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

III. INVENTORY - FUEL Lake Road

The fuel inventory will be allocated based on the minimum fuel inventory levels required for each operation, recognizing the fact that the LR electrical load is not predictable and a larger fuel inventory is required to sustain system reliability during extended periods of abnormally high electrical generation at LR. The Coal fuel inventory quantities above and beyond the minimum coal inventory levels will be allocated based on the Total Plant Coal Burn Allocation Factor. The #6 Oil fuel inventory quantities above and beyond the minimum #6 Oil inventory levels will be allocated based on the Total Plant #6 Oil Burn Allocation Factor. (See Attached Reports dated November 21, 1989 and November 20, 1991, marked Schedule 4 and 5 and the Appendix I found in VII. Expenses - O&M Expense Allocation document).

ST. JOSEPH LIGHT & POWER COMPANY

LAKE ROAD PLANT
MINIMUM FUEL OIL INVENTORY

DWIGHT V. SVUBA

November 21, 1989

ST. JOSEPH LIGHT & POWER COMPANY

MINIMUM FUEL OIL INVENTORY

Both No. 6 and No. 2 oil fuels are used at our Lake Road plant as standby and emergency fuels. No. 6 oil is also used as a secondary fuel for our 900 LB electric generation and industrial steam production when its price is less than natural gas.

The Lake Road 900 LB boilers #1, #2, #3, #4, and #5 can burn No. 6 oil for 900 LB steam production. These five 900 LB boilers supply steam to turbine generators #1, #2, and #3 which have a combined maximum generation of 60 MW. The 900 LB boilers also supply steam for our industrial steam customers. Boiler #5 is the only 900 LB boiler that is capable of burning coal. Since coal is our most economical fuel, Boiler #5 is used as our primary 900 LB steam supply. In addition, No. 6 oil is used as a primary fuel for the 900 LB steam production in boilers #1, #2, #3, and #4 when its price is less than natural gas. Recently this has been the case and No. 6 oil is burned regularly in these boilers to supplement the coal fired steam production. The combined maximum No. 6 oil burning capacity at Lake Road is approximately 170 Bbls/hr.

From the above it can be seen than No. 6 oil provides the emergency backup fuel source for 60 MW of St. Joseph Light & Power Company's electrical generation and for our industrial steam customers.

At the Lake Road plant No. 2 oil serves as the only fuel for our new jet generator No. 6. This unit, which has both quick start and black start capabilities, has a net electrical generating capability of 21 MW. This unit has the capability of starting and being fully loaded within 10 minutes which allows it to be included as ready reserve and part of our required operating reserve so is therefore a critical emergency generator for SJLP.

At the Lake Road plant No. 2 oil is also used as the alternate and emergency fuel for the combined cycle unit #5, HRSG boiler #7. The combined cycle unit has an electrical generating capability of 60 MW and a 900 LB steam production capability of approximately 185,000 lbs/hr. This combustion turbine generator will also start faster than conventional boiler and steam units, which can be critically important during emergency situations.

The emergency oil fuel must be in stock at the plant site if it is to be available when needed to provide operating reserve and system security in times of system emergencies.

It is always very difficult to predict the amount of an emergency fuel to have at the plant site since it is not known what the cause of the emergency might be or its duration. The winter of 1983-84 has taught us that during an extended cold weather emergency no fuel deliveries can be expected. As an example, SJLP ordered 2,500 bbls of No. 2 fuel oil on December 19, 1983 with delivery to be made by December 21. However, due to extremely cold weather and larger orders by other users, SJLP did not receive the first truck load of oil until December 29 and the order was not completed until January 5, 1984, seventeen days later.

During this time of severe December weather there were three different days when natural gas was curtailed and oil fuel was burned to provide our industrial steam and electric customers' requirements. The abnormally large amount of regional generation reserve capacity and the ability of Lake Road #4-6 and Iatan to remain on line prevented SJLP from burning large quantities of oil or being forced to curtail load.

