EXHIBIT

Exhibit No.: ______
Issue(s): Accounting Authority Order
Witness: Trippensee/Rebuttal
Sponsoring Party: Public Counsel
Case No.: EO-2000-845

REBUTTAL TESTIMONY

OF

RUSSELL W. TRIPPENSEE

Submitted on Behalf of
the Office of the Public Counsel

ST. JOSEPH LIGHT & POWER COMPANY

Case No. EO-2000-845

October 10, 2000

Exhibit No. 8 NP
Date 10-26-00 Case No. EO-2000-845
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TABLE OF CONTENTS

Name and Qualifications	1
Accounting Authority Order Overview	3
Accounting Authority Order Nature of the Event	4
Accounting Authority Order Other Considerations	33
Testimony Summary	38

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the matter of the application of St. Joseph Light & Power Company for the issuance of an accounting authority order relating to its electrical operations.	))))	Case No. EO-2000-845

AFFIDAVIT OF RUSSELL W. TRIPPENSEE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Russell W. Trippensee, of lawful age and being first duly sworn, deposes and states:

1. My name is Russell W. Trippensee. I am the Chief Public Utility Accountant for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony consisting of pages 1 through 38 and Schedule RWT-1 through RWT-5.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Russell W. Trippensee

Russell W. Trippensee

Subscribed and sworn to me this 10th day of October, 2000.

Bonnie S. Howard

Bonnie S. Howard
Notary Public

My commission expires May 3, 2001

REBUTTAL TESTIMONY

OF

RUSSELL W. TRIPPENSEE

ST. JOSEPH LIGHT & POWER COMPANY

CASE NO. EO-2000-845

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. Russell W. Trippensee. I reside at 1020 Satinwood Court, Jefferson City, Missouri 65109, and my business address is P.O. Box 7800, Jefferson City, Missouri 65102.

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

A. I am the Chief Utility Accountant for the Missouri Office of the Public Counsel (OPC or Public Counsel).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I attended the University of Missouri at Columbia, from which I received a BSBA degree, major in Accounting, in December 1977. I attended the 1981 NARUC Annual Regulatory Studies Program at Michigan State University.

Q. HAVE YOU PASSED THE UNIFORM CPA EXAM?

A. Yes, I hold certificate number 14255 in the State of Missouri. I have not met the two-year experience requirement necessary to hold a license to practice as a CPA.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. From May through August, 1977, I was employed as an Accounting Intern by the Missouri Public Service Commission (MPSC or Commission). In January 1978 I was employed by the MPSC as a

Public Utility Accountant I. I left the MPSC staff in June 1984 as a Public Utility Accountant III and assumed my present position.

Q. **PLEASE DESCRIBE YOUR PROFESSIONAL AFFILIATIONS.**

A. I served as the chairman of the Accounting and Tax Committee for the National Association of State Utility Consumer Advocates from 1990-1992 and am currently a member of the committee. I am a member of the Missouri Society of Certified Public Accountants.

Q. **PLEASE DESCRIBE YOUR WORK WHILE YOU WERE EMPLOYED BY THE MPSC STAFF.**

A. Under the direction of the Chief Accountant, I supervised and assisted with audits and examinations of the books and records of public utility companies operating within the State of Missouri with regard to proposed rate increases.

Q. **WHAT IS THE NATURE OF YOUR CURRENT DUTIES WITH THE OFFICE OF THE PUBLIC COUNSEL?**

A. I am responsible for the Accounting and Financial Analysis sections of the Office of the Public Counsel and coordinating their activities with the rest of our office and other parties in rate proceedings. I am also responsible for performing audits and examinations of public utilities and presenting the findings to the MPSC on behalf of the public of the State of Missouri.

Q. **HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE MPSC?**

A. Yes. I filed testimony in the cases listed on Schedule RWT-1 of my testimony on behalf of the Missouri Office of the Public Counsel or MPSC Staff.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My testimony will state the position of the OPC regarding the appropriate accounting and regulatory treatment of the June 7, 2000 explosion at the St. Joseph Light & Power (StJLP or Company) Lake Road generating station. I will also address the Company's request for an Accounting Authority Order (AAO), filed on June 23, 2000, which initiated this case. I will respond to specific comments, assertions, and recommendations made in the direct testimony of Company witnesses, Larry Stoll, Stephen Ferry, and Dwight Svuba filed on September 12, 2000 in this case.

ACCOUNTING AUTHORITY ORDER OVERVIEW

Q. WHAT IS THE ISSUE BEING ADDRESSED IN THIS CASE.

A. The Company has requested that this Commission authorize the deferral of certain expenses the Company alleges are the incremental costs resulting from the explosion and subsequent fire at Unit 4/6 of the Lake Road Generating Station. The Company is further requesting that it be allowed to maintain these amounts on its balance sheet until an unspecified future point in time when a rate change request is effective. An amortization of the deferred amount would begin at the effective date of the rate change. The focal point of the Company's request is that the amortization expense resulting from the deferral will be included in the cost-of-service on which the revised tariff rates are based. These requests are contained in paragraph 9 of the Company's Application For Accounting Authority Order filed on June 23, 2000.

Q. DOES PUBLIC COUNSEL SUPPORT COMPANY'S REQUEST FOR AN ACCOUNTING AUTHORITY ORDER?

A. No. The Company's AAO request is an attempt to insulate its shareholders not only from regulatory lag associated with the amortization of a deferral, but more importantly, the request attempts to insulate shareholders from inappropriate acts or omissions by Company management and its employees which precipitated the explosion and fire that caused a forced outage at Lake Road unit 4/6. These acts or omissions caused an event that does not justify an AAO being granted by this Commission.

ACCOUNTING AUTHORITY ORDER
NATURE OF THE EVENT

Q. PLEASE SUMMARIZE WHY PUBLIC COUNSEL BELIEVES THE EXPLOSION AND FIRE AT LAKE ROAD UNIT 4/6 WAS AN EVENT RESULTING FROM AN ACT OR OMMISSION BY THE MANAGEMENT AND/OR EMPLOYEES OF ST. JOSEPH LIGHT & POWER COMPANY.

A. The explosion and resulting fire at the Lake Road unit 4/6 occurred after the installation of a new unit Mark V control system by General Electric in May, 2000. A review of responses to data requests clearly indicates that this explosion and fire did not result from the unexpected failure of system components or from an act of God. In fact, these responses indicate that StJLP management decided to place Lake Road Unit 4/6 back on-line even though they knew employees had inadequate training on the new Mark V operating system. The responses also reveal that operating procedures were not followed in the days leading up to the event, and that employees were unable to properly operate the generating facility during the event in order to minimize or eliminate any damage to the unit.

Q. HAS PUBLIC COUNSEL RETAINED AN ENGINEERING CONSULTANT TO REVIEW THIS EVENT?

A. Yes, OPC has retained Mr. Jatinder Kumar, of Economic and Technical Consultants, Inc. who is also filing rebuttal testimony in this proceeding.

Q. THEREFORE IS IT FAIR TO STATE THAT YOUR COMMENTS REGARDING THE EVENT ARE BASED ON YOUR ANAYLYSIS OF DOCUMENTS AND EVENTS FROM THE PERSPECTIVE OF A REASONABLE MANAGER OR EMPLOYEE?

A. Yes.

Q. CAN YOU PROVIDE A SYNOPSIS OF THE EVENTS LEADING UP TO THE EXPLOSION AND FIRE ON JUNE 7?

A. The original Lake Road Unit 4/6 operating system was installed in 1966 and modified in 1995. GE commenced work on the new Lake Road Unit 4/6 operating system early in 2000 and completed installation during May of this year. Training of StJLP employees took place during the week of May 22 – 26, 2000 and Lake Road Unit 4/6 operated from June 2, 2000 until the event on June 7, 2000.

Attached to my testimony, as Schedule RWT-2, is a page from the Company's response to OPC DR#5001. The page is entitled Turbine Generator 4 June 7 Incident Possible Contributing Factors and has been marked highly confidential by the Company. This schedule outlines the events in more detail. The document is marked highly confidential but was declassified by the Company in the Deposition of John T. Modlin taken on October 4, 2000. Mr. Modlin indicated the document was not highly confidential on page 123, lines 4 – 12 of the deposition. At the beginning of the deposition of Mr. John T. Modlin taken on October 4, 2000 an update to OPC DR#5001 was provided to OPC. I have attached this document to my testimony as Schedule RWT-5. The document is marked highly confidential but was declassified by the Company in the Deposition of John T. Modlin taken on October 4, 2000. Mr. Modlin indicated the document was not highly confidential on page 150, lines 1 – 4 of the deposition.

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF COMPANY WITNESS DWIGHT SVUBA?

A. Yes, I have.

Q. DOES MR. SVUBA'S DIRECT TESTIMONY'S RECITAL OF THE CHRONOLOGY OF ACTS LEADING UP TO THE JUNE 7 EVENT DESCRIBE AN EVENT THAT COULD HAVE BEEN AVOIDED IN YOUR OPINION?

A. Yes. The physical cause of the explosion and resulting fires was the loss of lubrication to Lake Road Unit 4/6 bearings in the generator. Without lubricants, the bearing overheated, thus causing the explosion and fires. It is clear from reading Mr. Svuba's testimony that Company personnel failed to understand how the new Lake Road Unit 4/6 operating system worked. Despite this lack of understanding, the Company placed the unit back on-line on June 2. This lack of understanding of Lake Road Unit 4/6's basic system operations created the situation where the DC oil pump was unable to respond to the unit being tripped off line. The DC oil pump did not fail, it simply had been previously turned off and subsequently not returned to a ready status. Had it been in a ready status, it would have sensed the drop in oil pressure from the AC oil pumps going off-line. The lower oil pressure is the signal to the DC oil pump to automatically begin supplying oil lubricants to the bearings, thus preventing the overheating, failure of the hydrogen seals and resulting explosion and fire.

Q. HAVE COMPANY PERSONNEL SPECIFICALLY IDENTIFIED THE FAILURE OF THE DC OIL PUMP TO START PROVIDING LUBRICATION AS THE CAUSE OF THE EXPLOSION AND FIRE?

