ST. JOSEPH LIGHT & POWER COMPANY
ALLOCATION PROCEDURES
CASE NO. EO-94-36

VII. EXPENSES - O & M Expense Allocation

The allocation of the individual LR O & M Expense Accounts are described as follows.

OPERATION AND MAINTENANCE ACCOUNTS:
Refer to Appendix I & II

Account #	Account Description	Allocation
2500-000	Oper. Supv/Engr	Assign "Area 15" (SOC) expenses to Electric; remainder is allocated: • 1/3 based on "Equivalent Employment Factor" • 1/3 based on "900/1800 lb Steam Demand Factor" • 1/3 allocated 100% to Electric
2500-001	Oper. Supv/Engr	same as Account 2500-000
2500-002	Supv/Engr - Recruiting	same as Account 2500-000
2500-003	Oper. Training Payroll	same as Account 2500-000
2500-009	Oper. Supv. & Eng. Envir.	same as Account 2500-000
2500-011	Oper/Supv/Eng - Flyash	[account not used]
2500-700	Oper Supv & Eng - Iatan	100% Electric
2501-000	Fuel Exp Supervision	[account not used]
2501-010	Fuel Exp LR Coal	Allocate daily based on the Fuel Allocation Procedure.
2501-011	Flyash Offsite Dump	[account not used]
2501-012	Coal Handling Labor	Allocate daily based on the Fuel Allocation Procedure.
2501-020	Fuel Exp LR No. 6 Oil	Allocate daily based on the Fuel Allocation Procedure.
2501-030	Fuel Exp LR Gas	Allocate daily based on the Fuel Allocation Procedure.
2501-119	Daily Ash Removal Expense	Allocate based on Ash Allocation Factor. (See Attached Report dated April 14, 1994 and marked as Schedule 8 found in the section on Fuel Expense).

2501-219	Pond Cleaning/West Coal Pile Material Removal Expense - Total	Holding Account transferred between ash handling acct 2501-319 and feedwater acct 2502-019 per new procedure (See Attached Report dated April 14, 1994 and marked as Schedule 8 found in the section on Fuel Expense).
2501-319	Pond Cleaning/West Coal Pile Material Removal Expense - Ash	Allocate ash handling portion of total expenses per new procedure as shown in Schedule 8 found in the section on Fuel Expense.
2501-710	Fuel Exp Iatan Coal	100% Electric
2501-720	Fuel Exp Iatan No2 Oil	100% Electric
2502-010	Boiler Feedwater Expenses	Allocate 93.4% Steam and 6.6% Electric in accordance with the Schedule 9. (The report is attached and dated February 24, 1994 and marked as Schedule 9). *
2502-015	Boiler Feedwater Purch	[account not used]
2502-016	Blr No. 6 Feedwater	100% Electric
2502-019	Pond Cleaning/West Coal Pile Material Removal Expense - Feedwater	Allocate feedwater portion of total expense per new procedure as shown on Schedule 8 in the section on Fuel Expense.
2502-020	Steam Expenses Other	Allocate based on "900/1800 lb Steam Demand Factor"
2502-025	No. 5 Labor Ash	Allocate based on "900 lb. Coal Use Factor"
2502-026	No. 6 Labor Ash Slag	100% Electric
2502-029	Stm Exp Other Envir	100% Electric; (Blr 6 precip control house AHU mtce, Company will abandon this account and charge these expenses to a different account)
2502-710	Steam Exp Boiler Feed - Iatan	100% Electric
2504-010	Steam Transf Cr Fuel	Total fuel expenses allocated to Industrial Steam
2504-020	Steam Transf Cr Other	Total other expenses allocated to Industrial Steam
2505-000	Electric Expenses	100% Electric
2505-700	Electric Expenses - Iatan	100% Electric

Allocate 50% on 900# Feedwater Use Factor and 50% on the feedwater system demand factor used in the feedwater plant allocation study. (As of 3/1/95, these factors are 0.953 and 0.872, respectively). 91.3%

2506-000	Misc Steam Power Exp, i.e., secrt'l support, office supl's, jnt'rl svc, supplies&consumables, etc.	Allocate 1/2 based on "Equivalent Employment Factor"; the remaining 1/2 is allocated the same as Account 507-000.
2506-001	Misc Stm Exp - Training	same as Account 2506-000
2506-002	Stm Power Recruiting	Allocate based on "Equivalent Employment Factor"
2506-009	Misc Stm Power Envir.	Allocate based on "900/1800 lb Steam Demand Factor"
2506-100	Human Resources	Allocate based on "Equivalent Employment Factor"
2506-200	Safety Glasses	Allocate based on "Equivalent Employment Factor"
2506-201	HAZCOM	Allocate based on "Equivalent Employment Factor"
2506-202	Asbestos	Allocate based on "Equivalent Employment Factor"
2506-203	Respirators	Allocate based on "Equivalent Employment Factor"
2506-204	Poison Ivy Shots	Allocate based on "Equivalent Employment Factor"
2506-205	Audiometric	Allocate based on "Equivalent Employment Factor"
2506-206	First Aid / CPR	Allocate based on "Equivalent Employment Factor"
2506-700	Misc Steam Power Exp - Iatan	100% Electric
2507-000	Rents Production	Allocate between the combustion turbines (CT's) and the 900/1800 lb. steam plant based on the Combustion Turbine/Plant Capacity Factor. The portion allocated to the CT's is assigned to electric (and transferred to Account # 2549-000); the remainder is allocated based on "900/1800 lb Steam Demand Factor"
2507-700	Rents Production - Iatan	100% Electric
2546-000	Oper Supv/Engr - Other Gen	100% Electric
2547-020	Fuel Exp LR No 2 Oil	100% Electric
2547-030	Fuel Exp LR Gas Turbine	100% Electric
2548-000	Other Generation Expenses	100% Electric
2549-000	Misc Other Power Exp	100% Electric

