 89, including the towns of Panguitch, Circleville, Junction, and Marysvale. [No evidence submitted that retail outages have occurred].

In addition, as noted in the response to question 1.3, Garkane has interconnect agreements with PacifiCorp at Hildale and Panguitch. PacifiCorp has experienced outages in these two areas where Garkane could have assisted their customers by picking up the load, however, numerous personnel changes have meant no one was familiar enough on the PacifiCorp side to get the necessary approvals to facilitate Garkane carrying the load during the outage situations." UREA 1.11, page 3

Kaysville City

- "While taking calls regarding a general power outage at Kaysville City, we received a call from a customer in Layton who stated he realized that he was not a Kaysville City customer but was a customer of PacifiCorp. He had been trying repeatedly to reach someone at PacifiCorp to report a problem but had been unable to do so. He could not get any information as to what was causing the power outage and wondered if we could provide him with any information that would help him to understand what was going on and when the power might be restored.

  Kaysville City received a trouble call from a PacifiCorp customer living in Fruit Heights City to report an outage. We told him he was not one of our customers and that he needed to contact PacifiCorp. He said he had tried repeatedly to do so but they kept telling him he was not in their service area and to contact Kaysville City.

  Another irate customer called from Fruit Heights City during an outage and asked if we could explain to him how he could get off the PacifiCorp system and get onto Kaysville's system. With the number of outages he had experienced recently and the response he received from PacifiCorp, he was ready to change providers, if he could.

We received a call from a customer in Pleasant View, Utah asking if we could inform him as to how he could get hold of someone at PacifiCorp to express his feelings about the quality of service they had received. The number and length of outages they had experienced were excessive, he was not able to reach anyone to express his concerns, and wondered if we could provide him with names or phone numbers." Kaysville City 1.15, page 5

UMPA

- "UMPA is not in a position to comment on PacifiCorp's service or reliability to its own retail customers, since UMPA interfaces with PacifiCorp almost exclusively on its backbone transmission system." UMPA 1.11, page 12

UAMPS

- "As stated in response UAMPS 1.5, UAMPS believes that service to PacifiCorp's retail customers in Washington County is inadequate during summer peaks."

UAMPS 1.15, page 9

Transmission and Wheeling Contracts

The Division did not understand how there could be so many complaints by municipal and cooperative organizations about PacifiCorp transmission reliability and quality of service if there were contracts between PacifiCorp and these wholesale wheeling customers that should, in theory, include provisions/penalties to protect the purchasing wholesale entity. Parties were asked to tell us about those contracts, to give examples, etc. Responses follow:

UREA

- "Dixie Escalante's contracts with PacifiCorp are wholesale power supply contracts through Western Area Power Administration (Western) and Deseret Generation and Transmission (Deseret). *These contracts imply that service will be provided on a reasonableness basis.* Dixie Escalante has not taken any legal action; however, Western and Deseret were both involved in the meetings referenced above in the response to question 1.1. [which says: "Dixie Escalante has met on several occasions with PacifiCorp to inform them of the severity of the problem and to request that improvements be made to this portion of their system. However, no progress has resulted from the meetings. Our assumption, based on these discussions, is PacifiCorp has been unwilling to supply the necessary budget allocations for adequate maintenance and capital upgrades to minimize the outage problems in this area."]

Garkane Power Association has existing interconnect agreements with PacifiCorp at Panguitch and Hildale. These agreements allow for Garkane to pick up PacifiCorp load or for PacifiCorp to carry Garkane load, both under outage or emergency conditions and primarily would benefit PacifiCorp loads. Unfortunately, there are no PacifiCorp employees in the vicinity knowledgeable in the procedures to facilitate the switching. UREA 1.3, page 2

Kaysville City

- "UAMPS has the transmission contract with PacifiCorp."

Kaysville City 1.7, page 3

UMPA

- "UMPA's Member Cities do not have transmission agreements with PacifiCorp. UMPA entered into a Transmission Service and Operating Agreement ("TSOA") with PacifiCorp on July 31, 1991, through which it plans, provides, and coordinates, among other things, transmission of electric power on behalf of its

Member Cities. UMPA's TSOA with PacifiCorp contains a "*Prudent Utility Practice*" guideline for transmission service, under which PacifiCorp must "exercise its best efforts to supply continuous Firm Transmission Service." "Prudent Utility Practice" is defined, in relevant part, as

> "[a]ny of the practices, methods and acts...engaged in or approved by a significant portion of the electric utility industry to operate electrical equipment lawfully and in a safe, dependable, efficient and economic manner, or any practices, methods and acts which, in the exercise of reasonable judgment in the light of the known facts, could be expected to accomplish the desired result at reasonable cost and consistent with reliability, safety and expedition and the requirements of governmental agencies having jurisdiction."

The application of the "Prudent Utility Practice" standard necessarily requires a court or agency to undertake an extensive factual inquiry to explore the reasonableness of PacifiCorp's practices. Thus, UMPA must be prepared to invest considerable time and monies to challenge PacifiCorp's practices. UMPA does not have the incentive to pursue its reliability concerns in a legal forum because the costs of such litigation generally outweigh the potential cost savings resulting from a favorable judgment.

This point is illustrated by UMPA's challenge to PacifiCorp's voltage levels at the Manti interconnection during the course of PacifiCorp's rate case at FERC in Docket Nos. ER91-471-000 and ER91-494-000. Though the rate case did not raise reliability issues, UMPA used the case as an opportunity to negotiate a "side-bar letter agreement" with PacifiCorp, dated April 30, 1992, in which PacifiCorp agreed to test the voltage levels at the Manti interconnection and correct any deficiencies caused by its system. To date, PacifiCorp has not fully complied with its obligations under the side-bar agreement and, as a result, low voltage problems persist at the Manti interconnection. Although UMPA has considered using legal means to force PacifiCorp to meet its contractual obligations under the side-bar agreement, UMPA has not done so to date because of the time and expense required to pursue its claim.

Because only a portion of the side-bar letter agreement pertains to Manti, a copy of it is not attached hereto. The entire language of the agreement relating to Manti states:

> Manti Low-Voltage – PacifiCorp, upon receipt of certain testing equipment that it has on order, will test the voltage levels at the Manti interconnection to determine whether the low voltage problems are caused by problems on PacifiCorp's system or Manti's system. PacifiCorp will provide UMPA with a copy of the results of such testing and monitoring as well as PacifiCorp's determination of the action required to correct any deficiencies which are causing the problems. PacifiCorp will then undertake, at its expense, with reasonable diligence and in accordance with Prudent Utility Practice, actions necessary to correct any such deficiencies caused from PacifiCorp's system."
>
> UMPA 1.4, pages 5 & 6

UAMPS

- "The TSOA between UAMPS and PacifiCorp is a network transmission agreement designed to provide for delivery, on the PacifiCorp transmission system, of UAMPS' resources to UAMPS loads. The TSOA is for firm transmission service. UAMPS has the right to file a complaint before the FERC as to the level of service it receives under the TSOA and has raised the issue in the context of PacifiCorp's rate cases. UAMPS has received assurances that service will improve. Unfortunately, practical remedies available to FERC to mandate a level of service are rate-oriented only. Therefore, even if the level of service was litigated and proved to be inadequate before FERC, FERC's only remedy would be to lower the PacifiCorp's rates to match the level of service they are delivering. UAMPS has attempted to negotiate with PacifiCorp to raise the level of service to avoid lowering rates. Lowering rates does not adequately repair a deteriorating system." UAMPS 1.7, page 6

<u>Tree Trimming Expenditures and Policies</u>

PacifiCorp's annual tree trimming expenditures are shown in Exhibit 4.1. The data provided by the Company combined the distribution and transmission expenditures. For Utah, the figures include the distribution portion that is situs to Utah and an allocated portion of the total transmission expenditures. To facilitate a trend analysis, the dollar expenditures provided for each year since 1990 have been converted to constant 1998 dollars using a price deflator from the United States Bureau of Economic Analysis. As can be seen from the graph, the total company expenditures have increased from $10.4 million in 1990 to $19.3 in 1998, or about an eighty-six (86) percent increase. Over the same period, the figures for Utah increased from $3.2 million to $4.6 million, or about a forty-two (42) percent increase.

Several policy changes have occurred in PacifiCorp's tree trimming policies during this period. In 1992, the Company changed its tree trimming technique from the traditional "roundover" approach to a modern "training" approach using the *American National Standard for Tree Care Operations ANSI A300.* Under the traditional "roundover" method, a specified clearance was established between power lines and tree branches with the tree shaped in the form of a ball. This trimming resulted in significant tree damage and masses of fast growing new branch shoots. Under the new "training" approach, the trimming targets entire limbs and branches that interfere with or grow towards power lines. Other branches grow naturally and over the long-term the tree is trained to grow around the power lines.

Another change to PacifiCorp's tree trimming program was the centralization of the program management. Previously, tree trimming management was decentralized having district level managers determine each district's tree trimming needs. According to the Company, centralization offers three benefits: 1) overall program management could be provided by a professional forester, 2) more efficient allocation of resources to areas where the need is greatest, and 3) uniform application of tree trimming standards throughout the service territory.

After an early season storm during the fall of 1998, the Company indicated that it may reduce its tree trimming cycle back to three (3) years. A number of service outages were caused by limbs and branches falling into distribution lines as a result of heavy snow on leaf-filled limbs. Apparently, the Company believes that at least some of that damage may have been avoided by shorter trimming cycles. Such a change would indicate that PacifiCorp is still searching for the optimum tree trimming policy that balances costs and system reliability.

FERC Issues

The complaints given to the Commission in this Docket seem to center on transmission reliability and quality of service problems primarily regarding municipal and cooperative agencies that have wholesale wheeling or power supply agreements with PacifiCorp. Most, if not all, of these issues fall under the regulatory authority of the Federal Energy Regulatory Commission or FERC. Six parties were asked in data requests to respond to two questions concerning FERC and some responses are included. The questions were:

> (1) Please provide the Division information about PacifiCorp generation or transmission quality of service cases [your organization or your members] may have taken before the FERC and tell us what FERC has said or ordered in each case, and,
>
> (2) Please provide [your organization's] thoughts as to whether the State of Utah (the legislature, the Governor, State Agencies, or whomever) is or is not relying too heavily on the FERC to protect Utah customers from possible deteriorating transmission systems and interfaces that may not be properly maintained and/or upgraded.

The responses were:

UREA

- "Utah Rural Electric Association members have not formally taken PacifiCorp before FERC in a transmission case." UREA 1.4, page 2

- As to question #2: "No specific comments." UREA 1.10, page 3

Kaysville City

- "UAMPS has represented Kaysville City before the FERC."

  Kaysville City 1.9, page 4

- "Kaysville City believes it will be in the public interest if the Public Service

Commission considers quality of service issues when it determines rates and services for PacifiCorp's jurisdictional customers."

Kaysville City 1.15, page 5

UMPA

- "As set forth in UMPA's response to UMPA [data response] 1.3, above, UMPA pursued its concerns about the voltage levels at the Manti interconnection with PacifiCorp in PacifiCorp's rate case before FERC in Docket Nos. ER91-471-000 and ER91-494-000. UMPA and PacifiCorp negotiated an agreement in an attempt to resolve UMPA's reliability concerns because UMPA was not able to ask FERC to address the problems in the context of a rate case." UMPA 1.4, page 7

- As to question # 2: "The State of Utah is relying too heavily on FERC to protect Utah customers from deteriorating transmission systems and interfaces that are not properly maintained or upgraded. FERC unquestionably has jurisdiction over the transmission systems that transmit energy in interstate commerce to Utah customers. Federal Power Act, 16 U.S.C. Section 824(b)(1). Consistent with its jurisdiction, FERC can adjudicate reliability complaints. FERC has not, however, issued regulations governing reliability nor does it monitor the quality of utilities' transmission service. The result is that the burden of monitoring reliability and quality of service, and the corresponding financial burden of petitioning FERC for relief lie with customers. As a practical matter, it is difficult and costly for customers to track reliability problems. Even where customers can track and prove that there are problems, they will not likely file a complaint at FERC because the costs associated with pursuing such a proceeding are often prohibitive. The State of Utah is relying too heavily on FERC to protect Utah customers by failing to initiate and participate in reliability proceedings at FERC. Customers cannot afford to do so and, therefore, the State of Utah should act on their behalf." UMPA 1.10, pages 11 & 12

UAMPS

- "As stated in response UAMPS [data response] 1.7, UAMPS has not filed a separate "quality of service" complaint with FERC, but has attempted to negotiate specific issues as part of PacifiCorp rate cases." UAMPS 1.9, page 7

- As to question #2: "The intent of UAMPS' letter was, as a customer, to provide the Commission with information, as to the service history of PacifiCorp. UAMPS is in ongoing discussions to resolve it's quality of service problems with PacifiCorp. UAMPS believes it would be in the public interest if the Public Service Commission considers service quality and capital investment issues when it determines rates and services for PacifiCorp's jurisdictional customers."