A. Yes. OPC took the deposition of StJLP employee John T. Modlin on October 4, 2000. Mr. Doug Micheel was the attorney who took the deposition on behalf of Public Counsel. The following exchange confirms the physical cause of the explosion.

> Q. But for the failure of the DC oil pump to start on June 7th, 2000, do you have an opinion about whether the explosion and fire would have occurred at Unit 4/6?
>
> A. Well, the normal course of events in that situation would be that the DC oil pump would start and provide oil flow until the operators transferred power.
>
> Q. And so the failure of the DC oil pump to start providing lubrication to the bearings and the hydrogen seals caused increased friction heat, the explosion and the fire?
>
> A. Right. And resulted in the damage, yes.
>
> Q. So but for the failure of the DC oil pump to start, under normal operations, the explosion and fire that occurred on June 7th, 2000 would not have occurred?
>
> A. Under normal situation, yes.
>
> (Deposition of John T. Modlin Taken On Behalf of the Office of the Public Counsel, October 4, 2000, page 171, lines 7 – 24)

Q. DESPITE MR. STOLL'S ASSERTION TO THE CONTRARY, HAS THE COMMISSION PREVIOUSLY LOOKED AT THE NATURE OF THE EVENT AS THE PRINCIPAL INQUIRY IN DETERMINING WHETHER OR NOT TO DEFER COSTS IN AN AAO APPLICATION CASE?

A. Yes. The MPSC, in a StJLP case, specifically stated that the initial question that must be addressed is the nature of the event in an AAO application case;

> The **principal inquiry** is whether the costs and expense to be deferred **result from an extraordinary event**. The December, 1994 ice storm was a natural disaster which resulted in unusual expenses for restoring electric service to SJLP's customers. The Commission is of the opinion that that ice storm constitutes an extraordinary event and that the costs and expenditures described above, if prudently incurred, are extraordinary and material for SJLP's electric operations and are not now, nor have they previously been, reflected in SJLP's electric rates.
>
> (emphasis added)
>
> (St. Joseph Light & Power Company, Case No. EO-95-193, page 3).

Q. DOES PUBLIC COUNSEL BELIEVE THAT AN INCIDENT PRECIPITAED BY THE COMPANY'S FAILURE TO UNDERSTAND HOW ITS GENERATING FACILITIES OPERATE CONSTITUTES AN EXTRAORDINARY EVENT?

A. No. Public Counsel would submit that understanding how generating facilities operate is a fundamental obligation of the utility. The failure of the Company and its personnel to clearly and concisely know how to safely shut down the unit in the event of a trip off line and ensure that damage to the unit did not occur does not create an event that deserves special regulatory accounting treatment.

Q. PLEASE EXPLAIN WHY PUBLIC COUNSEL ASSERTS THAT THE COMPANY DID NOT UNDERSTAND HOW TO OPERATE THE LAKE ROAD UNIT 4/6.

A. Company personnel received inadequate training on the new Mark V operating system. The training received was not specific to the Lake Road Unit 4/6 system. Company management and employees recognized these facts prior to start-up of the unit on June 2 but went ahead and operated the unit anyway.

The poor quality of training or non-unit specific training is addressed in the document that is attached to my testimony as Schedule RWT-2. Attached to my rebuttal testimony, as Schedule RWT-3 is a letter from John Modlin (StJLP Director of Fuels & Projects) to Steve Ritter of General Electric. Attached to the letter are the course evaluation forms from the initial training held on May 22 – 26, 2000. The Company has marked these documents Highly Confidential. A review of these documents clearly indicates that the Company perceived a problem, recognized they were ** ____ ____ ** but nonetheless made the decision to start-up the unit despite this lack of training or an understanding of how to operate the unit as readily became apparent.

Q. WHEN DID THE COMPANY FIRST CONTACT GENERAL ELECTRIC ABOUT CONCERNS REGARDING THE TRAINING?

A. Mr. Modlin's letter indicates he called ** ____________________ ____________________ ** (Schedule RWT-3).

Q. ARE THERE SPECIFIC POINTS PUBLIC COUNSEL BELIEVES THE CORRESPONDENCE (SCHEDULE RWT-3) BETWEEN THE COMPANY AND

GENERAL ELECTRIC THAT INDICATE ** ______________ ** EXISTED AND WERE KNOWN TO THE COMPANY?

A. Yes, most definitely. The first three bullet points set out in Mr. Modlin's letter concisely explain StJLP's knowledge of the **________** in the training. A review of the employees' training evaluation form reveals that out of **____

____

____

______ **

Q. DID THE COMPANY'S PERSONNEL FOLLOW THE OPERATING AND TESTING PROCEDURES PRIOR TO THE EXPLOSION AND FIRE AT LAKE ROAD UNIT 4/6?

A. No. The procedures specifically required testing of the DC oil pump on a regular basis. The weekly test of the CD oil pump was scheduled to be performed on June 5. The test was not performed. Attached to my testimony, as Schedule RWT-4 is a document entitled SJLP Lake Road Turbine Generator 4 June 7, 2000 Incident Investigation Notes. The document is marked highly confidential but was declassified by the Company in the Deposition of John T. Modlin taken on October 4, 2000. Mr. Modlin indicated the document was not highly confidential on page 90, lines 12 – 20 of the deposition.

The entries from the Incident Investigation Notes for 6/12/00 indicate that the DC oil pump test was not done. The Company also provided the "Operations Schedule" for plant maintenance procedures in response to OPC DR# 6. Markings on this documents used by plant personnel indicate that the test was not performed (Schedule RWT – 4, entries for 6/8/00). This document measures 2 feet by 3 feet and therefore has not been reproduced for my testimony. OPC will have it available for Commission review at the hearing.

Q. IN HIS OCTOBER 4, 2000 DEPOSITION DID MR. MODLIN ADDRESS THE WEEKLY TEST OF THE DC OIL PUMP?

A. Yes. The following exchange took place between Mr. Micheel and Mr. Modlin;

> Q. Should the DC oil pump – should the DC oil pump have been tested on June 5th?
>
> A. It's scheduled to be tested every Monday.
>
> (Deposition of John T. Modlin Taken On Behalf of the Office of the Public Counsel, October 4, 2000, page 84, lines 7 – 9)

Q. DID START UP PROCEDURES CALL FOR THE DC OIL PUMP TO BE CHECKED AS PART OF THE START UP PROCEDURE?

A. Yes that is my understanding.

Q. WHEN WAS START UP OF THE UNIT AND WAS THE DC OIL PUMP TEST PERFORMED?

A. Lake Road Unit 4/6 was started up after the schedule outage (during which the Mark V system was installed) on June 2, 2000. The DC oil pump was not tested at that time as required by start up procedures.

Q. IN HIS OCTOBER 4, 2000 DEPOSITION DID MR. MODLIN ADDRESS THIS FAILURE TO TEST THE DC OIL PUMP AS PART OF THE START UP PROCEDURES?

A. Yes, the following exchange took place between Mr. Micheel and Mr. Modlin;

> Q. Let me ask you about the sixth main bullet on that document, the operation.
>
> A. Okay
>
> Q. First one on this new one is, The DC pump availability and operation not checked during the startup on 6/2/2000. Explain that.
>
> A. On the day of putting the unit on line, it does not appear that the DC pump was checked.
>
> Q. Should it have been checked?
>
> A. It's part of the unit startup procedure.
>
> (Deposition of John T. Modlin Taken On Behalf of the Office of the Public Counsel, October 4, 2000, page 146, lines 15 – 24)

Q. WAS THE DC OIL PUMP A CRITICAL FACTOR IN THE EXPLOSION AND SUBSEQUENT FIRE?

A. Yes. The inability of the DC Oil Pump to deliver lubrication to the bearings resulted in the damage sustained during the incident. (Schedule RWT-4, Response to OPC DR # 11)

Q. DID ST. JOSEPH LIGHT & POWER COMPANY PERSONNEL ADEQUATELY UNDERSTAND THE NEW OPERATING SYSTEM CONTROLING THE DC OIL PUMP?

A. The obvious answer is no since the operating personnel left the pump in a disabled status and therefore it could not respond to the need for lubrication to the bearings resulting from the unit tripping.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE MODIFICATIONS MADE TO THE OPERATING PROCEDURES FOR THE DC OIL PUMP.

A. The manual switch to operate the pump was removed during the installation of the new Mark V control system (Schedule RWT - 2 and RWT - 4). The Mark V operating system logic also had different operating characteristics regarding the DC oil pump that was not reviewed by StJLP personnel nor pointed out to them (Schedule RWT – 2).

Q. DID THE COMPANY HAVE ANY INCENTIVE TO PLACE THE LAKE ROAD UNIT 4/6 BACK INTO SERVICE AS SOON AS POSSIBLE DESPITE RISKS ASSOCIATED WITH OPERATING A SYSTEM WITH UNTRAINED PERSONNEL?

A. Yes. The Lake Road Unit 4/6 is the **____** lowest cost source of energy available to the Company according to the direct testimony of Company witness Ferry. During 1999, the unit provided over 27% of the system energy requirements and was budgeted to provide similar amounts during the year 2000. The Lake Road Unit 4/6 would be dispatched to provide energy to the system before **____** other sources of power available to the Company listed on page 6 of Mr. Ferry's direct testimony. These other sources have costs ranging form slightly less than ** ___** times the cost of Unit 4/6 to approximately **_ ** times the cost of producing power from Lake Road Unit 4/6. Two other sources of power are available at market prices. There was inherent financial incentive to put the unit back on line as soon as possible when compared to replacing the power with St. Joseph generation. The incremental cost increase that is subject of the AAO request also clearly indicates the same financial incentive existed for market based generation sources.

Q. **IN HIS DEPOSITION ON OCTOBER 4, 2000 DID MR. MODLIN ADDRESS PLACING THE LAKE ROAD UNIT 4/6 BACK ON LINE ON JUNE 4, 2000?**

A. ** ** The following exchange took place between Mr. Micheel and Mr. Modlin in a portion of the deposition that was deemed Highly Confidential;

**

______________**

(Deposition of John T. Modlin Taken On Behalf of the Office of the Public Counsel, October 4, 2000, page 162, line 21 – page 163, line 23)

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED LACK OF PROPER MANAGEMENT AS IT RELATES TO THE APPROPRIATENESS OF AN ACCOUNTING AUTHORITY ORDER?