3510-000	Maint Supv & Eng	Allocate based on the percentage of the total expenses allocated to industrial steam in accounts 3511, 3512 and 3513, less the Iatan sub-accounts
3510-001	Supv/Eng Training	~~same as 3510-000~~
3510-700	Maint Supv & Eng - Iatan	100% Electric
3511-000	Maint Structures	Allocate based on "Plant Structure Allocation Factor"
3511-100	Maint Structures	[account not used]
3511-700	Maint Structures - Iatan	100% Electric
3512-000	Misc 900# Steam Plant Mtce	Allocate based on the percentage of the total expenses allocated to Industrial Steam in Accounts 3512-010 through 3512-050
3512-001	Rotary Car Dumper Mtce	Allocate based on "Plant Coal Burn Allocation Factor"
3512-002	Coal Yard Eqpt Mtce	Allocate based on "Plant Coal Burn Allocation Factor"
3512-003	Ash Yard Eqpt Mtce	same as Account 2501-119
3512-004	900# Boiler Feedpump Mtce	Allocate based on the percentage of the total expenses allocated to Industrial Steam in Accounts 3512-010 through 3512-050
3512-010	No 1 Boiler Mtce	Allocate based "900 lb. Steam Demand Factor
3512-020	No 2 Boiler Mtce	same as Account 3512-010
3512-030	No 3 Boiler Mtce	same as Account 3512-010
3512-040	No 4 Boiler Mtce	Allocate 50% based on "900 lb. Steam Fuel Consumption Factor" & 50% based on "900 lb. Steam Demand Factor"
3512-050	No 5 Boiler Mtce	same as Account 3512-040
3512-051	No 5 Blr Coal Mills Mtce	same as Account 3512-040
3512-052	No 5 Blr Coal Bunker to Blr	same as Account 3512-040
3512-053	No 5 Blr Ash Blr To Tank	same as Account 3512-040
3512-054	No 5 Blr Electro Precip	same as Account 3512-040
3512-055	No 5 Boiler Repair	[account not used]
3512-060	No 6 Blr Misc	100% Electric
3512-061	No 6 Blr Coal Crushers	100% Electric
3512-062	No 6 Blr Coal Silo to Blr	100% Electric

3512-063	No 6 Blr Ash to Pit or Tank	100% Electric
3512-064	No 6 Blr Electro Precip	100% Electric
3512-065	No 6 Boiler Feedpump	100% Electric
3512-066	No 6 Blr Studding and Related	100% Electric
3512-067	Maint 1800# Boiler Plant	100% Electric
3512-700	Maint Boiler Plant - Iatan	100% Electric
3513-000	Maint Electric Plant	100% Electric
3513-010	No 1 Turb Ord	Set up a separate account to track the Turbine #1, Extraction #4 related maintenance expenses (including extraction control valve, V-2; the extraction pressure regulator; non-return valve; motor operated valve, MOV; and piping between the turbine and MOV) and assign those expenses to Industrial Steam. Remaining Turbine #1 maintenance expenses, including extraction piping from Turbine #1 to Turbine #3 (north line) and associated equipment, will be assigned to Electric.
3513-011	No 1 Turb CW Pumps	100% Electric
3513-012	No 1 Cooling Tower	100% Electric
3513-018	No 1 Turb Extraord	same as Account 3513-010
3513-020	No 2 Turb Ord	100% Electric
3513-021	No 2 Turb CW Pumps	100% Electric
3513-022	No 2 Cooling Tower	100% Electric
3513-028	No 2 Turb Extraord	100% Electric
3513-030	No 3 Turb Ord	100% Electric
3513-031	No 3 Turb CW Pumps	100% Electric
3513-032	No 3 Cooling Tower	100% Electric
3513-040	No 4 Turb Ord	100% Electric
3513-041	No 4 Turb CW Pumps	100% Electric
3513-042	No 4 Turb Pump House	100% Electric
3513-048	No 4 Turb Extraord	100% Electric
3513-050	Gas Turb Aux Maint	100% Electric
3513-700	Mtce Electric Plant - Iatan	100% Electric
3514-000	Mtce Misc Steam Plant	Allocate based on the percentage of the total expenses allocated to industrial steam in accounts 3511, 3512 and 3513, less the Iatan sub-accuunts

3514-009	Mtce Other Stm Pollut	same as Account 3514-000
3514-700	Maint Misc Steam Plt - Iatan	100% Electric
3551-000	Mtce Supv/Engr - Other Gen	100% Electric
3552-000	Mtce Structures - Other Gen	100% Electric
3553-000	Maint Gen & Elec Equip	100% Electric
3553-010	Maint Gen/Jet1 Unit 6	100% Electric
3553-020	Maint Gen/Jet2 Unit 7	100% Electric
3553-050	Maint No 5 Turbine Ord	100% Electric
3553-057	Maint No 7 Boiler	100% Electric
3553-060	Maint No 6 Turbine Ord	100% Electric
3553-070	Maint No 7 Turbine Ord	100% Electric
3554-000	Maint Misc Other Power Plant	100% Electric

M E M O R A N D U M

MEMO TO: Jim Moyer March 14, 1995

IN RE: Equivalent Employment Factor Review & Update

This memo documents the calculation to update the Equivalent Employment Factor used in our Steam/Electric allocation procedures for 1995. The adjustment is made primarily to account for less time needed for water softener operation by the Auxiliary Operator due to Monfort Pork and Swift Adhesive leaving the system. It is assumed the hours directly gained by reduced water softener work are redistributed between the two jurisdictions in the same proportion as the Equivalent Employment Factors.

The adjusted operator hours for steam are as follows:

	Before	After
Head Operator	0.5 hrs	0.5 hrs
Inside Operator	4.0 hrs	4.0 hrs
Outside Operator	0.5 hrs	0.5 hrs
Auxiliary Operator	5.0 hrs	4.5 hrs
Total time to steam	10.0 hrs	9.5 hrs

The adjusted Equivalent Employment Factors are as follows:

Steam: Equivalent Employment Factor = 9.5 ÷ 32 = 0.297

Electric: Equivalent Employment Factor = 1 - 0.297 = 0.703

Mike Smith

Mike Smith

/rb

cc: TMR
file

Appendix I

ST. JOSEPH LIGHT & POWER COMPANY

INDUSTRIAL STEAM EXPENSE ALLOCATION FOR ________________

Facto Oefi

OTHER OPERATING EXPENSE ALLOCATION

I. 900 LB COAL USE FACTOR HGW

$$\frac{\text{Previous 3 Calendar Years of Steam Coal Fuel (MMBTU)}}{\text{Previous 3 Calendar Years of 900 Lb Coal Fuel (MMBTU)}} = \_\_\_\_\_$$

II. COMBUSTION TURBINE/PLANT CAPACITY FACTOR JTM

(a) 900 LB total required fuel input (MMBTU/HR) less Boiler #7 Steam to produce maximum rated electric generation on turbines #1 through #3 = ________ MMBTU/HR.

(b) Total required fuel input (MMBTU/HR) to produce maximum rated electric generation on units #4 = ________ MMBTU/HR.

(c) Total required fuel input (MMBTU/HR) to produce maximum rated electric generation on units #5, #6 and #7 = ________ MMBTU/HR.

(d) Sum of maximum non-coincidental steam customer peak demands (MMBTU/HR) for the past 3 calendar years = ________.

(e) MMBTU of fuel required per MMBTU of industrial steam sold for the previous calendar year = ________.