UAMPS 1.14, page 8

UAMPS has also stated:

- "The TSOA between UAMPS and PacifiCorp is a network transmission agreement designed to provide for delivery, on the PacifiCorp transmission system, of UAMPS' resources to UAMPS loads. The TSOA is for firm transmission service. UAMPS has the right to file a complaint before the FERC as to the level of service it receives under the TSOA and has raised the issue in the context of PacifiCorp's rate cases. UAMPS has received assurances that service will improve. *Unfortunately, practical remedies available to FERC to mandate a level of service are rate-oriented only. Therefore, even if the level of service was litigated and proved to be inadequate before FERC, FERC's only remedy would be to lower the PacifiCorp's rates to match the level of service they are delivering. UAMPS has attempted to negotiate with PacifiCorp to raise the level of service to avoid lowering rates. Lowering rates does not adequately repair a deteriorating system.*" UAMPS 1.7, page 6

PacifiCorp

- "FERC tariffs and individual wheeling contracts provide only a small portion, approximately 9½ percent, of the company's transmission revenue requirement. There is no reason to believe that wheeling revenues under FERC jurisdiction are insufficient to support a reasonable proportion of the expenditures needed for maintenance and repair for service reliability in Utah. The majority of the transmission revenue requirement comes from retail tariffs approved by state commissions. To the extent that jurisdictional prices recover the allocated shares of revenue requirements, the costs of necessary maintenance, repair and replacement of the transmission system are recovered."

PacifiCorp PC1.6

Equipment and Technology Advances Affecting Reliability

Some of the initial reliability complaints against PacifiCorp implied that there are examples in Utah of seriously outdated physical facilities in the electric grid and that there might possibly be technological advances available to PacifiCorp that they are not utilizing to increase its quality of service and reliability.

Kaysville, UAMPS and UREA provided no specific examples in their data responses of outdated physical facilities or unutilized technological advances. UMPA indicates that for Manti City, the 46KV line from the Gunnison Substation to Manti needs to be rebuilt. They say the voltage regulators of the Gunnison substation are old and outdated. UMPA also indicates that the 46KW line from Ephriam to the Manti substation is in bad shape. It was reportedly built in the 1930's with no static neutral, which they claim is an unacceptable and outdated standard under their agreement with PacifiCorp under the "prudent utility practices" clause. In PacifiCorp's data response PC1.8, the Company details known problems with the transmission grid (including the Manti and Ephriam area) and its plans to rebuild, replace and/or upgrade its facilities. Some of these facilities are being addressed because of age, wear, structural failure, capacity limitations, raptor and human gun shot damage, lightning susceptibility, wind and fire damage, etc.

Inter-Company Communication and Coordination

A review of the data provided by the parties in this Docket indicates to the Division a lack of effective communication between PacifiCorp and its municipal and cooperative wheeling and power supply customers. The Division recommends that the Commission read through the attachments to this study (data responses of the parties, Attachments 4 through 11) for specific examples of inter-company communications problems. We also recommend that the

Commission review PacifiCorp's June 2, 1999 data response (see Attachment 11) which attempts to give PacifiCorp's response to claims of problems by the complainants including communications and coordination concerns.

1989-1998 Quality of Service/Reliability Trends

In a data request, the Division asked parties to respond to the following question: "The Division is trying to investigate PacifiCorp's quality of service performance from 1989 through 1998 or since the merger. Please provide [your organization's] position on PacifiCorp's service and reliability before and since the 1989 Merger. Is service better or worse? Also, please comment on service levels starting in 1989 or 1990 (first years of the merger) to the present. What is the trend?" The following lists some responses by the parties:

UREA

- "*Garkane Power Association and Dixie Escalante report service from PacifiCorp has deteriorated in the last 10 years, more significantly in the past 5 years with increased delays in service and longer response times.*"

UREA 1.2, page 2

Kaysville City

- "*Kaysville City believes service and reliability has deteriorated.* Outage data as recorded by the JEM meter supports this conclusion. Kaysville City's Attachment A." (Division note: Attachment A shows outages from 1992 through 1998 which range from a low of 0.03 hours per year [1995] to 11.24 hours per year [1998] after a 3.13 hours per year in 1997, an upward trend of outages in the last two years for Kaysville). Kaysville City 1.6, page 3

UMPA

- "UMPA has significant continuous interaction with PacifiCorp on their transmission system used to deliver power and energy to our member cities. *There* *does not appear to be a clear change in trend, favorable nor unfavorable, since the 1989 merger in system performance. However, personnel changes and reoccurring internal reorganizations have made locating and maintaining a contact list of the appropriate and responsible people in the organization a difficult challenge for us and our member cities. Generally there is no advance notice of changes, or we are directed to PacifiCorp's Portland office where finding the right person, is to say the least, a rigorous exercise. There is a clear and constant practice of large voltage fluctuations within ±5% of our 138 kV points of interconnect since 1990 (oldest available information). There have also been multiple incidents of non-communication (contrary to contract language) in PacifiCorp's dispatching and scheduling of DG&T's Bonanza generation and the Bonanza-Mona transmission line.*" UMPA 1.2, page 3

UMPA monitors voltage levels on PacifiCorp's transmission system at the interties with UMPA's Member systems. *After reviewing voltage levels at the 138-kV feeds from PacifiCorp's system into Provo City, UMPA found that there is no clear, consistent trend in the frequency of voltage drops below 95 percent lagging (131.1 kV) or spikes above 105 percent leading (144.9 kV), in accordance with prudent utility practice. We did note, however, that there have been a number of hours from 1990 to 1998 in which PacifiCorp's system voltage has dropped below or exceeded that standard of service (large voltage swings), requiring UMPA to provide excessive voltage support. Large voltage swings cause excessive operation and wear on our voltage regulators.*

UMPA 1.2, page 4

- "Manti City - *Subsequent to PacifiCorp's merger, their level of repairs, upgrades and service has dropped dramatically*, not at any fault of the local employees and crews. They are just following Company policy." UMPA 1.9, page 11

UAMPS

- "*UAMPS believes service has deteriorated across the board for all customers. When discussing, UAMPS' particular problems, PacifiCorp's response has often been "you are receiving the same level of service as our retail customers." Assuming this is true it speaks volumes about the "quality of service" issue. A* *complete review of expenditures made by PacifiCorp over the last several years vis-a-vis their transmission system in Utah should readily reveal why deterioration of the service and reliability of the PacifiCorp system is occurring."*

UAMPS 1.6, page 5

Investigation Findings

The Division's findings in Docket No. 99-2035-01 regarding PacifiCorp's quality of service and reliability performance in Utah since the 1988 merger are as follows:

Kaysville City

- The transfer switch problem that Kaysville City wrote to the PSC about last October that has caused customer service problems for Kaysville's retail customers has been fixed.

- Kaysville City most likely will continue to experience some service problems, especially in the summer, until PacifiCorp completes its rebuild of the 46KV Gadsby to Riverdale transmission line. Some of that work is underway with the complete rebuild scheduled to be completed in the next year or so.

UAMPS

- In a November 1998 meeting with Kaysville City and UAMPS, UAMPS informed the Division of four areas of the State where they had service problems and disputes with PacifiCorp. In its data response, UAMPS indicates that two of these areas of dispute have been resolved through joint efforts between UAMPS and PacifiCorp. UAMPS indicates it expects to continue discussions with PacifiCorp as to its service issues. UAMPS says it will also continue to advocate for the formation of regional transmission organizations as a partial long term solution to service quality and investment level issues.

ULCT

- Although the Division received no data response from the ULCT, an effort was made to address the concerns expressed in the ULCT letter to the Utah PSC of January 13, 1999.

Maintenance and Capital Expenditures

- Using changes in average plant in service as a proxy for capital expenditures, the Division's investigation shows that PacifiCorp made significant capital investment on steam plants in the early 1990's and this investment dropped to a lower and consistent level from 1994 through 1998. Other generation plant investment, which had been near zero, increased somewhat in the late 1990's. Hydro investment has remained nearly constant throughout the period. Transmission investment has declined since about 1993-1994 to a point somewhat below the levels that existed just after the merger. Utah distribution plant capital investment has increased throughout the post merger period.

- The Division's review of PacifiCorp's maintenance expenditures shows that steam plant and hydro dollar amounts spent by the Company have somewhat increased since the merger. Transmission expenditures have remained fairly consistent with the exception of an slight increase in 1997 on a total company basis. Distribution maintenance expenditures in Utah decreased in the first year after the merger with a steady increase through 1998.

- The Division's evaluation of maintenance expenditures as a percentage of average plant in service shows downward trends for steam, transmission and Utah distribution, but an upward trend for hydro.

- Based on this analysis of capital investment and maintenance expenditures trends alone, the Division finds no specific evidence that these levels have or have not directly impacted the quality of service or reliability of PacifiCorp's Utah electric grid. The reduction in transmission capital investment could possibly be some support for the claims of wheeling/power supply customers of PacifiCorp in this Docket. However, the reasons for this Company wide reduction have not been identified and may not have affected Utah transmission. Should there be a decline in service quality due to reduced investment levels, there could also be a lag between the reduction and the quality of service impact.

- Although the above information shows fairly constant levels of capital and maintenance expenditures by PacifiCorp since the merger (with the exception of transmission capital investment mentioned above), the data responses received from the four complaining parties in this Docket show a very strong perception and belief that little or no money for upgrades and maintenance has been being spent in their service areas. They extensively and repeatedly quote PacifiCorp field employees as saying there is not money available to fix the transmission and service problems. In the minds of these parties, there appears to be a problem in PacifiCorp's transmission expenditure levels in areas that affect their members.

PSC Complaints

- From the PSC complaint rate numbers, there has not been a significant change in the rate of complaints over the ten year period (1989-1998) being reviewed in this Docket. Also, complaint rates have declined somewhat since the period prior to the merger. Since the majority of the complaints come from PacifiCorp's retail customers, this data could possibly support a conclusion that, by this measure, PacifiCorp's jurisdictional customers in Utah have not seen a decline in quality of service and reliability since the merger.

Maintenance Staffing Levels

- In Utah, PacifiCorp's transmission and distribution headcount has declined over the last four years and the Company indicates it is using more contract labor to meet its needs. The comments of parties seem to reflect a reduction of presence and availability of knowledgeable Company personnel over the years since the merger, especially in the rural areas of the State. Party comments claim that the transmission system maintenance is not being performed, but the Division finds no evidence that PacifiCorp's maintenance staffing levels have directly influenced what is or is not maintained or how much maintenance is performed.

Skill Levels, Training, Outage Response, Service Restoration, etc.

- The Division sees a recurring theme regarding responses to questions from parties about trends in staffing, skill levels, training, responsiveness to outages, service capabilities, etc. The removal of PacifiCorp personnel (and perhaps the replacement of PacifiCorp headcount with less accountable private contractors) from local areas that these customers reside and operate in, seems to cause great concern to UMPA, UAMPS and UREA as they continue to try to provide top quality service to their members and their member's electric service customers. Availability of personnel, knowledge of who to contact, lack of knowledge of newly assigned personnel concerning geography and the electric grid (especially from Portland of the Utah system), and response delays due to geography, all contribute to the party's complaints as they deal with PacifiCorp over time.

PacifiCorp Service Indicators

- Based upon the four service indicators evaluated by the Division comparing 1990 data to 1998, the majority of the 22 PacifiCorp service districts (PacifiCorp's retail customers) appear to be experiencing worse service quality and reliability. However, the Division believes inconsistencies exist in data reporting over this nine year period making any firm conclusions concerning service quality based on this data suspect.

- Since 1990, State averages in Utah for SAIDI, SAIFI, MAIFI and CAIDI service indicators have, with a few exceptions since 1996, have remained relatively constant. On the other hand, when the Division compared the worst performing district (out of PacifiCorp's 22 Utah service districts) in each year with the State average, it observed that looking only at the State average can obscure the poorer service performance of the worst district.