A. Yes. The MPSC found that a company's lack of foresight does not justify the issuance of an AAO (United Water Missouri, Case No. WA-98-187, page 9). If a firm's employees are **__________ **, do not follow proper operating and testing procedures, and do not understand the operating control systems, a reasonable manager would anticipate problems occurring if the company proceeds without correcting the problems. StJLP proceeded despite the obvious risks. Therefore it should not be granted extraordinary accounting treatment for the costs associated with that decision.

ACCOUNTING AUTHORITY ORDER IMPLEMENTATION

Q. MR. STOLL BEGINNING ON PAGE 11, LINE 18 OF HIS DIRECT TESTIMONY AND CONTINUING THROUGH LINE 3 ON PAGE 12, RECOMMENDS THE COMMISSION AUTHORIZE THE COMPANY TO WAIT TO BEGIN THE AMORTIZATION OF AAO DEFERRED COSTS UNTIL SOME

UNKNOWN TIME WHEN NEW TARIFF RATES BECOME EFFECTIVE. DOES PUBLIC COUNSEL AGREE WITH MR. STOLL'S RECOMMENDATION?

A. No. Mr. Stoll's recommendation is premised on the MPSC determining in this proceeding that it is appropriate to include the amortization expense in the overall cost-of-service (i.e. revenue requirement) used to set rates for some undefined future period in a yet to be filed rate proceeding. Public Counsel does not believe it is appropriate or consistent with past Commission precedent to make such ratemaking determinations in an AAO proceeding.

Q. PLEASE EXPLAIN WHY YOU BELIEVE MR. STOLL'S RECOMMENDATION IS PREMISED ON MPSC APPROVAL OF THE RATEMAKING TREATMENT OF ANY AMORTIZATION RESULTING FROM THE AUTHORIZATION OF AN AAO.

A. Mr. Stoll's recommendation is based on the inappropriate concept of matching the amortization expense with the receipt of associated revenues (revised rates). Mr. Stoll presents this theory on page 12, lines 1 – 3 of his direct testimony. Stated in a different way, Mr. Stoll believes that matching is achieved if you record expenses during the same period that the MPSC adjusts rates so as to produce revenue that is available to pay for that specific expense.

Q. DOES MR. STOLL'S "MATCHING THEORY" CONFORM WITH BASIC ACCOUNTING THEORY UNDERLYING GENERALLY ACCEPTED ACCOUNTING PRINCIPLES?

A. No. The expenses, for which the Company requests deferral, are the cost of fuel and purchased power totaling $3,740,533 (Direct Testimony of Stephen Ferry, page 3, lines 19 - 21). These expenses were incurred to acquire electricity to sell to ratepayers during the period June 7 – August

31, 2000. The revenues associated with the sale of the electricity acquired with these expenditures will be recorded during the same June to August period. Accounting theory would dictate that the expenses (cost of goods sold) should be recorded in the same period;

> The matching principle holds that for any period for which net income is to be reported, the revenues to be recognized should be determined according to the revenue principle; then the expenses incurred in generating that revenue should be determined and ***reported for that period***. (emphasis added)
>
> (Intermediate Accounting, fourth edition, Welsch, Zlatkovich and White)

Mr. Stoll's definition of matching and the resulting reporting of net income can best be described by the phrase "What do you want it to be".

Q. WHAT IS THE PRACTICAL EFFECT OF AN AAO WITH RESPECT TO HOW A COMPANY REPORTS ITS EARNINGS?

A. An AAO allows the Company to "manage" its reported earnings by ignoring costs incurred (to produce revenue) in a specific period that would have an impact on earnings (always negative). These costs are then included in the determination of earnings for several periods in the future and thus minimize the negative impact on reported earnings in any one-year.

Q. IS THIS " MANAGEMENT OF EARNINGS" A GOAL OF OR BASED ON GENERALLY ACCEPTED ACCOUNTING PRINCIPLES?

A. Most definitely not. The Commission should use extreme caution when deciding whether to issue AAOs and also recognize that GAAP allows the recording of an asset (or deferral of costs) on the balance sheet only if that asset reasonably represents the flow of future cash revenues. It is analogous to the recording of a debit to for Allowance for Funds Used During Construction (which increases Plant-in-Service) and the corresponding credit entry increasing revenue (but not cash receipts) for the period. The cash is received in future periods when the Plant-in-Service is depreciated.

Public Counsel recognizes that MPSC Report and Orders addressing AAOs normally contain language expressly excluding ratemaking findings. Public Counsel believes the Commission should recognize this divergence from GAAP and only use AAOs when it can be shown that the costs deferred were incurred in response to events that are non-recurring and beyond the control of management.

Q. ARE FORCED OUTAGES A NORMAL COURSE OF UTILITY BUSINES FOR AN ELECTRIC UTITITY WITH GENERATION FACILITIES?

A. Yes. As will be addressed later in my testimony, Lake Road unit 4/6 has experienced numerous forced outages in each of the five years prior to the June 7 incident.

Q. WHAT DO YOU MEAN WHEN YOU USE THE TERM " FORCED OUTAGE" ?

A. I use the term "forced outage" to refer to those periods of time when a generating unit is unable to produce electricity due to failure of a system component as opposed to planned outages which are periods of time during which necessary maintenance or life-extension procedures are scheduled by management to be performed.

Q. PURCHASED POWER COSTS MAKE UP THE VAST MAJORITY OF INCREMENTAL COSTS THE COMPANY HAS REQUESTED TO BE DEFERRED.

ARE PURCHASED POWER COSTS A NORMAL OPERATING COST OF AN ELECTRIC UTILTIY?

A. Yes.

Q. **HAS THE COMMISSION PREVIOUSLY RULED THAT PURCHASED POWER COSTS SHOULD NOT BE INCLUDED IN AN ACCOUNTING AUTHORITY ORDER?**

A. Yes. In Case No. EO-91-358 and EO-91-360 involving Missouri Public Service Company the Commission stated;

> Purchasing power or capacity to meet a company's demand for service is a fundamental undertaking of a regulated utility.
>
> (Missouri Public Service Company, MPSC Report & Order Case No. EO-91-358 et al, page 15)

Q. **IF THE COMMISSION DOES GRANT AN AAO FOR THE INCREMENTAL EXPENSES ASSOCIATED WITH PURCHASE POWER RESULTING FROM THE INCIDENT AT LAKE ROAD, WHEN SHOULD THE AMORTIZATION OF THE DEFERRED AMOUNTS START?**

A. Public Counsel believes the amortization should start in the September, 2000 financial statements.

Q. **WHY DOES PUBLIC COUNSEL BELIEVE THE AMORTIZATION SHOULD START IN SEPTEMBER, 2000?**

A. Issuance of an AAO is a variance from the tradition method for setting utility rates. It creates a distortion in the financial statements of the utility as the Commission has recognized. The process necessary to eliminate this distortion should begin as soon as possible. Lake Road unit 4/6 returned to service on August 8, 2000 and the vast majority of costs were incurred by August 31, 2000.

Q. IS BEGINNING THE AMORTIZATION IN SEPTEMBER, 2000 CONSISTENT WITH THE COMMISSION'S PAST TREATMENT OF AMOUNTS DEFERRED UNDER AN ACCOUNTING AUTHORITY ORDER?

A. Yes. In Case No. EO-94-35 and Case No. EO-95-193, the Company was required to begin the amortization of amounts deferred under an AAO immediately. Specifically in Case No. EO-94-35, (July/August 1993 flood) the Company was allowed to accumulate costs related to flood costs through March 31, 1994 but was required to begin the amortization on November 1, 1993. In Case No. EO-95-193 (December 6, 1994 ice storm) the Company was allowed to accumulate costs related to service restoration through February 28, 1995 and begin the amortization on March 1, 1995.

Q. IF THE AMORTIZATION PERIOD BEGINS IN SEPTEMER, 2000, AND TARIFF RATES ARE NOT ADJUSTED TO REFLECT THE AMORTIZATION, WHAT IS THE EFFECT ON RATEPAYERS AND STOCKHOLDERS?

Q. Ratepayers are entitled to pay just and reasonable rates for utility services and stockholders are entitled to the opportunity to earn a reasonable return on their investment in the provision of utility services. Whether these entitlements are in balance can only be determined through a determination of the overall revenue requirement (a.k.a. overall cost-of-service). The effect of imbalances is commonly referred to as regulatory lag.

Q. PLEASE EXPLAIN THE CONCEPT OF REGULATORY LAG.

A. Regulatory lag refers to the difference in timing of a decision by management or other event that affects a utilities operations and resulting actual earnings and the Commission's recognition of that decision or event, and its effect, if any, on the rate base/rate of return/revenue/expense relationship in the determination of a company's revenue requirement. Prudent management decisions may alter the rate base/rate of return/revenue/expense relationship that is the basis for the overall cost of service (a.k.a., the Overall Revenue Requirement). The relationship change increases the profitability of the firm in the short-run, until such time as the Commission reestablishes rates which properly match the new levels of the overall cost of service components. Companies are allowed to retain costs savings, i.e., excess profits during the lag period between rate cases. When faced with escalating costs that will change the rate base/rate of return/revenue/expense relationship adversely with respect to profits, regulatory lag places pressure on management to take actions to minimize the change in the relationship and the resulting decrease in profitability. Regulatory lag, stated another way, provides management with real financial incentives to operate the business in an efficient manner.

Other events can also effect the return/revenue/expense relationship such as customer growth, customer usage patterns, inflation/deflation, technology changes, and any other influences or factors effecting utility operations.

Q. **DO EVENTS SUCH AS EXPENSE CHANGES RELATED TO AMORTIZATION OF AN AAO HAPPEN IN A VACUUM WITH RESPECT TO OTHER POSSIBLE CHANGES IN THE OPERATIONS OF THE UTILITY?**

A. No. The overall cost of service is made up of a multitude of factors. Isolating or focusing on only one component, such as AAO amortization, fails to look at all relevant factors in determining the overall cost of service. Other factors may have changed that have a corresponding decrease or increase on the overall cost of service. Unless all factors are analyzed, it is not appropriate to single out one specific event.