Combustion Turbine/Plant Capacity Factor =

$$\frac{c}{a + b + c + (d * e)} = \_\_\_\_\_\_\_ = \_\_\_\_\_\_\_\%$$

III. EQUIVALENT EMPLOYMENT FOR STEAM FACTOR MSS

(a) Lake Road Operation personnel manhours per shift

(b) Manhours per shift required to operate steam sales

Equivalent employment factor = b/a = _____%

IV. **900 LB STEAM DEMAND ALLOCATION FACTOR** JTM

Determine the maximum coincident peaks for each month in the three year period. This produces 36 individual monthly maximum demands for the 900 psi system. From these 36 values, the three highest amounts are taken for each calendar year. This result in nine values. The percentage of steam and electric use in each of these nine values is then determined. The last step in the process is to add each of the nine percentages for electric and industrial steam allocation factors and divide by nine.

V. **900 LB STEAM FUEL CONSUMPTION FACTOR** HGW

Past 3 Calendar Years of Steam Fuel (MMBTU from I)
Past 3 Calendar Years of L.R. 900 LB Fuel (MMBTU)
= ______________ = ______________%

VI. **TOTAL PLANT COAL BURN ALLOCATION FACTOR** HGW

Past 3 Calendar Years of Steam Coal Fuel (MMBTU) = ____ = ____%
Past 3 Calendar Years of L.R. Coal Fuel (MMBTU)

VII. **TOTAL PLANT #6 OIL BURN ALLOCATION FACTOR** HGW

Past 3 Calendar Years of Steam 6 oil Fuel (MMBTU) = ____ = ___% Past 3 Calendar Years of L.R. 6 oil Fuel (MMBTU)

VIII. **PLANT STRUCTURE ALLOCATION FACTOR** JDM

Steam A/C 311 = ____________ = ____________%
Total A/C 311

IX. **900/1800 LB STEAM DEMAND FACTOR** JTM

Determine the maximum coincident peaks for each month in the three year period. This produces 36 individual monthly maximum demands for the 900/1800 psi system. From these 36 values, the three highest amounts are taken for each calendar year. This result in nine values. The percentage of steam and electric use in each of these nine values is then determined. The last step in the process is to add each of the nine percentages for electric and industrial steam allocation factors and divide by nine.

FUEL INVENTORY ALLOCATION

X. COAL INVENTORY ALLOCATION FACTOR HGW

(a) Average Minimum Coal Inventory for Industrial Steam ________ tons

(b) Average Minimum Coal Inventory for Electric ________ tons

Coal Inventory Allocation Factor $= \frac{a}{a + b} =$ ______ $=$ ______%

XI. No. 6 OIL INVENTORY ALLOCATION FACTOR HGW

(a) Average minimum #6 oil inventory for industrial steam in bbl = ______ BBLS

(b) Average minimum #6 oil inventory for electric in bbl = ________ BBLS

#6 Oil Inventory Allocation Factor $= \frac{a}{a + b} =$ ______

$=$ ________%

Note: The industrial steam demand and energy levels used in determining the above allocation factors will be based on customer levels at the end of the period used in determining the allocations. For example, in the data used in this procedural manual, Monfort Pork was a customer during the period up to the end of the period used for determining the allocation factors. Then they ceased operations. Monfort Pork would be excluded from the allocation calculation, because they were not a customer during the intended use of the allocations. This includes the following allocations:

A.) Customer Allocator (and allocators based on the number of customers)

B.) Gross Margin Base (and allocators based on gross margin base)

C.) Direct Expense Base (and allocators based on direct expenses base)

D.) Adjusted Plant Base (and allocators based on adjusted plant base)

E.) 900 LB Coal Use Factor

F.) Combustion Turbine/Plant Capacity Factor

G.) 900 LB Steam Demand Allocation Factor

H.) 900 LB Steam Fuel Consumption Factor

I.) Total Plant Coal Burn Allocation Factor

J.) Total Plant #6 Oil Burn Allocation Factor

K.) 900/1800 LB Steam Demand Factor

Appendix II

Definitions of Terms

900 LB COAL USE FACTOR

The ratio of coal fuel energy used for industrial steam sales to the total coal energy consumed by the 900 psi plant, based on the previous three calendar years.

COMBUSTION TURBINE/PLANT CAPACITY FACTOR

The ratio of the fuel energy required to produce maximum rated electric generation on the Lake Road combustion turbines (Units 5, 6, and 7) to the fuel energy required to simultaneously supply both maximum industrial steam sales and maximum rated electrical generation on all Lake Road generating units. This factor is calculated from the peak non-coincident customer steam demands from the past three calendar years and the most recent available information from electric unit capability or performance tests.

EQUIVALENT EMPLOYMENT FACTOR

The fraction of time spent by a typical Lake Road Plant operating crew on the operation of the industrial steam system, based upon a breakdown of each operator's time.

900 LB STEAM DEMAND ALLOCATION FACTOR

Determine the maximum coincident peaks for each month in the three year period. This produces 36 individual monthly maximum demands for the 900 psi system. From these 36 values, the three highest amounts are taken for each calendar year. This result in nine values. The percentage of steam and electric use in each of these nine values is then determined. The last step in the process is to add each of the nine percentages for electric and industrial steam allocation factors divided by nine.

900/1800 LB STEAM DEMAND ALLOCATION FACTOR

Determine the maximum coincident peaks for each month in the three year period. This produces 36 individual monthly maximum demands for the 900/1800 psi system. From these 36 values, the three highest amounts are taken for each calendar year. This result in nine values. The percentage of steam and electric use in each of these nine values is then determined. The last step in the process is to add each of the nine percentages for electric and industrial steam allocation factors divided by nine.

900 LB STEAM FUEL CONSUMPTION FACTOR

The ratio of fuel energy used for industrial steam sales to the total fuel energy consumed by the 900 psi plant, based on the previous three calendar years.

PLANT COAL BURN ALLOCATION FACTOR

The ratio of coal energy used for industrial steam sales to the total coal energy consumed by the entire Lake Road Plant, based on the previous three calendar years.

PLANT STRUCTURE ALLOCATION FACTOR

The ratio of the total steam account 311 after the plant allocation has been made to the total plant in service for all 311 accounts.

COAL INVENTORY ALLOCATION FACTOR

The ratio of the average minimum coal inventory for industrial steam to the average minimum coal inventory for the entire plant.

NO. 6 OIL INVENTORY ALLOCATION FACTOR

The ratio of the emergency no. 6 fuel oil inventory for industrial steam to the emergency no. 6 fuel oil inventory for the entire plant.