Problem Facilities

- Parties to the quality of service and reliability Docket provided a list of numerous areas in the State where transmission facilities of PacifiCorp are causing poor service to municipal and cooperative retail customers. The Division concludes that there is a strong need for PacifiCorp to work with the complainants in this Docket to resolve the service affecting facility problems.

Economic Growth Impact of Infrastructure

- Complainants in this Docket have indicated that poor reliability and quality of service pose serious impediments to economic growth. Most parties were asked to respond to the following data request: "Is [your organization] aware of any specific examples and information where problems with PacifiCorp's electric grid system has had a negative impact on economic growth in Utah?" One example was submitted. Counter to claims of parties, the Division has been unable to find significant evidence that PacifiCorp's generation, transmission of distribution systems have had any real or broad based negative impact on Utah's economic growth since 1988. The Division is even inclined to speculate that PacifiCorp's decreasing rates for electric service since the 1988 merger could be shown to have had a positive impact on Utah's economic growth.

Generation/Transmission Effect on PacifiCorp's Retail Customers

- The Division has found little hard evidence in this investigation that PacifiCorp's retail electric service customers are experiencing any significant or increased quality of service or reliability problems due to its generation or transmission systems in its service territory in Utah since the 1988 merger.

Transmission Contracts

- It appears to the Division from the responses of parties in this Docket, that the existing contracts between PacifiCorp and these municipal and cooperative wholesale member agencies do not entirely protect the Utah retail customers of the municipals and cooperatives. This is due to the general generic nature of the wording of these contracts, and the apparent reluctance of these agencies to take the time and expense to litigate their complaints against PacifiCorp. It may also be due to the possible lack of ability (or interest?) of FERC to cause any remedy other than perhaps the threat of lowering transmission rates which, does not fix poor transmission systems. The Division may be able to help in this area by relating these concerns to FERC at their planned regional input meetings on RTO's (Regional Transmission Organizations).

Tree Trimming

- Total PacifiCorp tree trimming expenditures have increased from $10.4 million in 1990 to $19.3 in 1998, or about an eighty-six (86) percent increase. Over the same period, the figures for Utah increased from $3.2 million to $4.6 million, or about a forty-two (42) percent increase. The last change in PacifiCorp's policy has been the modification of the tree trimming cycle. From 1989 to 1993, the Company cycle was every three (3) years. From 1994 to 1996, the Company lengthened its trimming cycle to three and a half (3½) years. From 1997 to 1999, the tree trimming cycle was lengthened to four (4) years. Early 1999 meetings with PacifiCorp indicate its plans to return to a three (3) year trimming cycle.

- It appears to the Division that PacifiCorp is still searching for the optimum tree trimming policy that balances costs and system reliability. However, from the data reviewed in this Docket, the Division finds no significant evidence that PacifiCorp s tree trimming policies and performance has had a noticeable negative affect on its customers since the 1988 merger.

FERC Issues

- It appears to the Division that municipal and cooperative agencies are reluctant to take reliability and quality of service transmission problems (with PacifiCorp) to FERC due to the cost of litigation and time investment, and the perceived reluctance of FERC to deal with reliability issues, concentrating as they do primarily on setting transmission rates. The Division feels that this investigation indicates a probable problem area for State of Utah electric customers served by municipals and cooperatives. If these agencies do not have an easy way to resolve service quality and reliability issues then their customers can suffer poor service. The Division may be able to help by bringing these concerns to FERC at their regional input meetings on RTO's. (UAMPS advocates the formation of regional transmission organizations (RTO's) as a partial long-term solution to service quality and investment level issues).

Outdated PacifiCorp Transmission Facilities

- The Division did find from party's responses, some specific claims of what appear to be outdated physical facilities in PacifiCorp's electric grid. Kaysville, UAMPS and UREA provided no specific examples in their data responses of outdated physical facilities. UMPA indicates that for Manti City, the 46KV line from the Gunnison Substation to Manti needs to be rebuilt. They say the voltage regulators of the Gunnison substation are old and outdated. UMPA also indicates that the 46KW line from Ephriam to the Manti substation is in bad shape. It was reportedly built in the 1930's with no static neutral, which they claim is an unacceptable and outdated standard under their agreement with PacifiCorp under the "prudent utility practices" clause. While not admitting to having outdated equipment, PacifiCorp in its data response, indicates its known problems with the transmission grid (including the Manti and Ephriam area) and its plans to rebuild, replace and/or upgrade its facilities. Some of these facilities are being addressed due to age, wear, structural failure, capacity limitations, raptor and human gun shot damage, lightning susceptibility, wind and fire damage, etc.

Technological Advances

- The Division is unable to find any specific evidence that there are technological advances available to PacifiCorp that they are not utilizing to improve reliability.

Inter-Company Communication and Coordination Problems

- A review of the data provided by the parties in this Docket indicates a lack of effective communication between PacifiCorp and its municipal and cooperative wheeling and power supply customers. Parties indicate that the apparent reduction in the numbers of PacifiCorp personnel in the various field locations in Utah as well as changes in the actual personnel and their responsibilities (due to consolidations, early retirements, etc.), and the move of functions and centers to Salt Lake City and especially Portland, has caused a breakdown in the ability these customers have to identify, report and resolve quality of service and reliability problems. Data responses even seem to indicate a lack of system knowledge (Utah electric grid and geography) by Portland employees of PacifiCorp (and perhaps its SLC people also).

These wheeling and wholesale power supply customers of PacifiCorp provide examples of when discussions lead to no action or follow up by Company employees, leaving these customer organizations to have to assume that no action will be taken by PacifiCorp.

The Division feels that this lack of inter-company communication and coordination is one of the most significant problems found in its investigation which can have significant impact on the quality of service and reliability in the State if not improved by the PacifiCorp and the parties involved in managing the electric grid.

1989-1998 Quality of Service/Reliability Trends

- The four wheeling/power supply parties in this Docket generally indicate that service from PacifiCorp has deteriorated in the last 10 years, more significantly in the past 5 years, with increased delays in service and longer response times. These are transmission level customers of PacifiCorp.

From its limited investigation the Division concludes that the overall quality of service and reliability of PacifiCorp's wheeling and power supply municipal and cooperative customers has declined to some degree over the 10 year period of 1989 through 1998.

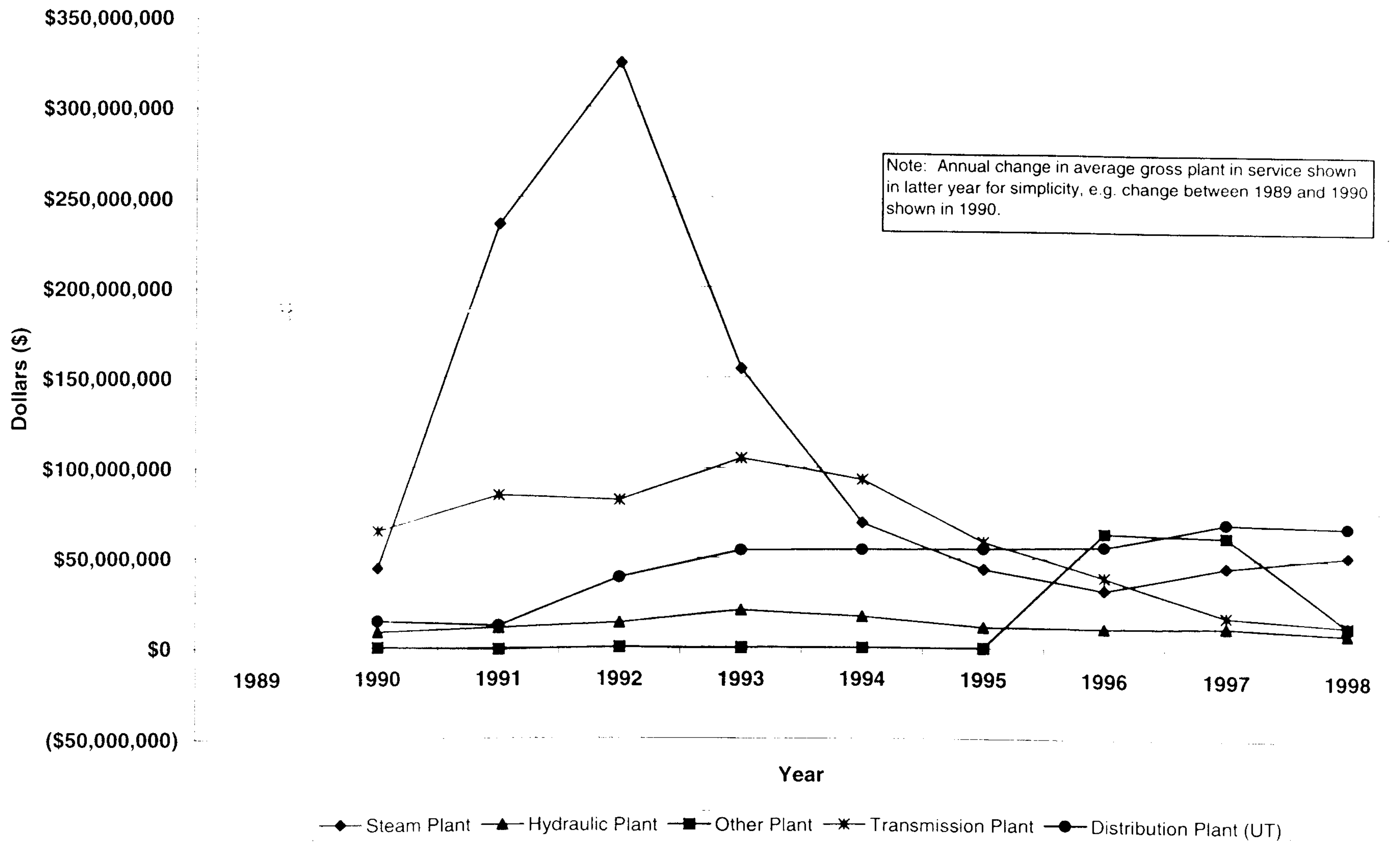
Other than some minor exceptions in "worst districts" data comparisons and some examples given for a few PacifiCorp customers by complainants, the Division concludes from this short term investigation that there is no significant evidence that PacifiCorp's overall quality of service and reliability has declined or changed significantly since the 1988 merger between Utah Power and Pacific Power.