Q. **HAS THIS COMMISSION ADDRESSED WHETHER IT IS REASONABLE TO PROTECT SHAREHOLDERS FROM ALL REGULATORY LAG?**

A. Yes. This Commission has held that it is **not** reasonable to protect shareholders from all regulatory lag. In Missouri Public Service Company, Cases Nos. EO-91-358 and EO-91-360, the Commission stated:

> Lessening the effect of regulatory lag by deferring costs is beneficial to a company but not particularly beneficial to ratepayers. Companies do not propose to defer profits to subsequent rate cases to lessen the effects of regulatory lag, but insist it is a benefit to defer costs. Regulatory lag is a part of the regulatory process and can be a benefit as well as a detriment. Lessening regulatory lag by deferring costs is not a reasonable goal unless the costs are associated with an extraordinary event.
>
> Maintaining the financial integrity of a utility is also a reasonable goal. The deferral of costs to maintain current financial integrity though is of questionable benefit. If a utility's financial integrity is threatened by high costs so that its ability to provide service is threatened, then it should seek interim rate relief. If maintaining financial integrity means sustaining a specific return on equity, this is not the purpose of regulation. It is not reasonable to defer costs to insulate shareholders from any risks. If costs are such that a utility considers its return on equity unreasonably low, the proper approach is to file a rate case so that a new revenue requirement can be developed which allows the company the opportunity

> to earn its authorized rate of return. Deferral of costs just to support the current financial picture distorts the balancing process used by the Commission to establish just and reasonable rates. Rates are set to recover ongoing operating expenses plus a reasonable return on investment. Only when an extraordinary event occurs should this balance be adjusted and costs deferred for consideration in a later period (Emphasis added).

Q. WAS THE COMMISSION'S "EXTRAORDINARY AND NONRECURRING" STANDARD AS OUTLINED IN RE: M.P.S. AFFIRMED BY THE WESTERN DISTRICT COURT OF APPEALS?

A. Yes, the Western District Court of Appeals states:

> "[An AAO deferral] . . . distorts the balancing process utilized by the Commission to establish just and reasonable rates. Because rates are set to recover continuing operating expenses plus a reasonable return on investment, only an extraordinary event should be permitted to adjust the balance . . ." State ex. Rel. Missouri Office of the Public Counsel v. Public Service Commission, 858 S.W. 2d 806, 810 (Mo. App. 1993).

The Court of Appeals also noted that the Uniform System of Accounts (USOA) defines "extraordinary items" as:

> [t]hose items related to the effects of events and transactions which have occurred during the current period and which are not typical or customary business activities of the company . . . Accordingly, they will be events and transactions of significant effect which would not be expected to recur frequently and which would not be considered as recurring factors on any evaluation of the ordinary operating processes of business. . . Id. at 810.

Q. WHAT DOES THE COMPANY MEAN WHEN IT USES THE TERM "DEFER"?

A. When a cost that normally would be expensed and therefore reflected on the income statement in the current accounting period is deferred, the expenditure is entered on the balance sheet in a special section called Deferred Debits. In this case, the specific account StJLP proposes to utilize is

Account 182.3, Other Regulatory Assets. The Company's request to defer purchase power expenses associated with the replacement power required because of the incident at the Lake Road generating facility falls into this category.

Q. PLEASE DEFINE AN EXPENDITURE?

A. An expenditure is any outflow of money paying for a good or service. An expenditure is either capitalized (recorded on the balance sheet) or it is considered an expense (recorded on the income statement).

Q. WHAT IS AN EXPENSE?

A. Expense is the use of assets and services in the creation of revenue during a specified period. Expenses are recorded on the income statement and are subtracted from revenues in order to determine net income for the period.

Q. PLEASE DEFINE THE TERM " COST" .

A. I use the term "cost" to refer to each component of the total revenue requirement of the utility. Cost includes all expenses along with the earnings and interest expense associated with the rate base. The total revenue requirement is also called the overall cost of service.

Q. HAVE YOU REVIEWED THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC), UNIFORM SYSTEM OF ACCOUNTS FOR CLASS A AND B ELECTRIC UTILITIES (USOA)?

A. Yes I have.

Q. **ARE THE DEFINITIONS YOU PREVIOUSLY PROVIDED CONSISTENT WITH HOW THE USOA APPLIES THESE TERMS?**

A. Yes.

Q. **FROM A REGULATORY ACCOUNTING PERSPECTIVE, WHAT OCCURS WHEN AN EXPENSE IS DEFERRED PURSUANT TO AN ACCOUNTING AUTHORITY ORDER?**

A. From a regulatory accounting perspective, when a cost has been deferred it is not recognized on the income statement as an expense in the current period. The expenditures are recorded on the balance sheet in a section called Deferred Debits, pending the final disposition of the costs at some future point, usually in a rate case. These deferred debit accounts act simply as a temporary holding accounts until the appropriate accounting ratemaking treatment can be determined.

Q. **IS THE DEFERRAL OF A COST FROM ONE ACCOUNTING PERIOD TO ANOTHER ACCOUNTING PERIOD FOR THE DEVELOPMENT OF A REVENUE REQUIREMENT CONSISTENT WITH TRADITIONAL RATEMAKING PRACTICES?**

A. No. Generally, the deferral of costs from one accounting period to another accounting period for the development of a revenue requirement violates the traditional method for setting utility rates. Rates in Missouri are usually established based upon a historical test year which focuses on four factors: (1) the rate of return the utility has an opportunity to earn; (2) the rate base upon which a return may be earned; (3) the depreciation expense related to plant and equipment; and (4) the allowable operating expenses including income and other taxes.

The relationship of the four factors is such that the expenses and rate base necessary to produce the revenues is synchronized. For example, the level of expense (fuel to generate electricity and purchase power costs to acquire electricity) is developed based on the expected amount of sales that is used in the determination of revenue for the test period. Similarly, the plant-in-service necessary to produce or deliver that electricity to customers is also based on the customers' demands for the same period. This process is often referred to as the "Matching Principle".

Deferral of expenses from one period to another (and the amortization in subsequent periods) results in costs associated with the production of revenue in one period being charged against the revenue in different unrelated periods. This violates the "Matching Principle" and if unfettered would allow a utility to manage its earnings in order to avoid regulatory oversight or adverse reactions from the financial community. In my professional opinion, avoiding this possibility is one of the fundamental purposes of Generally Accepted Accounting Principles and the USOA.

Q. HAS THE COMMISSION ALLOWED REGULATED UTILITIES SUCH AS ST. JOSEPH LIGHT & POWER COMPANY TO DEVIATE FROM TRADITIONAL RATEMAKING PRACTICES TO DEFER COSTS FROM ONE ACCOUNTING PERIOD TO ANOTHER ACCOUNTING PERIOD VIA AN ACCOUNTING AUTHORITY ORDER?

A. Yes. The Commission has determined that utilities, when warranted, can be allowed to defer costs from prior accounting periods on a limited basis when events occur during a period which are extraordinary, unusual and unique, and nonrecurring.

Q. IN RECENT REPORT AND ORDERS HAS THE COMMISSION EMPHASIZED THAT AAOS MOST PROPERLY ADDRESS ONLY "UNPREDICTABLE" EVENTS?

A. Yes. The Commission stated in St. Louis County Water Company, Case No. WR-96-263, page 13:

> As both the OPC and the Staff point out, the Commission has, to date, granted AAO accounting treatment exclusively for one-time outlays of capital caused by unpredictable events, acts of government, and other matters outside the control of the utility or the Commission. It is also pointed out that the terms "infrequent, unusual and extraordinary" connote occurrences which are unpredictable in nature."

The Commission reiterated this position in United Water Missouri, Inc., Case No. WA-98-187, page 6 – 7.

> In order to justify the issuance of an Accounting Authority Order to permit the deferral of such costs, the costs incurred by the utility must result from an event or circumstance that is extraordinary unusual and unique, and not recurring.

Q. MR. STOLL DISCUSSES THE RELEVANCE OF TWO PRIOR ACCOUNTING AUTHORITY ORDERS GRANTED THE COMPANY (DIRECT TESTIMONY, PAGE 7, LINE 16 - PAGE 8, LINE 8) AS THEY RELATE TO THE " EXTRAORDINARY" NATURE OF THE EVENT. DOES PUBLIC COUNSEL AGREE THAT THIS EXPLOSION EVENT WAS SIMILAR TO THE TWO CASES REFERENCED?

A. No. The two events referenced were a major flood (of the 500-year variety) and a major ice storm. Public Counsel would submit that the cause of or nature of either of those events could not in any way be under the control of Company management nor could management taken action to prevent or alter the outcome. In contrast, an explosion at a generating station has a specific cause. The identification of such a cause and the determination as to whether or not the cause could or should have been avoided is completely different question. The Company is responsible for operations at its generating stations; it is not responsible for acts of nature.

Q. ARE OUTAGES (FORCED OR PLANNED) A NORMAL OCCURANCE AT ELECTIC POWER GENERATING PLANTS?

A. Yes. Planned outages for maintenance or other activities are completely within the control of management. Forced outages caused by system failures (whatever the cause) occur on a frequent basis, are also part of the normal course of business for electric utilities, and are recognized in the ratemaking process.

Q. PLEASE EXPLAIN HOW FORCED (SOMETIMES CALLED UNPLANNED) OUTAGES ARE INCLUDED IN THE RATEMAKING PROCESS.

A. Fuel and purchased power costs are developed using computer model. There is a multitude of inputs into the model. Expected forced and planned outages are two of the inputs. The normalization process is often used to determine an estimate or expectation of the number of hours a unit will be unavailable during the test period used for the model. The normalization process looks at historic actual data and develops an average or trended number to be included in the modeling process for forced outages.

Q. WHAT IS THE PURPOSE OF THE NORMALIZATION PROCESS?

A. A normalization process levelizes fluctuating events (such as outages) for ratemaking purposes while providing the stockholder with an opportunity to earn a adequate return on that investment. The normalization process anticipates that actual occurrences will be either over or under the "normalized level" on which rates are set, but that over time a balancing of actual and normalized levels will occur.