ST. JOSEPH LIGHT & POWER COMPANY

Procedure for Determining
Lake Road Plant Electric/Industrial Steam 3-CP Demand Factors

March 1995

3 Fa G

The allocation of Lake Road Plant capital investment and operating and maintenance expenses between electric and industrial steam jurisdictions requires that the relative demand of the two utilities on the plant equipment be determined. The determination of this relative demand can be made in various ways, based on different types of measurements, and using different philosophical approaches. In the Missouri Public Service Commission Docket EO-94-36, the PSC Staff has recommended that the relative demands be determined utilizing a "3-CP" method with exergy flow as the measured demand variable. This procedure defines three-year, 3-CP factors and how they can be determined from Lake Road Plant operating records.

DEFINITIONS

Demand - The amount of product delivered to a single consumer or group of consumers during a relatively short period of time. In this procedure the "product" is the net "exergy" or available energy in the form of steam and/or condensate. The "consumers" consist of the industrial steam distribution system ("steam") and the Lake Road Plant steam turbine-generators, as a group ("electric"). Depending upon which 3-CP factor is being calculated the electric demand may be the total exergy demand of Turbines 1, 2, and 3 (900# 3-CP) or it may be the total exergy demand of Turbines 1, 2, 3, and the Turbine 4 steam cycle (900#/1800# 3-CP). Demand is measured over an one hour period.

The direct steam and electric demands, as defined above, do not constitute the total exergy demand upon the Lake Road Plant. Auxiliary steam loads, which typically benefit both steam and electric consumers, cause an additional demand on the plant equipment. These auxiliary loads fall into three areas: 1) The water treatment steam load, which primarily benefits the industrial steam system, 2) Loads that benefit the electric system (Unit 4/6 auxiliary steam, #2 fuel oil heating), and 3) Loads that benefit both systems in roughly the same proportion as the direct demands (Boiler 5 ash handling, #6 fuel oil heating, etc). These loads are ignored in measuring the steam and electric demands for the following reasons: 1) They are usually much smaller than the normal steam and electric demands (especially during peak demand periods), 2) The majority of these loads benefit both groups and would be allocated based upon direct demands anyway, 3) Loads which primarily benefit one jurisdiction or the other tend to offset each other, and 4) These auxiliary loads are difficult, and often impossible, to measure accurately.

Exergy - The thermodynamic quantity representing the maximum work than can be extracted from a given system or flow in an ideal, reversible process. It is calculated as $E = H - H_o + T_o(S - S_o)$ (neglecting kinetic and potential energy terms), in which H represents total enthalpy, S represents total entropy, and T represents absolute temperature. The subscript "o" indicates the property is at a reference state representative of ambient conditions or a "zero-energy level". In the case of steam, the reference state is defined by water at 14.3 psia and Lake Road well water temperature (typically 60 °F). Total exergy is measured in Btu and is often called "availability" or "available energy." The term "exergy" often refers to specific exergy, which is the amount of exergy per unit of mass in a system or flow. Specific exergy has units of Btu/lb and is calculated as $\epsilon = h - h_o + T_o(s - s_o)$ in which total enthalpy and entropy values are replaced with the corresponding specific enthalpy (h) and entropy (s). In practice, total exergy of a fluid flow, E, is usually calculated as the total mass flow (M) times specific exergy, or $E = M\epsilon$.

Coincident Demand - The total product delivered to two or more consumers from a common system over a relatively short period of time. For this procedure, the coincident demand is the sum of the industrial steam exergy demand and the electric exergy demand for the same one hour period.

Demand Factor - The ratio of one consumer's individual demand to the system's coincident demand for the same one hour period. For example, the industrial steam demand factor represents the ratio of the industrial steam demand to the corresponding coincident demand.

Coincident Peak or "CP" - The maximum coincident demand experienced by a system over an extended period of time. In this procedure, the coincident peak is defined as the maximum coincident demand of the industrial steam and electric systems occurring during a calendar month. Therefore, there are twelve CP's during a year.

3-CP Factor - In this procedure, the 3-CP factor is calculated from three calendar years' data. It is defined as the **un-weighted average of the nine demand factors corresponding to the three maximum coincident peaks from each of the three years.** The industrial steam 3-CP factor is calculated as the sum of these nine industrial steam system demand factors divided by nine.

900# 3-CP Factor - The 3-CP factor, as defined above, in which the electric demand is the total demand of Lake Road Turbines 1, 2, and 3, including condensers.

900#/1800# 3-CP Factor - The 3-CP factor for the total Lake Road steam production plant, including both the 900# and 1800# (Unit 4/6) systems. The electric demand is the total demand of Lake Road Turbines 1, 2, 3 and the Turbine 4 steam cycle (main steam + hot reheat steam - feedwater to the boiler economizer - cold reheat steam).

The steam turbines are considered for the 900# plant electric demand, while the turbine steam cycle (turbine and feedwater heaters) is used for the 1800# plant for the following reasons: 1) The 900# feedwater heating process benefits both steam and electric jurisdictions and therefore should not be charged against the turbines, but allocated. 2) On Unit 4/6, the feedwater heating process benefits only electric, and therefore the turbine steam cycle is appropriately treated as a totally electric exergy demand on Boiler 6. 3) Extraction steam metering is available on the 900# turbines; it is not available on Turbine 4. 4) It is much more straight forward to measure and calculate the exergy demand of the Turbine 4 steam cycle than Turbine 4 by itself.

PROCEDURE

The process of calculating either 3-CP factor requires the following steps for each month.

1. Determine the time (day and hour) of the monthly coincident peak.
2. Determine the steam and electric demands during the hour of the coincident peak. Check these demands for reasonableness against other sources (boiler loads, hourly generation, neighboring hours, etc).
3. Calculate the coincident peak (CP).

After the twelve CP's have been calculated for each of the three years, the following steps are completed.

4. Select the three maximum values from each set of twelve CP's determined in Step 3. The corresponding hours are the nine peak time to be used for the factor determination.
5. Calculate the industrial steam demand factor for each of the nine CP's selected in Step 4.
6. Sum the nine demand factors determined in Step 5.
7. The industrial steam 3-CP factor is the result of Step 6 divided by nine.
8. Calculate the electric 3-CP factor as 1 - (steam 3-CP factor).

The following sections describe the above steps in greater detail for each of the two factors.

900# 3-CP Factor

1. The coincident peak time is defined as the hour of maximum net 900# boiler exergy flow during the month, as calculated from hourly steam flow readings and typical boiler operating conditions. Determine the peak date and time for each of the 36 months of the three-year period.

2(a). The industrial steam system demand is the steam exergy flow measured leaving the plant through the 12" and 16" header meters plus the exergy flow through the high pressure steam customer meter plus the calculated exergy flow of desuperheating water to the low pressure steam customers and calculated exergy losses on the high pressure steam customer line between the plant and the customer meter. (The exergy contribution of the latter two calculated quantities is less than 0.5% of the total steam system exergy demand.)

