Exhibit No.:
Issues: Accounting Authority Order
Witness: V. William Harris
Sponsoring Party: MoPSC Staff
Type of Exhibit: Rebuttal Testimony
Case Nos.: EO-2000-845

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

REBUTTAL TESTIMONY

OF

V. WILLIAM HARRIS

ST. JOSEPH LIGHT & POWER COMPANY

CASE NO. EO-2000-845

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Jefferson City, Missouri
October, 2000

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REBUTTAL TESTIMONY

OF

V. WILLIAM HARRIS, CPA, CIA

ST. JOSEPH LIGHT & POWER COMPANY

CASE NO. EO-2000-845

Q. Please state your name and business address.

A. V. William Harris, Noland Plaza Office Building, Suite 110, 3675 Noland Road, Independence, Missouri 64055.

Q. By whom are you employed and in what capacity?

A. I am a Regulatory Auditor with the Missouri Public Service Commission (Commission or PSC).

Background of Witness

Q. Please describe your educational background.

A. I graduated from Missouri Western State College at St. Joseph, Missouri in 1990 with a Bachelor of Science degree in Business Administration with a major in Accounting. I successfully completed the Uniform Certified Public Accountant (CPA) examination in 1991 and subsequently received the CPA certificate. I am currently licensed as a CPA in the state of Missouri. I also successfully completed the Uniform Certified Internal Auditor (CIA) examination in 1995 and am currently certified as a CIA by the Institute of Internal Auditors in Altamonte Springs, Florida.

Q. Please describe your employment history.

A. From 1991 until I assumed my current position as a Regulatory Auditor with the Commission in 1994, I was employed as a Regulatory Auditor with the Federal Energy

Regulatory Commission in Washington, DC. Prior to that, I was an Internal Auditor and Training Supervisor with Volume Shoe Corporation (d/b/a Payless ShoeSource).

Q. What are your responsibilities with the Commission?

A. I am responsible for assisting in the audits and examinations of the books and records of regulated utility companies operating within the state of Missouri.

Q. Have you previously filed testimony before this Commission?

A. Yes, I have. A list of cases in which I have filed testimony is shown on Schedule VWH-1 of this rebuttal testimony.

Purpose of Testimony

Q. With reference to Case No. EO-2000-845, have you examined and studied the books and records of St. Joseph Light & Power Company (SJLP or Company) in conjunction with SJLP's application for the issuance of an Accounting Authority Order (AAO) relating to its electrical operations?

A. Yes, in conjunction with other members of the Commission Staff (Staff).

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony in this proceeding is to present the Staff's current position regarding the Commission's issuance of AAOs and how it specifically relates to the issuance of an AAO to defer certain costs relating to SJLP's electrical operations at its Lake Road Power Plant. In doing so, I will also address the direct testimonies of SJLP witnesses Dwight V. Svuba and Larry J. Stoll.

Discussion of Accounting Authority Orders (AAOs)

Q. What is an Accounting Authority Order (AAO)?

A. An AAO is a Commission order granting a utility the authority to depart from normal accounting treatment by deferring recognition of extraordinary costs that under normal circumstances would require immediate expense recognition.

Q. Does a utility benefit from the deferred cost recognition provided by an AAO?

A. Yes. A regulated utility's rates are established based on the recovery of its normal cost of providing service to its customers. The benefit to a utility of deferring the cost recognition of extraordinary events can be summarized as follows:

(1) The deferred cost recognition of an extraordinary event provides an opportunity for a utility to earn a higher rate of return as a result of not recognizing the immediate cost impact of a significant, extraordinary event or the expenses related to an extraordinary capital project.

(2) The deferred cost recognition for depreciation expense, related property tax expense, and carrying costs (allowance for funds used during construction) associated with an extraordinary capital project or event under an AAO enhances cash flow if the utility is allowed to recover these costs in its next rate case.

Q. Is the Commission's policy regarding deferred cost recognition under an AAO intended to protect shareholders from "all" risks that result from the extraordinary expenses incurred due to an extraordinary event and/or extraordinary capital project?

A. No. On page 10 of its Report and Order in Case No. EO-91-358, made in resolution of an application by Missouri Public Service for the issuance of an accounting authority order relating to its electrical operations, the Commission clearly stated, "It is not

reasonable to defer costs to insulate shareholders from any risks." The Staff believes that this policy continues to be appropriate today.

Q. How has the Commission addressed the risk between ratepayers and shareholders in prior cases that provided for deferred cost recognition under an AAO?

A. The Commission orders a specific amortization period, which determines the amount of the deferred balance to be recognized as expense on an annual basis. As an example, deferred costs resulting from a flood or ice storm have generally been amortized over a five-year period. The annual amounts amortized to expense have generally been included in the utility's cost of service in rate cases resulting in rate recovery of the deferred amounts. However, the unamortized balance has generally not been afforded rate base treatment. Thus, the shareholders are responsible for the carrying costs (rate of return) on the unamortized balance during the amortization period.

Past Commission policy on the approval of AAO's

Q. What has been the Commission's policy regarding the approval of deferred cost recognition under an AAO?

A. The Commission has approved deferred cost recognition if the costs were extraordinary and were not included in the normal cost of service assumptions used in determining a utility's existing rates. On page 7 of its aforementioned Report and Order in Case No. EO-91-358, the Commission stated in part, "Deferral of costs from one period to a subsequent rate case ... should be allowed only on a limited basis. This limited basis is when events occur during a period which are extraordinary, unusual and unique, and not recurring."