Lake Road No. 2 Oil

A supply of No. 2 oil needs to be stocked at Lake Road in order to provide SJLP system security and operating reserve during times of gas supply interruption and interconnected electrical system emergencies (i.e., when interchange purchases are not available in sufficient quantities). This No. 2 oil stock provides the on site emergency fuel for the 21 MW of black start and quick start capacity of the jet generator and for the 60 MW of quick start generating capability available in the combustion turbine unit. This minimum oil stock would need to be available for firing the combustion turbine and the jet generator for approximately three sixteen-hour days at full load plus an additional four days at half load for the jet generator. Based on a general knowledge of interconnected system operations, it is assumed that an interconnected system emergency, whether it be a transmission system problem or the unavailability of large coal-fired units, would be corrected to the point where the SJLP system would not be dependent upon heavy useage of No. 2 oil in these two units after three days. It is also assumed that four additional days of partial burn on the jet would be sufficient before additional No. 2 oil stocks could be secured. A forty-eight hour burn at 188 Bbl/Hr. plus sixty-four hours at 30 Bbl/Hr. would consume 10,944 Bbls of No. 2 oil. This minimum emergency burn results in a recommended minimum No. 2 oil stock of 10,944 Bbls.

Lake Road No. 6 Oil

The amount of No. 6 oil to stock at the Lake Road plant must strike a balance between supply adequacy and inventory expense. The minimum quantities recommended in this report may not be adequate for every conceivable circumstance but the risk is judged to be within acceptable limits. From past oil burning and delivery experience it is recommended that a one week emergency supply of No. 6 oil should be maintained at the Lake Road plant at all times. In addition, during the winter months, from December 15 through February 15, an additional week of emergency No. 6 oil supply should be maintained at the Lake Road plant.

Due to the predictable nature of the industrial steam load, the No. 6 oil inventory required for a one-week burn can be well defined by looking at the past history of our existing steam customers. The weekly average fuel burn for industrial steam sales was taken from the maximum industrial steam sales fuel month and was used as a basis for the one week emergency burn. The month of March 1989 was used which had a total sales of 118,580 Mlbs for a weekly average of 26,776 Mlbs. To supply this industrial steam load required 45,699 Mbtu's or an equivalent quantity of 7,254 Bbls of No. 6 oil.

The emergency electric generation for the week was taken to be the maximum 900# generation of 60 MW for the 16 peak hours each weekday and 30 MW for the remaining 8 off-peak hours. The two weekend days were taken at 30 MW for 16 hours and no generation for the other 8 hours. This results in a week's total generation of approximately 6,960 MWH. During this time there would be some operation of the combustion turbine/heat recovery steam generator (CT/HRSG) unit on No. 2 oil. This unit would, however, be run for electric generation requirements and at a minimum level to conserve the smaller stock of and higher priced No. 2 oil. The shorter run periods and minimum loading levels means there would be little or no production of 900# steam by the HRSG. For these reasons, this unit can not be relied upon as a source of 900# steam supply during emergency fuel-short conditions. Using a nominal heat rate of 13,500 Btu's per KWH, the generation of 6,960 MWH results in a No. 6 oil burn for electric generation of 14,914 Bbls. Adding the oil burn for industrial steam and electric generation results in a recommended year round minimum No. 6 oil fuel stock at Lake Road of 22,168 Bbls.

To recap the above discussion, I recommend that St. Joseph Light & Power Company maintain the following No. 6 oil fuel stocks at the Lake Road plant site:

No. 6 Oil	Year Round Min. BBls	Winter Min. Bbls
Electric	14,914	29,828
Industrial Steam	7,254	14,508
Total	22,168	44,336

Lake Road No. 6 Oil Minimum Inventory Schedule

	End of Month Minimum Inventory	
January	44,000	
February	40,000	
March	30,000	
April	22,000	
May	22,000	
June	22,000	
July	22,000	
August	22,000	
September	22,000	
October	30,000	
November	40,000	
December	44,000	
Average Minimum Inventory	30,000	
Electric Average Minimum Inventory	20,190	67.3%
Ind. Steam Average Minimum Inventory	9,810	32.7%

I believe that the above minimum inventory schedule provides a reasonable degree of fuel supply security to the Lake Road 900# system. This minimum inventory schedule assumes "normal" No. 6 oil delivery conditions and burning requirements. In addition to this schedule the annual maintenance outage of coal burning #5 boiler must also be considered when establishing procurement guidelines to maintain an adequate No. 6 oil stock. If there are extraordinary plant operating conditions, outages of the coal or gas burning capability or other unusual circumstances, this schedule should be modified.

