Acknowledgement

This Staff investigation and preparation of this report were accomplished by a Staff team headed by Mr. Bruce Mitchell and including Ms. Wendie Allstot and Mr. Saeed Barhaghi.

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Executive Summary

On July 17, 1998, for the first time in memory, Public Service Company of Colorado (PSCo or Company) did not have enough electric power supply resources and took actions to intentionally disrupt the supply of electricity to some of its firm supply customers to avoid more widespread and potentially severe outages. On July 20, through news releases and interviews, PSCo officials made pleas to the public to conserve power so that PSCo would not again have to resort to power supply disruptions. At the July 22 Commissioners' Weekly Meeting, managers from within the Utilities Section of the Commission Staff proposed an investigation of PSCo’s actions that might have contributed to the power supply emergency of July 17, as well as other events which occurred during the week of July 13th through July 20. At that meeting, the Commission approved the expenditure of Staff resources to investigate the actions of PSCo and stated a desire for a report from Staff within approximately 60 days. The proposed areas of investigation, outlined by Staff management in only the most general terms, were as follows:

- The peak demand load forecasting process of PSCo.
- Operation of the interconnected transmission system.
- Maintenance of PSCo’s power plants.
- Maintenance of transmission lines.
- Capital expenditures for distribution, transmission, and generation.
- Staffing levels of PSCo’s power plants.

To implement this directive, an investigative team was formed internally by Staff. Upon review of the general directives, Staff team members developed an investigation plan to more narrowly focus these general directives into an analysis that could be done within the time constraints requested by the Commission and the subsequent anticipation generated in the public for its release. In doing so, this forced reliance by the investigation upon generally available information, such as the Annual Report of PSCo to the Commission, i.e., the FERC FORM 1, or specific inquiries of PSCo for available data, as it became evident to team members that information on these subjects is not routinely reviewed by Staff.

This report is the response of the investigative team to the directions of the Commission. Even within the more narrowly defined investigative plan devised by the team, it took more time than we initially thought to compile this report. In some instances, we don’t think the analysis included within the report focuses as directly upon the essence of the topic as we might have desired, and there are still some areas that we might have pursued further had more time been available.

However, all in all, we believe that the material in the report provides an accounting and evaluation of the actions of PSCo that can be a useful tool to judge PSCo’s performance relative to the events of July 13th through 20. In some areas of inquiry, the Commission may want to conduct further investigation or to periodically review these topics through its ongoing audit functions for which many of these topics may be better suited. In particular, we would recommend that further interest in many of the topics of this report be channeled through existing or new docket related to the operational performance of the Company.
Dockets that provide an appropriate review venue include those associated with certain filings of PSCo under such regulatory programs as the Performance Based Regulation (PBR) Plan. (See pages 104-105I of PSCo’s Electric Tariff, the Qualifying Facility Capacity Cost Adjustment [QFCCA]; see pages 108-108D of the tariff, and the Incentive Cost Adjustment [ICA] mechanism, see pages 109-109C of the tariff.) For example, the discussion within this report of the performance of PSCo’s Arapahoe and Comanche power plants and the handling of costs as well as revenues associated with short-term firm power sales by PSCo are issues that should be and could be further addressed within the context of the ICA mechanism.

In order to address the Commission’s general directions, this report is organized into eight sections which address the general objectives as follows:

Executive Summary
Section 1. Load Forecast (PSCo’s Peak Demand Forecasting Process)
Section 2. Transmission System and Operations on July 17 (Operation of the Transmission System)
Section 3. Generation (Production) Plant Maintenance and Availability (Maintenance of PSCo’s Power Plants)
Section 4. Transmission Line Maintenance (Maintenance of Transmission Lines)
Section 5. Distribution Infrastructure (Distribution Capital Budgeting)
Section 6. Capital Budgeting and Maintenance Spending (Capital Expenditures for Distribution, Transmission, and Generation)
Section 7. Staffing of Power Plants and Other Service Supply Functions (Staffing Levels of PSCo’s Power Plants)

Based on the discussion within this report, we have summarized our conclusions or observations and recommendations by these reporting sections. In reviewing these conclusions, it should be kept in mind that the events of July 17 were a multiple-contingency situation. In other words, a number of individual parts of the electrical system were missing at the same time. Individual circumstances, were the main root cause of the loss of these parts of the electrical system while chance or fate played some part in bringing them altogether at the same time. Because of the below par status of PSCo’s load forecasting process and questionable reporting by it of the capability of some of its resources, the chance of this occurring was certainly increased. Probably if any one of these elements had not been out-of-service, the electric system would have been stressed as it was on July 20, but the involuntary disruption of service by PSCo to its firm supply customers would likely not have occurred.

The following are the conclusions and recommendations of this report:

**Load Forecast**

**Conclusions:**

The load forecast of 5,100 megawatts on July 20 cannot be traced back to the previous PSCo forecasts. PSCo’s system operations short-term hourly forecasting model projected a maximum
demand of about 4,875 megawatts on July 20. This is a number that is comparable to and about 6.5 percent greater than the long range corporate forecast of 4,577 megawatts that was included in the 1997 Integrated Resource Plan (IRP) Update.

PSCo had consistently been underforecasting its system demand by about 105 megawatts over the last few years. This is a built-in error of about 2.4 percent, so the extra error possibly attributable to the corporate long-range forecast is about 4 percent. This is within range of the 5 percent forecast errors reported by other utilities for that date.

PSCo should not have been consistently underforecasting over the last few years. For the 1996 IRP submittal, PSCo adjusted its corporate forecast downwards to be more consistent with higher historical load factors prior to 1995. At the least, this resulted in a loss of 70 megawatts in the forecasted 1998 value.

For the 1997 IRP Update, PSCo continued to track the higher load factors of the early 1990s although recent system load factor data indicated that demand was growing faster than PSCo’s assumptions. Conservatively, the forecasted 1998 demand contained in the IRP Update could have been at least 100 megawatts higher than shown by PSCo.

PSCo relies upon its load research results data in determining the various customer class demands for the forecast. At least for the residential class, this sample has not been updated since 1991.

Since the 1993 IRP, PSCo has constantly respecified its econometric model for forecasting the peak demand of its residential and commercial customers. These changes have been undertaken without a systematic means of measuring their effectiveness.

Generally, all the econometric equations used by PSCo have had statistically significant explanatory power. However, it is likely that almost any model would have given such results in tracking a growing commodity.

Because of this haphazard changing of the econometric model, it is impossible to gauge the merits of one form of the model against another form. Before changing its independent variables, PSCo should have ascertained these merits.

The constant respecification seems more geared to “simplifying” the forecasting data requirements than improving the peak demand forecasting process.

Generally, the corporate forecasting model indicates a weather sensitivity of about 20 megawatts per degree of temperature. The system operations department short-term hourly load forecasting model sensitivity is about 35 megawatts per degree of temperature. PSCo has systematically moved in one direction in terms of modeling the influence of weather on its peak demand and that is reducing any ability of the corporate long range forecasting model to account for weather variations.
The energy sales forecast projects that PSCo will be a continuing player in the short-term sales market.

Although short-term sales are included within the energy sales forecast, the PSCo demand forecast excludes them. PSCo does not assess the impact of short-term firm sales on the load forecast or its reserve margin within its IRP filings.

It appears that PSCo had short-term firm power sales commitments of at least 50 to 75 megawatts during the summer of 1998, which should have been recognized within the demand forecast.

Demand forecasting is a process that uses analytical tools and judgments on different factors that should reasonably tie together. While PSCo may have used questionable judgment in its forecasting process, there does not appear to directly be any rule or regulation violation of the Commission associated with these judgments.

The Commission has not approved the demand forecasts contained in the 1996 IRP or the 1997 Update.

In our opinion, PSCo did not fully explain its process and document the assumptions for its load forecasts submitted for the 1996 IRP. This could be viewed as a potential violation of 4 CCR 723-21-5.5.

**Recommendations:**

PSCo should prepare a complete documented description of the process by which it prepares its corporate demand forecast.

PSCo should institute a systematic method of measuring the benefits of changing its econometric models.

PSCo should continue to consider weather sensitivity in its demand forecasts.

PSCo should update its load research samples that are more than a few years old and more closely incorporate this data into its demand forecasting process.

PSCo should recognize short-term firm power sales in its forecast if it intends to be in that market and offer such sales during its peak demand season.

The Commission should consider whether PSCo has violated the disclosure requirements for its forecast within the IRP rules.

If the IRP reporting process continues in the future, the Commission should consider directing Staff to report to it on the process and reasonableness of the demand forecast submitted by PSCo during the initial stages of the IRP process.
The Transmission System and Its Operations on July 17

Conclusions:

In conjunction with the outages on the PSCo system, the City of Colorado Springs lost its 207 megawatt Nixon unit on July 17. This forced the electric network supplying power into the Front Range of Colorado to face at least five major simultaneous outages on July 17.

Power flow simulation of the network using estimated 1998 loads did not show any network problems in metro Denver for a double contingency loss of generation at PSCo’s Cherokee plant and loss of the Hayden-Gore Pass transmission line.

A single contingency outage should be withstood without loss of load or voltage support under transmission network reliability criteria. Likely double contingency outages should be studied and assessed but loss of load is permitted under that condition.

There is apparent confusion among some of the owners of the TOT 5 transmission lines at to what was the transfer capacity during July 17.

While the owners of the TOT 5 capacity did coordinate by telephone, it is difficult to determine how effective this process was.

There was a relaying error on the Blue River-Dillon transmission line during the events of July 17.

The events of July 17 did not progress into a stability or underfrequency problem. While voltages in some sections of the Colorado transmission network did decline and become unacceptable, there was no voltage collapse in the metro area.

TOT 3 was heavily loaded but the main problem appeared to be overloading of TOT 7 in northern Colorado which is a direct supply conduit into the Denver metro area. This TOT or interchange point is operated by PSCo. During the events of July 17, loading on this TOT reached about 1,000 megawatts while the rating is 880 megawatts.

The operating guidelines for TOT 7 require that loads on transmission lines be reduced to operating rating within 15 minutes. PSCo was concerned that the TOT 5 outages would result in additional cascading outages of the transmission network.

Because of coordination problems and the relatively slow ramping rates for the generation in the Hayden-Craig area, a quick reduction in output to reduce transmission loading was not a reasonable alternative to the load shedding instituted by PSCo.

PSCo has an internal plan for instituting load reductions through its White, Blue, and Red alerts. PSCo also has a very brief description in this plan of the “rolling blackout” procedure.
On July 17, the system operators were not able to fully execute the rolling blackout plan as described in the PSCo procedure.

PSCo only had approximately 70 distribution feeders under control of the plan on July 17.

It is not likely that this outage, by itself, will significantly impact the evaluation of whether PSCo will pay a bill credit to its customers or receive a monetary reward for above average service under the PBR.

PSCo has been increasingly engaging in short-term firm power sales to other utilities. On July 17 it continued to sell approximately 87 megawatts of power during the outage situation. However, only about 20 megawatts of these sales had any direct impact on the TOT loadings into the Colorado Front Range.

It appears that PSCo had short-term firm power sales commitments of at least 50 to 75 megawatts during the summer of 1998. As of September 1998, PSCo had not entered into commitments for the summer of 1999.

It appears that PSCo reasonably handled its power purchase schedules during the events of July 17.

The resources upon which PSCo counts to meet its reserve obligations appear to be overvalued in terms of the capabilities of QFs to deliver power during the summer months. A reasonable reevaluation of this type of resource would likely decrease PSCo’s current resources by about 55 megawatts.

Relative to its owned resources, PSCo reasonably used the QF capacity available to it during the events of July 17.

**Recommendations:**

PSCo should correct the erroneous relay on the PSCo network at Blue River. (This has already occurred.)

PSCo should better coordinate with the WAPA, the TOT 5 path operator, regarding a determination of the transfer capability of this path so that instantaneously, or nearly so, determinations of the path capability are available.

PSCo, in conjunction with the path operator, should review the interactions of the TOT 5 owners on July 17 to determine if better coordination is possible in restoring transmission lines to service.

PSCo should revise its expected purchase capacity from QFs to realistically reflect the dependable capacity of these units in the summer.
PSCo should provide language within the general conditions section of its tariff explaining its firm service disruption process under supply emergencies.

PSCo should expand and update its list of feeders for interruption under “rolling blackouts.”

PSCo should disaggregate the blocks of feeders by service area, e.g., Western Slope, Denver Metro, etc.

PSCo should have its operators periodically review or train for use of the interruption process so that interruptions are directed to those areas that can provide the greatest benefit and that the frequency and amount of outage time are minimized for the customers.

**Generation Plant Maintenance and Availability**

**Conclusions:**

The outages at Comanche and Cabin Creek were reasonably preventable with more proactive maintenance practices than historically used by PSCo.

PSCo has reasonably analyzed the reasons for the outages and has proposed solutions, but should look at more than just the proposals they have put forth.

For some units, the PSCo generating plant performance is above the national averages. For others, including the critical Comanche units, it performs below the national average.

PSCo has recently begun to use coal quality that differs from that for which the units were designed at Comanche and Arapahoe. Although this coal is evidently cheaper, performance may be adversely impacted by use of this fuel.

In reviewing the resource capabilities used in the PSCo reliability analysis included in the IRP reports, it appears that at least 50 megawatts of resources are included that do not actually exist.
Recommendations:

Besides its proposal for periodic wicket gate inspections, PSCo should also consider nondestructive testing as well as a different alarm circuit logic for the wicket gate shear pins at Cabin Creek.

PSCo should replace expansion joints in all units of similar vintage and manufacture to the Comanche Unit 1 before the summer of 1999.

PSCo should review its use of coals dissimilar to those for which the units are designed to assess the impact on heat rates and capabilities and provide such information for continued use of these different coals in the ICA review docket.

PSCo should critically review its existing resources, including interruptible loads, to determine whether the currently rated dependable capacity of each unit can be realistically obtained from its generators.

The Commission should consider whether PSCo’s conduct in inspecting its Comanche and Cabin Creek generating units was deficient in meeting any rule requirements on minimally acceptable maintenance practices.