Additionally, with the exception of extraordinary capital projects (such as the gas service line replacement programs approved for Missouri Gas Energy and Laclede Gas Company), the Commission has generally ordered a specific amortization period when approving an AAO. In two previous AAO approvals for SJLP, Case No. EO-94-35 regarding the deferral of extraordinary costs resulting from a major flood and Case No. EO-95-193 regarding extraordinary costs resulting from a major ice storm, the Commission ordered a specific amortization period beginning immediately following the approval.

Q. Has the Commission had any other requirements regarding its approval of the deferred cost recognition associated with an AAO?

A. No. The Commission's only requirement has been that the expenses were extraordinary. The Commission has deferred all other ratemaking implications, including the amount and the prudency of the costs, and the rate base treatment, to the utility's next rate case. With regard specifically to AAO approval for major capital projects such as the gas service line replacement projects (Laclede Gas Company and Missouri Gas Energy) and the Sibley 3 rebuild (Missouri Public Service) the Commission also specified a future date for the filing of the Company's next rate case as a condition of approval.

Current Staff position on the approval of AAO's

Q. Is the Staff recommending, in this Case No. EO-2000-845, that the Commission expand its requirements regarding the approval of deferred cost recognition under an AAO?

A. Yes. Continuation of the policy requiring only that expenses be extraordinary for the approval of an AAO may subject the Commission to AAO requests

that do not reasonably merit consideration. SJLP's application for the issuance of an AAO in this case is an example of such a request.

SJLP witness Larry J. Stoll makes it quite clear in his direct testimony (on page 11, lines 5 through 11) that SJLP does not want the Commission to consider what caused the incident. While the Staff readily agrees that the costs SJLP are seeking to defer are indeed extraordinary, the Commission should deny SJLP's request for reasons I will outline later in this testimony.

Q. What does Staff recommend be required from an AAO filing before the Commission should consider granting an AAO?

A. The Staff recommends requiring that the application meet the following conditions before the Commission should consider granting an AAO:

For an AAO request with no amortization period, i.e., amortization is to be deferred until the effective date of rates for a future rate case.

(1) The event must be extraordinary and material. The Staff is recommending that the costs, subject to deferral, represent at least 5% of the utility's regulated Missouri net income, computed before extraordinary items. This percentage should be applied to the company's twelve months of earnings prior to the event. This requirement is consistent with the materiality requirement for deferring costs in Account 182.3 of the Uniform System of Accounts (USOA) as defined in the seventh General Instruction, "Extraordinary Items," Subchapter C, Part 101 of the Code of Federal Regulations, Title 18. The USOA was established by the Federal Power Act and is the prescribed method used by the Federal Energy Regulatory Commission (FERC) and adopted by the Commission for book keeping purposes pursuant to 4 CSR 240-20.030. (It should be noted, however, that 4 CSR

240-20.030(4) states in part that "the Commission does not commit itself to the approval or acceptance of any item set out in any account for the purpose of fixing rates...").

(2) The utility's current rates must be inadequate to cover the event. If it can be determined, by examining surveillance reports and other information provided by the utility, that existing rates appear sufficient to cover the extraordinary cost and still provide the utility with a reasonable expectation of earning its authorized rate of return, then the AAO request should be rejected.

(3) The extraordinary expenses that the utility is seeking to defer must result from either:

(a) an extraordinary capital addition, such as the gas service line replacement program, that is required to insure the continuation of safe and adequate service, in which unique conditions preclude recovery of these costs through a rate case filing, or

(b) an extraordinary event that is beyond the control of the utility's management. Examples include a major flood or ice storm.

(4) The utility must file a rate case within 90 days of the AAO approval. If the utility intends to seek rate recovery and defer amortization of the AAO balance until the effective date of rates for a future rate case, the utility should be required to file a rate case soon after approval of the AAO. The Commission stated on pages 8 and 9 of its Report and Order in Case No. EO-91-358, "The Commission finds that a time limitation on deferrals is reasonable since deferrals cannot be allowed to continue indefinitely. The Commission finds that a rate case must be filed within a reasonable time after the deferral period for recovery of the deferral to be

considered." It is the Staff's position that if the impact of an extraordinary event is so significant as to require rate recovery, then the only logical justification for delaying the filing of the rate case is that the extraordinary event is on-going, such as a gas service line replacement program. Normal construction projects should not be afforded special AAO deferral treatment.

For an AAO request with a prescribed amortization period commencing upon the conclusion of the specified event or the Commission's approval date for the AAO request.

Requirements (1), (2) and (3) as discussed above, and

(4) The event or project is one that is traditionally amortized over several years in rate cases or there are benefits in future periods that will be better matched through the deferral of these costs. A five-year amortization of major flood or ice storm costs are two examples. The prescribed amortization will begin immediately upon either:

(a) completion of the event or project associated with the deferred costs, or

(b) the effective date of the order granting the AAO.

Q. Why should a utility immediately begin to amortize an expense deferred pursuant to an AAO, or else file a rate case shortly after the deferral is granted?

A. Either an immediate amortization or the filing of a rate case soon after approval of the AAO is appropriate because deferred costs should not be "suspended" on a company's books and records for a long period of time. To leave an item, normally charged to expense, in a deferral account on the balance sheet for an extended period of time would represent a distortion of both normal ratemaking and financial reporting principles and

practices. Both the ordering of an immediate amortization to expense and the ordering of an immediate rate case filing would prevent that distortion from occurring.