Summary

The goal of this oil inventory recommendation is to maintain the security of the fuel oil supply to the Lake Road plant while minimizing inventory expense. Even though these minimum oil stocks should provide adequate fuel for the more likely weather and fuel supply emergencies, they cannot be expected to be sufficient for all possible emergencies, including a national oil shortage or other major fuel supply disruption. However on the whole, this level of fuel oil inventory is judged to provide an acceptable level of risk balanced by an acceptable level of inventory expense.

Approved

12-7-89

Schedule 5

ST. JOSEPH LIGHT & POWER COMPANY

LAKE ROAD PLANT

MINIMUM COAL INVENTORY

DWIGHT V. SVUBA

NOVEMBER 8, 1984
Revised November 20, 1991

ST. JOSEPH LIGHT & POWER COMPANY

MINIMUM COAL INVENTORY

In analyzing the desired fuel stock levels for the St. Joseph Light & Power Company, it becomes apparent that the most catastrophic fuel shortage for the company would most likely occur during the winter months. This is not only a time when natural gas fuel may be curtailed but also potentially the time when extreme cold forces the largest number of generating units to be unavailable. The cold weather and possible snow also make fuel transportation extremely slow and difficult.

Winter is also a time when the combination of extremely cold weather and an electrical outage would have catastrophic results to the community. A large cold air mass over the midsection of the United States would cause extremely low temperatures and thereby curtailment of natural gas usage. It could also render a large number of coal-fired plants unavailable for service as it did in December 1983.

In this case the on-site fuel stocks at St. Joseph Light & Power Company would be used to fire Lake Road generation to supply life supporting electrical energy to the community. It is therefore vitally important that SJLP maintain adequate normal and emergency fuel stocks for its Lake Road power plant.

In Rate Case No. ER-81-43, St. Joseph Light & Power Company was allowed to include the cost of 65,686 tons of coal at its Lake Road Generating Station, of which 13.52% was allocated to industrial steam. The Lake Road coal inventory allowed in the rate case was a 3 month burn based on the allowed annualized burn. During the last several years exceptional performance by

Iatan Unit No. 1 and large regional generation reserves (i.e., inexpensive purchases) have combined to greatly reduce Lake Road coal-fired electric generation. The historical average three month coal burn at Lake Road for the last three years (1988, 1989, 1990) is 29,321 tons. Basing the Lake Road coal inventory on this historical average burn does not provide fuel stocks sufficient to meet the emergency public safety needs mentioned above.

It has been St. Joseph Light & Power Company's policy not to receive coal shipments from December 15th through February 15th due to the difficulties of unloading frozen coal and rail car demurrage costs. The current coal rail transportation agreement (effective January 1, 1991) provides for additional time to unload frozen coal without the payment of demurrage. In the agreement the minimum number of rail cars per shipment is 20. However, during severe weather, coal shipments will be suspended. This agreement will allow the receipt of some amount of coal during the winter months depending on the severity of the winter. The average amount of coal St. Joseph Light & Power Company can depend on receiving at the Lake Road Plant during the two worst winter months is 7,500 tons per month and 10,000 tons the third month. This results in a total dependable winter delivery of 25,000 tons. Additionally, the minimum emergency stock should be on site at the end of February to protect against any other natural or man-made interruption of coal supply or coal delivery system.