The Commission should consider whether the capacity of PSCo’s resources were properly listed in its IRP submittals and whether this constituted a deficiency in meeting any rule requirements.

Transmission Line Maintenance

Conclusions:

The outages on the Hayden-Gore Pass and Rifle-Hopkins-Malta transmission lines on July 17 were due to contact or flashover to vegetation.

These transmission lines were not overloaded during the day and should have been able to remain in service absent the vegetation contact.

Prior maintenance of the rights-of-way (ROW) of these lines was not adequate. While the outages on these transmission lines were not the sole cause of the PSCo shedding load, they did significantly contribute to it.

WAPA appears to be on track to complete vegetation management on the Hayden-Gore Pass transmission line this fall. PSCo appears to have fallen behind on its schedule and is now scheduled to complete its maintenance in 1999.
Recommendations:

PSCo should complete all necessary tree-trimming on the TOT 5 right-of-way that it controls before the middle of June 1999.

PSCo should monitor ROW maintenance practices on jointly owned transmission lines which it does not operate to assess whether maintenance is being periodically performed to a standard PSCo considers sufficient for its own facilities.

The Commission should consider whether its rules are sufficient to address minimally acceptable ROW maintenance practices.

The Commission should consider whether PSCo’s conduct in maintaining the TOT 5 ROW was deficient in meeting any rule requirements on minimally acceptable ROW maintenance practices.

Distribution Infrastructure

Conclusions:

Because of problems during the summer that brought into question certain problems with distribution substation and line transformers, they were reviewed for any indication of deficient placement and budgeting policies by the Company. We did not find any significant problems.

There may be some minor problems associated with the guidelines used by PSCo for sizing distribution line transformer installations. Also, on a going-forward basis, the continued use of transformer retirement data to determine whether replacements are required seems to increase the risk of customer outage. A more proactive method for assessing transformer loading might be better.

It appears that PSCo is not in compliance with its own tariff or Rule 8 of 4 CCR 723-3 regarding recording of customer complaints.

Recommendations:

PSCo should review and update its distribution transformer installation guidelines concerning using new load research data, coincidence factors, and demand per home.

PSCo should precisely describe to the Commission how it will use transformer retirement data to proactively replace overloaded distribution line transformers or review establishment of some process to monitor such transformers for approaching overload conditions. This might be reviewed under the PBR docket.

The Commission should consider whether PSCo’s conduct in not retaining records of customer complaints is a violation of Commission rules.
Capital Budgeting and Maintenance Spending

Conclusions:

Besides capital expenditures, we looked at payroll and overall operations and maintenance expenditures. This data is available through the Annual Report of Public Service to the Commission.

Overall maintenance payroll dollars declined in real terms for the operating functions of the Company by about 15 percent from 1992 to 1997.

Overall operations payroll dollars declined by about 43 percent in real dollars from 1992 to 1997. Excluding A&G type functions, this decline was about 26 percent.

Excluding fuel costs, total O&M costs for the production function of PSCo have declined by about 13 percent in nominal dollars over the 1992-97 time period.

Total O&M costs for the transmission function of PSCo declined significantly in the mid-90s but rebounded somewhat by 1997 to be about the same in nominal dollars as that of the 1992-93 time period.

Total O&M costs for the distribution function of PSCo have increased in nominal dollars by about 5 million dollars from the 1992-93 to the 1996-97 time period. This is a growth of about 18 percent which is roughly equivalent to the percentage increase in new customers over that time period.

While distribution operations expenditures have declined slightly, maintenance expenditures have increased by about 33 percent over this time period. This appears to be due to the use of more material as the directly assigned payroll for this function only increased by about one-third of this amount.

Historical additions to the plant investment account of PSCo have averaged about $200 million for the 1993-97 time period. These values were depressed in 1995 and 1996. Investments in 1996 were depressed across all functions, likely in deference to the outlay of capital for the Fort. St. Vrain generators.

Budget forecasts from the late 1997 or early 1998 time frame show the 1993-97 average level of spending continuing through at least 1999. Data from the five-year capital budget tends to show the level of spending declining in the last three years of the budget.

From our review, the PSCo electric department share of the total NCE budget appears to be roughly 50 percent over the five-year capital budget.
**Recommendation:**

To determine the specific causes of the O&M expenditure changes over time would require more in-depth investigation than our time restrictions permitted. These tabulations provide a means of beginning to assess these changes. Generally, PSCo has held constant such expenditures except for distribution maintenance.

As deemed necessary, the Commission could consider periodically monitoring the capital budgeting process of PSCo through its audit function. Such review should include analysis of historical and budgeted spending trends as they may impact adequacy and security of the network. This review could be under the aegis of the PBR Plan for PSCo.

At the present time, this review of capital and expenses could be under the aegis of the performance based regulation ("PBR") plan for PSCo.

**Staffing of Power Plants and Other Service Supply Functions**

**Conclusions:**

Production department staffing of PSCo has been declining but seems to be currently within reason. Staffing cuts have been more significant in management, fuel handling, and clerical functions. Over the last five years, PSCo has also made significant cuts in plant management and other categories.

At the current time, the performance factors for the generating plants do not indicate that such force reductions has had an adverse impact. However, if this is a problem, this may take some time to materialize. Monitoring of plant performance in the future should provide a means of gauging whether PSCo has adequately staffed these plants.

Electric department staffing of PSCo has also declined. However, because of the time restrictions on this report, we did not complete this analysis. If interested, this tabulation can be provided at a later date.

**Recommendation:**

As deemed necessary, the Commission could periodically monitor the staffing levels and relevant skill specialties of PSCo through its audit function. Such review should include analysis of historical and budgeted staffing trends as they may impact adequacy and security of the system. This review could be under the aegis of the PBR plan for PSCo.

**A detailed discussion of each individual investigation area follows.**
Section 1. Load Forecast

Internally, PSCo develops both a long-range planning forecast of annual and monthly energy sales and demand plus a short-term operations forecast of hourly demands. The long-range forecast is produced at least annually and is developed as a corporate forecast for purposes of estimating not only future revenues, but capital expenditures, fuel procurement, and maintenance planning. Generally, this forecast is used by the various budgeting and planning groups within the Company. The official version of this forecast, at the time of submittal, is also used to form the basis of the reports that PSCo must file to comply with the Integrated Resource Planning (IRP) rules of this Commission. (See 4 CCR 723-31.) The short-term forecast is essentially a daily output by the System Operations Department which is used by that organization for developing hourly expected loads within a one- to seven-day time frame for the purposes of scheduling the currently available resources, i.e., internal generation as well as purchases, to meet the anticipated next day loads.

While our focus in this report was on evaluation of the long-range planning forecast process, it is useful to briefly describe the short-term forecasting model as it, along with the planning forecast, played a significant role in the press reports that chronicled the events of the week of July 17. Basically, this operations forecast model projects the hourly demand as a function of the time of year (i.e., season, day, week and hour), as well as weather variables such as the previous hour high temperature, humidity, and cloud cover. It also takes into account abnormal system events as determined by the forecasters. From our understanding, this model initially uses a three-year history base for the given season that is then updated hourly by the model program as time progresses through the season. The temperature sensitivity of this model is about 35 megawatts per degree in the summer afternoon hours.

While short-term forecasting should be fairly accurate as it only has to predict the response of the system to events capable of immediate changes, i.e., weather and time of day, there is a degree of imprecision or error in even this type of model. In response to our requests for information on the daily operations dispatch and load forecasts for the days of July 16 through 23, PSCo also provided calculations of the hourly percent errors between the system operations forecast and the actual hourly loads. During this period of time, the “hot” weather days from approximately July 16 though 21, this short-term hourly forecasting model of PSCo’s System Operations Department had an error of at least 2 percent for the maximum demand hour while having a 3 to 5 percent cumulative error throughout the day.

In some of the press reports and through press releases of PSCo, there were statements to the effect that PSCo was expecting a peak demand of 5,100 megawatts on July 20. This was accompanied by a request from PSCo that customers conserve electricity. In our review, it has become apparent that this reported demand never existed in either of PSCo's planning forecasts. This value did not come from the long-range planning forecast. In our review, we did find that the Daily Unit Commitment Schedule of PSCo’s System Operations Department used a forecasted maximum three-minute peak demand of 5,014 megawatts and 4,925 megawatts for the maximum hourly integrated load for the hour ending at 1700 hours MST on that day.
These values are forecasted using the short-term load forecasting model of the Systems Operations Department. The former figure is based on the maximum load that PSCo expects to encounter over any 3-minute period within the hour. It is used by System Operations to gauge whether PSCo has sufficient resources within its control area to meet load on a minute-by-minute basis without pulling in unscheduled energy from other control areas. The latter figure, the load of 4,925 megawatts, is the maximum value of the forecasted range--high and low load estimate--for the load obligation of PSCo. This is the maximum estimate of the peak load hour for the day which the system operators must prepare to meet. The average value for that range was 4,875 megawatts. This is the value that appears most comparable to the long-range demand forecast projections of PSCo in that resource scheduling for operational and planning purposes is normally done on the capability to meet the hourly integrated demand and does not take into account variations or extremes around that value.

Generally, these press reports stated that the 5,100 megawatt load would be more than 10 percent above the previous peak load in July 1997. Eventually, in August, these reports began to reference a forecasted figure of approximately 4,577 megawatts which was the latest official forecast that PSCo had provided to the Commission as part of its requirements under the IRP rules of the Commission. This forecasted value is taken from the 1997 Update to the 1996 IRP that was filed with the Commission. The “Loads and resources” summary pages from these IRP submittals are attached as Table LF-1. The first page of this table is from the 1996 IRP and the second page is from the 1997 IRP Update.

While these forecasts were filed at the Commission, contrary to the press reports and PSCo’s own press release, these forecasts were never approved by the Commission or even formally approved by Commission Staff. Prior to September of this year, only the IRP submittal of PSCo in 1993 has ever been officially reviewed and approved by the Commission.

PSCo had forecasted that its load obligation, termed “Native Load with DSM,” would be 4,577 megawatts in its October 1997 IRP Annual Progress Report. Based on the figure of 4,875 megawatts as a reasonable value to compare with that forecast, it appears that the error in the planning estimate for 1998 was about 6.5 percent. On page 6 of its 1997 IRP update, PSCo stated that its analysis of its forecasting error indicated that it underforecasted by about 2.4 percent, or 105 megawatts over the last five years. The difference between these two values is about 4 percent or about 183 megawatts. This is the amount of additional forecasting error that PSCo had in 1998 over and above its “normal” amount of error.

Although an error of this size should not normally occur when forecasting only into the next year, the convergence of weather and other unforeseen short-term circumstances can contribute to increased forecasting error for a particular year. As previously noted, the short-term hourly forecasting model of PSCo’s System Operations Department can err in the range of 2 percent for the maximum demand hour while having a 3 to 5 percent cumulative error throughout the day. Furthermore, because of the hot weather conditions experienced during this time period, other utilities in the area had load increases greater than expected. For example, Tri-State Generation and Transmission Association (TSG&T) indicated that its actual July total system load, i.e., its
eastern and western system, was about 5 percent above its prior year forecast. The City of Colorado Springs also stated that its actual July load was about 5 percent more than forecasted.

As a means of comparison to the more recent IRP forecast submittals by PSCo, we will first briefly describe the demand forecasting process used by PSCo for the 1993 IRP. In that forecast, a econometric model was developed for system peak demand by using mutli-variable regression analysis to model the total retail firm load obligation of PSCo as a function of weather (temperature), electric prices, and appliance saturation. Separate equations were established for winter and summer demand. To this value was added resale and nonfirm customers and separate estimates were made for demand side management activities. From the firm retail load obligation, PSCo disaggregated this value into residential, commercial, and other loads.

In the 1996 IRP, PSCo only stated that the peak demand forecast for each class of customers studied under its energy sales forecast was derived from the total energy forecast by application of an annual average load factor. (For example, see the discussion on page 38 of the 1996 IRP submittal.) In the 1997 IRP Update, PSCo only stated that an econometric model is used to forecast retail demand as a function of employment, income, weather, and gas/electric prices. (See page 5 of the 1997 Update.) This basically is the whole of the response by PSCo to explain and justify its forecasts under the requirements of IRP Rule 723-21-5.5.

At face value, these statements seem to indicate PSCo had significantly changed its demand forecasting process from one IRP submittal to the next. In a sense, this is true as PSCo had essentially abandoned the modeling method used in the 1993 IRP. However, as stated in Attachment LF-1, the process used for 1996 IRP forecast and that for the 1997 IRP Update were similar. In each forecast, PSCo used an econometric model to develop a demand estimate for the commercial and residential portion of the retail firm load, which it refers to as the “adjusted firm load obligation” (AFLO). (Unlike the 1993 process, PSCo had broken down its total firm load to remove certain large industrial type customers.) For other customers, wholesale loads, PSCo developed a demand forecast primarily based on the load factor for the customer. In both the 1996 IRP and the 1997 Update, PSCo next took the forecasted energy sales, with some notable changes, for all the load components, derived what it considered to be group demands for each class of retail customers and each wholesale customer, and then ran this data through a load forecast adjustment module in the Proscreen computer program. PSCo stated that it needed to run this additional modification in order to derive forecasts by rate class, i.e., residential, etc.

While the forecasting process was similar for both, for the 1996 IRP forecast, PSCo made a specific adjustment to reduce the retail firm load forecast from its econometric model so that the overall demand input into the ProScreen module was about 70 megawatts fewer than that estimated by the econometric module. According to PSCo personnel, this was done to shift upwards the forecasted system load factor in the early years of the forecast to a value more near those actually experienced in the early to mid-1990s. (PSCo personnel initially denied that the demand value was adjusted for consideration of the historical level of the system load factor.)

For the 1997 IRP Update, PSCo used a different econometric equation to forecast its retail adjusted firm load obligation. While the equation structure was the same, i.e., adjusted firm load
as a function of various variables, the weather and income variables were changed as well as the
time period over which the dependent variable was measured. In making these changes, PSCo did
not engage in any methodical testing of whether the changes it made to the equation offered more
explanatory power than the previous version of the equation. As these equations were modeled
different time series, we cannot reasonably compare the models to determine whether there
was any benefit to the changes. In terms of weather sensitivity, both the 1996 and 1997 models
exhibited a temperature sensitivity of about 20 megawatts per degree of temperature although the
temperature variable(s) were structured differently.