The Incident at Lake Road

Q. Please describe the generating facilities at the Lake Road Power Plant.

A. The Lake Road Power Plant consists of four steam-turbine generators, three combustion turbines, six steam boilers and one heat recovery steam generator. The station's generating units have a combined net electric generating capability of 256 megawatts (MW). The station consists of three separate systems: a 900-pound system, a 1,800-pound system and a combustion turbine (CT) system. The 900-pound system also supplies industrial steam to six customers.

Q. Briefly describe the 1,800-pound system.

A. The system is so named because it operates at 1,800 pounds per square inch of steam pressure. The 1,800-pound system is a single generating unit consisting of Turbine-Generator Number 4 and Boiler Number 6 (collectively referred to as Unit 4/6). Unit 4/6 uses coal as the primary fuel and natural gas as the start-up fuel or as an alternative fuel. The unit operates at a full-load capacity of 97 MW and was expected to supply over 25% of SJLP's system energy requirements for the months of June, July, and August 2000.

Q. Briefly describe the incident at the Lake Road plant on June 7, 2000 that has become the basis for SJLP's application for an AAO in this case.

A. A new turbine-generator control system, the Mark V, and a new static generator excitation system (EX2000) were installed by General Electric (GE) during the scheduled spring outage that took place from May 2 through June 2, 2000. The new Mark V control system tripped Unit 4/6 off-line on June 7, 2000 due to high vibrations. The

unit's emergency direct current (DC) oil pump failed to start automatically when Unit 4/6 was forced off-line.

As a result, five bearings overheated and suffered mechanical damage. The loss of oil pressure allowed hydrogen to escape from the generator which in turn resulted in explosions and fires. The bearing damage resulted in additional damage to the unit.

The reason provided by the Company for the DC oil pump not coming on automatically was that the operator failed to set the emergency pump in the automatic mode. (Svuba direct, page 7 - lines 2 through 13.)

Criterion (1) Extraordinary and Material Event

Q. Explain the nature of the costs SJLP considers extraordinary and included in its AAO request.

A. The nature of the costs resulting from the forced outage of Unit 4/6 that SJLP considers extraordinary are summarized in Schedule LJS – 1 attached to the prefiled direct testimony of SJLP witness Larry J. Stoll:

Incremental energy and transmission costs	$3,184,000
Insurance deductible for repair costs	$ 150,000
Total costs subject to deferral	$3,339,000

Q. Have the amounts in Schedule LJS-1 changed since SJLP filed its direct testimony?

A. Yes, per SJLP's updated response to Staff Data Request No. 7, the amounts should be reflected as follows:

**_____

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As reflected above, 96% of the incremental costs are related to energy and transmission costs needed to replace the loss of generation from Unit 4/6 with higher-cost energy. This replacement energy included generation from other higher-cost Lake Road units and energy purchased from other utilities during the period of June 7 to August 8, 2000 while Unit 4/6 was offline for repairs needed due to the June 7, 2000 explosions and fires.

Q. Does the Staff consider the forced outage at Lake Road Unit 4/6 to be extraordinary as defined by the Staff's first recommended criterion for granting an AAO request?

A. Yes. A two-month forced outage of a coal-fired generating unit expected to provide 25% of the net system load during the peak summer months is not a normal event and should be considered extraordinary as required by the Staff's first recommended criterion. However, the Staff opposes the approval of an AAO to SJLP in this case since the event that caused the outage was within the control of SJLP. I will address this issue at length in my rebuttal testimony under the Staff's third recommended criterion.

Q. Does the amount of the incremental costs related to the Lake Road Unit 4/6 forced outage appear to meet the materiality requirement under the Staff's first recommended criterion?

A. Yes, initially it would appear to meet the materiality requirement. The after-tax impact of the **_____** in incremental costs resulting from the outage exceeds 5% of SJLP's electric net income using SJLP's surveillance report for the twelve months

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ended July 31, 2000. However, in this instance, the **_____** AAO deferral, if approved, should be **_____** based upon an analysis of SJLP's current earnings for its electric operations.

Q. Please explain what you mean by stating it would initially appear to meet the materiality requirement.

A. Apparently a dispute has arisen between UtiliCorp and SJLP regarding the fire and outage at Unit 4/6. On September 21, 2000, each company issued a statement indicating this potential dispute (See Schedule VWH-2, provided by UtiliCorp, and Schedule VWH-3, provided by SJLP, of this rebuttal testimony.). The SJLP News Release states in part:

> "St. Joseph, Missouri – St. Joseph Light & Power Company (SJLP) (NYSE-SAJ) announced today that UtiliCorp has completed a preliminary investigation of the impact and projected costs of the previously reported fire that occurred at SJLP's Lake Road power plant on June 7, 2000, and that, in the opinion of UtiliCorp, such impact is material."
>
> "UtiliCorp's letter states that '[t]his letter does not represent the termination notice' contemplated by the Agreement, but constitutes a request for SJLP 'to confirm whether it views the damage caused by the fire as material.'"
>
> "Following a meeting of its board of directors held on Wednesday, September 20, 2000, to review the UtiliCorp request, SJLP advised UtiliCorp that the impact and projected costs of the Lake Road Plant fire are not 'material' for purposes of the Merger Agreement . . ."