Since the addition of Iatan the maximum one-month winter coal burn occurred in January 1982 with a burn of 25,603 tons (electric 19,676, steam 5,927). If there had been an extended outage on Iatan, this maximum burn would have been much greater. During the months of January and February 1980 when Iatan's generation was restricted, 61,839 tons of coal were burned with January's burn being 32,166 tons. The all time maximum Lake Road coal burn occurred during the months of January, February and March of 1978. In these three months, during a prolonged coal miners strike, SJLP burned 126,503 tons of coal for an average of 42,168 tons per month. Based on the above discussion it is prudent to manage the Lake Road coal stock to provide for a minimum emergency burn rate of 30,000 tons per month. See Appendix I for monthly coal statistics.

The Lake Road coal inventory is our major base fuel supply in the event of an Iatan outage, disruption of Lake Road coal delivery, or the unavailability of purchased energy. Any number of instances beyond the control of St. Joseph Light & Power Company, such as floods, strikes, etc., could disrupt Lake Road coal deliveries for a minimum of 1½ months. This coal delivery disruption could occur at any time and probably would occur as the result of some external factor that would also have a detrimental effect on our other sources of energy supply. Through contacts with coal suppliers and transporters, the Purchasing Department has determined it would require 1½ months to begin receiving coal shipments at the rate of 30,000 tons per month. The minimum time period the Lake Road coal stock would be required to sustain a high burn rate of 30,000 tons per month would be 1½ months.

The minimum emergency burn rate of 30,000 tons per month for a minimum time period of 1½ months gives a minimum emergency coal stock for Lake Road of 45,000 tons. The steam portion of this minimum emergency stock is 9,000 tons.

A considerable amount of Lake Road coal at the bottom of the pile can be unrecoverable during extended wet spells. This is due to the fact that the Lake Road coal pile is built in a low-lying flood plain area next to the Missouri River. Due to its proximity to the river, the nature of the soil, and the heavy equipment required in the coal recovery process, it becomes impossible to recover the bottom layers of coal during periods of heavy rains or high river levels. These wet spells can occur at any time, but do occur regularly in the spring. In order to help alleviate this problem, the area of the coal pile was reduced. During times of dry weather of 1986 and 1987 much of the western part of the coal pile was scraped to the bottom. This very poor coal/soil mixture was mixed with good coal and burned, which helped contribute to the coal pile inventory adjustment in the spring of 1987. This has reduced the amount of inventory coal that would be unrecoverable during wet spells by approximately one-half. During extended wet spells 5,000 tons or more of coal would still be unavailable for burning.

The November 30 coal stock pile should be sufficient to provide for a maximum likely 3-month winter burn plus a winter ending minimum emergency inventory plus the unrecoverable wet coal that will likely occur in the spring. The minimum coal inventory during the summer and fall months should be the 45,000 ton emergency supply plus the additional stock that is required to achieve the November 30 inventory level.

The November 30 stock pile should be sufficient to supply the following:

		Total Tons	Electric	Ind. Steam
1.	Minimum emergency inventory 1½ month heavy burn (30,000 T/mo.)	45,000	36,000	9,000
2.	Maximum likely 3-month winter burn	55,000	39,000	16,000
	Subtotal	100,000	75,000	25,000
3.	Minimum winter coal receipts	-25,000		
4.	Unrecoverable wet coal	5,000		
	November 30 coal inventory	80,000	60,000	20,000

LAKE ROAD COAL MINIMUM INVENTORY SCHEDULE

Month	End of Month Minimum Inventory (1,000's Tons)	
January	60	
February	50	) 45 Kton emergency
March	50	) plus 5 Kton wet
April	50	) coal
May	45	
June	45	
July	45	
August	50	
September	60	
October	70	
November	80	) Minimum beginning) winter inventory
December	70	

Plant Average Minimum Inventory 675/12 = 56.25 Ktons

Electric Average Min. Inventory 75% = 42.2 Ktons
Ind. Stm. Average Min. Inventory 25% = 14.1 Ktons

This minimum inventory schedule assumes "Normal" coal delivery conditions. It also assumes "Normal" coal burning requirements and capabilities. This schedule should be used as a procurement guideline in controlling the Lake Road coal inventory. If there are extraordinary plant operating conditions or unusual market and supply circumstances, this schedule should be modified. The goal of this Lake Road minimum inventory schedule is to maintain the security of the coal fuel supply while minimizing coal inventory expense.