In deriving its 1997 IRP forecast, the system load factor continued to be in the range of those
from the early 1990s. However, at this point in time PSCo had several years of actual data which
clearly showed that the load factor had declined significantly as demonstrated in Table LF-2. Also
included in this table is data from the residential class load survey showing that the system
demands for the residential class load survey were increasing over what had been experienced in
the last of the high system load factor years. As this survey sample was set in 1990, an increasing
contribution to the system peak load in this classification would be an indication that summer
demand growth was strong. However, the forecast prepared for the 1997 IRP Update (see page
2 of Table LF-1) continued to assume the higher load factor values of the previous forecast even
though PSCo had recognized it was underforecasting demand by about 100 megawatts per year.

As noted on pages 1 and 2 of Attachment LF-1, by the spring of 1998, PSCo personnel had
decided that weather, i.e., peak day temperature, etc., no longer had any statistical significance in
estimating peak load. It was now proposing an equation that simply regressed demand against
energy sales, which is basically the load factor relationship, i.e., the ratio of energy to demand. In
this revision, PSCo’s peak demand forecasting process had essentially come full circle and was
back to the level of sophistication used in the late 1960s.

We further queried PSCo on the explanation of the rejection of weather data in forecasting
demand. As shown on page 3 of Attachment LF-1, respecification of the model has now found a
statistically significant relationship between weather and demand.

This example points out that when developing regression models with data that is essentially a
time trend, i.e., peak demand, results that are statistically significant can occur for a wide variety
of models. For example, we took the same AFLO data over the same time period as used by
PSCo in its 1996 IRP forecast and regressed that load against time and temperature. While our
results had slightly less statistical significance than the PSCo model, it was still very significant. In
specifying a model, one must use reasonable judgment in determining the variables as well as the
level of aggregation. In fact, the results of the model should be compared to other data, such as
load research information, to gauge whether they are reasonable. The value of these models is in
their explanatory power and the ability to reconcile them with other sources of data. During our
review we asked PSCo to plug the actual values for the independent variables of its econometric
to compare the resulting demands to the actual demand for AFLO. PSCo could not do this,
which is surprising because it would seem that the actual values for the independent variables
would be needed for updating the model.
In our view, several judgments, as have been discussed in the preceding paragraphs, used in the PSCo forecasting process for the 1996 and 1997 IRP are questionable. While we are not aware that these judgments specifically violated any rules of the Commission, they were not fully disclosed by PSCo in preparation of its demand forecast. This could certainly be viewed as a violation of Rule 4 CCR 723-21-5.5.

Another factor that is not apparent from the PSCo IRP forecast submittals is the treatment of short-term wholesale power transactions in the demand forecast. The PSCo energy sales forecast projects that PSCo will be in this market throughout the time period of the forecast. However, the demand forecast does not address them even though PSCo has been making short-term firm sales during the summer months. For the summer of 1998, it would have appeared appropriate to include some demand responsibility, at least in the 50 to 75 megawatts range, in the forecast for such sales. However, this would have impacted the expected reserve margins for PSCo.

As an interesting twist to the absence of the short-term sales from the data contained in Table LF-1, PSCo does add back into the forecast for Net Energy for Load and Loss, the total energy requirements of some of its firm wholesale customers while the Company’s official energy sales forecast only includes the sales to these customers by PSCo and does not account for economy energy purchases by these customers. This is another example of the difficulty in following the assumptions used by PSCo in its demand forecasting process.

Finally, we note that the method by which PSCo incorporated DSM savings into its forecast, as shown in LF-1, has the potential for double counting DSM savings. PSCo does not separate DSM out of its AFLO historical data, thereby including its effect in the regression analysis. However, PSCo gives full credit to DSM impacts that have been included in the historic AFLO data. The current effect of this is small, but left unchecked, it could provide a consistent underforecast bias to PSCo demand projection.
Section 2. The Transmission System and Its Operation on July 17

As the middle of the day on July 17 approached, the system operators of PSCo were already faced with a significant problem of supplying enough resources to meet the mounting demand. As noted later in this section, power purchases were running about 500 megawatts greater and off-system sales about 125 megawatts fewer than had been planned on the previous day by PSCo operators, before the two major generating units had been lost. In addition, power supply problems on the Front Range of Colorado were impacted by the loss of the 207 megawatt Nixon unit, owned and operated by the City of Colorado Springs, in the early morning of July 17. By 1100 hours, PSCo was receiving 75 megawatts of generating reserve assistance from the Rocky Mountain Reserve Group as well as buying approximately 340 megawatts of economy energy, including 100 megawatts from the Burlington combustion turbines of TSG&T. However, within a few hours of that time, several facilities in the Colorado transmission system would trip out-of-service, limiting the ability to deliver this power to loads within the state.

Attached as Table TSO-1 is a listing of the sequence of events for the components of the transmission system in Colorado impacted by the outages on July 17. To briefly recap the major events in this sequency, we initially begin at 1333 hours when a phase to ground fault caused the Hayden-Gore Pass 230 kilovolt line to trip. Next misoperation of protective devices at Blue River Substation caused the Gore Pass-Blue River-Dillon 230 kilovolt line to “sympathetically” trip and a combustion turbine in the San Luis Valley also tripped off-line. The protective devices at Blue River Substation should have recognized that the fault occurred on the Hayden-Gore Pass 230 kilovolt line and should not have tripped the Gore Pass-Blue River-Dillon 230 kilovolt line.

At 1339 hours operators attempted to close these lines but were unsuccessful. At 1344 hours overload of the Hayden-Gore Pass 138 kilovolt line caused it to trip. Soon after, at 1346 hours, the Rifle-Hopkins-Malta 230 kilovolt line also tripped. The Blue Mesa-Skito-Poncha UC 115 kilovolt line tripped on overcurrent (overload) at 1347 hours. At 1348 hours the San Luis Valley Substation 230/115 kilovolt autotransformer and the Poncha-San Luis Valley 230 kilovolt line were tripped because of overload.

As shown in Table TSO-2, at approximately 1345 hours, the load on TOT 7 had climbed to 1,034 megawatts and loading on the remaining transmission lines on TOT 5 was 1,247 megawatts. By 1348, these loads had declined, but TOT 7 was still overloaded. At 1349 hours, PSCo initiated its shedding of firm loads in the Denver area and placed all generators on full load.

Voltages in San Luis Valley had decreased to unacceptable levels, so TSG&T shed 55 megawatts of REA load to stabilize the voltages in the San Luis Valley until the San Luis Valley Substation 230/115 kilovolt autotransformer and the Poncha-San Luis Valley 230 kilovolt line were returned to service at 1406 hours.

By about 1414 hours, PSCo was able to close back in the Malta side of the Rifle-Hopkins-Malta and restore that line to service and began restoring the customers it had shed to service. At 1437 hours the Rifle-Hopkins-Malta line again tripped out-of-service and PSCo began its second round
of load shedding. These loads were restored to service at about 1710 hours and the remaining transmission lines out-of-service on TOT 5, the Rifle-Hopkins-Malta and Hayden-Gore Pass-Blue River transmission lines were restored at about 2023 hours after, presumably, line patrols had retired for the day.

The Hayden-Gore Pass 230 kilovolt line and the Gore Pass-Blue River 230 kilovolt line are part of TOT 5, the transmission system that moves power from west to east across the continental divide in Colorado. Attached as Attachment TSO-1 is a brief description of the system of TOTs that define the various power interchange points in Colorado.

The normal transfer capability of TOT 5 is limited to 1,680 megawatts. The transfer capability of TOT 5 is reduced whenever any of the facilities that make up TOT 5 are not operating. The reduced TOT 5 transfer capability with the Hayden-Gore Pass 230 kilovolt line and the Gore Pass-Blue River 230 kilovolt line out-of-service is about 1,100 megawatts. The Hayden-Gore Pass 138 kilovolt line and the Hopkins-Malta-Rifle 230 kilovolt line are also part of TOT 5. The transfer capability of TOT 5 was further reduced to 950 megawatts according to our best guess. The TOT 5 limits shown on TS-2 are from WAPA which calculated a higher value than the 950 megawatts claimed by PSCo. An estimate of the TOT 5 limit was not available from WAPA, the path operator, until later in the day. From our viewpoint, there seems to be some discrepancy or confusion as to what the path limits on TOT 5 were during July 17.

The operators for the path owner also conferred by telephone during the initial stages of the outage situation. Although WAPA is the path operator and is nominally responsible for coordination of the operation and restoral during outages, it is not clear that WAPA took charge of this function. Rather, it seems the operational changes that were made were reactive to what the other owners were willing to do. For instance, there was discussion between PSCo and TSG&T as to whether Mountain Parks REA loads would be transferred to the PSCo system to avoid overly high voltages on the 138 kilovolt system. PSCo also indicated that it wanted generation in the Hayden-Craig area backed down earlier than it was. TSG&T claimed that wasn’t the case.

In all, these examples leave room for the TOT 5 owners to review how successful their coordination efforts were. The question of coordination in this area also serviced in the WSCC preliminary report on the western system disturbances of July 1996.

In our review we requested that PSCo provide a power flow simulation of the network using estimated 1998 loads for a double contingency loss of generation at PSCo’s Cherokee plant and loss of the Hayden-Gore Pass transmission line. The results of this power flow analysis did not show any network problems in metro Denver.

It is our understanding that a single contingency outage should be withstood without loss of load or voltage support under transmission network reliability criteria. Double contingency outage scenarios with potential for significant impacts on the system should be studied and assessed but loss of load is permitted under that condition according to such criteria. Under the power flow simulation, it does not appear that a double contingency would have caused any problems on the
Front Range on July 17. However, what actually occurred was about five forced outages of
major elements of the network on that day.

Even with this many forced outages with which to contend, the events of July 17 did not progress
into a stability or underfrequency problem. While voltages in some sections of the Colorado
transmission network did decline and become unacceptable, there was no voltage collapse in the
metro area. Generally, the voltage problems occurred along the TOT 5 boundary to the west of
Denver and in northern and southern Colorado.

As previously noted, PSCo had wanted to reduce the generation out of the Hayden-Craig area as
a means of reducing the loading on the transmission system. Eventually, this was done but not for
an hour or two after the loss of the transmission lines. There was difficulty in reducing load on a
multi-owner generator plant and coordinating this with the power schedules plus the relatively
slow response (“ramping”) rates for the generation in the Hayden-Craig area. Therefore, this
would not produce a quick reduction in output to reduce the transmission loading that was facing
PSCo on TOT 7 at 1349 hours. In our view, there does not appear to have been a reasonable
alternative to the load shedding instituted by PSCo.

In this action, PSCo deliberately shed approximately 200 megawatts of load on July 17. As
recently as the July 2, 1996 WSCC system disturbance PSCo shed load. However, in this
instance, it was for a supply emergency on its own system. The process by which this was done is
different than the underfrequency load shedding procedure that utilities have established to keep
different control or load areas within the interconnected system from isolating from each other,
_i.e._, “islanding.” When use of the underfrequency load shedding process is required, all feeders at
a substation are disconnected automatically by underfrequency relays when the system frequency
reaches a certain level. This type of load shedding progresses on the basis of the dropping
frequency through a prioritized list of substations.

For the situation on July 17, the PSCo system operators manually selected blocks of feeders from
different substations by which to interrupt service to firm supply customers. In this manner, the
interruptions of load were spread throughout the service area without totally interrupting service
to any specific geographic area. PSCo refers to this process as “rolling blackouts.” PSCo
institutes this process as part of its response plan to a crisis on its electric system. Attachment
TSO-2 is the internal documentation for the response plan. White, Red and Blue alerts are
normally first instituted by PSCo before beginning rotating blackouts. At 0830 hours, a White
alert was issued and all interruptible tariff loads were interrupted at 1335 hours. The Blue and
Red alerts were not given until 1400 hours, some 10 minutes after the rotating blackout began.

Although the blocks were manually selected by an operator sitting at a computer control console,
the feeders were automatically disrupted by opening circuit breakers controlled through the
Supervisor Control and Data Acquisition (SCADA) system. Operations personnel stated that
PSCo had recently, within a few months of July 17, updated this load shedding process so that the
operator could select from approximately 14 blocks consisting of 5 feeders which, altogether,
accounted for 70 feeders. In the past, feeder selection would have been done one at a time. The
blocks were each sized for about 50 megawatts of interruptible load, which the PSCo system
operators considered to be about the minimum amount per block to be effective. By approximately August 25, PSCo had increased the number of feeders under this load control program to approximately 90, or 18 blocks. It is our understanding that PSCo has approximately 650 separate substation feeders.

The blocks are arranged in order of increasing priority, i.e., the feeders considered least important on the system are interrupted first. The selection of the initial 70 feeders has not been recently reviewed by PSCo. As stated in Attachment TSO-2, PSCo “targets” the blackouts to last no more than 30 minutes on a feeder. Page 1 of TSO-2 also states that “critical” loads, i.e., hospitals, et al., are taken into “consideration” when rolling blackouts are implemented. (Through a later response, page 2 of TSO-2, PSCo clarified that critical loads are not to be included in any rolling blackouts and further clarified its exemption to include loads affecting “public health and safety.”)

At 1349 hours on July 17, PSCo interrupted blocks 1-1 through 1-4, 2-1 and 2-2 of its 14-block rolling blackout process. The substation designation for these feeders are as shown on page 4 of Table TSO-3 along with the amount of individual interruption time and number of customers for each feeder and the cumulative results. As shown, some of the customers were interrupted for only 17 minutes or until approximately 1407 hours. This time corresponds with the closure of the 230 kilovolt transmission lines into the San Luis Valley. By approximately 1417 hours all load was restored. This time period corresponds with the reclosure, after several attempts, of the Malta end of the Rifle-Hopkins-Malta line by PSCo. At approximately 1437 hours the breaker at Malta again opened and PSCo subsequently began to again shed load.