The statement issued by UtiliCorp states in part:

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". . . [A] very serious issue awaits resolution involving the financial and operational implications of a June 7, 2000 fire that damaged a unit at the Lake Road power plant operated by St. Joseph. UtiliCorp has asked St. Joseph to provide a detailed explanation regarding the materiality of this incident, and remains hopeful that a satisfactory response will be forthcoming."

Q. Does the Staff consider this apparent dispute to be relevant to SJLP's Application for an AAO?

A. Most definitely. SJLP has stated that UtiliCorp has (a) made a preliminary investigation of the materiality of the incident, (b) determined that the incident is material and (c) asked that SJLP confirm that the incident is material. SJLP also has asserted that "the impact and projected costs of the Lake Road Plant fire are not 'material' for purposes of the Merger Agreement . . ." UtiliCorp has publicly stated that it has requested a detailed explanation as to the materiality of the incident. There appears to be a significant inconsistency between SJLP and UtiliCorp regarding the materiality of the fire and outage at Lake Road Unit 4/6.

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Q. What, if anything, has the Staff done in regards to these statements from SJLP and UtiliCorp?

A. The Staff has submitted data requests to both UtiliCorp and SJLP. Initially, the data requests to SJLP were submitted in the merger case, Case No. EM-2000-292, through UtiliCorp, according to the procedures established with SJLP and UtiliCorp in that proceeding.

Q. Has the Staff received any responses to these data requests?

A. To date, the Staff has only received the following objections from SJLP's Vice President, General Counsel and Secretary and its local counsel in Case No. EM-2000-292:

Staff Data Request No. 317:

"1. Please provide the workpapers/documents relied upon by Saint Joseph Light & Power in determining 'that the impact and projected costs of the Lake Road plant fire are not 'material' for purposes of the Merger Agreement.'

Objection: The data request is not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, it is vague in that the origin of the quoted material is not identified, and is irrelevant. Any response to this data request will be without waiver of this objection.

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2. Please identify all reasons why St. Joseph Light & Power believes the June 7, 2000 fire at Lake Road plant is not material to the merger between UtiliCorp and St. Joseph.

Objection: The data request is not reasonably calculated to lead to the discovery of admissible evidence. The data request is 1) irrelevant; 2) seeks legal conclusions related to the interpretation of the merger agreement between UtiliCorp and SJLP, and 3) seeks the work product of SJLP's attorneys, which is privileged matter."

Q. Has SJLP made a commitment to respond to rebuttal testimony on these matters?

A. Yes. On October 4, 2000, SJLP replied to the September 29, 2000 Staff Motion For Commission Order Directing The Filing Of Supplemental Direct And Rebuttal Testimony And Directing Expedited Treatment. In the October 4 Response Of SJLP To Staff Motion, local counsel for SJLP in the instant AAO case stated as follows:

". . . [the Staff] can say in its prepared rebuttal testimony whatever it wants to about the exchange of correspondence between UtiliCorp United Inc. and SJLP. SJLP and other parties can then file surrebuttal per the established schedule on October 17. . . ."

Response Of SJLP To Staff Motion, pp. 1-2.

". . . As stated previously, if the Staff thinks there is an inconsistency, it can file prepared testimony on the topic and SJLP will address the allegations or facts in prepared surrebuttal testimony. . . ."

". . . On a more practical note, SJLP at the present time does not have anything to say in 'supplemental direct testimony' on this topic. It stands ready, however, to respond to the prepared rebuttal testimony of Staff and any others with

prepared surrebuttal on October 17 in accordance with the previously established procedural schedule."

Response Of SJLP To Staff Motion, p. 2.

Criterion (2) Inadequacy of Current Rates

Q. Referring back to the Staff's recommended criteria for AAO approval, please provide the Staff's position regarding SJLP's AAO request in reference to Staff's second recommended criterion for AAO approval.

A. Staff's recommended second criterion states that an AAO deferral request should be rejected if evidence shows that existing rates are sufficient to cover the impact of the extraordinary event in question. Attached as Schedule VWH-6 to my testimony is a comparison of SJLP's actual earned return on equity for its electric operations, for the year ending July 31, 2000, to the recommended midpoint return on equity (ROE) sponsored by Staff witness David P. Broadwater, of the Commission's Financial Analysis Department. (Please refer to Mr. Broadwater's rebuttal testimony.). Line 8 reflects SJLP's actual ROE of **_____** for a 12-month period ending July 31, 2000. Line 9 reflects the midpoint ROE recommendation for SJLP sponsored by Staff witness Broadwater. Line 16 reflects **__

_____

_____** for SJLP's electric operations as of July 31, 2000.

Q. How should the **_____** reflected on Schedule VWH-6 and explained in your previous answer be reflected in the context of SJLP's AAO request in this case?

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A. AAO requests should only be approved when existing rates are insufficient to absorb the impact of an extraordinary event. In this instance, SJLP's unadjusted financial results for the 12-month period ending July 31, 2000 indicate **_____ _____.** The Staff's primary recommendation concerning SJLP's request is that an AAO should not be approved on the basis that the cause of the incident, operator error and inadequate training, were under the control of management. Only extraordinary events outside the control of management (including an extraordinary capital project required for safe and adequate service) should be afforded AAO deferral treatment.

However, if the Commission disagrees with the Staff's recommendation to reject the AAO request, the Staff would recommend that the Commission **_____ _____** for SJLP's electric operations as of July 31, 2000.