Maintenance of the above schedule would provide for a reasonably secure electric and steam supply against the major disruptions such as an extended outage of the Iatan unit or a major breakdown in the coal supply and delivery system. Due to a number of smaller, normal irregularities in the production, delivery and usage of coal at the Lake Road plant, it is not possible to adhere closely to any inventory schedule. Economical procurement methods make it necessary to cooperate with coal suppliers and transporters on the scheduling of deliveries, which means that the delivery schedule will be a compromise among these parties.

If the foregoing minimum inventory schedule is to actually be a minimum, it will be necessary to maintain inventories above the minimum amounts most of the time in order to avoid frequent violations of the minimum schedule during the normal excursions in burn rates and delivery schedules. A reasonable allowance for these practical factors is 10% of the average minimum inventory, or 5,625 tons. This factor added to the average minimum inventory produces an annual average inventory level of 61.9 Ktons (electric 46.4 Ktons, steam 15.5 Ktons).

Appendix I

Lake Road Coal Burn 1978 - 1990
Coal in Tons
November 19, 1991

MONTH	ELECTRIC BURN	INDUSTRIAL STEAM BURN	TOTAL BURN
Jan-78	38,170	6,007	44,177
Feb-78	34,996	5,335	40,331
Mar-78	35,938	6,057	41,995
Apr-78	16,302	2,545	18,847
May-78	19,902	2,576	22,478
Jun-78	5,542	318	5,860
Jul-78	9,487	506	9,993
Aug-78	13,027	1,116	14,143
Sep-78	5,232	373	5,605
Oct-78	11,683	997	12,680
Nov-78	13,113	1,735	14,848
Dec-78	37,396	5,470	42,866
1978 TOTAL BURN	240,788	33,035	273,823
Jan-79	29,049	5,419	34,468
Feb-79	31,875	5,603	37,478
Mar-79	35,617	5,651	41,268
Apr-79	24,585	4,381	28,966
May-79	24,501	4,166	28,667
Jun-79	33,998	3,560	37,558
Jul-79	26,778	2,980	29,758
Aug-79	28,193	2,993	31,186
Sep-79	20,893	2,291	23,184
Oct-79	16,371	2,891	19,262
Nov-79	24,809	4,008	28,817
Dec-79	21,365	3,599	24,964
1979 TOTAL BURN	318,034	47,542	365,576
Jan-80	26,436	5,730	32,166
Feb-80	24,089	5,584	29,673
Mar-80	24,555	5,335	29,890
Apr-80	9,227	3,291	12,518
May-80	3,137	3,491	6,628
Jun-80	8,345	2,158	10,503
Jul-80	22,618	2,586	25,204
Aug-80	16,395	3,242	19,637
Sep-80	9,860	3,191	13,051
Oct-80	3,188	2,917	6,105
Nov-80	4,110	3,871	7,981
Dec-80	10,475	5,513	15,988
1980 TOTAL BURN	162,435	46,909	209,344

MONTH	ELECTRIC BURN	INDUSTRIAL STEAM BURN	TOTAL BURN
Jan-81	5,257	5,629	10,886
Feb-81	7,418	4,729	12,147
Mar-81	8,610	3,951	12,561
Apr-81	11,266	3,839	15,105
May-81	10,420	3,627	14,047
Jun-81	17,935	2,611	20,546
Jul-81	16,794	1,963	18,757
Aug-81	6,571	2,909	9,480
Sep-81	2,388	3,925	6,313
Oct-81	8,390	2,958	11,348
Nov-81	8,674	5,765	14,439
Dec-81	10,303	5,889	16,192
1981 TOTAL BURN	114,026	47,795	161,821
Jan-82	19,676	5,927	25,603
Feb-82	9,683	4,757	14,440
Mar-82	6,336	3,643	9,979
Apr-82	13,398	4,785	18,183
May-82	2,610	3,164	5,774
Jun-82	4,836	2,962	7,798
Jul-82	9,918	3,761	13,679
Aug-82	2,642	4,157	6,799
Sep-82	921	2,408	3,329
Oct-82	952	4,724	5,676
Nov-82	226	5,008	5,234
Dec-82	765	5,566	6,331
1982 TOTAL BURN	71,963	50,862	122,825
Jan-83	328	5,464	5,792
Feb-83	1,337	4,633	5,970
Mar-83	2,742	4,923	7,665
Apr-83	1,941	4,996	6,937
May-83	1,977	4,128	6,105
Jun-83	3,831	1,681	5,512
Jul-83	10,555	4,129	14,684
Aug-83	17,873	3,831	21,704
Sep-83	6,659	3,368	10,027
Oct-83	898	3,171	4,069
Nov-83	1,760	4,247	6,007
Dec-83	12,251	5,564	17,815
1983 TOTAL BURN	62,152	50,135	112,287