As shown on page 4 of Table TSO-3, PSCo did not keep interruption times within 30 minutes for a number of feeders. The amount of interruption time varies significantly from about 18 minutes for feeder 1576 at East Substation to 151 minutes for feeder 1913 at Glen Substation. All of these feeders appear to be located outside the core metropolitan area served by PSCo except for possibly Harrison feeder 1773 and Dakota feeder 1502. Generally, these feeders appear to be primarily serving residential and small commercial loads in metropolitan suburban locations. In reviewing the PSCo feeder interruption data, it does not appear that these feeders were always interrupted or reclosed in lock-step batches of 5 at a time. We also note that some of the feeders interrupted later in the day appear to have had little value in supporting resources on the Front Range of Colorado. For instance, as shown on sheet 3 of TSO-3, PSCo interrupted feeders in the Grand Junction area of western Colorado during the latter stages of the events on July 17.

Under the PBR plan which currently governs PSCo’s form of regulation, there is a quality of service plan (QSP). The QSP includes determination of a factor called the System Average Interruption Duration Index (SAIDI) which is a rolling 12-months average of the total number of customer outage minutes recorded by PSCo divided by the number of customers on the PSCo system. As of the end of June 1998, this value was approximately 67 minutes for the PSCo system. Based on the outage minutes in Table TSO-3, the event of July 17 will add about 13 percent to this value or the SAIDI value would be approximately 76 minutes. From the bill credit/reward mechanism as stated on page 105H of PSCo’s electric tariff, it would appear that the addition of the amount of customer outage minutes experienced on July 17 may cause PSCo
to lose a potential reward of about $1.5 million but, by itself, is not likely to cause PSCo to have to credit any money to its customers.

We believe that the use of interruptions to firm loads in a supply emergency is a reasonable tool for PSCo to use, and it may possibly have to do so again within the next few years. As stated on page R32 of PSCo’s Electric Rate Tariff, the Company reserves for itself the right to apportion and curtail service as it sees fit in the event of a supply shortage. As PSCo has an internal policy on how to implement such plans, references as to how it will be done in a general sense, i.e., the color alerts and exclusions, should be included within the general conditions tariffs of PSCo so that customers are given reasonable notice of this process. We do not believe that PSCo should have to tariff a prioritized list of feeders that may be interrupted, as has been done in some states. This creates needless controversy. However, it occasionally should be required to provide justification of its list through the audit function of the Commission.

In terms of the number of feeders that are computerized for interruption, PSCo needs to increase the list and expand the number of blocks. While it did recently increase the list to about 90 feeders, we view the need in the metropolitan area as being in the range of 180 feeders in order to provide about 300 megawatts of load for about 3 hours of interruption without interrupting any feeder more than once for 30 minutes. Generally, feeders should not be interrupted for more than 30 to 60 minutes during any one outage.

The feeder blocks should also be assigned by service area. Disruption of load in far western Colorado for this outage seemed unnecessary while voltage problems in the Greeley area on July 17 may have been helped by interruption of feeders in northern Colorado.

Because this tool may be necessary to use again, PSCo system operators should conduct periodic training or review of implementation strategies under different potential situations. Operators that are busy with trying to restore facilities to service or coordinate resources with others should not be burdened also with the coordination of the interruptions as may have happened here.

Table 6 of the 1997 Update to the 1996 IRP, Table LF-1, shows PSCo planned to have 5,116 megawatts available to serve its retail and wholesale loads for the summer of 1998. Approximately 1,705 megawatts were expected to be supplied from purchases with 1,018 megawatts of that from firm long-term purchases from other utilities, 625 megawatts from purchases from qualified facilities under long-term contract to PSCo, and 62 megawatts of firm but unspecified short-term purchases. As shown on Table TSO-4, the Daily Unit Commitment Schedule for the PSCo operators anticipated purchases on July 17 for the hour ending at 1300 hours MST as being 1,858 megawatts, and sales, economy, and firm short-term of 211 megawatts. This schedule was prepared the day before, on July 16, with the anticipation that both Comanche Unit 1 and Cabin Creek Unit B would be available for July 17. The actual purchase amount of 2,220 megawatts and amount of sales of 137 megawatts for that hour on July 17 are also shown in this table. This table gives a brief review of the ability of PSCo to purchase power on July 17 during the initial hours of the outage on the transmission lines.
As previously discussed under the section on load forecasting, the PSCo IRP does not take into account short-term firm power sales. In this instance, for the hour ending at 1300 hours, PSCo had anticipated power sales of about 211 megawatts with about 150 megawatts of this coming from additional firm purchases over and above what PSCo had estimated from its IRP for the summer peak day. Under its Unit Commitment Schedule for this day, the PSCo operators had forecasted an hourly integrated demand of 4,615 megawatts for the peak load for the day, which is about 60 megawatts greater than the maximum annual demand from the long-range planning forecast from Table 6 of the 1997 IRP update.

Because of the loss of the Comanche and Cabin Creek units, the actual purchases were 2,220 megawatts, or about 515 megawatts greater, and sales were about 124 megawatts fewer than anticipated by the operators on the previous day for 1300 hours on July 17. This differential essentially made up for the loss of the two generating units (approximately 489 megawatts) as well as other units that were not available that day. At approximately 1332 hours the Hayden-Gore Pass transmission line tripped and at 1346 hours the Rifle-Hopkins-Malta transmission also tripped. At 1400 hours, the data in Table TSO-4 shows that PSCo had begun backing off unscheduled purchases but not firm energy sales. After the Rifle-Hopkins-Malta line had been reclosed and tripped again at approximately 1430 hours, PSCo further reduced its scheduled short-term purchases at 1500 hours until at 1600 hours these short-term purchases were minimized for these hours. At this point, PSCo began to lower its long-term firm purchases.

Most of the purchases initially dropped by PSCo were higher cost ones coming from either the southwest, over TOT 5 or, to a lesser extent, from the north, over TOT 3. When PSCo reduced its long-term utility purchases, these were from the TSG&T Craig unit sales. In terms of sales, PSCo continued to supply 87 megawatts of sales on July 17. Of this amount, 20 megawatts went to locations on the Front Range of Colorado, slightly impacting the TOT loadings. On July 13th, at the peak load hour when it appealed to customers to conserve, PSCo was also selling 90 megawatts of short-term firm power and 20 megawatts on July 20.

Over the last couple of years, PSCo has dramatically increased its participation in selling power. It went from just selling economy energy without capacity reservations to entering into short-term firm contracts for power sales over its peak summer demand season. Such contracts typically require the seller to be responsible for replacement power if it is unable to deliver as specified in the contract. In this instance, on July 17, it appears that PSCo reasonably readjusted its purchases within the context of the load shedding it initiated at 1349 hours and its assessment of the TOT loading during this period. At 1500 hours it had decreased total purchases by 209 megawatts and at 1600 hours by 372 megawatts. Because of the high load requirements throughout the area and the suddenness of the loss of the Comanche and Cabin Creek generating units the night before, it appears PSCo could not obtain replacement power for these sales or at least not at a price it would pay relative to the delivery location points. (Approximately 67 megawatts were being delivered on the Western Slope of Colorado and there was little necessity to reduce these deliveries because of the inability to deliver generation from the Hayden-Craig area into the Colorado Front Range.)
In entering into this market, PSCo did not account for any potential power supply responsibility for short-term firm sales in its long-range planning forecast within its IRP submittals. Within both the 1996 IRP and the 1997 Update, PSCo only describes these activities in terms of energy sales and notes that it shares margins, i.e., profits, on these sales with retail customers. While the 1996 IRP submittal (see page 131) does note that capacity limitations may limit sales in 1997 and 1998, this language is missing in the 1997 Update (see page 14 of that document), although the short-term sales projections for 1998 have been increased by 59 percent. Nowhere in these IRP submittals does PSCo provide a qualification of the potential responsibilities or liabilities for engaging in these transactions, especially during the peak load season of the Company. As previously noted, we would place a reasonable estimate of participating in this market at roughly 50 to 75 megawatts during the summer peak load season. This amount of power should have been shown in the IRP submittals, particularly as PSCo chose to show unspecified short-term purchases as a means of meeting its reserve margin in the 1997 IRP Update.

Within its 1997 Update, PSCo has included 625 megawatts of purchases from contracts entered into with facility providers qualified under the aegis of the Public Utilities Regulatory Policy Act (PURPA) requirements, i.e., “qualified facilities” (QFs). (This was shown as 629 megawatts in the 1996 IRP submittal and was tabulated in Table D.8 of that report which has been included as Table TSO-5 in this report.) Upon review of the anticipated availability of this resource from the System Operators' Daily Unit Commitment Schedule, we found that for at least July 17 through 19, PSCo estimated the total available QF capacity at no more than 565 megawatts. This consists of about 385 megawatts for the 5 dispatchable QFs plus 149 megawatts for two large non-dispatchable QFs plus approximately 31 megawatts for 27 small QFs. The difference between the amount reported in the 1997 IRP Update and the capabilities used by the operators for dispatch was about 60 megawatts. We also note that the noncoincident purchases, i.e., billing demand, from the 1997 QF Purchase Report of PSCo show no more than about 616 megawatts being paid for by PSCo during the summer of 1997. This indicates that the hourly available QF capacity is less than this summation of the billing demands. In inquiring into this issue, PSCo responded that some QFs limit their capacity on hot days during the summer, which is precisely the peak demand period of PSCo. (See Attachment TSO-3.)

Inquiring into the short-term adequacy of PSCo’s power supplies, the Company as part of its recent submittal in Docket No. 98M-351E estimated that it could normally expect that 362 megawatts might be considered as being out-of-service during any particular day in the June through September peak load season. This included 57 megawatts for QFs that are unavailable due to high temperature restrictions. This was based on an analysis by PSCo of the resources available to it. We have included as Attachment TSO-4, PSCo’s explanation of how it derived these expected unavailable numbers. In the case of the QFs, the 57 megawatts reduction appears to be a derating of the dependable capacity from these resources during the summer, rather than an expected forced outage amount. This is very similar to the reduction in the expected dependable capacity used by the system operators. Unless further explained by PSCo, the amount of QF capacity used in the 1997 IRP should have been approximately 55 megawatts fewer than reported by PSCo as dependable capacity to meet its forecasted system maximum demand.
Section 3. Generation (Production) Plant Maintenance and Availability

A contributing factor to the events of July 17 was the loss of part of the generating capacity which PSCo owns and relies upon to serve its firm supply customers. As noted in the news reports, PSCo did not have available one of its steam-fired generating units at the Comanche power plant near Pueblo nor did it have available one of the two generators at its Cabin Creek pumped storage facility near Georgetown, Colorado. According to the data in PSCo's 1996 IRP report provided to the Commission, the Comanche Unit 1 has a net dependable summer capacity of 325 megawatts while Unit B at the Cabin Creek facility adds another 162 megawatts to the generation units that PSCo owns and operates within its control area.

The Cabin Creek Unit B was forced out-of-service at 2335 hours on July 16 due to what was described as a “wicket gate” failure. The wicket gate is the mechanism that controls the volume of water emitted to the turbine. There are 28 such gates on the Cabin Creek unit. Generally, this type of failure is caused by the breakage of a shear pin within the control linkage of each gate. Such pins are designed to break if a foreign object becomes stuck in the gate, thereby allowing other gates to function independently of the jammed gate so that the generating unit can continue to be operated. Generally, operation of the generating unit can continue with as many as three broken pins. Occasionally, usually no more than once per year, a shear pin has broken because of metal fatigue which is typically attributed to unit vibration by PSCo. These pins are inspected visually but are not subjected to stress testing or periodic replacement. Spare pins and one thrust collar are kept in stores.

According to PSCo’s internal investigative report entitled “Root Cause Investigation Report,” which has been attached as Attachment GPM-1, operators initially received an alarm for a shear pin failure on Cabin Creek Unit B at 1527 hours on July 16. Inspection confirmed that a single shear pin had broken. Because of the heavy system load, PSCo chose to continue to operate the unit with the intention of replacing the shear pin in the early morning hours of July 17. At 2210 hours on July 16, the unit was shut down, but at the direction of the system operators, it was restarted at 2320 hours for use in the pumping mode without replacement of the broken shear pin. At 2330 hours the event occurred. This event involved the failure of 23 wicket gate assemblies (shear pin, thrust collar, and adjusting link) in one incident. This was most likely due to the failure of the shear pins in the gate assembly. No evidence was found of any foreign objects in the turbine.

As stated in its report, PSCo does have an alarm connected to the shear pins for detection of shear pin breakage. However, because of the alarm circuit is wired in series, detection of further shear pin failures is impossible.

The Cabin Creek Unit B was not returned to service until 1519 hours on August 19. The length of the outage was caused by the need to manufacture parts such as the brass collars, and disassemble/reassemble the turbine.

In Attachment GPM-1, PSCo states that it believes a solution to preventing a reoccurrence of a problem of this magnitude is measuring the wicket gate clearances during the semiannual
maintenance outages of these units. However, PSCo personnel also indicated that they were in
discussions with Voight Hydro concerning possible design changes to prevent this type of
problem. In our interview with PSCo, the possibility of periodic replacement of the shear pins
was discussed. PSCo personnel agreed that this should be considered.

In our view, PSCo has reasonably analyzed this outage as described in Attachment GPM-1.
While inspections of the gate clearances as a new addition to the maintenance routine is a
reasonable change to the normal practices of the Company, we believe that either nondestructive
ultrasonic testing or, preferably, periodic replacement of the shear pins should also be considered
in conjunction with the proposed clearance measurements. We also must question why this type
of measurement wasn’t already a part of the routine maintenance practice. In addition, as a
minimum design change, we believe PSCo should investigate whether alarms can be installed to
record multiple wicket gate assembly failures. Because PSCo apparently has run this unit with
several broken shear pins in the past, an indication of whether and how many more pins are
broken would appear to be helpful to maintenance and operations personnel in deciding whether
to continue to run the unit.