Criterion (3) Nature or Type of Event

Q. Does SJLP's requested AAO in this case meet the Staff's recommended requirement under part (a) of the third criterion that the extraordinary expenses SJLP is seeking to defer result from an extraordinary capital addition?

A. No, it does not.

Q. Does SJLP's requested AAO in this case meet the Staff's recommended requirement under part (b) of the third criterion that the extraordinary expenses SJLP is seeking to defer result from an extraordinary event that was beyond the control of SJLP's management?

A. No, it does not.

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Q. Please explain why the forced outage at Lake Road Unit 4/6 does not meet the "beyond the control of management" criterion recommended by the Staff for AAO approval.

A. As stated on page 7, lines 2 through 13, of SJLP witness Svuba's direct testimony, the plant operator failed to realize that the emergency DC oil pump control did not return to the automatic mode after a stop command. The failure of the operator to insure that the DC oil pump was on caused the damage to the unit that resulted in the forced outage and subsequent **_____** in incremental energy costs.

It is the Staff's position that it is SJLP management's responsibility to insure that its operators are adequately trained. The failure of SJLP management to insure the operator received adequate training resulted in the operator error that caused the **_____** in incremental costs to SJLP. SJLP's shareholders should bear the risk of an extraordinary event when its cause is within the control of management. To do otherwise shifts "all" risk to ratepayers from extraordinary events, both within and outside the control of management.

Q. Are there specific references in Mr. Svuba's direct testimony for the Staff concluding that the extraordinary event at the Lake Road plant on June 7 resulted from operator error that was within the control of management?

A. Yes. On page 7 of Mr. Svuba's direct testimony, he makes the following statement on lines 9 through 13:

> "Due to control changes that were completed during the GE turbine control replacement project, the operators failed to realize that the pump control did not return to the automatic mode. We believe that the pump control was in the 'local' mode at the time of the incident, i.e. the pump would not automatically start." (Emphasis added).

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On page 8, lines 9 through 15 of Mr. Svuba's direct testimony he makes additional comments regarding the lack of understanding by SJLP personnel regarding the existing SEGA control system controlling the DC oil pump:

"It was generally believed by plant personnel (not only operators, but also engineers and supervisors) that the DC oil pump control in the DCS returned to the automatic mode after the pump was stopped by the operator. It was not discovered that the pump did not 'return-to-auto' until the investigation after the June 7th incident. Since the pump control did not return-to-auto (as the manual switch had done), it was necessary for the operator to make a second control action to place the pump in automatic mode after stopping it." (Emphasis added).

Q. **

A. ___

Q. _____

A. _____

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- _____
- _____
- _____

Q. _____

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A. _____

_____

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[redacted]**

Q. Does the SJLP response to OPC Data Request No. 6 provide additional evidence regarding the **[redacted]

A. [redacted]

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[redacted]**

Q. Does the new Mark V control system control the operation of the emergency DC oil pump, which was responsible for the damage to Lake Road Unit 4/6?

A. No. The computer software system, which controls the emergency DC oil pump, is an original system installed by SEGA in 1995. However, GE/SJLP made modifications to the existing SEGA control system when installing the Mark V control system during the Spring 2000 scheduled outage at Lake Road which ended on June 2, 2000.

Q. Did the modifications which were made to the existing control system contribute to the failure of the emergency DC oil pump?

A. Yes. The existing control system included a computer software system and a manual switch. GE/SJLP removed the manual switch in connection with the installation of the Mark V control system. Removing the manual switch would force SJLP operators to rely on the computer software system. However, the operators, engineers and supervisors at the Lake Road plant had been relying on the manual switch since the installation of the SEGA system in 1995. They were not adequately trained on the SEGA software system, and therefore, did not understand how it controlled the emergency DC oil pump. This lack of training falls squarely on SJLP.

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Q. If the new Mark V control system did not control the DC oil pump, then why is the **_____** relevant to this AAO case?

A. **_____ _____** failed to train its personnel regarding operating changes required with the use of SEGA computer software system which, as a result of the removal of the manual switch, became the only control available.

SJLP management should not have removed, nor permitted the removal of, the manual switch on the existing control system without a complete understanding of the system's operation, including the computer software system, and the impact that removing the manual switch would have on SJLP operators and their operation of the SEGA control system that controlled the emergency DC oil pump.

It is clear from **_____** and Mr. Svuba's direct testimony, that from June 2 to the June 7 forced outage at Lake Road, the plant was being operated by personnel who were not properly trained on the existing SEGA system **_____ _____ _____** A failure did occur because the operator was not properly trained on the SEGA system controlling the DC oil pump.

Q. Is granting AAO approval for an extraordinary event, resulting from operator error due to inadequate training, consistent with the Commission's stated policy in its Report and Order in Case No. EO-91-358?

A. No. On page 10 of the Report and Order, the Commission made it clear that granting an AAO was not intended to protect shareholders from all risk by stating, "It is not reasonable to defer costs to insulate shareholders from any risks." To allow deferred accounting treatment for both:

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(1) extraordinary events beyond the control of management (e.g., major floods or ice storms), and

(2) extraordinary events that are within the control of management (e.g., operator error arising from inadequate training or any other unreasonable and/or imprudent conduct)

essentially protects shareholders from "any" risk from extraordinary events and shifts all risk to ratepayers.