MONTH	ELECTRIC BURN	INDUSTRIAL STEAM BURN	TOTAL BURN
Jan-84	1,263	5,469	6,732
Feb-84	247	5,472	5,719
Mar-84	162	5,564	5,726
Apr-84	11,239	5,069	16,308
May-84	17,131	1,101	18,232
Jun-84	10,414	4,551	14,965
Jul-84	13,001	3,402	16,403
Aug-84	15,350	3,875	19,225
Sep-84	2,341	3,542	5,883
Oct-84	3,420	4,848	8,268
Nov-84	4,699	5,128	9,827
Dec-84	7,233	6,029	13,262
1984 TOTAL BURN	86,500	54,050	140,550
Jan-85	3,485	6,155	9,640
Feb-85	2,066	5,406	7,472
Mar-85	6,416	4,948	11,364
Apr-85	8,446	4,720	13,166
May-85	526	2,178	2,704
Jun-85	1,431	3,759	5,190
Jul-85	9,040	4,196	13,236
Aug-85	3,212	4,685	7,897
Sep-85	4,475	5,390	9,865
Oct-85	582	5,818	6,400
Nov-85	368	5,194	5,562
Dec-85	10,594	6,600	17,194
1985 TOTAL BURN	50,641	59,049	109,690
Jan-86	4,170	5,903	10,073
Feb-86	4,721	5,635	10,356
Mar-86	365	5,576	5,941
Apr-86	88	3,237	3,325
May-86	655	4,691	5,346
Jun-86	6,617	4,529	11,146
Jul-86	14,128	4,450	18,578
Aug-86	3,490	4,979	8,469
Sep-86	4,921	5,007	9,928
Oct-86	1,594	5,527	7,121
Nov-86	5,036	5,551	10,587
Dec-86	4,093	5,586	9,679
1986 TOTAL BURN	49,878	60,671	110,549

MONTH	ELECTRIC BURN	INDUSTRIAL STEAM BURN	TOTAL BURN
Jan-87	810	6,375	7,185
Feb-87	195	6,056	6,251
Mar-87	10,602	5,933	16,535
Apr-87	8,487	3,557	12,044
May-87	7,727	4,480	12,207
Jun-87	11,943	3,742	15,685
Jul-87	12,675	4,893	17,568
Aug-87	10,214	5,408	15,622
Sep-87	2,789	5,561	8,350
Oct-87	722	3,004	3,726
Nov-87	3,162	511	3,673
Dec-87	3,832	6,030	9,862
1987 TOTAL BURN	73,158	55,550	128,708
Jan-88	8,618	6,076	14,694
Feb-88	13,289	4,773	18,062
Mar-88	10,890	6,518	17,408
Apr-88	1,721	5,769	7,490
May-88	3,715	4,587	8,302
Jun-88	15,004	2,658	17,662
Jul-88	16,273	4,968	21,241
Aug-88	18,607	5,003	23,610
Sep-88	11,240	5,756	16,996
Oct-88	8,640	6,175	14,815
Nov-88	4,654	6,679	11,333
Dec-88	7,193	6,526	13,719
1988 TOTAL BURN	119,844	65,488	185,332
Jan-89	7,744	7,117	14,861
Feb-89	12,599	5,724	18,323
Mar-89	10,818	6,768	17,586
Apr-89	10,653	5,396	16,049
May-89	6,860	5,047	11,907
Jun-89	5,204	5,736	10,940
Jul-89	14,373	5,133	19,506
Aug-89	9,721	6,097	15,818
Sep-89	5,787	2,827	8,614
Oct-89	5,555	5,865	11,420
Nov-89	11,621	7,008	18,629
Dec-89	14,706	6,550	21,256
1989 TOTAL BURN	115,641	69,268	184,909