Q. HAS LAKE ROAD UNIT 4/6 EXPERIENCED FORCED OUTAGES OVER THE PAST FIVE YEARS?

A. Yes.

Q. HAVE YOU REVIEWED ANY SCHEDULES THAT SUMMARIZED THE OUTAGE RATES?

A. Yes, the Company response to OPC data request 5022 provided a listing of each forced outage from 1995 through the present. Excluding the year 2000, Lake Road unit 4/6 experienced the following annual hours of forced outages;

	Hours of Outages
1995	1,145.62
1996	206.54
1997	109.99
1998	200.04
1999	154.59

For the year 2000 until Lake Road unit 4/6 came back on line, August 8, 2000, the Company has experienced 148.82 hours of forced outages not associated with the June 7 incident. The Company experienced approximately 1,473.54 forced outage hours due to the fire and subsequent repairs resulting from the June 7 incident.

Q. HAVE YOU ALSO REVIEWED FORCED OUTAGE HOURS FOR THE MONTHS OF JUNE, JULY AND AUGUST SPECIFICALLY?

A. Yes. Excluding the year 2000, Lake Road unit 4/6 experienced the following annual hours of forced outages during those three specific months;

	Hours of Outages
1995	136.15
1996	97.07
1997	63.58
1998	85.34
1999	1.09

These monthly totals represent a range from less than 1% to more than 57%, as a percentage of annual forced outage hours for the same year.

Q. WOULD IT BE FAIR TO DESCRIBE FORCED OUTAGES AS BEING EXTREMELY VARIABLE BASED ON THE DATA YOU HAVE REVIEWED?

A. Yes, most definitely. This type of variability is exactly why normalizations occur in the ratemaking process.

Q. WOULD YOU DESCRIBE THE YEAR 2000 AS A YEAR IN WHICH THE ACTUAL EXPERIENCE EXCEEDS THE NORMALIZED EXPERIENCE?

A. Yes, I believe that would be a fair characterization. However, that fact in and of itself does not mean an AAO is warranted. The normalization process anticipates overages and underages. The regulatory process also provides the stockholder the opportunity, not a guarantee, to earn a rate of return. That opportunity involves business risk. Absent risk, authorized returns would reflect a risk-free return such as US government securities (T-bills).

If AAOs were warranted when actual results exceed normalized levels used to set rates, fairness would dictate that AAOs would also be warranted when actual results are below normalized levels. Public Counsel would point out that this Company has not (nor has any other Missouri utility) proposed a "reverse" AAO to address actual results being less than normalized levels. The excess earnings flowing from such situations are simply retained by the stockholders.

Q. HAS ST. JOSEPH LIGHT & POWER EXPERIENCED OUTAGE RATES THAT WOULD BENEFIT THE STOCKHOLDER?

A. Yes. During the 3 summer months of 1999, Lake Road unit 4/6 was only unavailable for 1.09 hours. This represents only 1.71% of the next lowest forced outage hours in the same period for the prior 4 years. The Company's ability to avoid the higher costs of replacement power during this period benefited stockholders.

Q. MR. STOLL ALSO ASSERTS THAT WHEN DECIDING WHETHER TO GRANT AN AAO IS " THE ONLY CRITERIA THAT SHOULD BE USED IS THE FINANCIAL IMPACT ON OPERATIONS, CONSISTENT WITH PAST COMMISSION ORDERS" (STOLL DIRECT, PAGE 9, LINES15 - 16). DO YOU AGREE WITH MR. STOLL?

A. No. I do not agree with Mr. Stoll. A review of past MPSC Report and Orders does not support his contention that financial impact in the only consideration. Mr. Stoll would have this completely ignore the event or the cause of the event (Stoll Direct, page 11, lines 5 – 11).

As previously cited in my testimony, the St. Louis County Water and United Water Missouri, Inc. cases indicate that the cause of the event is the first consideration of the Commission in determining whether or not an AAO is to be granted. Only after an event is determined to be appropriate for AAO does the financial impact become a consideration. Mr. Stoll would have this Commission completely ignore the event and its cause. Mr. Stoll's position is understandable given that acts or omissions by Company management and its employees caused this event to occur. Mr. Stoll would have the Commission grant extraordinaary accounting treatment even when the event was caused by the of acts and omissions of StJLP employees. The Company's application even requests that:

> SJLP also proposes that in such rate case, the incremental costs which are deferred and recorded in account 182.3 be amortized in rates over a five-year period, in a manner similar to that previously utilized by the Commission to allow recovery of costs of other unforseen events, such as floods and ice storms.
>
> (Application For Accounting Authority Order, June 23, 2000, paragraph 9)

This request, as set out in the Company's application, would require the Commission to predetermine that the ratepayers pay for the cost of the explosion and fire resulting from the acts and ommissions of Company management.

Q. IF FINANCIAL IMPACT IS THE ONLY CONSIDERATION, WOULD THAT OPEN A FLOODGATE OF OPPORTUNITY FOR A UTILITY TO MANAGE ITS EARNINGS THROUGH THE USE AN AAO?

A. Yes. An event such as an abnormally cool summer or warm winter would have a significant impact on earnings. Other significant impacts could occur from any event in the normal course of utility operations that had a material impact on earning. Other cyclical costs that are normalized for ratemaking treatment but expensed on the utilities financial records include tree-trimming expenses for electric utilities, tank painting for water utilities, and over-time hours.

A.A.O. -- OTHER CONSIDERATIONS

Q. IF THIS ACCOUNTING AUTHORITY ORDER IS APPROVED, ARE THERE ANY IMPLICATIONS TO THE RATEMAKING PROCESS OTHER THAN THE AMORTIZATION OF THE DEFERRED EXPENSES?

A. Yes, the Commission would have to ensure that any impact of the forced outages related to this explosion would not be taken into effect in the normalization process involved in fuel modeling used to set rates in the future. The removal of the impact would be necessary because the amortization would reimburse the stockholders for all costs associated with the outage. To subsequently include the forced outage hours in a normalization of fuel & purchase power expense would double count the outage and its effect on rates.

Q. OTHER THAN TO MANAGE THE COMPANY'S REPORTED EARNINGS TO THE FINANCIAL COMMUNITY, WHY HAVE AAOS BEEN GRANTED IN THE PAST IN YOUR OPINION?

A. The only real purpose an AAO serves is to determine whether or not an event is extraordinary and if found to be extraordinary whether or not it deserves special regulatory accounting treatment. An

AAO provides for the accumulation of costs associated with an event that has been deemed to be extraordinary. An assumption inherent in the AAO process is that the costs incurred for the extraordinary event or similar levels of cost drivers have not been recognized previously in setting rates. This assumption must be confirmed in the process. The incremental costs associated with the extraordinary event are accumulated and deferred on the balance sheet. The parties in a subsequent rate case address the accumulated deferred costs that have not been amortized to the income statement in the intervening period. The deferral allows the Commission to determine in a subsequent rate case whether or not the unamortized costs related to the extraordinary event should be included in the cost of service in that subsequent case.

An AAO and its resulting deferrals does not legally bind the MPSC to include the resulting amortization expense in the cost of service in a future rate case based on my discussion with counsel. However, GAAP provides that capitalized or deferred items represent future revenue flows. AAOs are reported for financial purposes as a deferral of costs. Therefore an AAO creates an theorectical inconsistency between GAAP-based publically released financial reports and regulatory accounting and should not be granted for events caused by or within the control of utility management.

Q. YOUR REFERRED TO THE INCREMENTAL COSTS BEING ACCUMULATED AND DEFERRED. PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM INCREMENTAL AND WHY IT IS IMPORTANT.

A. I use the term incremental costs to refer to those costs over an above the normalized level on operating costs that would be expected to be incurred. As example, an ice storm requires extensive overtime hours worked by an utilities crews. Obviously the crews also work their normal 40-hour week. The 40-hour normal workweek would not be considered a cost of the extraordinary event and overtime hours would need to be evaluated so as to ensure that a normalized level of overtime hours were exceeded because of the extraordinary event.

Q. WOULD DENIAL OF AN AAO PREVENT THE COMMISSION FROM CONSIDERING COSTS ASSOCIATED WITH PAST EVENTS IN THE RATEMAKING PROCESS?

A. No. I previously discussed the normalization process utilized in all rate proceedings. This process if applied correctly would capture and consider the past event and its associated cost and/or cost drivers. If deemed appropriate by the Commission the cost drivers would then be included in the development of the "normalized" level of expense included in the cost of service in the subsequent rate case.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY COST DRIVERS?

A. Cost drivers would include activities that cause a utility to incur costs. Examples would include forced outage hours, as is the primary driver in this case, or could include overtime hours that are the primary driver in events such as ice storms or floods. Fluctuating maintenance expense excluding payroll can also be reviewed over several years to ensure that a normalized annual level of expense is included in the cost of service. Maintenance expense normally increases in response to an extraordinary event absent an AAO and its resulting deferral. In each normalization, historic levels of cost drivers would be analyzed an included in the ratemaking process. These cost drivers usually must then be "priced out" in order to be included in the cost of service. For example, overtime hours are taken times current wage rates, outage hours would precipitate alternative fuel or purchase power costs at current cost rates, or tree trimming would be priced out at the current rate per mile trimmed.

Q. HAVE YOU REVIEWED THE COMPANY'S CALCULATION OF THE INCREMENTAL FUEL & PURCHASE POWER COSTS?

A. Yes, I have. These workpapers were supplied in an electronic format via e-mail on September 19, 2000 at 4:11p.m. from Harold Wyble at the direction of Tim Rush, both of whom are employed by the Company.