Q. Is there evidence of other possible operator error?

A. Yes. SJLP's response to Staff Data Request No. 4102 in Case No. ES-2001-28, the Staff's investigation of the June 7 incident, includes a document dated July 13, 2000 that contains the heading "Turbine Generator 4 June 7, 2000 Incident Possible Contributing Factors". I have attached it as Schedule VWH 9-1. This document which was marked as Exhibit 11 in the deposition of John Modlin contains several entries that concern Staff. This document was revised and a copy was marked as Exhibit JM-12 in the deposition of John Modlin. This document is attached as Schedule VWH 9-2. This revision contains several entries that concern Staff. A partial list of the individual items set out in Schedule VWH 9-2 follows:

- Mark V Installation Engineering (Feb – May 2000)
  - Manual switch removed in design without sufficient review
  - Installation drawings delivered to SJLP after outage was underway
  - Limited time for Company review.
- 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 oil pump test not performed on 6/5/00.
  - Pump readiness less apparent to operators due to removal of manual switch.

(Emphasis added).

This list indicates there were various things, one would reasonably expect to be under management's control, that contributed to or caused the June 7 incident.

Q. Are you aware of any other evidence that supports the information attached as Schedule VWH-9?

A. Yes. In response to OPC Data Request No. 5001, SJLP provided an 8-page document titled "SJLP Lake Road Turbine Generator 4 June 7, 2000 Incident Investigation Notes." This document supports many of the entries listed above and expands upon others. I have attached it as Schedule VWH-10. A copy of this document was marked as Exhibit JM-10 in the deposition of John Modlin.

Q. Does the Staff have any other concerns regarding SJLP's position that ratepayers should bear the cost of the forced outage at the Lake Road plant?

A. **_____

_____

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_____

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[redacted]**

Criterion (4) Immediate Amortization or Deferral to Future Rate Case

Q. Does SJLP's AAO request meet the Staff's fourth recommended criterion regarding AAO requests with a prescribed amortization period?

A. No. The Staff's fourth recommended criterion for an AAO with a prescribed amortization period requires amortization to begin either (a) upon completion of the event, or (b) the effective date of the order granting the AAO. With reference to SJLP witness Larry J. Stoll's direct testimony (page 6, line 22 through page 7, line 2, and again on page 11, line 18 through page 12, line 3), SJLP is requesting that the amortization period for this AAO not take effect until the effective date of rates established in a future rate case.

Q. Does SJLP's AAO request meet the Staff's fourth recommended criterion regarding AAO requests without a prescribed amortization period?

A. No. The Staff's fourth recommended criterion for AAO requests without a prescribed amortization period requires the utility to file a rate case within 90 days of the AAO approval. Mr. Stoll has provided no indication as to when SJLP would file this rate case. In fact, Mr. Stoll's testimony suggests that SJLP may never file a rate case seeking recovery of these costs at all. On page 11, lines 14 through 17, Mr. Stoll states, "If the

NP

Commission grants the merger request in Case EM-2000-292 with the regulatory plan proposed by the joint applicants, the rate moratorium in place would result in the Company writing off the deferred balance at that time." The Staff refuted in Case No. EM-2000-292 SJLP's assertion that, but for the proposed moratorium of the SJLP/UtiliCorp merger regulatory plan, SJLP would file two rate cases in the next five years. In fact, as discussed above, SJLP is presently **_____**

Mr. Stoll's references to these uncertain events suggest that SJLP is seeking to defer these costs indefinitely. As I stated earlier in this testimony (page 7, lines 19 through 24), the Commission clearly stated, in its Report and Order in Case No. EO-91-358, "The Commission finds that a time limitation on deferrals is reasonable since deferrals cannot be allowed to continue indefinitely. The Commission finds that a rate case must be filed within a reasonable time after the deferral period for recovery of the deferral to be considered." (Emphasis added).

Q. What is SJLP's requested deferral period in this case?

A. The deferral period in this case is essentially the period of the extraordinary event itself. It began on the day of the incident (June 7, 2000) and effectively ended on the day the Lake Road Unit 4/6 was returned to service (August 8, 2000).

Q. Is the amortization period SJLP is requesting for its deferrals in this case consistent with those that were granted in prior AAO requests approved for SJLP?

A. No. SJLP has had two prior AAOs approved, which it views as being of a similar nature to this application. The extraordinary costs resulting from a major flood and major ice storm were granted AAO deferral treatment in Case Nos. EO-94-35 and EO-95-193, respectively. In both cases, an amortization period was ordered to begin immediately following the Commission's approval of the request.

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SJLP should be required to file a rate case within 90 days of the Commission's approval or begin an amortization of the deferred costs immediately upon the Commission's approval of its AAO request.

Summary and Conclusion

Q. Please summarize the Staff's recommendation regarding SJLP's **_____** request for AAO deferral treatment in this case.

A. The Staff is recommending that the Commission expand its policy regarding the approval of AAO deferral treatment based on the following criteria:

For an AAO request with no amortization period, i.e., amortization is to be deferred until the effective date of rates for a future rate case.

(1) The event must be extraordinary and material. The amount to be deferred must be at least 5% of the utility's regulated Missouri net income for the 12-month period prior to the event.

(2) The utility's existing rates must be inadequate to cover the event.

(3) The extraordinary costs must be either related to:

(a) an extraordinary capital project, such as a gas service line replacement program, that is required to insure the continuation of safe and adequate service and that, because of unique circumstances, cannot be recovered in a normal rate case filing, or

(b) an extraordinary event that is beyond the control of management. Examples would include a major flood or ice storm.