2(b). The electric system demand is net exergy flow to Turbines 1, 2, and 3. This is calculated as the total main steam exergy flow to the turbines minus the exergy flow returned to the 900# plant as extraction steam and/or condensate.

3. Calculate the CP as the sum of 2(a) and 2(b).

4. Select the three maximum values from each set of twelve CP's determined in Step 3.

5. Calculate the nine industrial steam demand factors corresponding to the CP's selected in Step 4. This factor is the ratio of the demand from step 2(a) to the corresponding CP from step 3.

6. Calculate the sum of the nine demand factors from Step 5.

7. Calculate the industrial steam 900# 3-CP factor as the result of Step 5 divided by nine.

8. Calculate the electric 900# 3-CP factor as 1 minus the result of Step 7.

900#/1800# 3-CP Factor

1. The coincident peak time is defined as the hour of maximum combined net 900#/1800# boiler exergy flow during the month as calculated from hourly 900# boiler steam flows and 1800# (Unit 4/6) gross generation.

2(a). The industrial steam system demand is determined in the same manner as in the 900# 3-CP Factor, Step 2(a) above.

2(b). The electric system demand is the net exergy flow determined in the same manner as in the 900# 3-CP factor, Step 2(b) above, plus the net exergy flow to the Turbine 4 steam cycle. This latter exergy flow is calculated directly from the Unit 4/6 gross generation using a least-squares, quadratic equation based on heat rate test data. The exergy flow to the Turbine 4 steam cycle is the exergy to the turbine in the main steam and hot reheat steam flows minus the exergy returned to Boiler 6 in the feedwater and cold reheat flows.

3. Calculate the CP as the sum of 2(a) and 2(b).

4. Select the three maximum values from each set of twelve CP's determined in Step 3.

5. Calculate the nine industrial steam demand factors corresponding to the CP's selected in Step 4. This factor is the ratio of the demand from step 2(a) to the corresponding CP from step 3.

6. Calculate the sum of the nine demand factors from Step 5.

7. Calculate the industrial steam 900#/1800# 3-CP factor as the result of Step 5 divided by nine.

8. Calculate the electric 900#/1800# 3-CP factor as 1 minus the result of Step 7.

ST. JOSEPH LIGHT & POWER COMPANY
CASE #EO-94-36
SETTLEMENT SCENARIO

Maintenance Factors		Account #	Total Amount	Allocation Factor	Allocation Amount
35.62%		3510-000	$192,049	% of TE to IS (3511+3512+3513) - Iatan	$68,408
35.62%		3510-001	27,285	% of TE to IS (3511+3512+3513) - Iatan	9,719
13.60%		3511-000	187,261	PCTPLT - 13.6%	25,468
40.66%		3512-000	302,967	% of TE to IS (3512-010 thru 3512-050)	123,186
31.20%		3512-001	45,562	PCTCB - 31.2%	14,215
31.20%		3512-002	61,083	PCTCB - 31.2%	19,058
31.20%		3512-003	53,182	PCTCB - 31.2%	16,593
40.66%		3512-004	526	% of TE to IS (3512-010 thru 3512-050)	214
23.10%		3512-010	41,793	PCTMD - 23.1%	4,827
23.10%		3512-020	34,491	PCTMD - 23.1%	3,984
23.10%		3512-030	98,230	PCTMD - 23.1%	11,346
75.50%	23.10%	3512-040	395,982	50% PCTMF - 75.5% & 50% PCTMD - 23.1%	195,219
75.50%	23.10%	3512-050	191,978	50% PCTMF - 75.5% & 50% PCTMD - 23.1%	94,645
75.50%	23.10%	3512-051	70,372	50% PCTMF - 75.5% & 50% PCTMD - 23.1%	34,693
75.50%	23.10%	3512-052	3,101	50% PCTMF - 75.5% & 50% PCTMD - 23.1%	1,529
75.50%	23.10%	3512-053	4,571	50% PCTMF - 75.5% & 50% PCTMD - 23.1%	2,253
75.50%	23.10%	3512-054	1,349	50% PCTMF - 75.5% & 50% PCTMD - 23.1%	665
0.00%	0.00%	3513-010	50,573		0
0.00%	100.00%	3513-~~010~~ 014	2,691	100% Industrial Steam	2,691
0.00%	0.00%	3513-018	0		0
35.62%		3514-000	51,448	% of TE to IS (3511+3512+3513) - Iatan	18,326
35.62%		3514-009	0	% of TE to IS (3511+3512+3513) - Iatan	0
0.00%		3553-057	122,678	100% Electric	0
			$1,939,173		$647,039

Operation Factors		Account #	Total Amount	Allocation Factor	Allocation Amount
31.30%	10.70%	2500-000	$414,420	1/3 PCTEQR - 31.3%, 1/3 PCTPD - 10.7% 1/3 Elec	$58,019
93.40%		2502-010	202,955	Water Treatment	189,560
0.00%		2502-016	22,409	Water Treatment, 100% Electric	0
93.40%		2502-019	15,030	Water Treatment	14,038
10.70%		2502-020	338,510	PCTPD - 10.7%	36,221
23.10%		2502-021	96,936	PCTMD - 23.1%	22,392
0.00%		2502-022	23,853	100% Electric	0
77.00%		2502-025	38,833	PCTCU - 77.0%	29,901
0.00%		2504-010	0	Steam - 100%	0
0.00%		2504-020	0	Steam - 100%	0
31.30%	10.70%	2506-000	401,546	1/2 PCTEQR - 31.3% & 1/2 Comb. Turbine 38.4% to Elec.	76,075
31.30%	10.70%	2506-001	0	1/2 PCTEQR - 31.3% & 1/2 Comb. Turbine 38.4% to Elec.	0
31.30%		2506-002	39	PCTEQR - 31.3%	12
10.70%		2506-009	56,420	PCTPD - 10.7%	6,037
31.30%		2506-100	0	PCTEQR - 31.3%	0
31.30%		2506-200	916	PCTEQR - 31.3%	287
31.30%		2506-201	0	PCTEQR - 31.3%	0
31.30%		2506-202	956	PCTEQR - 31.3%	299
31.30%		2506-203	2,935	PCTEQR - 31.3%	919
31.30%		2506-204	0	PCTEQR - 31.3%	0
31.30%		2506-205	1,566	PCTEQR - 31.3%	490
31.30%		2506-206	0	PCTEQR - 31.3%	0
10.70%		2507-000	614	Comb. Turb. 38.4% to Electric - PCTPD - 10.7%	40
100.00%			67,250	Missouri Air Law Fee	67,250
100.00%			187,635	Auxiliary Station Use - Fuel	187,635
100.00%			57,556	Auxiliary Station Use - Demand	57,556
Total Operations			$1,930,378		$746,731
Total Operation & Maintenance			$3,869,551.49		$1,393,769.94

OFFICE MEMORANDUM

June 24, 1991

TO: Dwight Svuba

FROM: John Modlin

RE: Equivalent Employment Factor to be used in plant O&M allocation

As a part of the company's review of the allocation of plant accounts between steam and electric, the method of determining the equivalent employment factor has been reviewed by Mike Smith. He has proposed the following method which is more representatvie of current plant operation. The following text would replace the section of the allocation procedure which begins with the last paragraph of page 5 of the "Electric/Industrial Steam Allocation Procedure" which was effective January, 1987.