Q. DO YOU HAVE ANY SPECIFIC CONCERNS WITH THE CALCULATION?

A. Yes, I do. Previously I discussed the outage rates for the prior five years. Lake Road Unit 4/6 experienced forced outages not only in each and every year on an annual basis but also experienced forced outages during the period of June through August each and every year. The Company's calculation of incremental costs made <u>no</u> adjustment for forced outages. That is, the Company's calculation assumed the unit would be available each and every hour during the period in question. This is not a reasonable assumption given past history of the unit and common sense. Generating units experience mechanical failures (not influenced by management decisions) and the stress on a unit is only increased the more the unit is used. Lake Road Unit 4/6 is a low cost unit and therefore would be used (i.e. dispatched) during periods of high demand as is prevalent during the period in question.

Q. **WHAT DOES PAST HISTORY INDICATE A NORMAL LEVEL OF FORCED OUTAGE HOURS FOR LAKE ROAD UNIT 4/6 DURING THIS PERIOD WOULD BE?**

A. A simple five-year average of forced outages, during the period June through August, would be approximately 77 hours. The average monthly forced outage over the prior five years was 30 hours per month or 90 hours for any three-month period. This would create a range of reasonableness for forced outage hours of 77 – 90 hours for the period in question.

Q. **WHAT IS THE GENERAL EFFECT ON THE CALCULATION OF INCREMENTAL COSTS DUE TO THE FAILURE TO RECOGNIZE A NORMALIZED FORCED OUTAGE RATE DURING THE PERIOD?**

A. The calculation would overstate the incremental costs by an amount equal to the normal forced outage rate multiplied times the difference in the MWH cost/replacement power less MWH cost for Lake Road Unit 4/6.

Q. **DO YOU HAVE AN ESTIMATE OF THE EFFECT ON THE OVERSTATEMENT OF THE COMPANY'S ESTIMATE OF INCREMENTAL REPLACEMENT COSTS?**

A. Yes. The overstatement would be in the range of **________________** based on a range of forced outage hours for the period of 77 to 90 hours. These estimates utilize the Company's replacement costs from the workpapers provided by Mr. Wyble.

TESTIMONY SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The Company made the decision to rush the Lake Road Unit 4/6 back on line without adequate review of the operational changes resulting from the installation of the new Mark V operating system. The decision was also made despite the fact the Company and its employees recognized its employees were ** ________ ** as a result of inadequate training on the system. The only benefit of this rush to on-line status would be to enhance the earnings of the Company and therefore its stockholders. The Company also failed to adequately review the modifications and failed to follow the operating procedures for testing system components. The responsibility for the results (i.e. explosion and fire) of this poorly executed modification and operation of the Lake Road Unit 4/6 operating system should rest with those responsible, the Company and its stockholders. The June 7 event resulted from the acts and omissions of the Company and **not** from an event that was beyond the control of management. This event should not be given the special regulatory accounting treatment that is provided by an Accounting Authority Order nd the resulting ability to manage its reported earnings.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Missouri Power & Light Company, Steam Dept., Case No. HR-82-179
Missouri Power & Light Company, Electric Dept., Case No. ER-82-180
Missouri Edison Company, Electric Dept., Case No. ER-79-120
Southwestern Bell Telephone Company, Case No. TR-79-213
Doniphan Telephone Company, Case No. TR-80-15
Empire District Electric Company, Case No. ER-83-43
Missouri Power & Light Company, Gas Dept., Case No. GR-82-181
Missouri Public Service Company, Electric Dept., Case No. ER-81-85
Missouri Water Company, Case No. WR-81-363
Osage Natural Gas Company, Case No. GR-82-127
Missouri Utilities Company, Electric Dept., Case No. ER-82-246
Missouri Utilities Company, Gas Dept., Case No. GR-82-247
Missouri Utilitites Company, Water Dept., Case No. WR-82-248
Laclede Gas Company, Case No. GR-83-233
Great River Gas Company, Case No. GR-85-136 (OPC)
Northeast Missouri Rural Telephone Company, Case No. TR-85-23 (OPC)
United Telephone Company, Case No. TR-85-179 (OPC)
Kansas City Power & Light Company, Case No. ER-85-128 (OPC)
Arkansas Power & Light Company, Case No. ER-85-265 (OPC)
KPL/Gas Service Company, GR-86-76 (OPC)
Missouri Cities Water Company, Case Nos. WR-86-111, SR-86-112 (OPC)
Union Electric Company, Case No. EC-87-115 (OPC)
Union Electric Company, Case No. GR-87-62 (OPC)
St. Joseph Light and Power Company, Case Nos. GR-88-115, HR-88-116 (OPC)
St. Louis County Water Company, Case No. WR-88-5 (OPC)
West Elm Place Corporation, Case No. SO-88-140 (OPC)
United Telephone Long Distance Company, Case No. TA-88-260 (OPC)
Southwestern Bell Telephone Company, Case No. TC-89-14, et al. (OPC)
Osage Utilities, Inc., Case No. WM-89-93 (OPC)
GTE North Incorporated, Case Nos. TR-89-182, TR-89-238, TC-90-75 (OPC)
Contel of Missouri, Inc., Case No. TR-89-196 (OPC)
The Kansas Power and Light Company, Case No. GR-90-50 (OPC)
Southwestern Bell Telephone Company, Case No. TO-89-56 (OPC)
Capital City Water Company, Case No. WR-90-118 (OPC)

Laclede Gas Company, Case No. GR-90-120 (OPC)
Southwestern Bell Telephone Company, Case No. TR-90-98 (OPC)
Empire District Electric Company, Case No. ER-90-138 (OPC)
Associated Natural Gas Company, Case No. GR-90-152 (OPC)
Southwestern Bell Telephone Company, Case No. TO-91-163
Union Electric Company, Case No. ED-91-122
Missouri Public Service, Case Nos. EO-91-358 and EO-91-360
The Kansas Power and Light Company, Case No. GR-91-291
Southwestern Bell Telephone Co., Case No. TO-91-163
Union Electric Company, EM-92-225 and EM-92-253
Southwestern Bell Telephone Company, TO-93-116
Missouri Public Service Company, ER-93-37, (January, 1993)
Southwestern Bell Telephone Company, TO-93-192, TC-93-224
Saint Louis County Water Company, WR-93-204
United Telephone Company of Missouri, TR-93-181
Raytown Water Company, WR-94-300
Empire District Electric Company, ER-94-174
Raytown Water Company, WR-94-211
Missouri Gas Energy, GR-94-343
Capital City Water Company, WR-94-297
Southwestern Bell Telephone Company, TR-94-364
Missouri Gas Energy, GR-95-33
St. Louis County Water Company, WR-95-145
Missouri Gas Energy, GO-94-318
Alltel Telephone Company of Missouri, TM-95-87
Southwestern Bell Telephone Company, TR-96-28
Steelville Telephone Exchange, Inc., TR-96-123
Union Electric Company, EM-96-146
Imperial Utilites Corporation, SC-96-247
Laclede Gas Company, GR-96-193
Missouri Gas Energy, GR-96-285
St. Louis County Water Company, WR-96-263
Village Water and Sewer Company, Inc. WM-96-454
Empire District Electric Company, ER-97-82

UtiliCorp d/b/a Missouri Public Service Company, GR-95-273
Associated Natural Gas, GR-97-272
Missouri Public Service, ER-97-394, ET-98-103
Missouri Gas Energy, GR-98-140
St. Louis County Water, WO-98-223
United Water Missouri, WA-98-187
Kansas City Power & Light/Western Resources, Inc. EM-97-515
St. Joseph Light & Power Company, HR-99-245
St. Joseph Light & Power Company, GR-99-246
St. Joseph Light & Power Company, ER-99-247
AmerenUE, EO-96-14, (prepared statement)
Missouri American Water Company, WR-2000-281
Missouri American Water Company, SR-2000-282
UtiliCorp United Inc./St. Joseph Light & Power Company, EM-2000-292
UtiliCorp United Inc./Empire District Electric Company, EM-2000-369
St. Joseph Light & Power Company, EO-2000-845

Turbine Generator 4 June 7, 2000 Incident
Possible Contributing Factors

- Original system (c. 1966): System was designed and built to rely on DC oil pump until AC power was transferred every time there was a generator trip. DC oil pump served both as "normal" and emergency role (no second line of defense).
- DCS design and installation (1995): DCS oil pump control logic was installed in parallel with manual control switch.
  - DCS control for DC pump did not "return to auto" after stop, as manual control switch did.
  - AC pumps DID return to auto in DCS, misleading plant personnel to believe DC pump operation was similar.
  - No alarm for DC pump in off position.
  - Control station shows "local" instead of "off," which was no longer meaningful.
  - No alarm for loss of pump control power.
  - DCS weaknesses since 1995 were not apparent due to continued use of manual switch.
- Mark V Installation Engineering (Feb – May 2000)
  - GE several weeks behind in project engineering, rushed job.
  - Multiple lead engineers involved in construction design, little continuity.
  - Manual switch removed in design without sufficient review.
  - Installation drawings delivered to SJLP after outage was underway.
  - Inadequate time for Company review.
- Mark V Installation (May 2000)
  - System installed and tested per GE drawings and other documents.
  - Company personnel did not recognize hazard.
- Mark V Training (May 2000)
  - Poor GE training, not specific to Lake Road Plant.
  - Change in DC pump control not explicitly pointed out to operators.
- Operation (May 25 – June 7, 2000)
  - DC pump breaker may not have been returned to normally closed position after opened for hydrogen seal work on about 5/25.
  - DC pump availability and operation not checked during start-up on 6/2/00.
  - Weekly DC oil pump test not performed on 6/5/00.
  - Routine check of pump readiness not performed at shift changes.
- Vibration Trip (June 7, 2000)
  - Source of high indicated vibration levels not found, possibly instrumentation problem.
  - Work on vibration equipment was underway by GE/Company personnel at time of trip.
  - Turbine trip caused 86G trip, which in turn shut off AC power to lube oil pumps.
- Roll Down (June 7, 2000)
  - DC oil pump did not start.
  - Loss of lubrication to bearings, subsequent vibration, oil fires.
  - Loss of hydrogen seals, subsequent explosions, hydrogen fire.
  - Apparent steam flow after turbine trip may have contributed to mechanical damage.
  - No injuries, fire damage contained.

HC

Schedule RWT-3 has been deemed "Highly Confidential" in its entirety.