DOCKET NO. 99-2035-01 PACIFICORP
SERVICE QUALITY AND RELIABILITY

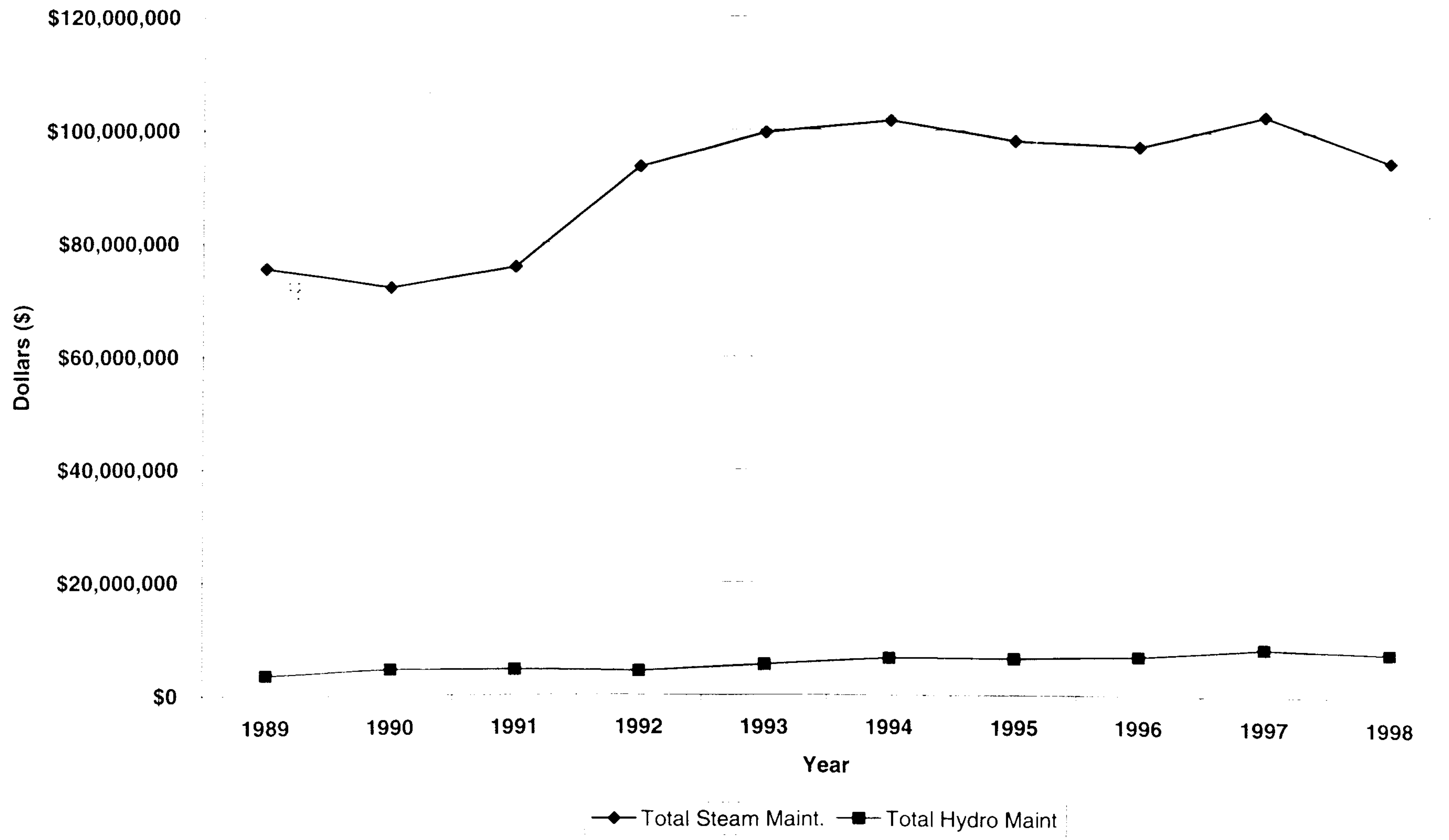
LIST OF EXHIBITS

EXHIBIT No. 1.1	PacifiCorp Annual Change in Average Gross Plant In Service
EXHIBIT No. 1.2	PacifiCorp Maintenance and Expense Analysis Total - Steam Generation and Hydro
EXHIBIT No. 1.3	PacifiCorp Maintenance and Expense Analysis Total - Transmission System
EXHIBIT No. 1.4	PacifiCorp Maintenance and Expense Analysis Utah - Distribution
EXHIBIT No. 1.5	PacifiCorp Maintenance and Expense Analysis Maintenance Expense as a Percentage of Plant In Service
EXHIBIT No. 1.6	PacifiCorp Plant and Maintenance Expense Data and Calculations (4 backup spreadsheets)
EXHIBIT No. 2.1	Utah PSC PacifiCorp and Questar Gas Company Complaint Rates
EXHIBIT No. 3.1	System Average Interruption Duration Index (SAIDI) State of Utah vs Year's Worst District
EXHIBIT No. 3.2.	System Average Interruption Frequency Index (SAIFI) State of Utah vs Year
EXHIBIT No. 3.3	Momentary Average Interruption Frequency Index (MAIFI) State of Utah vs Year
EXHIBIT No. 3.4	Customer Average Interruption Duration Index (CAIDI) State of Utah vs Year
EXHIBIT No. 4.1	PacifiCorp Tree Trimming Expenditures

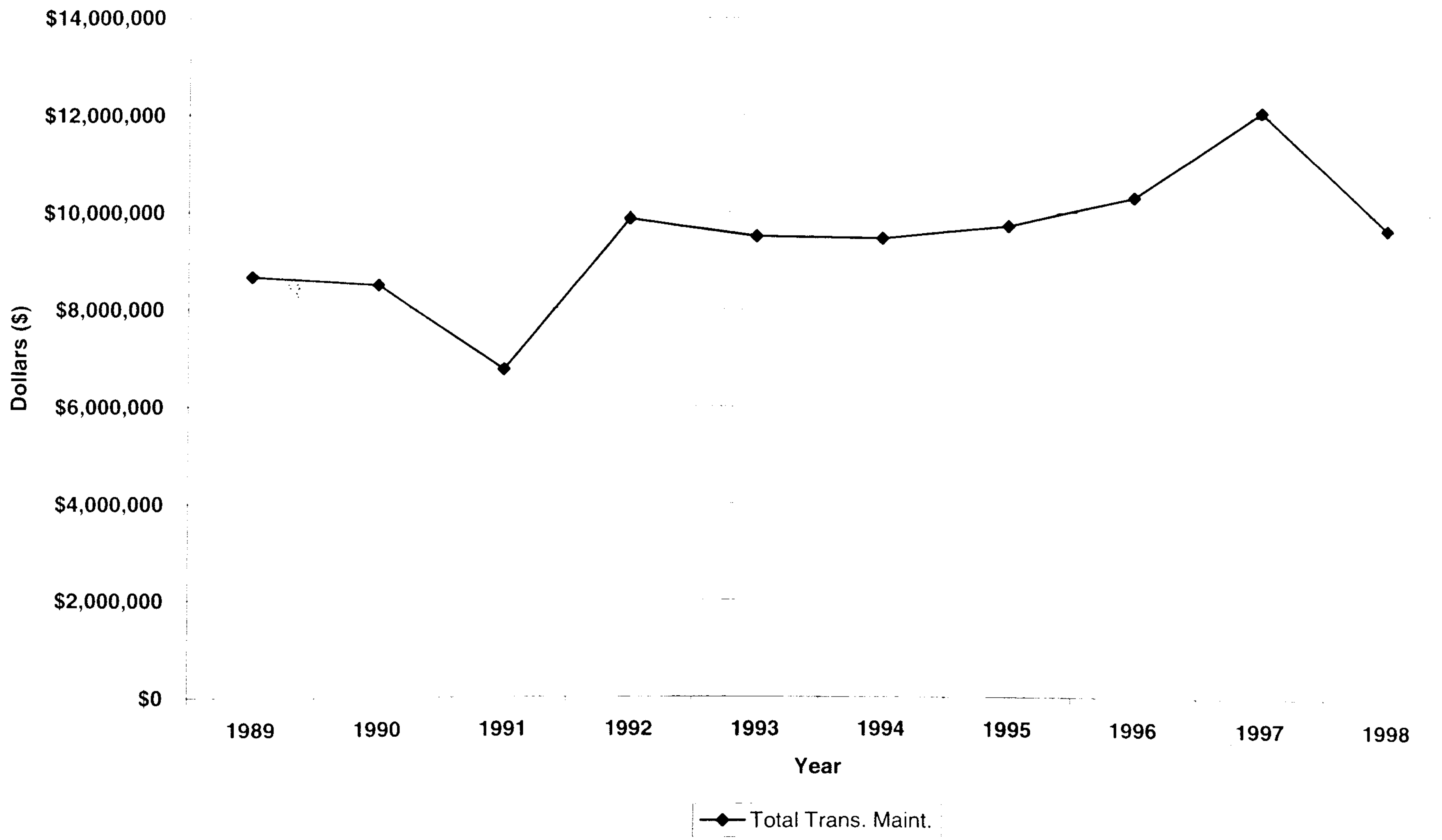
PacifiCorp Annual Change in Average Gross Plant in Service
(Constant 1998 Dollars)



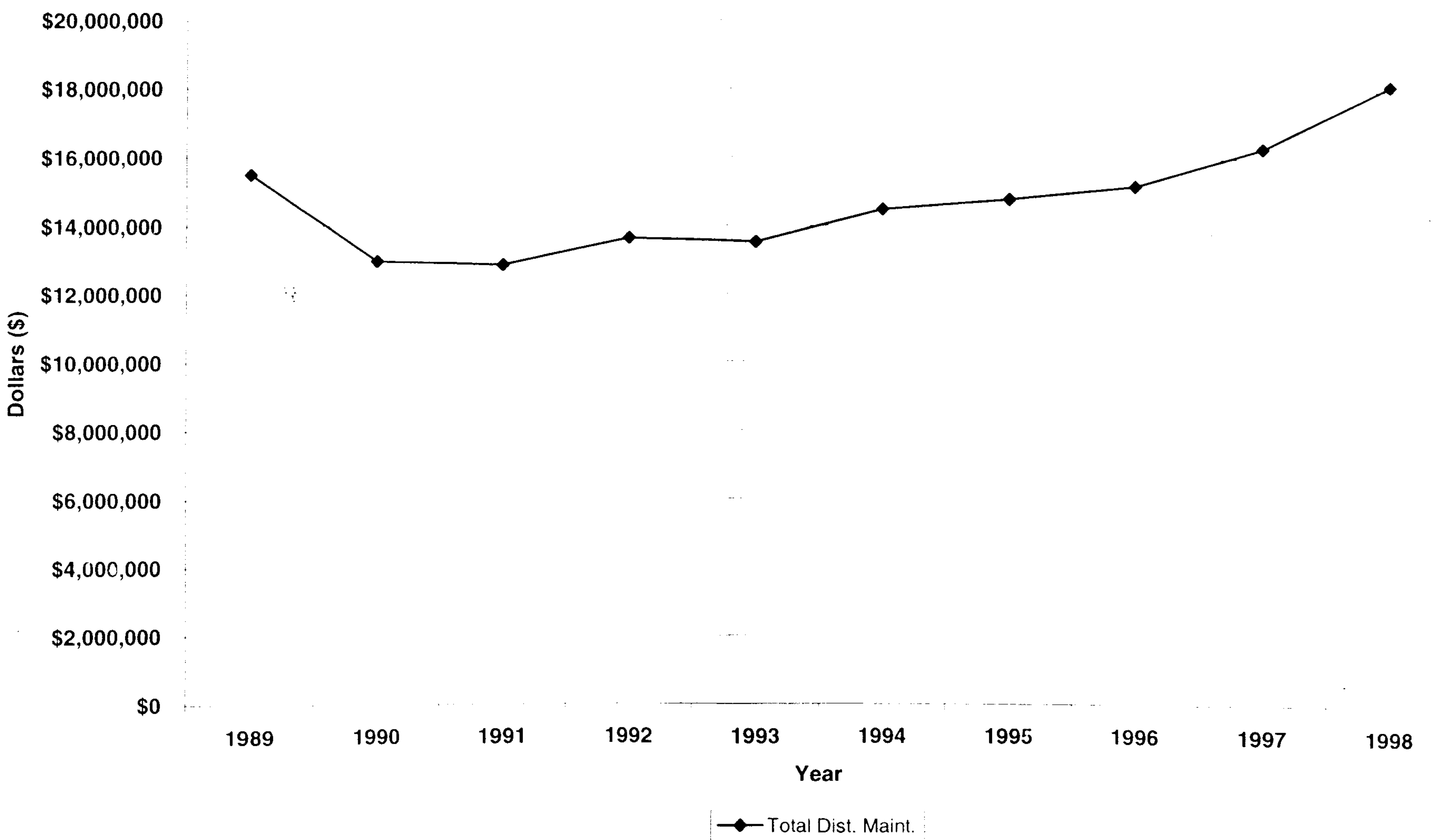
PacifiCorp Maintenance Expense Analysis
(Total - Steam and Hydro Generation)
1998 Dollars