Beginning at approximately midnight on the morning of July 16, the Comanche Unit 1 was limited
to 116 megawatts of output, its minimum load rating, because of ash accumulation on the water
tubes within the boiler. This situation develops when the boiler is run at high load for extended
periods of time and can be due to use of a quality of coal for which the boiler was not designed
plus sootblower limitations restricting ash removal. Load reduction allows a change in boiler
temperature which precipitates a contraction in the boiler tube metal allowing the ash to fall off
the tubes.

Comanche Unit 1 was forced out-of-service at 1539 hours on July 16. This happened after a
short period for evaluation of the effect of a failure of the expansion joints on the deareator
extraction lines beneath the low pressure section of the turbine just inside the condenser. PSCo
did not believe there was any linkage between the derating for ash accumulation and the
expansion joint failure. The expansion joints had last been inspected during a boiler/turbine
inspection in February 1998. The joints are only visually inspected without removal of the outer
covers. This is done during either boiler/turbine inspections or major overhauls. The last time an
expansion joint was replaced was in 1984. According to PSCo, failures have been occurring
about every 13 to 14 years.

According to PSCo’s internal investigative report entitled “Root Cause Investigation Report,”
which is attached as Attachment GPM-2, PSCo does not place much credence in the possibility
that the joint failure was due to over-pressure since the deareator was functioning normally. The
analysis attributes the outage cause to mechanical failure of the expansion joint. Likely reasons
for this failure were: (1) expansion joint age; (2) improper sizing of the expansion joint; and, (3)
contribution of turbine noise to joint fatigue.

Among several recommendations included within Attachment GPM-2, PSCo states that it believes
a solution to preventing a reoccurrence of this type of failure would be an inspection of the joints
in which the outer cover is removed or possible periodic replacement of the joints. The turbine
manufacturer for this unit, Westinghouse, recommended replacement after 10 years of use. While PSCo has again provided a reasonable analysis of this outage, we would place particular emphasis on periodically replacing these joints as a means of minimizing future forced outages.

We emphasize this issue because in our discussions with PSCo maintenance personnel, in all functions, we became acquainted with the term “diagnostic maintenance” as the policy which now evidently drives PSCo’s current maintenance programs. This appears to be a different approach than the proactive periodic maintenance practices that have been typically used by utilities in the past. This concept appears to be to not initiate repairs until there is some indication that something is wrong with the equipment, i.e., a “run until it breaks” type of philosophy if pursued to an extreme.

In the instance of these two generating units, Comanche Unit 1 and Cabin Creek B, we did not find that this new philosophy was responsible for these outages. Rather, the failures were due to practices developed by PSCo over many years. As implicitly acknowledged by PSCo in its recommendations for these units, these practices could have been more proactive and effective. In these instances, as with other parts of the PSCo resource portfolio discussed in this report, no one incident is responsible for the events of July 17. Rather, a number of small errors or omissions, such as the maintenance of the equipment at fault for the outages of these generators, lies at the heart of this event.

As part of its maintenance program, each Root Cause Investigation Report is sent to the PSCo generating plant managers. The plant manager can choose whether to implement the recommendations. In this instance, there are two other units on the PSCo systems that have a similar vintage, i.e., the same design type, and the same manufacturer: Comanche Unit 2 and Cherokee Unit 3. As stated in Attachment GPM-2, PSCo is considering replacing the expansion joints on Comanche Unit 2 in the winter of 1999. This statement was explained to us as meaning January of 1999. This date is consistent with the 1999 maintenance schedule provided by PSCo. The Cherokee Unit 3 is also scheduled for maintenance in April of 1999 according to this schedule. Therefore, PSCo should be able to replace all currently installed joints before the summer of 1999 and the likelihood of this particular type of equipment failure should pose no threat during next year.

With both of these units out-of-service, a question arises as to how well PSCo’s plants were performing relative to other utilities. To answer this question we compared the PSCo units to data from the NERC Generating Availability Data System (GADS). An explanation of GADS is contained in Attachment GPM-3. In the attached Table GPM-1, we compared the PSCo generating units Equivalent Availability Factor (EAF) and Equivalent Forced Outage Rate (EFOR) to similar data from GADS. For the smaller PSCo units, i.e., fewer than 200 megawatts, the EAF, and EFOR have been better than the national average. For the 300 megawatts size units, such as the Comanche units, PSCo has performed below the national averages. In particular, the EFOR for these units is significantly above the national averages. This is especially true for the Comanche Unit 1 which was forced out-of-service on July 17.
The second page of Table GPM-1 contains coal costs and heat rates for various PSCo generating plants. The Arapahoe units recently have been using coals different than that for which they were designed. While this coal appears to be less expensive per ton, there appears to be some impact from this switch on the heat rates for these units. The outage rate and heat rate for the Comanche units also call into question the quality of the coal being used in these units. As this may also have an impact on the outage rates for the units and evidently has caused a derating of the Arapahoe unit for this summer, PSCo should provide some justification for the coal quality being used in these units. Perhaps the appropriate docket for this explanation would be during the ICA mechanism review.

As shown in Table 6 of the 1997 Update to the 1996 IRP, PSCo had planned to have 5,116 megawatts available to serve its retail and wholesale loads for the summer of 1998. Of that amount, approximately 3,423 megawatts were from facilities owned and operated by PSCo. In general, with the availability of all these resources, PSCo should have been able to meet an unanticipated demand in the range of 5,100 megawatts, which is approximately 11 percent greater than its forecasted “Native Load with DSM” figure shown in that table. However, with the outage of these two units, the resources which were planned by PSCo to be available on July 17 had declined to 4,629 megawatts, of which it owned only 2,936 megawatts.

Besides the loss of these two units, it has come to our attention that PSCo had several other units which were either totally or partially unavailable on July 17 due to maintenance problems. These units and the reasons provided for their unavailability are shown in Table GPM-2 of this report. Altogether, these units accounted for another 134 megawatts being unavailable to PSCo. (In addition to the units listed by PSCo, we have included one of the Boulder hydro units as unavailable due to water release restrictions and the additional capacity included in the PSCo resource plan for the turbine blade installation at Pawnee Generating Station.) This further reduces the planned resource availability to 4,495 megawatts. As can be seen by reviewing Table 6 from the 1997 IRP Update, this value is less than the 1998 forecasted “Native Load with DSM” load of 4,577 megawatts.

As can be seen by comparing these two figures, even with no error in its planning load forecast for the summer of 1998, i.e., the actual load remained below 4,577 megawatts. For the amount of its internal generation that was unavailable on July 17, PSCo would have been forced to seek additional unplanned purchases to meet its load on July 17. However, as discussed elsewhere in this report, additional purchases were unavailable, mainly due to the loss of transmission capabilities. As shown in Table GPM-1, PSCo still had approximately 268 megawatts of internal generation capability unavailable on July 20. Fortunately, PSCo was able to return the Comanche Unit 1 to service by noon of that day, and although some utilities felt the system was significantly stressed on that day, no load shedding was initiated.

The likelihood of generating units being out-of-service during the utility's annual peak load period is anticipated through the planning reserve margins that a utility carries for such events. According to Table 6 of the 1997 IRP Update or Table A.1 of the Appendix to the 1996 IRP, PSCo believed that it had reserves of at least 713 megawatts to meet its 1998 forecasted load. The loss of its internal generation capability lowered that planned reserve amount to 140
megawatts on July 17 and to 445 megawatts on July 20 without consideration of any other events on those days.

PSCo generally has not scheduled maintenance for its generating units during the summer months when its peak load occurs. Review of the maintenance planning schedules for 1996 through 1998 and the planned schedule for 1999 provides confirmation of this intent. However, maintenance during off-peak months can average several hundred megawatts per day which induces some risk into meeting loads during those months.

As part of its recent submittal for Docket No. 98M-351E, inquiring into the short-term adequacy of PSCo’s power supplies, the Company estimated it could normally expect that 362 megawatts might be considered as being out-of-service during any particular day in the June through September peak load season. This analysis was based on an analysis by PSCo of the resources available to it. For internal generation, PSCo reviewed its operation records to determine the amount of coincident unit forced outages that had occurred over the period of 1996 through year-to-date 1998. While we did not check the actual data used in this analysis, the methodology description provided by PSCo did appear reasonable as a basis for preparing such an estimate. Of that amount, approximately 265 megawatts was from internal resources of PSCo. In Table 4.3 of its 1996 IRP submittal, PSCo also submitted a history of the amount of generation resources, internal and external, that it did not have available at the time of system peak. Over the 6-year period of 1991 through 1996, the average amount of unavailable capacity during the peak hour was 321 megawatts.

In reviewing the resource capabilities shown in Table 6 of the 1997 IRP Update, which were used by PSCo to determine whether the forecasted load requirements could be served within the reliability guidelines it uses, we question whether some of the listed resources should have been included. First, the Zuni Unit 1 is prohibited from discharging water from its cooling system into the South Platte above a certain temperature. Without additional capital expenditures to expand the cooling system capability, this limitation could reasonably be viewed as permanent and reduces the 39 megawatts summer capability of this unit by 16 megawatts. Second, according to PSCo personnel, there are water release restrictions on Boulder Hydro which limit its ability to produce the 10 megawatts that are claimed as dependable capacity by PSCo. Realistically, this value is probably 5 megawatts fewer than claimed.

We also have some question about the continued listing of the diesel generators at the Cherokee Power Plant as part of the net dependable generating capability of PSCo. When questioned by us, PSCo did state that these units were run on July 17 for about 8 hours. However, they were not run on either July 13th or July 20. On July 20, as previously noted, PSCo had requested retail customers to reduce load as well as asking certain customers to bring their internal back-up generation on line. It appears these units are run only as an emergency and are not part of the capacity normally used by PSCo to meet its peak load.

In addition, PSCo was aware at the time of the production of the 1997 IRP Update--October of 1997--that the net dependable summer capability of the Valmont Unit 5 was reduced by 8 megawatts due to the need for turbine blade maintenance. As this condition was not planned to
be remedied until 1999, the capability for this unit should have been reduced for 1998. Furthermore, the derating of the Arapahoe 4 unit because of the use of a different coal, seems permanent rather than temporary until PSCo makes additional plant investments at that location.

Another category included by PSCo in its resource analysis in Table 6 is that for “Interruptible Loads.” In the 1993 IRP, PSCo treated such loads as part of its resource report and continued that in the 1996 report and its 1997 Update. As shown in Table A.1 of the 1996 report and in Table 6 of the 1997 Update, PSCo planned for 178 megawatts of “Interruptible Load” as a resource upon which it could count to meet its reliability requirements. This value consists of 170 megawatts of load and 8 megawatts of loss savings on the transmission and distribution system. As shown in Table 3.15 of the 1996 IRP, this resource was equivalent to the 170 megawatts of load that PSCo forecasted for its interruptible customers in 1998. However, for the 1997 IRP update, the amount of interruptible load that PSCo forecasted to have on at the time of the system peak was 152 megawatts in 1998. Furthermore, review of the interruptible demands on the system at the time of the peak demand over the last 10 years does not indicate the interruptible load ever exceeding 164 megawatts. (It does not appear that PSCo had to interrupt such load during that time.) Finally, on July 17, PSCo only recorded 50 megawatts of load actually interrupted, although the contractually interruptible load at CF&I was already off when the interruption signal went out to customers. On July 20, this amount was only 130 megawatts, so on these two days of maximum system stress, the PSCo forecasted resource capability of interruptible load was not met. The result of this deviation between the forecasted interruptible resource and load appears for the 1997 IRP Update is the creation of a “paper” resource in that the difference between these two numbers directly contributes to the reserve margin which PSCo maintains for reliability purposes.

Based on the preceding discussion, the capacity used in PSCo's 1997 IRP Update should have been reduced by at least 50 megawatts. While PSCo might have just adjusted its report for the 1997 IRP to include more short-term purchases to account for this reduction, this would have been a more realistic assessment of where PSCo must obtain resources to meet its load obligation. PSCo then would have had to actively pursue such purchases well before the events of July 13th through 20. By creating “paper” resources, PSCo effectively lowers its long-range forecast planned capacity reserve margin below that of the WSCC power supply design criteria while avoiding any expenses associated with procuring firm resources. (See pages 81-92 of the 1996 IRP report for a discussion of PSCo's reserve margin requirements.) At the very least, we believe PSCo management should review the existing resources of the Company to determine the dependable capacity which can be realistically obtained from its generators. For its part, the Commission should consider whether to include the previously referenced generating units at the capacities previously nominated by PSCo in reviewing plans of PSCo.

Finally, because of these deficiencies, there is a reasonable question as to whether PSCo met the requirements of various sections of Rule 6 of 4 CCR 723-21-6, the Electric Integrated Resource Planning Rules. Under Rule 6.1.2.2, PSCo is supposed to report the net dependable capacity of its generators. As previously discussed, the capabilities of several units were less than shown in the 1997 Update. In terms of the outages on July 17 for the Comanche and Cabin Creek generating units, the only rules of the Commission regulating electric utilities that specifically
addresses maintenance requirements are Rules 4 and 18 of 4 CCR 723-3. Rule 18 deals with properly maintaining electrical equipment in a safe manner and does not pertain to this situation. Rule 4 essentially states that utilities are to inspect plant with such frequency as would be good practice and so that equipment may be maintained in proper condition. In this instance, both units were inspected but the question is whether the inspection was thorough enough to maintain the units in “proper condition.” As the remedies proposed by PSCo for these units are additional or more intensive inspections, one could reason that Rule 4 was not fully observed by PSCo.
Section 4. Transmission Line Maintenance

The Western Area Power Administration (WAPA), PSCo, and TSG&T all claim to conduct periodic inspections for maintenance purposes of the transmission lines they operate. Although there are differences between these entities, they all generally patrol transmission lines by airplane about one to three times per year. Patrols by ground crews can be as frequent as every several months to only annually. In the past, these entities have typically noted or “flagged” sections of line spotted by these patrols and dispatched maintenance crews at convenient times, i.e., weekends or times of low system demand, to repair the line. Maintenance can be required for transmission line structures or towers and insulators as well as to remove obstacles, typically trees, in the right-of-way that might directly contact the transmission line or provide a path for a current arc from the line if close enough to a conductor. (Typically, such situations result in phase to ground faults unless the vegetation can contact more than one conductor.)