SJLP Lake Road Turbine Generator 4
June 7, 2000 Incident Investigation Notes

6/7/00

- Turbine generator tripped at 14:06. See individual employee statements.
- Obtained Mark V (M5) turbine generator and INFI-90 DCS boiler alarm printouts.
- Obtained M5 trip log computer file from Steve Alexander of GE and printed.
- Asked TMN to print all pertinent trend screens from DCS.
- Provided statement to GLM re observations.
- Asked Steve Alexander to look for any other trip information, logs, trends, etc on M5. He reported that none were available.

6/8/00

- DVS assigned me to investigate cause of event.
- Obtained M5 CSP and cross-reference from Steve Alexander of GE and printed.
- Worked on retrieving data from DCS.
- Discussed operating steps with Dave Rehm.
- Reviewed M5 and DCS printouts in detail.
- Started sequence of events document.
- Checked DC oil pump test on 6/5 on operations schedule sheet. Not highlighted, which would indicate not performed.

6/9/00

- Worked with Steve Barton and Lance Brumbaugh to investigate DC oil pump starting logic and verify operation.
- Verified DCS wiring through auto start (NO), start (NO) and stop (NC) contacts. Checked fuses and continuity through DCS contacts from starter.
- Checked pressure switches, PS-101, PS-105.
- Checked relay coils in circuit (1A, 2A, M, MX).
- All circuit checks were okay.
- Obtained detailed event log from DCS.
- M5 showed reheat stops going closed but not main stop valve. Review of M5 logic indicates that M5 uses valve position feedback to determine if valve is closed, not a limit switch. This may be why M5 did not show valve closed on alarm printer. 86GOT trip indicates that main stop valve closed enough to make up limit switch and trip 86GOT.

6/12/00

- Mark Phillips confirmed that DC oil pump was not tested on 6/5.
- Wayne Matthews and Mike Tullis stated that DC oil pump breaker was already open when they isolated turbine on 6/8.
- Danny Kukuc showed me valve used to dump hydraulic fluid in final attempt to stop turbine.
- Reviewed event log and hydraulic oil pressure to tried to pinpoint time turbine stopped rolling.
- Lifted DC oil pump motor leads and closed breaker. Verified control logic through Infi-90. Pump "started" when put in automatic mode. Indication of pump starting and running printed on alarm printer. Did another test with breaker open: Put pump in auto and it did not start nor alarm due to failure to start (which makes sense).

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6/13/00

- Obtained detailed Brg 5 vibration troubleshooting steps from Lance Brumbaugh.
- Met with Jim White of Bently Nevada regarding damage assessment. Asked him to look for any problems. Assigned Lance to work with him and keep me informed of any findings.
- Reviewed steam flow trend. Steam flow did not immediately go to zero, took several minutes to reach zero. (This makes sense, since steam flow is measured by first stage pressure. There will be period of time for pressure to decay, even when there is very little flow.)
- Reviewed hydraulic pressure trend. Did not see a sudden drop to indicate hydraulic oil bypass valve opening by operators.
- Reviewed lube oil pressure trend. Shows that unit had oil pressure during roll-down, after aux power was restored.
- Met with insurance team and discussed sequence of events. Provided alarm listings (Mark V alarms and trip log, operator log sheet, DCS events, DCS trends).
- DVS provided draft/preliminary sequence of events write-up to insurance team mid-afternoon.
- Danny Kukuc reports that DC oil pump breaker was already opened when he got to it after the unit trip.

6/14/00

- Met with Jim White, re Bently Nevada assessment. Discussed possibility of false trip due to putting signal from one probe back on common side of other probes. He said it could cause false readings.
- Contacted Sega re third party assistance on reviewing incident. Fred Tolman to be on-site tomorrow. Bob Tolman to email me a proposal.
- Typed up Lance's description of bearing 5 vibration equipment troubleshooting and had him review: ok.
- Started review of hydraulic trip system to understand how steam may have continued to be admitted to turbine after trip.
- Found HMI screen with trips did not show that vibration trip was "active".
- Confirmed that DCS console trip and manual trip on M5 printout were same event. Somebody pushed DCS console turbine trip push buttons.
- Met with Joe Byrd, turbine control engineer for MD&A, regarding the DC oil pump issue and false trip issue.
- Met with MDC, Terry Hedrick and Dave Kramer? (UCU) regarding sequence of events.
- Discussed DC oil pump breaker with Bill White. He thinks House or Pflugradt opened breaker after incident and before Danny went to open it.

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6/15/00

- Scope of damage/repairs meetings all day.
- Fred Tolman of Sega came on-site and verified DC oil pump control logic (non-DCS).
- Met with insurance team to review scope of repairs (a.m.) and both insurance and GE to review same in the afternoon.
- Discussed cause of failure with Joe Byrd, MD&A.

6/16/00

- Lance checked vibration probe common to M5 cabinet ground, found 40 ohms resistance.

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- Received request for root cause data from Bill Cissell, GE. MDC to respond.

6/19/00

- Worked on list of items for FM Global. Request event logs from DCS – very large. Submitted request for DC pump related tags at 5 pm, not successful.
- Asked Gary House and Joe Pflugradt about opening DC oil pump breaker. Both said that they did not open breaker on day of incident.

6/20/00

- Jim Parker verified with Dave Rehm that he pushed turbine trip on DCS console, as shown on Mark V printout. Also, Dave believes that DCS DC pump control station was in "local" at time of incident.
- Interviewed operators with insurance team and David Evenger all afternoon: Jim Parker, Dennis Fletcher, Gary House, Dave Rehm, Bill White. Rick Strasser was present with union employees.
- Between Dave and Bill, they believe that Dave pressed console pushbuttons less than a minute before Danny Kukuc dumped hydraulic fluid and turbine stopped.
- "Controversial" issue is that Bill White maintains that steam continued to enter turbine until the point in time when Danny dumped hydraulics. Scott and Danny's statements support Bill. This is my next area to research.

6/21/00

- Met with John Mitchell, GE Customer Training Specialist. He is gathering information for root cause analysis for GE. Provided John the following items and explained what each one was: Mark V trip log, Mark V alarm printout, DCS event log from 1300 to 1800, DCS trend packet, Unit 4/6 log sheet.

- John asked questions about sequence of events. He was already aware that work was being done on bearing #5 vibration instruments at the time of the trip, AC power was lost on trip, DC oil pump did not start, and that there was some concern that stop valve did not close. I confirmed the first three and told him I was looking into the latter.

- The following Q&A is summary of discussion.
- Q. He asked if we knew why the DC pump did not start. A. I responded that we were looking into it. Q. Related to the Mark V installation?, A. Yes. Q. Was functional testing done on pump before startup? A. Yes, I performed it and it operated as designed. However, it appears that it was not in a condition to run at the time of the incident. Q. (Indirectly) Did the Mark V control the motor? A. No.

- We discussed design philosophy of unit (that we rely on DC on every generator trip), the fact that the pump starts on pressure only (not on loss of AC), that the 86GOT operates when turbine valves show closed with generator breaker closed.

- We looked at Mark V trip log and discussed the bearing 5 trouble-shooting that was going on at the time of the event. We agreed that vibrations appeared to be false and that we need to take a hard look at Mark V as far as grounding. etc. Q. Prox cable shields properly grounded. A. I

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said yes, I believed so (grounded at M5 only). Q. Did Bently Nevada (BNC) do check-out and commissioning? A. I explained that GE had responsibility under our PO. BNC installed and tested instruments, but were not here when Mark V was powered up and unit was rolled. I did call Matt Mangus (BNC) and Steve Ritter (GE – pretty sure it was Steve that I called) the week of start-up to ask whether a BNC person should be present. They were comfortable with the fact that BNC's scope was complete and that GE field engineer could complete check-out and watch things satisfactorily via the M5 (there was not a BNC equipment panel/cabinet installed on project.)

- I explained the steps performed by Lance during the bearing #5 vibration trouble-shooting on the day of the event. It appeared that IF his work caused it, it would have happened earlier in the day. John mentioned that it look like something "hit" the M5 cabinet to cause so many probes to show high vibration.

- He asked specifically about speed indication and I explained that speed probes were damaged during the event, so speed indication was sketchy. However, it appeared that the unit did overspeed and returned to synch speed 48 seconds after the trip. John said he would expect the unit to reach peak speed about 3 seconds after the trip and return to synch speed at about 10 seconds. If the unit was actually above synch speed for 48 seconds, this is another clue that the unit may have been driven by steam after the trip.

<u>6/22/00</u>

- Continued to study hydraulic system and possibility of failure that would keep stop valve open. Five things should have tripped turbine: ETD should have seen a trip signal three times: vibration, 86GOT, console buttons; also low bearing pressure trip relay (on loss of pumps) and mechanical overspeed (caused by vibration?, indicated at 14:06:59, 33 seconds after initial trip). PS ETD-1 showed a tripped condition immediately after the trip was indicated.

- Plotted hydraulic oil pressure data from DCS to try to ascertain when pressure was dumped by opening bypass. It appears that it was closer to 14:14 than 14:13. Testing after hydraulic system is released on re-assembly could help pinpoint time.

- Had discussions with John Mitchell of GE re above. During course of conversation, he asked whether I knew of any fault on the part of GE that contributed to the accident. I said that yes, there appeared to be contributing factors. He asked for more information, but I said that I wasn't sure I had the okay to elaborate at this time.

<u>6/23/00</u>

- Lance checked calibration of two pressure switches and verified that they operated certain Mk V alarms.
  - ETD-1, "Emergency Trip Header Tripped," opens: 700 psi rising, closes: 320 psi falling
  - SFPA, "Hydraulic Oil Pressure Low," opens: 1450 psi rising, closes: 1250 psi falling

- Discussed with DVS the amount of information that I shared with John Mitchell. DVS told me there was to be a "free flow" of information, and that included telling John how GE's design and installation engineering contributed to the incident. Therefore, I gave John a summary review of GE's poor performance during the project and explained how they overlooked the

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impact of removing the oil pump control switch. I also explained that GE's installation package was not delivered until we were into the outage, and that resulted in insufficient time for proper SJLP engineering review.