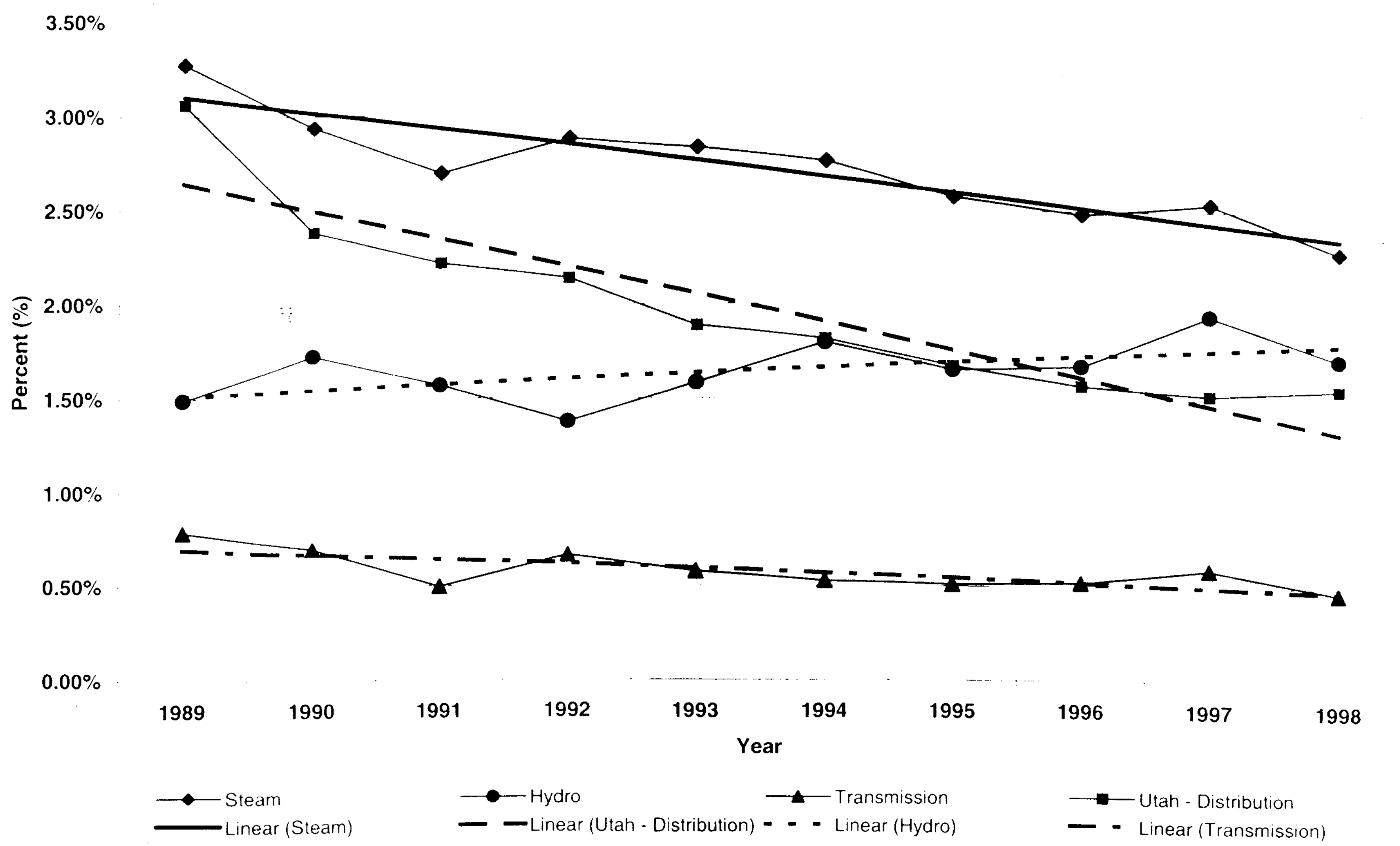
PacifiCorp Maintenance Expense Analysis
(Total - Transmission System)
1998 Dollars



PacifiCorp Maintenance Expense Analysis
(Utah - Distribution)
1998 Dollars



PacifiCorp Maintenance Expense Analysis
(Maintenance Expense as a Percentage of Average Gross Plant in Service)



PacifiCorp Maintenance Expenses by Account by Year

Account	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
	Nominal Dollars									
Steam Generation										
510 Maint. Superv.	$13,980,214	$15,615,000	$14,672,984	$15,817,422	$18,912,853	$17,108,942	$18,798,935	$15,522,869	$16,492,362	$13,545,654
511 Maint. Struct.	$7,195,405	$8,684,000	$7,453,176	$7,594,734	$9,032,438	$8,620,090	$8,082,281	$7,021,148	$6,392,009	$5,831,374
512 Maint. Boiler Plt.	$51,831,949	$46,728,000	$46,240,307	$48,143,171	$55,930,837	$58,036,805	$53,062,251	$49,443,591	$53,905,088	$49,636,528
513 Maint. Elect. Plt.	$11,166,551	$10,132,000	$11,793,675	$12,749,948	$14,494,358	$13,341,642	$11,635,629	$12,749,680	$12,326,710	$9,990,205
514 Maint. Misc. Plt.	$10,754,914	$5,647,000	$7,451,728	$21,045,539	$10,795,952	$11,931,570	$11,324,294	$15,401,922	$14,675,387	$15,787,485
Total Steam Maint.	$94,929,033	$86,806,000	$87,611,870	$105,350,814	$109,166,438	$109,039,049	$102,903,390	$100,139,210	$103,791,556	$94,791,246
Nuclear Generation										
528 Maint. Superv.	$264,107	$275,000	$302,108	$421,764						
529 Maint. Struct.	$52,657	$68,000	$174,850	$96,508						
530 Maint. Reactor	$248,642	$478,000	$766,092	-$347,209						
531 Maint. Elec. Plt.	$165,043	$135,000	$128,554	$26,236						
532 Maint. Misc. Nuc.	$201,540	$922,000	$302,313	$179,503						
Total Nuclear Maint.	$931,989	$922,000	$1,673,917	$376,802	$0	$0	$0	$0	$0	$0
Hydro Generation										
541 Maint. Superv.	$292,625	$1,014,000	$192,817	$139,174	$160,953	$225,083	$368,775	$541,876	$676,475	$468,911
542 Maint. Struct.	$494,063	$493,000	$686,002	$450,660	$529,754	$581,689	$501,629	$422,826	$486,249	$329,123
543 Maint. Dams	$1,556,184	$1,562,000	$1,676,072	$1,135,789	$1,535,409	$1,605,335	$1,635,772	$1,538,415	$1,340,414	$1,788,589
544 Maint. Elec. Plt.	$1,379,017	$1,471,000	$1,593,101	$1,928,544	$2,149,927	$2,896,007	$2,371,688	$2,813,607	$3,066,065	$2,141,711
545 Maint. Misc. Plt.	$771,323	$849,000	$974,346	$1,066,328	$1,467,304	$1,715,432	$1,824,524	$1,694,686	$2,856,071	$2,882,278
Total Hydro Maint	$4,493,212	$5,389,000	$5,122,338	$4,720,495	$5,843,347	$7,023,546	$6,702,388	$7,011,410	$8,425,274	$7,610,612
Other Generation Maint.										
551 Maint. Superv.	$30,935	$34,000	$35,089	$40,635	$47,652	$47,084	$49,216	$4,897	$21,484	[illegible]
552 Maint. Struct.	$1,675	$1,000	$0	$0	$1,517	$6,909	$508	$520	$521	$0
553 Maint. Gen. Plt.	$207,440	$250,000	$148,654	$241,597	$118,084	$100,856	$56,186	$149	$3,299	$1,591
554 Maint Misc. Other	$79,484	$60,000	$81,366	$71,317	$117,224	$86,600	$63,234	$11,880	$14,766	[illegible]
Total Other Gen. Maint.	$319,534	$345,000	$265,109	$353,549	$284,477	$241,449	$169,144	$17,148	$39,028	$25,776
Transmission Maint										
568 Maint. Superv.	$523,600	$894,000	$692,801	$666,435	$653,537	$531,320	$812,991	$1,022,875	$982,551	[illegible]
569 Maint. Struct.	$145,238	$149,000	$163,266	$188,475	$188,239	$181,148	$241,832	$213,755	$190,406	$177,311
570 Maint. Station Equip.	$5,313,457	$4,564,000	$3,482,102	$4,257,662	$5,474,022	$5,426,729	$5,191,209	$5,067,514	$4,415,850	$4,519,272
571 Maint. Ovhd. Lines	$4,146,301	$3,946,000	$3,040,741	$3,410,172	$3,415,703	$3,178,067	$3,768,927	$3,584,200	$5,616,536	$2,795,402
572 Maint. Udgd. Lines	$18,885	$4,000	$1,308	$1,608	$37,969	$28,711	$951	$2,226	$6,788	[illegible]
573 Maint. Misc. Trans. Plt.	$752,099	$669,000	$426,249	$2,578,049	$657,973	$802,207	$175,282	$735,589	$1,013,673	$1,460,615
Total Trans. Maint.	$10,899,580	$10,226,000	$7,806,467	$11,102,401	$10,427,443	$10,148,182	$10,191,192	$10,626,159	$12,225,804	$9,706,105
Distribution Maint - Utah Only										
590 Maint. Superv.	$733,000	$861,000	$826,786	$751,956	$896,455	$853,564	$889,153	$877,658	$797,782	[illegible]
591 Maint Structures	$472,000	$375,000	$307,968	$313,361	$251,699	$215,057	$228,595	$192,257	$190,040	[illegible]
592 Maint. Station Equip.	[illegible]	$1,363,000	$1,394,427	$1,470,628	$1,508,120	$1,574,773	$1,584,595	$1,726,535	$1,510,792	$1,503,691
593 Maint. Ovhd. Lines	[illegible]	$8,442,000	$6,838,388	$7,152,431	$6,945,780	$7,298,303	$7,037,458	$7,053,344	[illegible]	[illegible]
594 Maint. Undg. Lines	[illegible]	$2,581,000	$2,833,801	$2,259,449	$2,715,981	$2,905,065	$2,952,720	$3,138,749	[illegible]	$3,861,966
595 Maint. Transformers	[illegible]	$576,000	$503,572	$524,590	$541,803	$563,196	$550,646	$650,290	$569,528	[illegible]
596 Maint. Str. Lighting	[illegible]	$658,000	$1,059,366	$676,269	$783,900	$720,909	$904,708	$826,701	$951,822	[illegible]
597 Maint. Meters	$201,000	$218,000	$315,736	$264,985	$318,686	$337,295	$394,599	$469,395	$525,672	$198,061
598 Maint. Misc. Dist. Plt.	$622,000	$516,000	$773,192	$1,945,045	$866,206	$1,073,850	$949,027	$682,711	$958,908	[illegible]
Total Dist. Non-Wires Maint.										
Total Dist. Maint.	$19,475,000	$15,590,000	$14,853,236	$15,358,714	$14,828,630	$15,542,012	$15,491,501	$15,617,640	$16,457,304	$18,136,638
General Plant Maint										
935 Maint. Gen. Plant	$3,460,973	$6,239,000	$6,208,167	$6,232,830	$4,949,552	$5,372,677	$5,085,306	$4,345,778	$3,085,690	$2,357,970
Total Gen. Plt. Maint.	$3,460,973	$6,239,000	$6,208,167	$6,232,830	$4,949,552	$5,372,677	$5,085,306	$4,345,778	$3,085,690	$2,357,970

Data Source: PacifiCorp 1989 through 1998 Semi Annual Reports

Pacificorp Average Gross Plant in Service by Function by Year

Total Company *Electric Plant in Service (average plant in service)*	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	% Change '98 from '89
Steam Plant	$2,901,329,500	$2,956,279,500	$3,251,510,364	$3,659,249,946	$3,853,599,709	$3,941,179,395	$3,995,921,790	$4,036,285,750	$4,093,172,912	$4,158,545,697	43
Nuclear Plant	$17,381,000	$18,561,500	$20,256,813	$10,601,968	$0	$0	$0	$0	$0	$0	100
Hydraulic Plant	$302,099,000	$312,797,500	$326,418,227	$343,634,930	$369,285,680	$390,787,050	$405,272,141	$419,208,959	$434,201,971	$445,235,482	47
Other Plant	$4,502,500	$4,525,500	$3,266,920	$3,372,168	$3,412,063	$3,406,366	$3,425,201	$84,100,689	$162,509,402	$178,634,740	[illegible]
Transmission Plant	$1,392,037,000	$1,473,547,500	$1,579,729,271	$1,682,690,271	$1,814,938,820	$1,932,448,585	$2,006,634,513	$2,055,839,566	$2,078,294,771	$2,094,865,862	50
Distribution Plant (UT)	$636,454,500	$654,723,500	$669,801,120	$718,328,538	$786,623,426	$855,263,486	$924,628,723	$995,568,857	$1,083,476,982	$1,169,455,973	84
General Plant	$291,571,000	$331,910,000	$730,910,231	$788,408,149	$848,059,047	$961,203,707	$1,064,609,599	$1,074,725,153	$1,095,296,175	$1,154,992,266	[illegible]
Coal Mines	$592,014,000	$660,440,000									

Data Source: PacifiCorp 1989 through 1998 Semi-Annual Reports

Annual Change in Average Gross Plant in Service by Function by Year (Nominal Dollars)

Total Company *Electric Plant in Service (change in avg plant in service)*	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	% Change '98 from '90
Steam Plant		$54,900,000	$295,230,864	$407,739,582	$194,349,763	$87,579,686	$54,742,395	$40,363,960	$56,887,162	$65,372,785	19
Nuclear Plant		$1,180,500	$1,695,313	$9,654,845	-$10,601,968	$0	$0	$0	$0	$0	100
Hydraulic Plant		$10,698,500	$13,620,727	$17,216,703	$25,650,750	$21,501,370	$14,485,091	$13,936,818	$14,993,012	$11,033,511	[illegible]
Other Plant		$23,000	$1,258,580	$105,248	$39,895	$5,697	$18,835	$80,675,488	$78,408,713	$16,125,338	70010
Transmission Plant		$81,510,500	$106,181,771	$102,961,000	$132,248,549	$117,509,765	$74,185,928	$49,205,053	$22,455,205	$16,571,091	80
Distribution Plant (UT)		$18,269,000	$15,077,620	$48,527,418	$68,294,888	$68,640,060	$69,365,237	$70,940,134	$87,908,125	$85,978,991	371
General Plant		$40,339,000	$261,439,769	$57,497,918	$59,650,898	$113,144,660	$103,405,892	$10,115,554	$20,571,022	$59,696,091	48
Coal Mines		$68,426,000									

Note: Annual change in average gross plant in service shown in latter year for simplicity, e.g. change between 1989 and 1990 shown in 1990.