(4) The utility must file a rate case within 90 days of the AAO approval.

NP

For an AAO request with a prescribed amortization period commencing upon the conclusion of the specified event or the Commission's approval date for the AAO request.

Requirements (1), (2) and (3) as stated above, and

(4) The event or project is one that is traditionally amortized over several years in rate cases or there are benefits in future periods that will be better matched through the deferral of these costs. A specific amortization period should be included in the AAO application. A five-year amortization of major flood or ice storm costs are two examples. The prescribed amortization will begin immediately upon either:

(a) completion of the event or project associate with the deferred costs, or

(b) the effective date of this order granting the AAO

With regard to SJLP's request in this case, the Staff is recommending that the AAO request be denied because the underlying cause of the event, operator error arising from inadequate training, was within the control of management.

SJLP management should not have removed, nor permitted the removal of, the manual switch on the existing control system without a complete understanding of the system's operation, including the computer software system, and the impact that removing the manual switch would have on SJLP operators and their operation of the SEGA control system that controlled the emergency DC oil pump. Also, once the manual SEGA switch had been removed, SJLP should have provided, or arranged for the provision of, adequate training for its operators on the operating changes necessary to be followed for the continued operation of the DC oil pump. In both instances, it was the responsibility of SJLP's management to insure that the proper steps were taken in the modifications of the

control system and that its operators were properly trained on the functions and use of the replacement equipment.

Shareholders should not be protected from "all" risks resulting from an extraordinary event, especially those that occur within the direct control of its management. SJLP's management should be expected to make prudent and reasonable decisions regarding its personnel and operations, particularly those that are paramount in terms of reliability and safety and just and reasonable rates.

Q. If the Commission decides not to accept the Staff's recommendation to deny the AAO request, even though the extraordinary event was within the direct control of SJLP management, what conditions should the Commission impose for approving the AAO cost deferral?

A. SJLP's request does not include a prescribed amortization period. SJLP should be required to file a rate case within 90 days of the Commission's approval of the AAO or be ordered to use a prescribed amortization period beginning immediately upon the Commission's approval of the AAO. An AAO should not be deferred for an indefinite period of time. Additionally, the **_____

_____** as of July 31, 2000 based upon surveillance information that SJLP supplied to the Staff and the Staff has analyzed.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

NP

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 Order relating to its Electrical Operations.	))))	Case No. EO-2000-845

AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

V. William Harris, is, of lawful age, and on his oath states: that he has participated in the preparation of the foregoing Rebuttal Testimony in question and answer form, consisting of 31 pages to be presented in the above case; that the answers in the foregoing Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

V. William Harris

Subscribed and sworn to before me this 11th day of October, 2000

Notary Public
My Commission Expires 06-21-04

D SUZIE MANKIN
NOTARY PUBLIC STATE OF MISSOURI
COLE COUNTY
MY COMMISSION EXP. JUNE 21,2004

V. William Harris

Schedule of Testimony Filings

Case No.	(Type)	Company
ER-95-279	(Direct)	Empire District Electric Company
GR-96-285	(Direct, Rebuttal, Surrebuttal)	Missouri Gas Energy (Southern Union Co.)
GR-97-272	(Direct)	Associated Natural Gas Company
EC-98-573	(Direct, Rebuttal, Surrebuttal)	St. Joseph Light and Power Company
HR-99-245	(Direct, Rebuttal, Surrebuttal)	St. Joseph Light and Power Company
GR-99-246	(Direct, Rebuttal, Surrebuttal)	St. Joseph Light and Power Company
ER-99-247	(Direct, Rebuttal, Surrebuttal)	St. Joseph Light and Power Company
EM-2000-292	(Rebuttal)	Utilicorp United / St. Joseph Light & Power
EM-2000-369	(Rebuttal)	Utilicorp United / Empire District Electric

Case Nos. GR-96-285, EM-2000-292, and EM-2000-369 were litigated. All others were stipulated.

September 21, 2000 – UtiliCorp United (NYSE:UCU) today issued the following statement in response to a news release issued today by St. Joseph Light & Power Company (NYSE:SAJ):

A great deal of solid, responsible work has been accomplished by both companies in preparing to complete the terms of our merger agreement, and the transition effort is on track and on schedule. However, a very serious issue awaits resolution involving the financial and operational implications of a June 7, 2000 fire that damaged a unit at the Lake Road power plant operated by St. Joseph. UtiliCorp has asked St. Joseph to provide a detailed explanation regarding the materiality of this incident, and remains hopeful that a satisfactory response will be forthcoming.

***St. Joseph Light & Power Statement Awaited**
St. Joseph (Mo.) News-Press – 09/21/2000
By Robyn L. Davis

Amid rumors and speculation about the St. Joseph Light & Power and UtiliCorp United merger, Light & Power plans to issue a press release early this morning

But company officials won't say what it entails, and won't comment on rumors that the merger may be dead. However, UtiliCorp spokesman Jerry Cosley denied the rumors.

It probably all started with a memo to Light & Power employees saying that the transition teams formed to handle the merger were suspending operations. Mr. Cosley said it was a natural pause for the seven transition teams looking at 30 subjects.

"It's very clear that the work is on schedule and continuing in the right direction," Mr. Cosley said.