> The other half of the sum of these accounts will be allocated based upon the equivalent employment required to operate the steam plant under normal plant operating conditions. In order to determine this factor, the fraction of time spent by operating personnel devoted to the operation of the steam plant is determined. At the time of this writing, a normal operating crew is made up of four individuals each working eight hours for a total of 32 operating manhours per shift. The amount of time devoted to the industrial steam system spent by each operator on a typical shift is as follows.

Head Operator	0.5	hour
Inside Operator	4.0	hours
Outside Operator	0.5	hour
Auxiliary Operator	5.0	hours
Total time to steam	10.0	hours

> By taking the ratio of 10 to 32, the allocation would be 31.2% to steam and 68.8% to electric. Each year, Lake Road Operations Supervision will review plant operations to determine if changes have occurred which effect the equivalent employment factor, and update the above figures as appropriate.

If you have any questions or require further information regarding the above, please contact me at extension 169.

cc:				
	R. Sullwold	J. Weisensee	S. Ferry	
	M. Smith	J. Fangman	H. Wyble	
	T. Rush	B. Dillon	D. Buresh	file

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To Tim Rush	From JTM
Co.	Co.
Dept.	Phone #
Fax #	Fax #

St. Joseph Light & Power Co.

Payroll Amounts by Month

Department 16: Lake Road-Maintenance

1997

Report ID: PAYROLL
Layout: PAYROLL
As of: December 31, 1997
Filename: N:\FS510\NVISION\REPORTS\ABM_RPTS\16\97_12\PAYROLL.xls
Run: November 04, 1997 at 12:28

		1997-1	1997-2	1997-3	1997-4	1997-5	1997-6	1997-7	1997-8	1997-9	YTD
Supervise maint of IS system	G0201	122	823	-	-	-	-	75	-	-	1,020
Maintain IS lines	G0210	1,129	3,667	1,047	1,227	601	2,867	4,303	877	1,198	16,915
Maintain IS instrumentation	G0220	2,201	3,274	1,689	754	1,076	965	3,500	1,545	1,073	16,077
Handle coal	H0110	-	-	729	-	-	-	-	-	-	729
Operate 900# boilers	H0210	-	-	-	-	-	-	150	-	-	150
Operate water treatment plant	H0220	-	-	-	-	-	-	1,155	-	-	1,155
Clean water plant	H0222	-	-	-	-	1,555	3,533	4,582	7,052	2,767	19,489
Clean boilers 1-5	H0225	-	-	-	-	-	-	224	-	1,738	1,962
Operate 900# units	H0310	-	7	-	-	-	-	-	-	-	7
Clean boiler 6	H0363	-	26	-	56	215	-	-	-	-	297
Operate steam plant- misc.	H0410	47	-	-	-	-	107	-	-	-	154
Maintain coal yard equipment	H0510	649	1,041	2,595	658	1,652	2,599	2,893	2,166	1,675	15,929
Maintain rotary dumper	H0512	1,324	1,133	59	-	354	355	802	1,063	-	5,091
Maintain #2 oil rec/stor equip	H0520	15	-	-	293	46	38	-	30	-	422
Maintain propane equipment	H0550	-	-	-	-	32	150	136	411	-	729
Maintain #6 oil rec/stor equip	H0560	183	283	710	50	2,528	5,656	2,696	1,338	1,116	14,560
Maintain ashyard equipment	H0570	169	2,190	194	969	481	336	408	424	772	5,942
Maintain 900# water plant	H0601	3,004	1,224	111	87	2,102	5,018	4,563	3,444	956	20,508
Maintain boiler 1	H0610	269	1,048	-	412	-	928	1,645	615	385	5,302
Maintain boiler 2	H0620	1,137	766	-	286	29	502	246	860	474	4,299
Maintain boiler 3	H0630	642	477	-	128	1,257	434	217	231	230	3,615
Maintain boiler 4	H0640	2,811	900	303	2,390	391	534	1,865	593	728	10,516
Maintain boiler 5	H0650	3,336	1,860	1,254	545	2,802	5,919	2,690	3,637	32,643	54,685
Maintain coal mills	H0651	1,177	1,163	849	626	222	2,325	516	102	15,281	22,260
Maintain coal bunker to blr	H0652	245	251	617	-	90	-	339	1,234	1,108	3,882
Maintain ash blr to tank	H0653	591	651	125	225	105	432	64	234	44	2,473
Maintain blr #5 elect precip.	H0654	185	71	328	130	13	97	96	60	1,704	2,684
Maintain 900# plant	H0690	17,658	19,770	5,664	5,039	7,215	9,874	11,444	8,880	4,732	90,278
Maintain 900# boiler feed pump	H0691	752	1,388	244	126	407	539	91	-	-	3,547
Maintain pressure red. equip.	H0692	-	-	-	-	-	-	-	-	89	89
Maintain turb 1-4 extraction	H0694	-	424	54	-	-	-	-	-	-	478
Maintain 900# compr. air syst.	H0695	-	1,032	-	515	89	248	767	-	359	3,010
Maintain electric plant	H0701	477	193	316	32	21	178	743	44	564	2,568
Maintain turbine 1 ordinary	H0710	412	2,627	118	130	402	319	534	217	339	5,099
Maintain T1 cooling tower	H0712	105	387	-	-	97	282	86	48	-	1,005