Annual Change in Average Gross Plant in Service by Function by Year (Constant 1998 Dollars)

Total Company	Constant 1998 Dollars										% Change
Electric Plant in Service (change in avg plant in service)	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	'98 from '90
Steam Plant		$43,705,661	$235,032,060	$324,599,781	$154,721,036	$69,721,823	$43,580,192	$32,133,580	$45,287,632	$52,043,002	19
Nuclear Plant		$939,791	$1,349,632	($7,686,182)	($8,440,183)	$0	$0	$0	$0	$0	100
Hydraulic Plant		$8,517,031	$10,843,404	$13,706,145	$20,420,455	$17,117,151	$11,531,521	$11,095,043	$11,935,874	$8,783,752	[illegible]
Other Plant		$18,310	($1,001,950)	$83,787	$31,760	($4,535)	$14,994	$64,225,420	$62,420,849	$12,837,314	70010
Transmission Plant		$64,890,169	$84,530,865	$81,966,823	$105,282,518	$93,549,034	$59,059,108	$39,171,937	$17,876,495	$13,192,176	80
Distribution Plant (UT)		$14,543,875	$12,003,230	$38,632,475	$54,369,276	$54,644,066	$55,221,376	$56,475,145	$69,983,292	$68,447,516	371
General Plant		$32,113,710	($208,131,110)	$45,773,853	$47,487,831	$90,073,992	$82,320,999	$8,052,950	$16,376,505	$47,523,809	48
Coal Mines		$54,473,653									

Note: Annual change in average gross plant in service shown in latter year for simplicity, e.g. change between 1989 and 1990 shown in 1990.

Note: After 1990, coal mines were included in General Plant accounts.

U.S. Bureau of Economic Analysis GDP Implicit Price Deflators for 1989 to 1998 (1998 = 1.0).
Data Source: Annual Time Series Data from http://www.bea.doc.gov/bea/dn1.htm

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Constant Dollar Adjustment Factor	0.796	0.831	0.864	0.887	0.911	0.932	0.954	0.972	0.990	1.000

PacifiCorp Maintenance Expenses by Account by Year

Account	Constant 1998 Dollars										% Change
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	'98 from '89
Steam Generation											
510 Maint. Superv.	$11,129,590	$12,968,625	$12,670,584	$14,034,980	$17,224,625	$15,953,671	$17,933,217	$15,086,245	$16,326,999	$13,545,654	22
511 Maint. Struct.	$5,728,232	$7,212,266	$6,436,052	$6,738,894	$8,226,171	$8,038,024	$7,710,080	$6,823,659	$6,327,919	$5,831,374	2
512 Maint. Boiler Plt.	$41,263,198	$38,808,703	$39,929,962	$42,717,987	$50,938,253	$54,117,905	$50,618,657	$48,052,853	$53,364,602	$49,636,528	20
513 Maint. Elect. Plt.	$8,889,645	$8,414,864	$10,184,210	$11,313,175	$13,200,540	$12,440,756	$11,099,791	$12,391,060	$12,203,115	$9,990,205	12
514 Maint. Misc. Plt.	$8,561,942	$4,689,966	$6,434,802	$18,673,948	$9,832,267	$11,125,898	$10,802,794	$14,968,700	$14,528,242	$15,787,485	84
Total Steam Maint.	$75,572,607	**$72,094,424**	**$75,655,609**	**$93,478,983**	**$99,421,856**	**$101,676,253**	**$98,164,538**	**$97,322,517**	**$102,750,878**	**$94,791,246**	25%
Nuclear Generation											
528 Maint. Superv.	$210,254	$228,394	$260,880	$374,236	$0	$0	$0	$0	$0	$0	100
529 Maint. Struct.	$41,920	$56,476	$150,988	$85,633	$0	$0	$0	$0	$0	$0	100
530 Maint. Reactor	$197,943	($396,990)	$661,545	($308,083)	$0	$0	$0	$0	$0	$0	100
531 Maint. Elec. Plt.	$131,390	$112,121	$111,010	$23,280	$0	$0	$0	$0	$0	$0	100
532 Maint. Misc. Nuc.	$160,445	$765,743	$261,057	$159,275	$0	$0	$0	$0	$0	$0	100
Total Nuclear Maint.	**$741,953**	**$765,743**	**$1,445,480**	**$334,341**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	-100%
Hydro Generation											
541 Maint. Superv.	$232,958	$842,151	$166,504	$123,491	$146,586	$209,884	$351,292	$526,634	$669,692	$468,911	101
542 Maint. Struct.	$393,321	$409,448	$592,384	$399,876	$482,466	$542,411	$478,528	$410,933	$481,374	$329,123	16
543 Maint. Dams	$1,238,872	$1,297,278	$1,447,341	$1,007,799	$1,398,353	$1,496,936	$1,560,442	$1,495,143	$1,326,974	$1,788,589	44
544 Maint. Elec. Plt.	$1,097,830	$1,221,700	$1,375,693	$1,711,219	$1,958,017	$2,700,456	$2,262,468	$2,734,467	$3,035,323	$2,141,711	95
545 Maint. Misc. Plt.	$614,047	$705,114	$841,378	$946,165	$1,336,327	$1,599,598	$1,740,502	$1,647,018	$2,827,434	$2,882,278	369
Total Hydro Maint	**$3,577,027**	**$4,475,691**	**$4,423,300**	**$4,188,549**	**$5,321,749**	**$6,549,285**	**$6,393,733**	**$6,814,195**	**$8,340,797**	**$7,610,612**	113%
Other Generation Maint.											
551 Maint. Superv.	$24,627	$28,238	$30,300	$36,056	$43,398	$43,905	$46,950	$4,759	$21,269	$5,190	[illegible]
552 Maint. Struct.	$1,333	$831	$0	$0	$1,382	$6,442	$485	$505	($516)	$0	100
553 Maint. Gen. Plt.	$165,142	$207,631	$128,367	$214,372	$107,543	$94,046	$53,599	($145)	$3,266	($1,591)	101
554 Maint Misc. Other	$63,277	$49,831	$70,262	$63,280	$106,760	$80,752	$60,322	$11,546	$14,618	$22,177	65
Total Other Gen. Maint.	**$254,380**	**$286,531**	**$228,930**	**$313,708**	**$259,084**	**$225,145**	**$161,355**	**$16,666**	**$38,637**	**$25,776**	-90%
Transmission Maint											
568 Maint. Superv.	$416,856	$742,488	$598,255	$591,335	$595,200	$495,443	$775,552	$994,104	$972,699	$732,718	[illegible]
569 Maint. Struct.	$115,623	$123,748	$140,985	$167,236	$171,436	$168,916	$230,695	$207,743	$188,497	$177,311	[illegible]
570 Maint. Station Equip.	$4,230,021	$3,790,509	$3,006,905	$3,777,872	$4,985,391	$5,060,292	$4,952,146	$4,924,976	$4,371,574	$4,519,272	[illegible]
571 Maint. Ovhd. Lines	$3,300,853	$3,277,246	$2,625,776	$3,025,885	$3,110,805	$2,963,470	$3,595,362	$3,483,384	$5,560,221	$2,795,402	15
572 Maint. Udgd. Lines	$15,034	$3,322	$1,129	$1,427	$34,580	$26,772	$907	$2,163	$6,720	$15,796	5
573 Maint. Misc. Trans. Plt.	$598,743	$555,620	$368,079	$2,287,532	$599,240	$748,038	$167,210	$714,899	$1,003,509	$1,460,615	144
Total Trans. Maint.	**$8,677,110**	**$8,492,933**	**$6,741,130**	**$9,851,287**	**$9,496,653**	**$9,462,932**	**$9,721,873**	**$10,327,269**	**$12,103,221**	**$9,706,105**	12%
Distribution Maint -Utah Only											
590 Maint. Superv.	$583,558	$715,081	$713,956	$667,219	$816,434	$795,928	$848,206	$852,971	$789,783	$740,595	[illegible]
591 Maint Structures	[illegible]	$311,446	$265,940	$278,049	$229,231	$200,535	$218,068	$186,849	$188,135	$144,788	[illegible]
592 Maint. Station Equip.	[illegible]	$1,132,004	$1,204,132	$1,304,905	$1,373,500	$1,468,437	$1,511,622	$1,677,971	$1,495,644	$1,503,691	[illegible]
593 Maint. Ovhd. Lines	[illegible]	$7,011,280	$5,905,163	$6,346,434	$6,325,775	$6,805,489	$6,713,373	$6,854,949	$7,698,824	$8,924,371	[illegible]
594 Maint. Undg. Lines	$2,451,179	$2,143,581	$2,447,076	$2,004,835	$2,473,543	$2,708,902	$2,816,743	$3,050,463	$3,144,067	$3,861,966	58
595 Maint. Transformers	$573,189	$478,382	$434,850	$465,475	$493,440	$525,167	$525,288	$631,999	$563,867	$748,327	31
596 Maint. Str. Lighting	$584,354	$546,484	$914,296	$600,061	$713,926	$672,230	$863,045	$803,448	$942,278	$992,870	71
597 Maint. Meters	$160,015	$181,054	$272,648	$235,124	$290,239	$314,519	$376,427	$456,192	$520,401	$198,061	24
598 Maint. Misc. Dist. Plt.	$495,122	$428,550	$667,676	$1,725,861	$788,885	$1,001,339	$905,323	$663,508	$949,293	$1,016,772	105
Total Dist. Non-Wires Maint.	$4,347,479	$3,793,001	$4,473,997	$5,276,694	$4,705,650	$4,978,155	$5,247,979	$5,272,938	$5,449,402	$5,350,301	23
Total Dist. Maint.	$15,503,966	**$12,947,862**	**$12,826,237**	**$13,627,963**	**$13,504,974**	**$14,492,547**	**$14,778,095**	**$15,178,351**	**$16,292,293**	**$18,136,638**	17%
General Plant Maint											
935 Maint. Gen. Plant	$2,755,266	$5,181,636	$5,360,948	$5,530,461	$4,507,738	$5,009,890	$4,851,120	$4,223,541	$3,054,751	$2,357,970	14
Total Gen. Plt. Maint.	$2,755,266	$5,181,636	$5,360,948	$5,530,461	**$4,507,738**	**$5,009,890**	**$4,851,120**	**$4,223,541**	**$3,054,751**	**$2,357,970**	-14%