Generally, ROW maintenance strives to keep a proper amount of clearance between the transmission line conductors at their lowest expected point of sag between any two structures and terrain based obstructions. The expected amount of sag for a conductor is dependent on such factors as the conductor cross sectional area, ambient and conductor temperature, wind speed, and duration of loading, i.e., the continuous current carrying capability of the line. Based on assumptions about these parameters, which define its thermal characteristics, the maximum current carrying capability of the transmission line can be determined so that sag can be limited to meet specified clearance criteria. From a standpoint of physical safety for the public, guidelines for clearance criteria are specified in the National Electrical Safety Code.

While the preceding paragraphs describe the typical manner in which transmission lines are maintained, PSCo switched to a program of maintaining lines on a terminal-to-terminal basis on a periodic cycle in 1997 rather than concentrating on segments of lines that had been identified by patrols as needing maintenance. Under this new program, the cycle for maintaining lines is every three years. For 1998, PSCo included in its maintenance program those transmission lines which it owns and operates that it considered to be most critical, including the Rifle-Hopkins-Malta and Basalt-Malta 230 kilovolt transmission lines. These lines also cross national forest lands.

Under PSCo’s program, contractors perform the ROW maintenance based on PSCo specifications. Such contractors are under review scrutiny by PSCo team leaders and transmission line patrol crews also interface with the contractors. However, patrols continue to be done.

Our review of maintenance of the transmission system concentrated on the issue of ROW maintenance, primarily tree trimming. This became an area of concern as the Hayden-Gore Pass 230 kilovolt transmission line outage was apparently caused by tree contact when the line was carrying less than its maximum rated thermal load. Just prior to the outage, it was carrying approximately 336 MegaVolt-Amperes which is 68 percent of its thermal rating. This loading value is also no more than the normal expected transfer capability for this line under the TOT 5 operating guidelines.
Based on representations by PSCo, the outage on the Rifle-Hopkins-Malta 230 kilovolt line was also caused by contact with trees. Just before the loss of this line, it had been carrying approximately 327 MegaVolt-Amperes for several minutes. Prior to that time it was loaded to about 305 Mega-Volt-Amperes which is 82 percent of its thermal rating. While this loading value, 305 MVA, is above the normal expected transfer capability for this line under the TOT 5 operating guidelines, it is still less than the accepted maximum rating for this line under those guidelines.

Our concern with the issue of ROW maintenance was also heightened by knowledge that major system disturbances on the interconnected western United States transmission system on July 2 and July 3, 1996 had been precipitated by contact between a transmission line and a tree. In the words of theWSCC report on the incident, """" . . . tree(s) had grown too close to the line."" While it was true that the tree(s) wasn’t the sole responsible factor in the July 2, 1996 western system incident, nor is it so in this instance. It was only a contributing factor.

The WAPA is the operating authority for the jointly owned Hayden-Gore Pass 230 kilovolt line. It is responsible for all maintenance on this transmission line. This line was originally placed into service in about 1987 and crosses land controlled by the U.S. Forest Service. In 1988, TSG&T certified by letter that the clearances to terrain obstacles on this line were sufficient for operation at 345 kilovolts, approximately 20 feet from the lowest expected point of sag. Between 1988 and 1996, there was no significant vegetation clearance on the ROW for this transmission line. In 1996, a tree fell onto the line causing an outage.

Up until this time, the Forest Service had, at times, limited access to the ROW for this line and also wanted only tree-topping used for clearing of vegetation. With this first tree-line contact in 1996, WAPA began to make a concentrated effort to educate the Forest Service on the need for maintenance on this transmission line ROW. At the same time, WAPA budgeted monies to scope the extent of the ROW problem on this line. In May 1996, another tree fell onto the line. In July of 1996, approximately 50 “dangerous” trees, within 10 to 12 feet of the transmission line conductor were cut. The Hayden-Gore Pass line was patrolled by WAPA in 1997 and the patrol had the authority to cut “dangerous” trees. In 1997, approximately four acres of aspen trees at one location were cut because of their close proximity to the conductors of this transmission line.

During 1996-97, WAPA and the Forest Service were in negotiations concerning a plan to maintain the ROW for this transmission line. However, a Forest Service request that it be reimbursed for the timber value of trees cut by WAPA prolonged the negotiation process for some time. By spring 1997, the parties had basically agreed that the Forest Service would conduct a timber sale through its budgeting process with financial help from WAPA. Contract crews for the Forest Service will first remove trees of commercial value, then WAPA contract crews will go in and remove remaining trees that are viewed as being a danger to maintaining a proper clearance for the transmission line, which will be a 20-foot clearance. Pursuant to the 1997 WAPA and Forest Service negotiations, the period of September 15 to October 17 of 1998 was chosen as the time to trim trees on this ROW. WAPA estimates that it will have to cut several thousand trees on this ROW in order to have a 20-foot clearance.
On July 13th, 1998, the Hayden-Gore Pass transmission line went out of service for a brief period of time, for approximately 10 minutes. WAPA did not mount a patrol of the line at that time, as it thought the cause might be lightning. WAPA does not know the cause of this outage, but allows it may have been tree contact based on the events of July 17, 1998. Concerning the outage on July 17, a WAPA line crew verified that the Hayden-Gore Pass line sagged into trees.

As previously noted, the Basalt-Malta and the Rifle-Hopkins-Malta transmission lines were scheduled for ROW maintenance in 1998. On July 13th, 1998, contract crews were deployed on the Basalt-Malta line, although no crews were at work on the Rifle-Hopkins-Malta line. After the Hayden-Gore Pass line tripped out of service, the Rifle-Hopkins-Malta line also experienced an outage on July 17.

On the weekend of July 18-19, PSCo crews were moved onto the Rifle-Hopkins-Malta line to remove trees. During this time, the crews found evidence of tree-line contact for the July 17 outage. After the outage on July 17, PSCo revised its contractor work schedule to immediately move the contractor crews over to the Rifle-Hopkins-Malta line, which occurred on July 21. Until completed, these crews will be working on this line for the balance of the year. When finished, PSCo believes this line will be in good shape for 1999 from a vegetation management viewpoint.

We originally wanted to review with PSCo budgets and expenditures for substation and transmission line maintenance over the last five years in terms of labor and investment as well as, separately, the amount budgeted and spent on tree trimming. However, we were only able to obtain figures for budgeted and actual transmission line maintenance plus the amount actually spent on tree-trimming for selected years. These amounts are as shown in Table TM-1.

In general, this table shows that budgeted amounts for transmission line maintenance have declined by about 40 percent in nominal dollars from 1993 to 1998. This decline is somewhat tempered by knowledge, as noted by PSCo, that the effect of reorganizations in 1994, due to downsizing of personnel, and 1997, due to the merger with Southwestern Public Service, may have led to reclassification of some of these budgeted dollars into other departments. Still, one can note that PSCo typically does not actually spend as much on ROW maintenance as it budgets in any given year. The amount of funds expended on vegetation management for transmission lines was only about .8 percent of the total spent on operations and maintenance in the mid-1990s. This is expected to increase almost ten-fold in 1998 under the new vegetation management program.

It is evident from the information we have collected that the outages on these transmission lines were not caused by events outside the control of WAPA or PSCo. In the case of the Hayden-Gore Pass transmission line, it is evident that this line came into close enough contact with trees to cause the outage on July 17 even though it was not loaded to anywhere near its maximum thermal capability. The outage on July 13th may have been a precursor to the July 17 outage as lightning would not typically cause a sustained 10-minute outage. Although not a certainty by any means, in hindsight it is apparent that the dispatch of a line patrol to search for the cause of
the outage on July 13th could have provided at least an opportunity to have found the danger trees that precipitated the July 17 outage.

PSCo had already recognized the need to do vegetation maintenance on the Rifle-Hopkins-Malta transmission line. PSCo had designated it among its priority lines on which to complete the terminal-to-terminal vegetation management program in 1998. However, PSCo could not explain to us why it had decided to first initiate vegetation maintenance on the Basalt-Malta line beginning July 13th.

In our opinion, the previously described maintenance of the Hayden-Gore Pass transmission line in terms of vegetation management was deficient and had probably been so for a number of years. Quite simply, sufficient clearance was not being provided between the expected conductor sag and the vegetation. Whether this deficiency is primarily due to intransigence on the part of the Forest Service or lack of a concerted effort by WAPA to overcome the natural reluctance of the agency in charge of the forest to remove vegetation from it, we do not know or need to answer at this time. However, as operator of this transmission line, the responsibility for proper maintenance rests with WAPA.

While PSCo’s Rifle-Basalt-Malta transmission line failed in the same manner as the Hayden-Gore Pass transmission line, the egregiousness of the deficiency in vegetation maintenance is not as evident as for the WAPA operated line. Upon review of transmission line outage statistics supplied by PSCo for the years 1995-98, it appears that the Rifle-Hopkins-Malta line has been forced out of service once in 1995 due to a “foreign object” in the line and once in 1998 when a helicopter hit the line.

However, until recently, as shown in Table TM-1, spending on transmission vegetation management by PSCo has been minimal, particularly when compared to what PSCo now believes is necessary under its new more aggressive vegetation management program. During the earlier 1990s spending on ROW clearing actually declined but recently the amount has been increasing significantly. Again, intransigence on the part of government agencies, such as the Forest Service, controlling parts of the ROW may have played a role in the past on how and how often vegetation management was done by PSCo. However, as operator of the transmission line, the responsibility for proper maintenance rests with PSCo.

While we believe that the outages on these transmission lines contributed to the events that led to the load shedding in the Denver metropolitan area on July 17, we reemphasize that they alone did not cause that event. Rather, a number of individual circumstances lead to simultaneous losses of distinct elements in the electrical system serving the Front Range of Colorado that culminated in PSCo’s decision to shed load. However, as with some of the other elements, the loss of these transmission lines might have been avoided.

If vegetation maintenance on these two transmission lines is completed this year, both lines should be in the best condition in 1999, relative to maintaining proper terrain and vegetation clearances, that they have been in years. However, in the latest schedule of ROW maintenance activities, PSCo has indicated that this may not be done for these two lines until 1999. It seems imperative
that PSCo complete vegetation maintenance on these lines prior to the summer of 1999. If this is done, it is reasonable to conclude that similar outages should not reoccur next year.

As a final observation, we note that during the scheduled outage of the Hayden-Gore Pass line in September and October of 1998, PSCo has scheduled approximately 230 megawatts of generation for maintenance at the same time. Together, these outages would reduce PSCo’s total resource capability by about 360 megawatts during that time period, depending on the availability of excess transmission capacity on the remaining lines on TOT 5.

Of the previously described entities, this Commission has regulatory jurisdiction over only PSCo. Currently, the only rules of the Commission regulating electric utilities that specifically address maintenance requirements are Rules 4 and 18 of 4 CCR 723-3. Rule 4 essentially states that utilities are to inspect plant with such frequency as would be good practice and so that equipment may be maintained in proper condition. Rule 18 states that, at a minimum, plant shall be installed and maintained in accordance with the requirements of the National Electric Safety Code (NESC). This rule currently references the 1993 version of the code although there now is a more recent code edition.

Vertical clearances are specifically described under the NESC in Section 23 of the code. Clearance above vegetation, such as trees, is not specifically noted in the code although Section 21 of the Code does address tree trimming in terms of a general requirement to do so. However, the code does describe required clearance requirements for conductors from buildings, signs, billboards, antennas, tanks, and other installations, excluding bridges under Rule 234C for line to ground voltages of 22 kilovolts or fewer to which are not readily accessible by pedestrians. As shown in Table 234-1 of the NESC, the minimum vertical clearance for the previously described installations is approximately 8.0 feet. Rule 234G1 and 2 requires that additional clearances be added to this total depending upon the line to ground voltage which is upon the conductor as well as the elevation of the conductor above sea level. For a conductor operated at 133 kilovolt line-to-ground (230 kilovolt three phase) and at an average elevation of 8,300 feet, this additional clearance is approximately 4.3 feet. This implies the total required clearance for a line operated at 230 kilovolt three-phase should be about 12.3 feet from any installation that is not readily accessible to a pedestrian.

While one might try to infer into the NESC rules that specific clearance requirements could be applied to a tree, it is not so stated in the code. Therefore, regardless of the amount of clearance actually provided, it is problematic as to whether PSCo could be viewed as violating Rule 18 of the Commission regarding vegetation maintenance of any transmission or distribution ROW unless action is taken pursuant to Section 218 of the NESC. The Commission may want to consider clarifying Rule 18 so that at least the minimum clearances related to signs and billboards apply as well to trees.

In terms of Rule 4, it is obvious that prior to July 17, PSCo had not removed all potential vertical obstructions from the ROW on the Rifle-Hopkins-Malta transmission line. At that point in time, the ROW was not in the “proper condition” as stated in the Rule. However, we did not find information to indicate a continuing problem with keeping this line in operation, i.e., proper
condition, over the last few years nor that PSCo was not conducting inspections of it. Overall, it would seem that at least a partial violation of this rule may have occurred on July 17.
Section 5. Distribution Infrastructure

Although not part of the events on July 17, during this same time period of July 13th through 20, PSCo was experiencing problems with maintaining service to customers in the Highlands Ranch area. (See Attachments DI-1 for newspaper articles on this issue.) As noted in Attachment DI-2 in response to our inquiries during this investigation, a main distribution substation transformer, a 53 MVA, 230-13 kilovolt transformer, had failed at PSCo’s Prairie Substation on July 4. A smaller portable replacement had been installed and power rerouted, with some initial difficulties, over several distribution feeders within the Highlands Ranch area.

As Commission Staff had previously inquired of the infrastructure being used to supply service in the area, we asked for an update of the status of the ongoing construction. Attachment DI-3 provides that information and shows that modifications to the transmission system to improve reliability for that component in the service delivery path to this area is on schedule.