Sheet1

Maintain turbine 1- extr. ord.	H0718	122	-	-	23	-	-	-	-	-	144		
Maintain turbine 2 ordinary	H0720	21	3,866	86	-	187	46	1,008	1,128	233	6,575		
Maintain T2 cooling tower	H0722	64	122	-	88	93	-	-	155	-	523		
Maintain turbine 3 ordinary	H0730	-	258	781	4,257	24	285	476	86	-	6,167		
Maintain T3 cooling tower	H0732	-	59	-	172	26	61	-	44	-	363		
Maintain turbine 4 ordinary	H0740	226	150	522	2,510	850	284	1,009	594	162	6,307		
Maintain T4 traveling screens	H0742	333	973	43	833	-	1,379	227	1,470	529	5,787		
Maintain turbine 5 ordinary	H0750	198	75	9,688	8,597	2,318	2,665	4,504	2,287	377	30,709		
Mtn 5-7 common plant	H0755	-	-	-	395	74	54	34	1,281	68	1,906		
Maint 5-7 compressed air sxm	H0756	-	258	806	1,071	-	-	-	-	-	2,135		
Maintain B7 ordinary	H0757	-	-	1,056	241	-	122	206	84	-	1,710		
Maintain boiler 6 misc	H0760	3,092	2,801	5,983	60,905	16,032	3,971	2,580	6,908	3,478	105,749		
Maintain coal crushers	H0761	-	308	1,256	-	200	-	373	44	89	2,270		
Maintain coal silos to boiler	H0762	-	46	129	1,699	-	3,309	118	166	2,605	8,072		
Maintain blr #6 ash to pit	H0763	272	615	4,019	2,936	1,720	265	1,373	274	9	11,484		
Maintain boiler #6 ESP	H0764	419	165	377	1,610	270	549	553	1,722	853	6,519		
Maintain boiler feed pump	H0765	-	-	-	1,897	1,864	-	-	-	129	3,890		
Maintain boiler #6 cyclones	H0766	-	438	-	164	376	23	-	89	297	1,387		
Maintain 1800# plant	H0767	6,232	4,709	2,630	4,890	3,766	3,345	2,497	2,486	1,956	32,513		
Maintain 1800# water plant	H0768	-	70	184	172	112	21	40	81	460	1,140		
Maintain blr #6 CEMS equipment	H0769	2,602	2,039	2,791	1,358	3,803	3,171	2,699	2,908	1,767	23,139		
Maintain 1800# compr. air sys.	H0770	534	848	864	208	92	1,154	627	126	109	4,561		
Maintain jet turbine common pt	H0773	-	-	-	-	-	-	19	-	-	19		
Maint jet turb compr air syst	H0775	-	42	217	-	32	-	34	-	-	325		
Maintain unit 6 ordinary	H0776	177	43	1,350	-	241	140	867	1,176	104	4,097		
Maintain unit 7 ordinary	H0777	-	118	1,484	38	237	103	372	1,058	74	3,484		
Maintain unit 7- extr. ord.	H0779	-	-	161	-	-	-	-	-	-	161		
Mnt common plant facilties	H0810	7,886	7,503	10,148	5,761	6,361	7,154	7,011	6,678	6,246	64,748		
Maintain structures	H0820	1,169	2,139	1,805	778	1,698	1,183	1,501	1,616	989	12,878		
Plan/mng safety/community act	R0201	-	-	251	-	-	-	-	-	-	251		
Plan/mng civic activities	R0203	-	-	-	-	-	126	422	476	95	1,119		
Plan/mng employee activities	R0302	-	-	-	-	-	-	-	-	665	665		
Manage safety programs	S0301	-	-	-	-	-	-	-	450	-	450		
Manage facilities	T0101	6,336	6,021	6,025	7,064	6,182	6,324	6,917	6,676	6,575	58,119		
ABM Activities		68,322	80,340	69,660	122,344	70,342	79,970	82,297	75,170	97,842	746,287		
Z's and X's		-	-	-	-	-	-	-	-	-	-		
Balance Sheet		-	-	-	-	-	-	-	-	-	-		
		-	-	-	-	-	-	-	-	-	-		
All Accounts		68,322	80,340	69,660	122,344	70,342	79,970	82,297	75,170	97,842	746,287	Query excludes B/S accounts other than 107230 and 183nnn	
		-	-	-	-	-	-	-	-	-	-		

ST. JOSEPH LIGHT & POWER COMPANY
ALLOCATION PROCEDURES
CASE NO. EO-94-36

VIII. Expenses- General & Administrative Expenses

General & administrative (G&A) expenses refer to expenses associated with general and administrative functions of the Company, as contrasted with expenses directly associated with the production and transmission and distribution functions. G&A expenses include salaries and wages, supplies, outside services, injuries and damages, employee benefits, regulatory commission expenses, advertising, rents and maintenance. G&A expenses are classified in FERC accounts 920 through 935.

Not all charges to G&A FERC accounts are allocable. Costs incurred which benefit only a particular utility operation are directly charged to that operation.

SJLP allocates its allocable G&A expenses to its electric, natural gas and industrial steam operations based on the following methods:

1)- A payroll allocator is used to allocate employee benefit expenses and two payroll-related insurance expenses- crime and workers compensation.
2)- An inventory and plant balance allocator is used to allocate property insurance.
3)- A computer equipment allocator is used to allocate rental expense, almost all of which is computer related.
4)- A general plant allocator is used to allocate maintenance expense of general plant.
5)- A general and administrative (G&A) allocator is used to allocate all remaining allocable expenses.

Payroll Allocation Rate

The payroll allocation rate is calculated based on a three step process. First, the Company determines the percentage of total payroll (exclusive of construction and retirement) related to G&A activities and the percentage related to non-G&A or direct activities. This determination is based on actual payroll charges.

Next, the G&A portion is allocated between electric, gas and steam based on the G&A allocation factor discussed below. The direct portion is allocated among the three operations based on their respective percentage of direct payroll, after consideration of Lake Road payroll transferred to steam.

Finally, the Company determines the payroll allocation rate by weighing the two factors noted above (G&A and direct).

Inventory and Plant Balance Allocation Rate

The inventory and plant allocation rate for electric is determined by dividing total electric plant in service, at original cost, by the sum of electric and steam plant in service, fuel inventory and materials and supplies. The steam factor is calculated the same way, with steam plant as the numerator. The electric and steam plant in service balances include the effects of the Lake Road and general plant allocations.

Computer Equipment Allocation Rate

The computer equipment allocation rate is obtained from the general plant allocation for Plant Account 391.1 (see Section II of this manual).

General Plant Allocation Rate

The general plant allocation rate is obtained from the composite general plant allocation (see Section II of this manual).

G&A Allocation Rate

The G&A allocation rate is based on two factors that are given a 80/20% weighting: direct O&M expenses, excluding fuel and purchased power, and allocated plant, respectively.

There should be a reasonable correlation between the factor(s) used and the G&A costs incurred. The two factors selected include that correlation as G&A expenses primarily represent costs incurred in <u>managing</u> the Company's personnel and operating and maintenance activities and <u>controlling</u> the Company's investment in plant.

The primary function of most of the administrative, finance and other management of the Company is to monitor and control these two key elements of revenue requirements (i.e., cost of service (O&M expenses) and rate base). The 80/20 weighting reflects recognition that Comapny G&A personnel devote more of their time to managing personnel and related activities than managing plant.