Data Source: PacifiCorp 1989 through 1998 Semi-

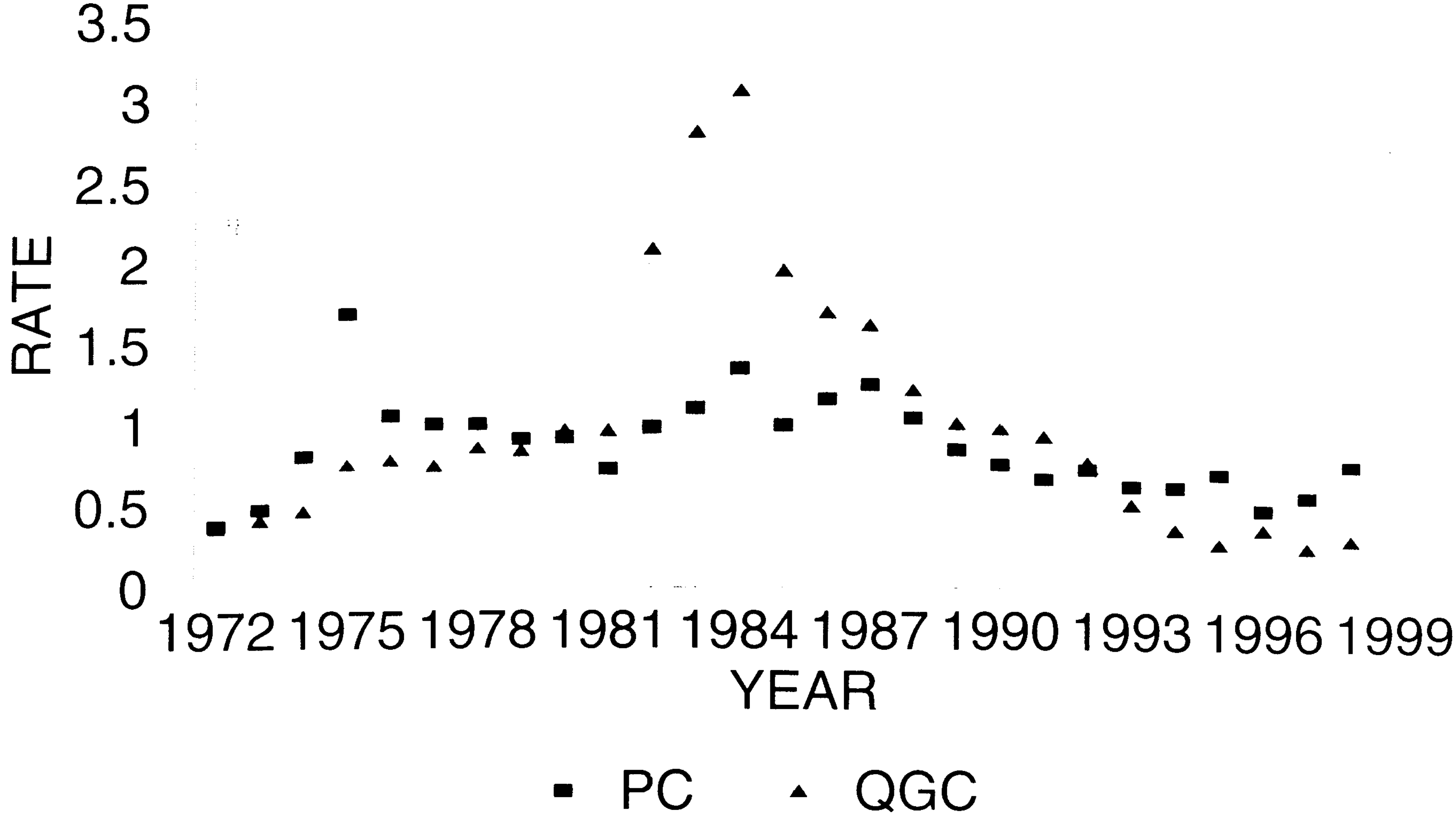
PacifiCorp Maintenance Expenses by Account by Year

Account	Maintence Expense as a Percentage of Average Gross Plant in Service using Nominal Dollars (%)									
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Steam Generation										
510 Maint. Superv.	0.48%	0.53%	0.45%	0.43%	0.49%	0.43%	0.47%	0.38%	0.40%	0.33%
511 Maint. Struct.	0.25%	0.29%	0.23%	0.21%	0.23%	0.22%	0.20%	0.17%	0.16%	0.14%
512 Maint. Boiler Plt.	1.79%	1.58%	1.42%	1.32%	1.45%	1.47%	1.33%	1.22%	1.32%	1.19%
513 Maint. Elect. Plt.	0.38%	0.34%	0.36%	0.35%	0.38%	0.34%	0.29%	0.32%	0.30%	0.24%
514 Maint. Misc. Plt.	0.37%	0.19%	0.23%	0.58%	0.28%	0.30%	0.28%	0.38%	0.36%	0.38%
Total Steam Maint.	**3.27%**	**2.94%**	**2.69%**	**2.88%**	**2.83%**	**2.77%**	**2.58%**	**2.48%**	**2.54%**	**2.28%**
Nuclear Generation										
528 Maint. Superv.	1.52%	1.48%	1.49%	3.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
529 Maint. Struct.	0.30%	0.37%	0.86%	0.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
530 Maint. Reactor	1.43%	2.58%	3.78%	-3.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
531 Maint. Elec. Plt.	0.95%	0.73%	0.63%	0.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
532 Maint. Misc. Nuc.	1.16%	4.97%	1.49%	1.69%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Nuclear Maint.	**5.36%**	**4.97%**	**8.26%**	**3.55%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Hydro Generation										
541 Maint. Superv.	0.10%	0.32%	0.06%	0.04%	0.04%	0.06%	0.09%	0.13%	0.16%	0.11%
542 Maint. Struct.	0.16%	0.16%	0.21%	0.13%	0.14%	0.15%	0.12%	0.10%	0.11%	0.07%
543 Maint. Dams	0.52%	0.50%	0.51%	0.33%	0.42%	0.41%	0.40%	0.37%	0.31%	0.40%
544 Maint. Elec. Plt.	0.46%	0.47%	0.49%	0.56%	0.58%	0.74%	0.59%	0.67%	0.71%	0.48%
545 Maint. Misc. Plt.	0.26%	0.27%	0.30%	0.31%	0.40%	0.44%	0.45%	0.40%	0.66%	0.65%
Total Hydro Maint	**1.49%**	**1.72%**	**1.57%**	**1.37%**	**1.58%**	**1.80%**	**1.65%**	**1.67%**	**1.94%**	**1.71%**
Other Generation Maint.										
551 Maint. Superv.	0.69%	0.75%	1.07%	1.21%	1.40%	1.38%	1.44%	0.01%	0.01%	0.00%
552 Maint. Struct.	0.04%	0.02%	0.00%	0.00%	0.04%	0.20%	0.01%	0.00%	0.00%	0.00%
553 Maint. Gen. Plt.	4.61%	5.52%	4.55%	7.16%	3.46%	2.96%	1.64%	0.00%	0.00%	0.00%
554 Maint Misc. Other	1.77%	1.33%	2.49%	2.11%	3.44%	2.54%	1.85%	0.01%	0.01%	0.01%
Total Other Gen. Maint.	**7.10%**	**7.62%**	**8.11%**	**10.48%**	**8.34%**	**7.09%**	**4.94%**	**0.02%**	**0.02%**	**0.01%**
Transmission Maint										
568 Maint. Superv.	0.04%	0.06%	0.04%	0.04%	0.04%	0.03%	0.04%	0.05%	0.05%	0.04%
569 Maint. Struct.	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
570 Maint. Station Equip.	0.38%	0.31%	0.22%	0.25%	0.30%	0.28%	0.26%	0.25%	0.21%	0.22%
571 Maint. Ovhd. Lines	0.30%	0.27%	0.19%	0.20%	0.19%	0.16%	0.19%	0.17%	0.27%	0.13%
572 Maint. Udgd. Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
573 Maint. Misc. Trans. Plt.	0.05%	0.05%	0.03%	0.15%	0.04%	0.04%	0.01%	0.04%	0.05%	0.07%
Total Trans. Maint.	**0.78%**	**0.69%**	**0.49%**	**0.66%**	**0.57%**	**0.53%**	**0.51%**	**0.52%**	**0.59%**	**0.46%**
Distribution Maint -Utah Only										
590 Maint. Superv.	0.12%	0.13%	0.12%	0.10%	0.11%	0.10%	0.10%	0.09%	0.07%	0.06%
591 Maint Structures	0.07%	0.06%	0.05%	0.04%	0.03%	0.03%	0.02%	0.02%	0.02%	0.01%
592 Maint. Station Equip.	0.31%	0.21%	0.21%	0.20%	0.19%	0.18%	0.17%	0.17%	0.14%	0.13%
593 Maint. Ovhd. Lines	1.72%	1.29%	1.02%	1.00%	0.88%	0.85%	0.76%	0.71%	0.72%	0.76%
594 Maint. Undg. Lines	0.48	0.39%	0.42%	0.31%	0.35%	0.34%	0.32%	0.32	0.29%	0.33%
595 Maint. Transformers	0.11%	0.09%	0.08%	0.07%	0.07%	0.07%	0.06%	0.07%	0.05%	0.06
596 Maint. Str. Lighting	0.12%	0.10%	0.16%	0.09%	0.10%	0.08%	0.10%	0.08%	0.09%	0.09%
597 Maint. Meters	0.03%	0.03%	0.05%	0.04%	0.04%	0.04%	0.04%	0.05%	0.05%	0.02%
598 Maint. Misc. Dist. Plt.	0.10%	0.08%	0.12%	0.27%	0.11%	0.13%	0.10%	0.07%	0.09%	0.09%
Total Dist. Non-Wires Maint.										
Total Dist. Maint.	**3.06%**	**2.38%**	**2.22%**	**2.14%**	**1.89%**	**1.82%**	**1.68%**	**1.57%**	**1.52%**	**1.55%**
General Plant Maint										
935 Maint. Gen. Plant	0.39%	0.63%	0.85%	0.79%	0.58%	0.56%	0.48%	0.40%	0.28%	0.20%
Total Gen. Plt. Maint.	**0.39%**	**0.63%**	**0.85%**	**0.79%**	**0.58%**	**0.56%**	**0.48%**	**0.40%**	**0.28%**	**0.20%**

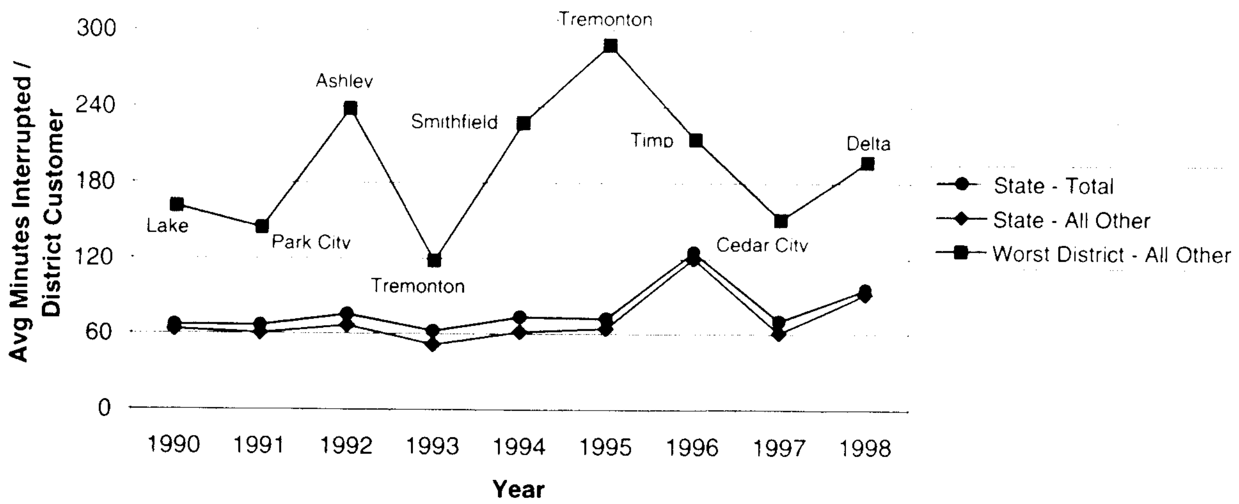
Data Source: PacifiCorp 1989 through 1998 Semi-

UTAH PSC PC & QGC COMPLAINT RATES

COMPLAINTS/1000 CUSTOMERS



System Average Interruption Duration Index (SAIDI)
(State of Utah vs Year's Worst "District")



Avg Minutes Interrupted / State Customer				
	State of Utah		Worst District - All Other	
Year	State - All Other	State - Total	Max. - All Other	District
1998	91.980	95.880	196.800	Delta
1997	60.780	70.440	151.320	Cedar City
1996	120.408	125.520	214.620	Timp
1995	64.500	72.240	288.480	Tremonton
1994	61.740	73.620	227.400	Smithfield
1993	51.540	62.340	118.380	Tremonton
1992	66.600	75.660	238.440	Ashley
1991	60.300	66.660	144.360	Park City
1990	63.300	66.900	161.400	Lake
AVG	71.239	78.807	193.467	