As of the date of Attachment DI-2, a new main distribution transformer had been installed at Prairie Substation in place of the undersized portable unit that was used during July of this year. As stated in Attachment DI-2, PSCo is planning on additional substation capacity to serve growth in the Highlands Ranch area. PSCo further stated a new Surrey Ridge Substation will be installed in November 1999 that should relieve Prairie feeders 1352 and 1357. This was verified by review of the Distribution Engineering Feeder and Substation Forecast as well by review of the New Centuries Energy Approved Capital Budget for 1998-2002.

In the year 2001, according to Attachment DI-2, a second main distribution transformer would be added at Marcy Substation. (Normally, such additions trigger the installation of four main distribution feeders from the substation.) However, neither the previously referenced substation forecast or PSCo’s official 1998 budget included this item. In fact, the distribution forecast does not show a need for this facility. However, there was a budget item for a third transformer at Littleton Substation, which may be the intended budgeted additional supply for the area. (It may be that a modified budget proposal was initiated this year in response to the supply problems to add further capacity in the southern rather than the northern end of the Highland Ranch area.)

Finally, at a later date, Attachment DI-2 states PSCo is proposing to place a distribution substation on the western boundary of the Highlands Ranch area. We cannot find that this item is presently within the substation forecast or the official budget. This implies an installation date of 2003 or later. Overall, with these new substations, this area will have substations serving it from the north (Littleton), south (Marcy), west (new site), and the east (Prairie and Surrey Ridge) by the early part of the next decade. With enough feeder capacity, this would appear to provide sufficient infrastructure for shifting load between substations and increasing substation capacity within the next decade in this area.

During review of PSCo’s Substation Forecasts, estimated substation overload situations in the forecast were compared to the Approved Capital Budget to gauge whether PSCo was funding substation transformer capacity projects as determined from the forecasts. In general, it appears that in the early years of the five-year budget it was consistent with the forecasts but a deviation
occurred in the latter years. (This difference is not entirely unexpected as some latter year projects may not be ripe for budget approval in terms of critical path timelines.) Overall, it appears the budget process is reasonably funding substation transformer capacity as needed.

We also briefly reviewed PSCo’s distribution line transformer placement policies and performance. These are the transformers located in a customer’s yard in the subdivision and generally serve several individual customer premises. This was done as several news reports indicated that there were numerous transformer failures during the summer. Such failure, if premature, can be caused by overloading and consequently overheating the transformer to eventually cause insulation failure on the internal cabling.

As was stated in Attachment DI-2, PSCo began in 1998 to place only transformers of at least 50 kilovolt ampere (KVA) in serving customers located in subdivisions. We were also informed by PSCo that in 1997 it had discontinued its program to monitor distribution transformer loading by computer analysis of monthly energy consumption. (In this process, the computer program converts monthly energy consumption into a demand value for all customers connected to the transformer and generates an exception report if the value exceeds some percentage, e.g., 25 percent, of the maximum capacity of the transformer.) PSCo personnel stated that they were now monitoring the transformer retirement logs to determine whether there was an abnormal number of retirements in each maintenance service area.

As noted in DI-2, we requested information on the number of transformers retired over the last several years, i.e., the transformer retirement logs. With this information, a tabulation of the number of transformers failing by size was conducted for the years 1996-98 (year-to-date). The cumulative percentage of the total number of failures within the last 15 years was reviewed for single-phase transformers sizes of 25, 50, and 100 KVA. It was felt that transformers failing because of inadequate size when placed would show up within a few years of initial placement. A comparison of the typical sizes placed, i.e., 25 and 50 KVA, should provide some indication of whether the smaller sized transformers are being improperly placed. The results are tabulated in Table DI-1.

Basically, the number of transformers failing has been no greater recently than it was in 1995. The percentage of transformer failures for 100 KVA transformers is slightly down as it is for the 25 KVA transformer size for 1998 compared to 1995. The 50 KVA transformer class has been relatively constant but did experience a significant upturn for year-to-date 1998. As this is now the minimum standard transformer size placed by PSCo, this may be a slight indication of some recent undersized placements. (Of the 47, 50 KVA transformers that have been placed during the last 15 years and failed in 1998, 6 of them were due to transformers just placed in 1998.)

To check the overall magnitude of the transformer failures against the typical mortality data for such equipment, we compared the percentage failures over the first 15 years to the depreciation data for distribution line transformers in PSCo’s last depreciation study presented to the Commission Staff. In that study, the average service life for a distribution transformer was 30 years and a standard R1 survivor curve was used to represent the mortality distribution for the transformer investment. Included in this report as Attachment DI-4 is a copy of this curve.
Basically at 15 years, one-half of the average service life, the curve indicates that approximately 83 percent of the investment should still be in service. As shown in Table DI-1, the percentage of transformers retired in each of the last few years has been about 12 to 17 percent with lives of 15 or fewer years. Except for the notable exception with the 50 KVA transformers in 1998, the retirement data appears to correlate with mortality expectations, and it is not obvious from this information that PSCo has had a significant problem with undersizing distribution line transformer installations up to this point in time.

Besides the transformer failure data, we obtained from PSCo a distribution of its transformers by size, both for the overall company service area and for the Highlands Ranch area. Basically, as shown in Table DI-2, the percentage of installed single-phase transformers, the type used by residential and small commercial customers, in Highlands Ranch that are 25 KVA or fewer are significantly lower than for the overall Company, while the total of 50 KVA transformers is significantly greater. However, the percentage of 100 KVA single-phase installed transformers in Highlands Ranch is slightly less than for the overall Company. From this data, it is not obvious that transformer installations are being routinely undersized unless there are a small number of currently installed 50 KVA transformers that should have been of the 100 KVA size.

As of approximately August 25, PSCo also had 197 transformers ordered but waiting for placement in the Highlands Ranch area. Of this amount, 5 percent were 25 KVA transformers, 80 percent were 50 KVA and 13 percent were 100 KVA. Again, this might indicate a small undersizing problem in the 50 to 100 KVA classifications for currently placed transformers but, as PSCo has phased out 25 KVA installations, a comparison to the installed base of 25 and 50 KVA units is not appropriate. (We are also unsure of why PSCo would have so many transformers classified as “size unknown” in Highlands Ranch. This may skew the preceding statistics based on the actual size of these transformers.)

We also asked for a copy of the engineering guidelines for sizing distribution transformers. Attachment DI-5 is a copy of the two pages within the guidelines that set out procedure for the sizing of distribution transformers. These guidelines are based on expected maximum load, as a function of house size and whether central air conditioning is installed, and the number of customers to be connected to a transformer at one location. This guideline was developed in late 1995 and appears to be based upon internal PSCo load research data.

As we previously noted, the residential load research sample was installed in 1991, so these guidelines may be somewhat undersized along the breakpoints when considering moving to the next size transformer for today’s new customers. Also, upon review of these tables, there may be some question regarding the coincidence factors used by the Company in these guidelines. As shown in Table DI-3, the implied coincidence factor derived from the coincidence multiplier, i.e., the inverse of that value, shown in the PSCo standards reaches a value that is less than the ratio of the residential group coincidence factor derived from the load research data supplied to us by PSCo. Again, if these factors are too low, this may reinforce a tendency for these guidelines to provide an undersized result along the breakpoints when considering moving to the next size transformer in the service design. (However, when the load calculated from the guideline is well below the selected transformer size, these factors may not make a difference.)
Based upon the vintage of the load research sample that underlies these guidelines and some question on the magnitude of the consequence factors used by PSCo, these guidelines should be reviewed. In such review, some consideration should also be given to the load values in the guidelines as typical installation demands and number of central air conditioning units in houses today could differ from that assumed by PSCo.

We also have some concern about PSCo only relying on the transformer retirement log to gauge whether its distribution line transformers are being overloaded. PSCo offered no insight into how the retirement logs will be used to proactively determine that transformers are being loaded too heavily and should be replaced. While this may be viewed as a form of “diagnostic maintenance,” i.e., waiting to reach until more than the normal amount of transformers fail, it could leave more customers to experience outages before a replacement program is undertaken. Unless PSCo can more fully define a proactive maintenance policy in relying on transformer retirement data, it should consider reactivating some version of its computerized monitoring program or undertake some type of statistically-based sampling program in which measurements are taken of some distribution line transformer loads periodically.

However, overall, we do not find in our review that the distribution transformer placements made in the recent past by PSCo indicate any significant errors in service design. Further scrutiny could be given to specific areas through on-site inspections but this was precluded by the time constraints on this report.

We also requested from PSCo a frequency distribution or tabulation for the last 5 years of the total number of distribution trouble tickets resulting from employee observations or in response to customer complaints. This would be disaggregated by cause such as transformer overload, low voltage, cause found/not found, etc. and the location in the system, i.e., feeder, secondary, etc., as well as geographic location, i.e., serving substation. PSCo did not supply this information in the form requested but did supply a tabulation of outages by cause over the last 5 years which is included as Table DI-4. As can be seen from this table, outages due to overloads are a small percentage of all outages by cause. However, this number has been constantly growing while the other categories generally have not.

As PSCo could not produce a tabulation of complaints by category, we further inquired of it whether complaints made to it by customers are recorded and kept for review. This inquiry was made as on sheet 23 in the Rules and Regulations section of the PSCo Electric tariff it is clearly stated that the Company will keep a record of each written complaint in a categorized manner. This provision in the tariff of PSCo is essentially the same requirement as in Rule 8 of 4 CCR 723-3.

Upon requests to produce samples of customer complaints from such departments as distribution, rates, and corporate correspondence, PSCo personnel stated that there was no tracking of complaints by PSCo or a process in place to uniformly record them in any manner. Therefore, this means there is no possibility of authorized representatives of the Commission reviewing such records as contemplated by Rule 8. Based on the information provided by PSCo, we believe
PSCo is in violation of its tariff as well as Rule 8 of 4 CCR 723-3 concerning retaining records of written complaints made to it by customers.

Here, we will also note that the Commission has even more comprehensive rules on logging customer complaints for the telecommunications industry. Attachment DI-6 is a copy of that rule for informational purposes. If the distribution function of PSCo remains under regulatory authority while other functions, i.e., generation, becomes more competitive within the electric industry, it may be reasonable to consider revising Rule 8 to be more in line with the telecommunications industry requirements. In a new regulatory environment, this would enable the Commission to more thoroughly review the promptness of distribution service providers in addressing such customer complaints.
Section 6. Capital Budgeting and Maintenance Spending

In order to gauge whether the amount of expenditures by the Company on maintenance and operations has changed significantly over the last few years, data from the “Annual Report of Public Service Company to the Colorado Public Utilities Commission” was reviewed. One set of reviewed data was the direct payroll expenditures which PSCo attributes to operations and maintenance by service function. Maintenance payroll dollars are the labor costs for repair and upkeep of the electric plant while operation payroll dollars are the labor costs associated with operating the electric plant and providing service to customers. Under FERC accounting requirements, PSCo is required to record this information by function, i.e., production, transmission, etc.

As shown in Table CAP-1, overall maintenance payroll expenses in nominal dollars has declined by about 5 percent from 1992 to 1997. Most of this decline was due to lower payroll expenditures for production maintenance. While the payroll dollars for distribution maintenance activities increased by about 29 percent, some of this increase could be attributed to customer growth which increased by about 17 percent from 1992 to 1997. During this same time period, additional generation was added at Fort. St. Vrain in 1996 but, as will be discussed in conjunction with Table CAP-2, recorded expenses for this plant were minor so we have not attempted to gauge the effect of this additional plant within the annual production payroll dollars. In addition, there appeared to be no need to discuss the transmission payroll in terms of additional facilities to operate and maintain as total structure miles of transmission over the 1992 to 1997 time period were essentially constant. In terms of real dollars, the decline in total direct payroll expenditures for maintenance activities was approximately 15 percent. Again, the production maintenance payroll absorbed a real dollar decline while distribution and transmission maintenance payroll dollars showed an increase in real terms. However, the real dollar increase in distribution maintenance payroll dollars was slightly less than the percentage growth of new customers over this time period.

Payroll dollars directly assigned to the operating functions declined more significantly than did the maintenance payroll over this time period. The overall operational payroll declined by about 35 percent from 1992 to 1997 in terms of nominal dollars and about 43 percent in real dollars. However, a very significant part of this decline occurred in the administrative and customer service functions. Within the payroll dollars for the production, transmission, and distribution functions, there was a decline of about 17 percent in nominal and 26 percent in real dollars over this time period. Here, we have a different scenario than for the maintenance payroll as most of the decline in the operations payroll came from distribution operations which declined by 45 percent from 1992 to 1997 even though customer growth amounted to 17 percent in this time period.

Another set of data reviewed from the Annual Report of PSCo was the operation and maintenance data by FERC expense accounts, i.e., not just payroll. This data is contained within Attachment CAP-2. In this case, operation is basically both the labor and material costs for operating the system and providing service to customers. Maintenance includes the labor and material costs in the repair and upkeep of the system. As material costs can be included within
these accounts, we did not specifically attempt to look at them in terms of real dollars. For the accuracy to justify this additional information, data from a breakdown between labor and material form subaccounts of PSCo would be required to apply deflators in terms of labor and plant investment. Within our time constraints for this report, we did not attempt this additional analysis. However, as the operational accounts are likely to have fewer material expenditures included within them than the maintenance accounts, one could roughly apply the wage deflator to them to gauge the probable levels of spending in real dollars.

The first page of CAP-2 details operation and maintenance expenses for PSCo’s generating plants over the 1992 through 1997 time period as taken from the Annual Report of PSCo to the Commission. In this instance, we are concerned with the amount of non-fuel related expenses, such as expenses for operating and maintaining the generators. Here, we find that these expenses have declined by about 12 percent from the 1992-93 time frame until 1996-97. In 1996, PSCo added a generating unit at Fort. St. Vrain. The additional expenses for this unit added about $1.2 million to the 1997 total operation and maintenance cost, excluding fuel, and roughly $0.5 million to the 1996 total. Adjusting for this addition, the decrease in production operation and maintenance costs, excluding fuel, was about 13 percent.