St. Joseph Light & Power Company
G&A Allocation Method – Electric

Account	Allocation Method	Percentage to Electric	1993 Allocable $'s	Allocation
920	80% O&M/ 20% plant	0.8840 (2)	$2,842,686	$2,512,934
921	80% O&M/ 20% plant	0.8840 (2)	448,849	396,783
923	80% O&M/ 20% plant	0.8840 (2)	605,766	535,497
924 – Property insurance	Inventory & plant balances	0.9245 (3)	407,769	376,982
924 – Crime insurance	Payroll	0.8686 (1)	6,330	5,498
925 – W/C insurance	Payroll	0.8686 (1)	38,449	33,397
925 – General liab. insurance	80% O&M/ 20% plant	0.8840 (2)	340,839	301,302
925 – Other (non–insurance)	80% O&M/ 20% plant	0.8840 (2)	130,184	115,083
926 – Fiduciary insurance	Payroll	0.8686 (1)	14,898	12,940
926 – 01, 02, 07 & 08	Payroll	0.8686 (1)	1,713,731	1,488,547
926 – Other	Payroll	0.8686 (1)	1,768,573	1,536,183
930 – D&O insurance	80% O&M/ 20% plant	0.8840 (2)	57,152	50,522
930 – Lawyer insurance	80% O&M/ 20% plant	0.8840 (2)	635	561
930 – Other	80% O&M/ 20% plant	0.8840 (2)	485,882	429,520
931	Computer equipment	0.9220 (4)	262,832	242,331
935	General plant equipment	0.9239 (5)	310,545	286,913
Total			$9,435,120	$8,324,993

(1) – SJLP uses the ratio of electric payroll (including the allocated G&A payroll) divided by total company O&M payroll, adjusting for the steam transfer effect. The factors used were determined based on a study using 1993 payroll data.

(2) – Based on SJLP's 12/31/93 G&A allocation calculation (used by SJLP in 1994), adjusted for the revised steam transfer amounts.

(3) – Based on calculation done in 1993 (JE 44), adjusted for revised plant allocations.

(4) – Based on the allocation of computer equipment per the revised general plant allocation method.

St. Joseph Light & Power Company
G&A Allocation Method– Steam

Account	Allocation Method	Percentage to Steam	1993 Allocable $'s	Allocation
920	80% O&M/ 20% plant	0.0743 (2)	$2,842,686	$211,212
921	80% O&M/ 20% plant	0.0743 (2)	448,849	33,349
923	80% O&M/ 20% plant	0.0743 (2)	605,766	45,008
924– Property insurance	Inventory & plant balances	0.0373 (3)	407,769	15,210
924– Crime insurance	Payroll	0.0781 (1)	6,330	494
925– W/C insurance	Payroll	0.0781 (1)	38,449	3,003
925– General liab. insurance	80% O&M/ 20% plant	0.0743 (2)	340,839	25,324
925– Other (non–insurance)	80% O&M/ 20% plant	0.0743 (2)	130,184	9,673
926– Fiduciary insurance	Payroll	0.0781 (1)	14,898	1,164
926– 01, 02, 07 & 08	Payroll	0.0781 (1)	1,713,731	133,842
926– Other	Payroll	0.0781 (1)	1,768,573	138,126
930– D&O insurance	80% O&M/ 20% plant	0.0743 (2)	57,152	4,246
930– Lawyer insurance	80% O&M/ 20% plant	0.0743 (2)	635	47
930– Other	80% O&M/ 20% plant	0.0743 (2)	485,882	36,101
931	Computer equipment	0.0344 (4)	262,832	9,041
935	General plant equipment	0.0276 (5)	310,545	8,571
Total			$9,435,120	$674,412

(1)– SJLP uses the ratio of electric payroll (including the allocated G&A payroll) divided by total company O&M payroll, adjusting for the steam transfer effect. The factors used were determined based on a study using 1993 payroll data.

(2)– Based on SJLP's 12/31/93 G&A allocation calculation (used by SJLP in 1994), adjusted for the revised steam transfer amounts.

(3)– Based on calculation done in 1993 (JE 44), adjusted for revised plant allocations.

(4)– Based on the allocation of computer equipment per the revised general plant allocation method.

St. Joseph Light & Power Company
G&A Allocation Method– Gas

Account	Allocation Method	Percentage to Gas	1993 Allocable $'s	Allocation
920	80% O&M/ 20% plant	0.0417 (2)	$2,842,686	$118,540
921	80% O&M/ 20% plant	0.0417 (2)	448,849	18,717
923	80% O&M/ 20% plant	0.0417 (2)	605,766	25,260
924– Property insurance	Inventory & plant balances	0.0000 (3)	407,769	0
924– Crime insurance	Payroll	0.0533 (1)	6,330	337
925– W/C insurance	Payroll	0.0533 (1)	38,449	2,049
925– General liab. insurance	80% O&M/ 20% plant	0.0417 (2)	340,839	14,213
925– Other (non–insurance)	80% O&M/ 20% plant	0.0417 (2)	130,184	5,429
926– Fiduciary insurance	Payroll	0.0533 (1)	14,898	794
926– 01, 02, 07 & 08	Payroll	0.0533 (1)	1,713,731	91,342
926– Other	Payroll	0.0533 (1)	1,768,573	94,265
930– D&O insurance	80% O&M/ 20% plant	0.0417 (2)	57,152	2,383
930– Lawyer insurance	80% O&M/ 20% plant	0.0417 (2)	635	26
930– Other	80% O&M/ 20% plant	0.0417 (2)	485,882	20,261
931	Computer equipment	0.0436 (4)	262,832	11,459
935	General plant equipment	0.0485 (5)	310,545	15,061
Total			$9,435,120	$420,139

(1)– SJLP uses the ratio of electric payroll (including the allocated G&A payroll) divided by total company O&M payroll, adjusting for the steam transfer effect. The factors used were determined based on a study using 1993 payroll data.

(2)– Based on SJLP's 12/31/93 G&A allocation calculation (used by SJLP in 1994), adjusted for the revised steam transfer amounts.

(3)– Based on calculation done in 1993 (JE 44), adjusted for revised plant allocations.

(4)– Based on the allocation of computer equipment per the revised general plant allocation method.

ST. JOSEPH LIGHT & POWER COMPANY
ALLOCATION PROCEDURES
CASE NO. EO-94-36

IX. EXPENSES - Property Taxes

Property tax expenses are accounted for by department with an adjustment made on JE 21 for general plant and Lake Road plant allocations. This adjustment is based on adjusted net plant after allocation as net plant balances are a key factor in the determination of property tax assessments.