- John Mitchell, Mike Ceglenski and I then met to discuss John's draft report. We made a few corrections and discussed some of his findings. His report and sequence of events generally agreed with mine. He does not believe the unit oversped for more than ten seconds, while I suggested there was evidence to support an overspeed lasting nearly a minute. This is related to the "alleged" stop valve failure, which I am still investigating. His draft report did not include any mention of GE's role in the failure, as I had just informed him of that.

6/26/00

- No investigative work today.

6/27/00

- Bryan Nold and Luke Hinkle started checking the turbine valve limit switch string that picks up 86GOT relay. Finished main and right stop/intercept valves (plan to continue on 6/29). All okay so far. Verified the external trip wires (console pushbuttons) wired into PTBA.

- Long phone call with Ray Heyd re incident and how M5 trip relay is picked up. Read through M5 applications manual (re tripping) and PTBA, TCTS cards, etc. Ray does not believe the "synchronous speed" indication from M5 is reliable, i.e. we don't know when unit returned to 3600 rpm after overspeed.

6/28/00

- Electrician unavailable today.

- Looked at stop valve disk and three bypass valves and how they are assembled and operate. Pat Bauer, GE reports that stop valve stem has 0.030" run-out, which "may" have caused a hang-up in the stop valve. Problem is that dumping hydraulic header pressure would not have freed stop valve and stopped steam flow.

- In discussion with DVS, new theory on steam flow. Stop valve could have hung up and control valves did not close all the way, thus allowing a small amount of steam into turbine. When hydraulic pressure dumped, stop valve didn't move (hydraulic pressure was already tripped), but control valves went closed because the hydraulic pressure was released and spring pushed valves closed. Need to see if this theory works (see 7/11).

6/29/00

- Bryan Nold/Luke Hinkle back on stop valve limit switches. Left side RH stop and intercept wired as shown on F-1.
- Discussed incident with Danny Kukuc, again. He is sure DC oil pump breaker was open prior to when he went to open it on the day of the incident. He also confirmed that he heard turbine rolling (rough) prior to opening hydraulic oil bypass valve. When he opened valve, "it got quiet."

- Tried to retrieve trends from DCS for 4/25/00, similar trip, to compare 1st stage and CRH pressures, looking for indication that there was a driving force in turbine. No luck getting trends off the optical disk. Later found out that trends were not archiving at that time due to a console problem.

6/30-7/4/00
No investigation activity.

7/5/00
- Joe Byrd (MD&A) called: He asked about DCS indication of DC pump operation after unit was on line. Told him I was unsuccessful at extracting "focused" data at this time. He also had a theory about turbine mechanically re-setting due to vibration in TFS. After some discussion however, he didn't think it was possible.
- Talked with Dave Evinger, re 6/29 meeting with Danny Kukuc. Confirmed that Danny found the breaker open. Dave asked if there was any documentation of start-up check of DC oil pump was performed. I left question with Jim Parker.
- Dave requested Equipment Isolation documents that show lock-out and release of DC pump. I requested copies from JLP.

7/6/00
- JLP answered that there was no documentation that the DC oil pump was checked at start-up.
- JLP provided Equipment Isolation sheets for Isolations 00-0501, 00-0522. Faxed to Dave Evinger.
- JLP provided Operations Schedule sheets for period of 4/24 – 6/11/00.

7/7/00
- Reviewed DCS printouts. Found that on June 1 at 09:38:28 the DC pump motor overloads were logged as okay and at 09:38:31 a STOP command was issued. These only make sense if the pump had control power, i.e. breaker was closed. Since this is after the last equipment isolation was cleared and during a period when we were actively starting up the unit (lighting boiler and rolling turbine), it appears that the breaker was closed when unit was started up. (See 7/12 for follow-up).
- Looked at drawing K-1 at the contact that shows status of pump overload. It doesn't make sense that this contact is changing state as often as it does on the DCS print-outs. Discussed with Homer Clark of Sega, Suspect an input problem. Will look at next week with electrician. Homer will visit on Wed, 7/12 to review DCS printouts and provide clearer interpretation of events. (See 7/12 for follow-up.)
- Spent considerable time trying to retrieve trends and filtered events from DCS.

7/10/00
- Contacted ABB-Automation regarding retrieving DCS data from optical disk. Worked with Bob Schworm at ABB over the phone, but no progress. Right now, there are two problems: 1) Trying to limit events to tags related to DC oil pump in order to review activity on this pump prior to incident, 2) Cannot load trends from the day of the incident; need this to look at differential between first stage and cold reheat and see if there is energy present to drive turbine

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- Met with Ray Heyd all afternoon re Mark V punch-list. Also discussed need for GE to follow up on Mark V/Bently Nevada instrumentation to assure that system is reliable and functioning properly when we re-start. As we discussed the vibration indicaiton trouble-shooting steps, we reviewed Steve Alexander's statement. Steve's statement indicates that he observed the turbine trip "about the time" of the first explosion, which would have been several seconds after we previously believed it tripped. It also changes the sequence of events: If Lance heard loss of hydrogen and observed no. 5 bearing "smoking," prior to the trip then it means that there was a loss of hydrogen seals prior to the loss of AC power. A hydrogen explosion before the trip would explain two things: 1) it could send a large sudden vibration down the shaft that would have then caused the unit trip; 2) the sound of the unit trip (that nobody heard) may have been lost in the explosion that immediately preceded it.

7/11/00

- DCS retrieval: Tried suggested changes to archive retrieve event request with no luck. Also, trends did not retrieve either. Faxed event retrieve results to Bob Schworm at ABB. Lance Brumbaugh started looking into trend retrieval problem. Lance changed trend retrieval from "sample" to "average" to match trend set-up. With this change, we were able to retrieve trends from day of event.
- Based on trends and differential between first stage and cold reheat pressures, the differential between the two had dissipated in less than two minutes, which does not support the observation that the turbine appeared to be powered several minutes after the trip. Unsure what level of differential would be required and how much of a first stage drop was present.... The data don't disprove the observation, they just doesn't support it.
- Talked to Bill Cissell re Steve Alexander's observations. Evidently, GE noted the timing "problem" with Steve's statement and he has rescinded it. Bill was on cell phone on way to Wolf Creek, so connection was bad.
- Talked to Lance re Steve's statement. Lance was not in a position to see HMI screen when he entered control room, so he could not say that turbine had already tripped. However, he did remember that operators were already responding to a boiler upset and Bill White was on the way into control room when Lance entered, which means safeties had already lifted, which would have followed turbine trip. Also discussed with Mike Ceglenski. He clearly remembered hearing explosion several seconds after safeties lifting. So, it seems, that Steve's statement must be incorrect. I left a message with Bill Cissell requesting any information regarding Steve's current position on his observations during the event.
- Discussed following theory with Ray Heyd: Both stop and control valves failed to close all the way on trip, allowing steam to enter turbine. Control valves closed under spring load when hydraulic pressure dumped, stopping steam flow and therefore turbine stopped. It seems this would be possible only if control valve calibration was way off. He didn't think that was likely based on operation prior to trip.

7/12/00

- DC PUMP STATUS Met with Homer Clark of Sega for most of day to interpret DCS alarms and events. Conclusions: DC pump ran in auto on 5/24, was stopped and returned to auto state. Pump was later turned off. Most likely breaker was opened to isolate oil for GE to repair collector-end hydrogen seal. No other "real" activity recorded for pump after 5/24. DC pump events on 5/26 and 6/1 were most likely due to resetting of OIS console. In any case, the events on 5/26 and 6/1 do not prove that the DC breaker was closed (one event is DCS powered, the

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Schedule RWT-4.7

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other is an internal state, neither requires field power to operate). The pump overload OK alarm input was found to be okay by Homer and Steve Barton. It also was most likely being printed in response to the OIS console being reset.

<u>7/13/00</u>

- Informed JLP of DC pump findings from yesterday. He discussed with Scott Hinkle, who got back to me bel
- Most of day preparing OPC DR responses.

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Turbine Generator 4 June 7, 2000 Incident
Possible Contributing Factors

- Original system (c. 1966): System was designed and built to rely on DC oil pump until AC power was transferred every time there was a generator trip. DC oil pump served both as "normal" and emergency role (i.e. no second line of defense).
- DCS design and installation (1995): DCS oil pump control logic was installed in parallel with manual control switch.
  - DCS control for DC pump did not "return to auto" after stop, as manual control switch did.
  - AC pumps DID return to auto in DCS, misleading plant personnel to believe DC pump operation was similar.
  - No alarm for DC pump in off position.
  - Control station displayed "local" instead of "off," which was no longer meaningful after removal of the "local" (i.e. manual) control switch.
  - No alarm for loss of pump control power.
  - DCS weaknesses since 1995 were not apparent due to continued use of manual switch.
- Mark V Installation Engineering (Feb – May 2000)
  - GE several weeks behind in project engineering.
  - Multiple lead engineers involved in construction design, little continuity.
  - Manual switch removed in design without sufficient review.
  - Installation drawings delivered to SJLP after outage was underway.
  - Limited time for Company review.
- Mark V Installation (May 2000)
  - System installed and tested per GE drawings and other documents.
  - Company personnel did not recognize hazard.
- Mark V Training (May 2000)
  - Poor GE training, not specific to Lake Road Plant.
  - Change in DC pump control not explicitly pointed out to operators.
- Operation (May 25 – June 7, 2000)
  - DC pump availability and operation not checked during start-up on 6/2/00.
  - Weekly DC oil pump test not performed on 6/5/00.
  - Pump readiness less apparent to operators due to removal of manual switch.
- Vibration Trip (June 7, 2000)
  - Bently Nevada/GE testing in August 2000 indicates that high indicated vibration was likely a false indication caused by troubleshooting work, which was underway by GE/Company personnel at time of trip.
  - Turbine trip caused 86G trip, which in turn shut off AC power to lube oil pumps.
- Roll Down (June 7, 2000)
  - DC oil pump did not run.
  - Loss of lubrication to bearings, subsequent vibration, oil fires.
  - Loss of hydrogen seals, subsequent explosions, hydrogen fire.
  - Apparent steam flow after turbine trip may have contributed to mechanical damage.
  - No injuries, fire damage contained.

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