Data Source: Pacificorp Response to DPU Data Request PC1.4, Docket # 98-2035-01

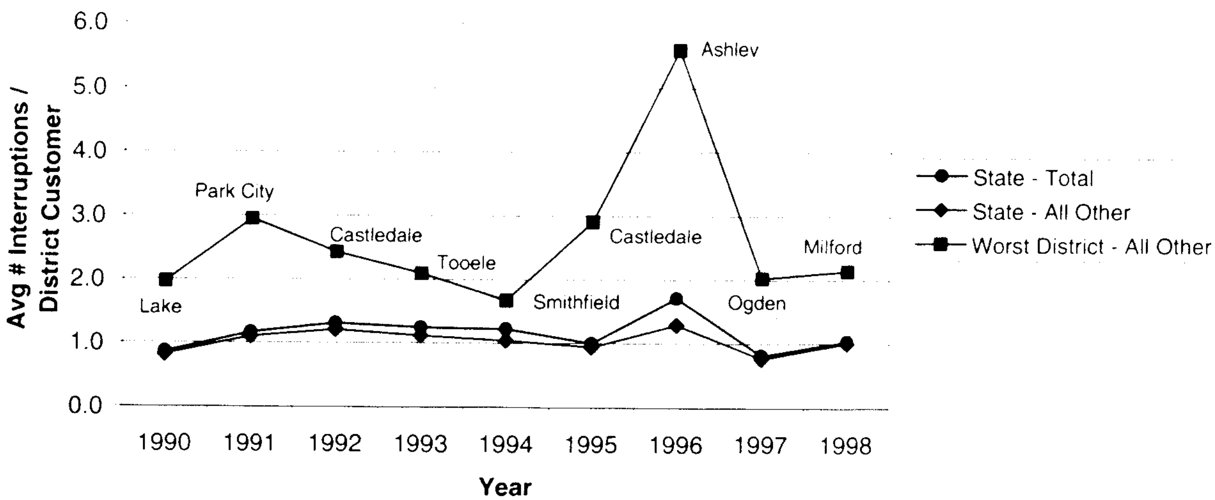
= Data modified by DPU to match data provided by Scottish Power in Docket # 98-2035-04

Category Descriptions:

"All Other" - **This category excludes data related to Extreme Storms, Pre-arranged Outages, and Transmission outages (defined as a transmission fault causing outages on other circuits serving retail customers).**

"Total" - **This category includes all data, i.e. no data exclusions.**

System Average Interruption Frequency Index (SAIFI)
(State of Utah vs Year's Worst "District")



Avg # Interruptions / State Customer				
	State of Utah		Worst District - All Other	
Year	**State - All Other**	**State - Total**	**Max. - All Other**	**District**
1998	1.003	1.034	2.140	Milford
1997	0.765	0.817	2.021	Ogden
1996	1.287	1.705	5.587	Ashley
1995	0.938	0.998	2.907	Castledale
1994	1.040	1.222	1.673	Smithfield
1993	1.113	1.244	2.093	Tooele
1992	1.210	1.307	2.432	Castledale
1991	1.095	1.162	2.951	Park City
1990	0.817	0.859	1.970	Lake
AVG	1.030	1.150	2.642	

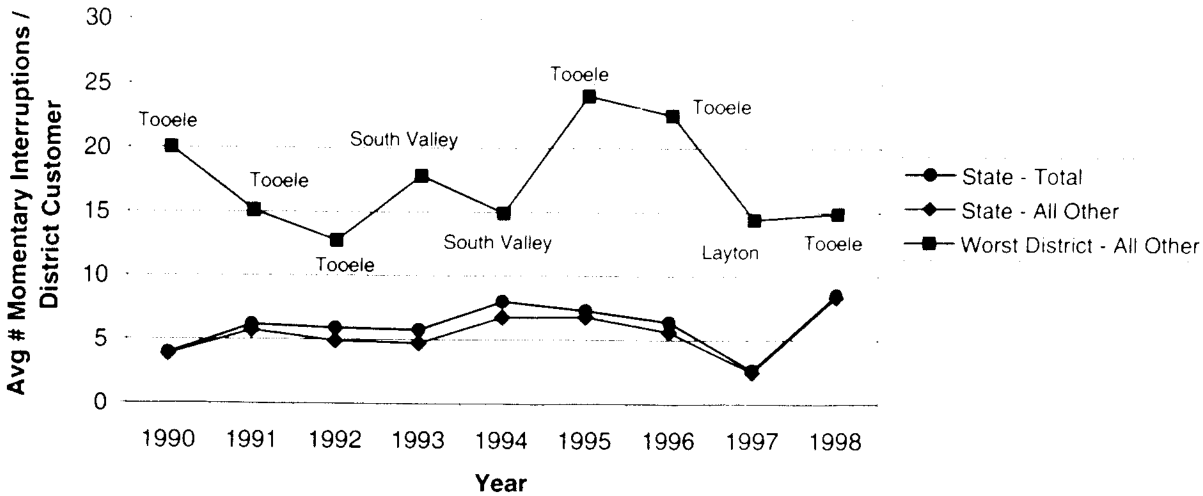
Data Source: Pacificorp Response to DPU Data Request PC1.4, Docket # 98-2035-01

Category Descriptions:

"All Other" - **This category <u>excludes</u> data related to Extreme Storms, Pre-arranged Outages, and Transmission outages (defined as a transmission fault causing outages on other circuits serving retail customers).**

"Total" - **This category <u>includes</u> all data, i.e. no data exclusions.**

Momentary Average Interruption Frequency Index (MAIFI)
(State of Utah vs Year's Worst "District")



Note: A "Momentary" interruption is defined as an outage lasting less than 5 minutes.

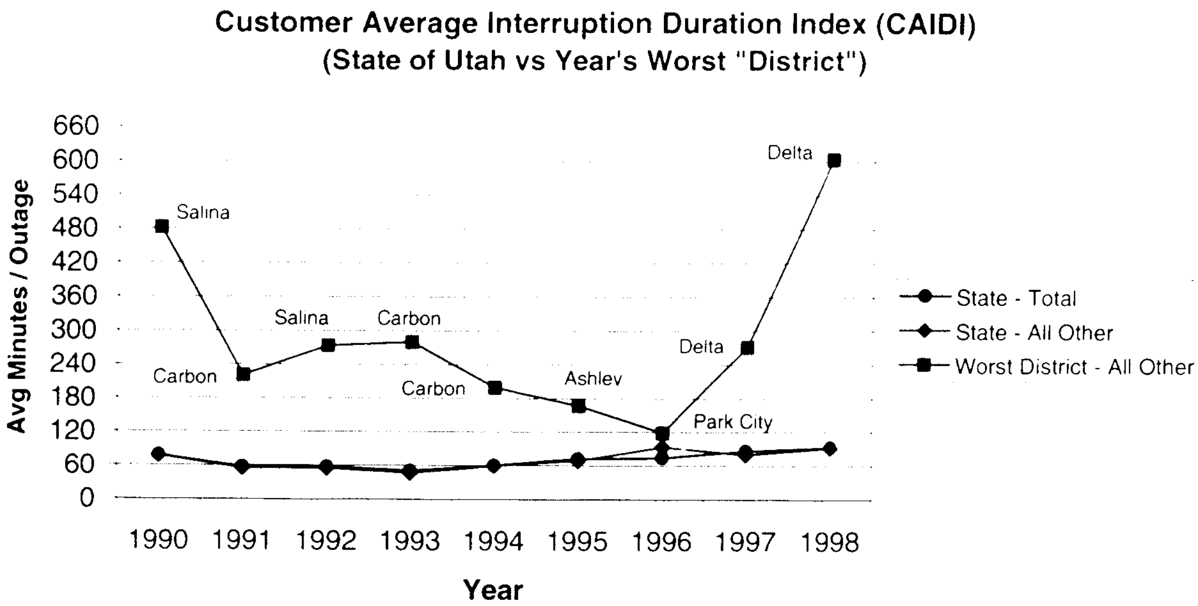
Avg # Momentary Interruptions / State Customer				
	State of Utah		Worst District - All Other	
Year	**State - All Other**	**State - Total**	**Max. - All Other**	**District**
1998	8.367	8.560	14.917	Tooele
1997	2.476	2.637	14.430	Layton
1996	5.620	6.370	22.566	Tooele
1995	6.790	7.288	24.089	Tooele
1994	6.764	7.990	14.948	South Valley
1993	4.717	5.760	17.830	South Valley
1992	4.900	5.921	12.781	Tooele
1991	5.718	6.165	15.125	Tooele
1990	3.865	3.968	20.048	Tooele
AVG	5.469	6.073	17.415	

Data Source: Pacificorp Response to DPU Data Request PC1.4, Docket # 98-2035-01

Category Descriptions:

"All Other" - This category <u>excludes</u> data related to Extreme Storms, Pre-arranged Outages, and Transmission outages (defined as a transmission fault causing outages on other circuits serving retail customers).

"Total" - This category <u>includes</u> all data, i.e. no data exclusions.



Avg Minutes / Outage				
	State of Utah		Worst District - All Other	
Year	**State - All Other**	**State - Total**	**Max. - All Other**	**District**
1998	91.705	92.727	603.681	Delta
1997	79.451	86.218	271.448	Delta
1996	93.557	73.619	118.542	Park City
1995	68.763	72.385	166.753	Ashley
1994	59.365	60.245	199.286	Carbon
1993	46.307	50.113	280.123	Carbon
1992	55.041	57.888	273.750	Salina
1991	55.068	57.367	220.513	Carbon
1990	77.479	77.881	482.759	Salina
AVG	69.637	69.827	290.762	

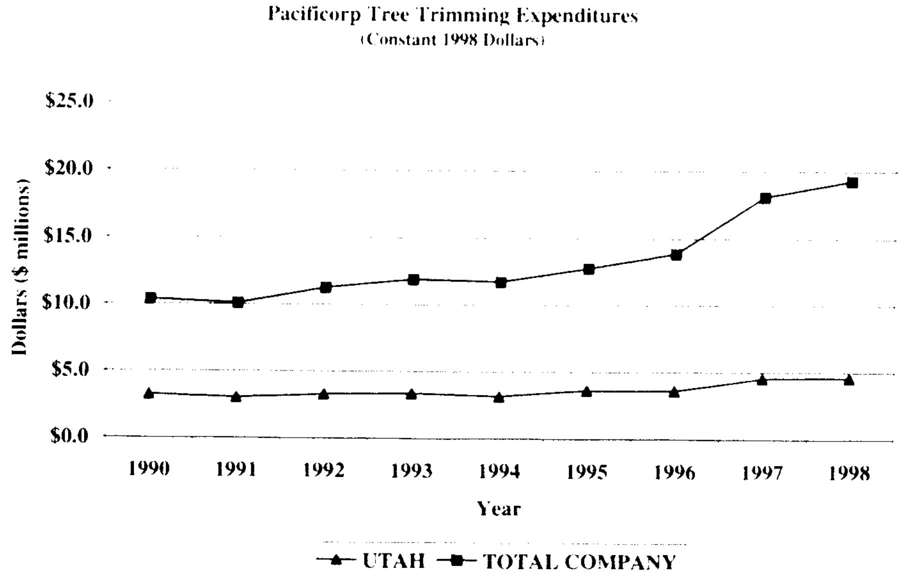
Category Descriptions:

"All Other" - **This category <u>excludes</u> data related to Extreme Storms, Pre-arranged Outages, and Transmission outages (defined as a transmission fault causing outages on other circuits serving retail customers).**

"Total" - **This category <u>includes</u> all data, i.e. no data exclusions.**

Pacificorp Tree Trimming Expenditures

(Includes Distribution (Situs) and Transmission (Allocated))



Constant 1998 Dollars			
Year	Constant Dollar Adjustment Factor (1998 = 1.0)*	UTAH (In Millions of Dollars)	TOTAL COMPANY (In Millions of Dollars)
	0.796		
1990	0.831	$3.2	$10.4
1991	0.864	$3.0	$10.1
1992	0.887	$3.3	$11.3
1993	0.911	$3.4	$11.9
1994	0.932	$3.2	$11.7
1995	0.954	$3.6	$12.8
1996	0.972	$3.6	$13.9
1997	0.990	$4.6	$18.1
1998	1.000	$4.6	$19.3

* Note: U.S. Bureau of Economic Analysis GDP Implicit Price Deflators for 1989 to 1998 (1998 = 1.0).
Data Source: Annual Time Series Data from http://www.bea.doc.gov/bea/dn1.htm

Nominal Dollars**		
Year	UTAH (In Millions of Dollars)	TOTAL COMPANY (In Millions of Dollars)
1990	$3.9	$12.5
1991	$3.5	$11.7
1992	$3.7	$12.7
1993	$3.7	$13.1
1994	$3.4	$12.6
1995	$3.8	$13.4
1996	$3.7	$14.3
1997	$4.6	$18.3
1998	$4.6	$19.3

** Data Source: Pacificorp Response to DPU Data Request PC 1.5