The second page of CAP-2 tabulates operation and maintenance expenses over the 1992 through 1997 time period related to the transmission and distribution function of the Company. For this review, we have removed the costs associated with wheeling of power by others, i.e., the charges paid for the use on another entity’s transmission system, and load dispatching from the transmission operations expenses. As we are interested in the operations and maintenance costs for PSCo’s own system, including wheeling costs would mask the data we want to review. Based on this data, the transmission operation costs reported in the PSCo Annual Report have declined significantly in 1994-96 compared to the 1992-93 time period. In 1997, these recorded expenses have basically returned to the 1992-93 level. As the amount of transmission structure miles have essentially remained constant, it appears one could surmise there has been significantly fewer real dollars spent on this function than in the early 1990s.

Distribution operation and maintenance dollars have grown by about 18 percent between 1992 and 1997, which approximately matches the growth in the number of customers over that period. However, again, most of this increase, 9 percent, was growth in spending between 1996 and 1997 as the average level of expenditures in 1995-96 compared to 1992-93 was only about a 4 percent increase in nominal dollars. As with the transmission function, it appears there were significant real declines in operation and maintenance expenditures by PSCo between the mid- and early 1990s. However, distribution maintenance does appear to be one category in which PSCo has steadily increased its expenditures in nominal dollars during this time. This category has increased by about 33 percent from the 1995-96 compared to 1992-93 time period. At the same time, the direct payroll assigned to this category in Attachment CAP-2 does not show the same amount of increase, being roughly only 12 percent over the same time period. We did not attempt to review this discrepancy further, but it may indicate material costs used in the maintenance function have increased sharply in the last few years.
The dispatching costs are separately reviewed as it appears cost allocations among internal transmission and system control costs for dispatching have changed over the years. By looking separately at the total dispatching costs over the transmission and distribution functions of the Company, it appears that these have also remained relatively flat and have certainly declined in terms of real dollars. This is somewhat surprising as our impression is that the changes initiated by the FERC in terms of requiring open access for the transmission system under FERC order 888 would seem to require additional complexity and costs for network control and dispatching.

We also attempted to look at capital expenditures for PSCo primarily through use of its Annual Report as well as review of its latest available capital budget. Table CAP-3 is the tabulation of the data used in this review. For historical data, the real dollar value of plant appears on these sheets and we tend to view the additions to plant recorded by PSCo as more indicative of its capital spending than the net amount recorded on the accounting records of the Company. In reviewing capital investments in facilities, one should be cognizant that such investments by electric utilities are “lumpy” in nature, i.e., an investment in one year may offer sufficient capacity for several years. This negates the need for year-to-year spending similar to the operations and maintenance expenditures of PSCo for large facilities, i.e., generation and transmission. However, as facility requirements come closer to the customer (i.e., customer loop, meter, and transformer) one can begin to, again, think in terms of comparable annual levels of spending. In this attachment, we used only data beginning in 1993 because in 1992 PSCo had significant additions to its accounting records. The additions were due to the acquisition of facilities from the Colorado-Ute Electric Association, Inc., a generation and transmission cooperative regulated by this Commission that went bankrupt in the early 1990s.

As shown on sheet one of Table CAP-3, the total production plant additions in nominal dollars has significantly fluctuated over the 1993-97 time period. In 1996, part of this fluctuation in total investments was due to the Fort. St. Vrain generating unit being added to the investment records of the Company. Also, during the 1993-94 time period, we understand that PSCo was making significant investments in pollution control facilities, e.g., Nox abatement investments for boilers, etc. These two significant capital investments tend to obscure the ongoing investments in production facilities. An adjustment in this tabulation was made to the boiler account to reflect investments similar to other years, i.e., excluding the effect of the pollution control investments. An additional adjustment was also made to partially exclude investments recorded in the accounts for turbine generators as part of the 1997 total that could be due to upgrading the turbine blades at the Pawnee Power plant and the 1996 date includes the cost of the Fort St. Vrain generators which is another nonrecurring type investment.

With these adjustments it appears that a tabulation of continual annual investments in production equipment, i.e., the Adjusted Total Production Plant in the table, finds the total being about $39 million in 1997 compared to roughly $34 million in the 1993 period. This indicates that year-to-year production investment, exclusive of significant nonrecurring projects, has risen slightly in nominal dollars. In terms of real dollars, using a price deflator for private purchases of electrical transmission, distribution, and industrial apparatus, over the 1992-97 time frame, the amount of investment in 1997 still appears to be slightly above that in 1993. However, the table does
indicate that normal 1996 investments were depressed, possibly in deference to the significant
capital investments in the new generators at Fort St. Vrain.

Transmission plant investment is presented in this report only for informational purposes as we
have no additional insight on the drivers for this investment during the 1993-97 time period to
present in this report. Again, this is a “lumpy” type of investment and tracking of individual
projects would be necessary to determine a trend in this type of investment. We have also
presented annual capital additions for the category of “General Plant” shown on the second sheet
of Table CAP-3. However, as with the preceding pages of this attachment, one can note that
plant investment for 1996 was depressed across all categories except for the addition of the
generation facilities at Fort. St. Vrain and the purchase of approximately 270,000 distribution
meters. In 1997, it appears that investment in the other categories was higher, possibly due to
more funds being available for investment. In other words, one could hypothesize from these
observations that PSCo is funding capital investments within a set capital budget. Whether PSCo
is actually doing this and if such investment limitations are constraining needed system
improvements is beyond the time constraints on this report to reasonably analyze.

The distribution plant investment shown on the second sheet of Table CAP-3 is in terms of total
plant investment and investment categories closely linked to customer additions, i.e., line
transformers, services, and meters. Subtracting these investments from the total provides a
measure of the amount of dollars spent on the distribution network. Again, we see the previously
described upshot in facility spending in 1997. However, the amount of funds spent for the
distribution network in 1996 was significantly less than for other years, being about 40 percent of
that in either 1997 or 1995 even though the average number of customers added to the network
was more in 1996 than in either of those two years. As previously stated, 1997 appears to be a
“catch-up” year for spending, and whether this was sufficient would require monitoring which is
outside the scope of this report.

Sheet 3 of Table CAP-3 is taken from a filing before the Commission by PSCo. It shows
forecasted budget expenditures for the electric department of the Company for the years 1998-
2000. In all, budgeted expenditures appear to be running above the total amount of electric plant
(i.e., production, transmission, and distribution plant) investment additions recorded in the
accounting records of the Company over the last few years.

We also reviewed the latest approved capital budget of the Company. The information provided
to us was not broken down into proposed investments only for PSCo so we had to disaggregate
this data. In some instances, we were not entirely sure how to categorize the project, e.g., as
A&G investments. We also had to allocate portions of some joint projects to PSCo, e.g., the
transmission line tie to SPS which was done on a 50 percent basis.

The results or our review are attached as page 4 of Table CAP-3. Basically, our analysis appears
to be consistent with the budgeted investments shown on page 3 of Table CAP-3. In the year
2000, the data for total investments on page 4 indicates fewer expenditures than the PSCo data
provided on sheet 3. Budgeted investment on sheet 4 remains fairly constant in the year 2001 but
falls off in the last year of the forecast. The investment numbers on sheet 4 are in terms of escalated dollars. PSCo stated that the escalation rate was about 3 percent from 1997.

We have also shown total expenditures without large projects, i.e., Fort. St. Vrain investments and the transmission tie line to SPS. At least for 1998 and 1999 investment estimates, without large projects from the January 1998 approved budget, appear to be as large as total actual additions to plant over the last few years. The budgeted numbers appear to tail off in the later years of the forecast. However, this is not uncommon in capital budgeting as the critical date to approve specific projects in the planning pipeline for those years may not have been within this budget. Generally, PSCo (actually NCE) appears to be continuing to budget for an investment total similar to PSCo's actual investments over the last few years. In relation to the total budget for all projects of NCE, our allocated budget figures indicate that the PSCo electric department share of the capital budget is roughly 50 percent over this 5-year budget time frame.
Section 7. Staffing of Power Plants and Other Service Supply Functions

In preparation of this report, on August 13th, we requested PSCo to provide a dissaggregation of its employees by work function, *i.e.*, distribution, transmission, generation, administrative, and general, consistent with its previously described payroll distribution contained in Attachment CAP-1 such that the total number of employees would be consistent with the count of total electric department employees as shown on page 323 of the PSCo Annual Report to the Commission. After review of the provided material, we found that the original response from PSCo was not consistent with the request. This was evident from adding the annual total employee count data provided separately by PSCo for both production and other electric department workers and comparing that to the data reported in the Annual Report. For instance, the PSCo response gives the following aggregate employee count data:

<table>
<thead>
<tr>
<th>Year</th>
<th>Electric department</th>
<th>Production department</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1997</td>
<td>1096</td>
<td>809</td>
<td>1905</td>
</tr>
<tr>
<td>1996</td>
<td>1439</td>
<td>905</td>
<td>2344</td>
</tr>
<tr>
<td>1995</td>
<td>1472</td>
<td>939</td>
<td>2411</td>
</tr>
<tr>
<td>1994</td>
<td>1686</td>
<td>1011</td>
<td>2697</td>
</tr>
<tr>
<td>1993</td>
<td>1077</td>
<td>1087</td>
<td>2241</td>
</tr>
<tr>
<td>1992</td>
<td>1094</td>
<td>1085</td>
<td>2179</td>
</tr>
</tbody>
</table>

However, the Annual Report of PSCo to the Commission shows a total electric department employee count for these years of:

<table>
<thead>
<tr>
<th>Year</th>
<th>Electrical employee count</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>2712</td>
</tr>
<tr>
<td>1991</td>
<td>2795</td>
</tr>
<tr>
<td>1992</td>
<td>3708</td>
</tr>
<tr>
<td>1993</td>
<td>4285</td>
</tr>
<tr>
<td>1994</td>
<td>4268</td>
</tr>
</tbody>
</table>

We again requested the originally sought data but only received the same data set but in a different format. In explaining its second response, PSCo appears to state that its annual report responses, *i.e.*, the FERC FORM 1 submittal, was based on allocations and not actual employee counts and that “common employees,” *i.e.*, those in administrative and general functions could not be quantified in terms of assignment to the electric department. Faced with a time constraint and PSCo’s inability to fully document its annual report filings with the Commission, we analyzed the data that PSCo had given us in terms of production and electric department employees.

As can be seen from the preceding tabulation of the annual report data and the PSCo responses, the data provided for 1997 is fairly close to the total number of electric department employees stated on page 323 of the annual report. We surmise this difference may be due to the transfer of a number of the “common employees” (*i.e.*, administrative and general functions such as accounting and payroll functions to New Centuries Energy [NCE], which is now the holding company for PSCo). Comparing the differences in this tabulated data from the 1992-93 time frame with that from the 1996-97 time frame suggest that PSCo has significantly reduced its employee counts in the administrative and general (A&G) function over that time period. Additional validation of that assumption can be found in Table CAP-1 as the payroll dollars for A&G plus customer service functions has declined by about $23 million in real dollars. This is roughly enough for about 1000 positions, assuming that the average salary was about $24,000 in 1992 dollars.
Table STA-2 is a compilation of the employee count within the production department of PSCo. These are the employees that operate and maintain the electric generating plants operated and, at least jointly, owned by the Company. As previously noted from the employee tabulation in this discussion, production department employees have fallen by about 300 positions over the last 5 years. In this table, we have taken the employee data provided by PSCo and attempted to categorize the number of employees by job title. In 1997, PSCo significantly revised some of its craft job descriptions which made it difficult to track personnel by the old job functions. For this data, we have proportioned the number of personnel in the revised job descriptions back into the previous job category functions.

With this data, we were interested in assessing whether the levels of craft and technical personnel had absorbed most of this decline. These personnel are more directly responsible for the daily operation and maintenance of the plant. As the data allowed us to do so, we tabulated the craft function in terms of mechanics, operators, and electrical plus fuel handling. Technical type positions were categorized into analysts, engineers, and technicians. Support staff would include the clerical and stores category. Management has been tabulated in terms of senior managers, (i.e., plant manager, plant operations, and plant maintenance managers), while supervising personnel were tabulated in terms of their function, i.e., maintenance, operations, or engineering.

The tabulation shows that the greatest percentage reductions in personnel occurred in the stores (41 percent), fuel handling (32 percent), engineering/engineering management (29 percent), and clerical (24 percent) between 1996 and 1997. Of these engineering seems most likely to have some potential for impacting plant performance. Fuel handling may be able to absorb some personnel reductions in that another craft could do some of these functions and coal train unloading is tied to specific delivery schedules for which staffing plans can be made. While these functions have been reduced significantly in the last year, others have had significant declines over the full 5-year period considered in this table. PSCo has apparently reduced plant management personnel by about 46 percent, stores, i.e., warehouse personnel, by about 45 percent and clerical by about 63 percent. While craft personnel have also declined, the magnitude doesn’t appear to be as severe.

In 1992, PSCo had about 3,341 megawatts of generating nameplate capacity. Based on 1085 personnel assigned to its plants, this is a ratio of about .33 employees per megawatt. In 1997, with about 3,474 megawatts of production capacity, this value had declined to about 0.23 employees per megawatt, which is more in line with the employee ratio that Commission Staff found for comparable coal fired generating plants in the Pawnee Efficiency Docket. As previously discussed in this report, PSCo has been able to obtain an EAF or EFOR for its major generating plants similar to that for other utilities in recent years. Overall, we don’t presently see that the current staffing levels have had a negative impact on these power plants. However, statistics such as the EAF or EFOR should be tracked to see if there is any longer term problems that may be attributable to these manpower cuts.

Table STA-3 is a compilation of the employee count of the electric department within PSCo but excluding the production department. These are the employees that operate and maintain the electric transmission and distribution system operated and, at least jointly, owned by the
Company. In conjunction with those types of employees, some years of the data furnished by PSCo also included personnel with the customer services function of the Company. These are people who deal directly with answering customer questions and also billing personnel. In this table, we have taken the employee data provided by PSCo and attempted to categorize the number of employees by job title. We were interested in assessing whether the levels of craft and technical personnel had experienced a significant decline. These personnel are more directly responsible for the daily operation and maintenance of the plant.