Light & Power held its monthly board meeting at The Elms Hotel in Excelsior Springs, Mo., Wednesday.

Employees say they have no idea what's going to be announced today, but they hope whatever it is ends the speculation.

"Truthfully, I wish we would know one way or the other," said one employee who wouldn't give her name.

Another said, "I wish it was over."

Light & Power announced in March 1999 that it would merge with UtiliCorp. Since then, both companies have jumped through a series of state and federal regulatory boards. Among the toughest has been a weeklong hearing before the Missouri Public Service Commission, held in July in Jefferson City. The staff of the PSC filed testimony against the merger.

PSC spokesman Kevin Kelly said no decision has been issued in the case.

St. Joseph, Missouri – St. Joseph Light & Power Company (SJLP) (NYSE-SAJ) announced today that it has received a letter from UtiliCorp United Inc. (NYSE-UCU) advising SJLP that UtiliCorp has completed a preliminary investigation of the impact and projected costs of the previously reported fire that occurred at SJLP's Lake Road power plant on June 7, 2000, and that, in the opinion of UtiliCorp, such impact is material.

The letter indicates that, under its existing Merger Agreement with SJLP entered into on March 4, 1999, UtiliCorp may terminate the Merger Agreement if SJLP breaches its representation and warranty in

Schedule VWH-2

the Merger Agreement relating to the absence of a material adverse effect on SJLP since December 31, 1998, and fails to remedy any such breach within 45 business days after receiving notice in writing of the breach.

UtiliCorp's letter states that "[t]his letter does not represent the termination notice" contemplated by the Agreement, but constitutes a request for SJLP "to confirm whether it views the damage caused by the fire as material."

On September 15, 2000, UtiliCorp further advised SJLP orally that UtiliCorp was "suspending" ongoing merger transition team meetings pending resolution of certain issues between the two companies.

Following a meeting of its board of directors held on Wednesday, September 20, 2000, to review the UtiliCorp request, SJLP advised UtiliCorp that the impact and projected costs of the Lake Road plant fire are not "material" for purposes of the Merger Agreement, that SJLP remains in full compliance with the Merger Agreement and that SJLP sees no reason why the merger with UtiliCorp cannot be completed promptly following receipt of Missouri Public Service Commission approval.

SJLP further advised UtiliCorp that, while SJLP is willing to meet with UtiliCorp as soon as possible to clarify any confusion on the part of UtiliCorp regarding the fire, SJLP intends to pursue any and all appropriate remedies available to SJLP to ensure its shareowners the benefits of the merger.

"We were disappointed to receive the recent inquiry from UtiliCorp and disturbed by UtiliCorp's decision to suspend transition team meetings," commented Terry F. Steinbecker, president and chief executive officer of St. Joseph Light & Power Company.

"The fire was a one-time event and the unit was returned to service within weeks with no disruption of service to our customers. We have applied for regulatory approval to defer the costs and seek recovery over a five-year period in SJLP's next general rate case. We continue to believe the merger with UtiliCorp is beneficial to shareowners of both SJLP and UtiliCorp and we intend to take the action necessary to ensure that the merger is completed," he said.

* * * * *

Schedule VWH-2

= Bill Washburn

(573) 526-0145

From Tim Rush

LIGHT & POWER

St. Joseph
Light & Power
Company

For immediate release
September 21, 2000

News Release

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(more)

520 Francis Street
P.O. Box 998
St. Joseph, MO
64502-0998
816-233-8888
FAX 816-387-6332

Schedule VWH-3

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######

Contact: Jerry Musil, manager
Corporate Communications
816-387-6236 (office)
816-262-0374 (cellular)
jmusil@sjlp.com (email)

* * * * *

Forward-Looking Statements

This press release contains forward-looking statements within the meaning of the federal securities laws. These forward-looking statements reflect the Company's expectations and are based on currently available information. Such statements include, but are limited to, information relating to the operations of the Company, the outcome of regulatory proceedings, and the status, timing and certainty of the proposed merger between the Company and UtiliCorp. When used in this press release, the words "anticipates," "believes," "expects," "intends" and similar expressions as they relate to the Company or its management are intended to identify such forward-looking statements. Actual results, performance, achievements or other information may vary materially from those expressed in, or implied by, such forward-looking statements and are subject to numerous risks and uncertainties. No assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what impact they will have on the results of operations and financial conditions of the Company. These statements are made in reliance upon the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

SCHEDULE 4

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

SCHEDULE 5

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

SCHEDULE 6

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

SCHEDULE 7

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

SCHEDULE 8

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

SCHEDULE 9

HAS BEEN DEEMED

TO BE

NOT HIGHLY CONFIDENTIAL

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.

JJH-11
EXHIBIT
10-4-00 KF

Schedule VWH-9

HIGHLY CONFIDENTIAL

JM-12
EXHIBIT
10-4-00 KF

Turbine Generator 4 June 7, 2000 Incident
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- 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.

Schedule VWH-9

SCHEDULE 10

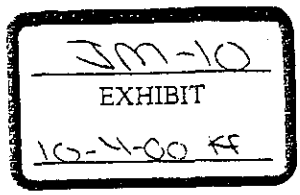
HAS BEEN DEEMED

TO BE

NOT HIGHLY CONFIDENTIAL

HIGHLY CONFIDENTIAL

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).

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.

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.

- 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

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.

6/22/00

- 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.

6/23/00

- 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

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.

- 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

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.

7/13/00

- 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.