MONTH	ELECTRIC BURN	INDUSTRIAL STEAM BURN	TOTAL BURN
Jan-90	3,225	6,843	10,068
Feb-90	14,908	5,958	20,866
Mar-90	10,256	6,556	16,812
Apr-90	1,708	5,153	6,861
May-90	4,221	666	4,887
Jun-90	15,029	5,448	20,477
Jul-90	11,624	5,572	17,196
Aug-90	10,168	5,493	15,661
Sep-90	15,511	3,318	18,829
Oct-90	12,950	303	13,253
Nov-90	6,741	3,740	10,481
Dec-90	10,030	6,389	16,419
1990 TOTAL BURN	116,371	55,439	171,810

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

IV. INVENTORY - Materials and Supplies

A. Materials and Supplies Inventory Allocation - Lake Road

There are three categories of materials and supplies (M&S) at the Lake Road plant. They are: 1) M&S strictly for the use in the electric area, 2) M&S strictly for the use in the industrial steam area and 3) M&S commonly use in both the electric and industrial steam areas. The method of allocation for that portion which is identified as commonly used for electric and industrial steam will be allocated based on the ratio of the allocable plant dollars which are assigned to steam and electric. This would include accounts 311, 312, 315 and 316. (See Attached Memorandum dated March 14, 1994 and marked Schedule 6).

B. Other Materials and Supplies

Other Materials and supplies are located at the North Division, Iatan and T&D areas. M&S at North Division consists of electric and gas with the stores ledger specifically identifying gas department materials. Therefore, no allocation is necessary. Iatan and T&D materials and supplies are 100% electric. Overhead and clearing accounts are allocated proportionately.

MATERIAL & SUPPLIES
13 MONTH AVERAGE & ALLOCATIONS
UPDATED THROUGH DECEMBER 31,1993

Month	Total Per Ledger	154	154-01	Less Gas	154 & 154-01 Allocable	163	Iatan 154-07	Settlement Total Electric	Settlement Total Gas	Settlement Total Steam
Dec 1992	4,845,271	3,714,908	137,391	58,411	3,793,888	0	992,972	4,786,860	$58,411	
Jan 1993	4,889,857	3,745,760	142,179	64,989	3,822,950	11,868	990,050	4,824,868	$64,989	
Feb	4,954,281	3,800,395	143,880	63,728	3,880,547	27,382	982,624	4,890,553	$63,728	
March	4,814,147	3,688,843	134,515	63,319	3,760,039	16,365	974,424	4,750,828	$63,319	
April	4,940,095	3,783,667	137,212	59,585	3,861,294	40,429	978,787	4,880,510	$59,585	
May	5,057,529	3,884,848	138,402	59,022	3,964,228	59,273	975,006	4,998,507	$59,022	
June	5,064,482	3,911,798	137,651	57,804	3,991,645	43,747	971,286	5,006,678	$57,804	
July	5,066,642	3,916,971	138,435	58,440	3,996,966	41,280	969,956	5,008,202	$58,440	
Aug	5,164,237	4,026,169	143,520	61,118	4,108,571	40,143	954,405	5,103,119	$61,118	
Sept	5,072,018	3,941,640	151,775	59,627	4,033,788	21,326	957,277	5,012,391	$59,627	
Oct	5,015,512	3,912,719	145,356	55,117	4,002,958	5,388	952,049	4,960,395	$55,117	
Nov	4,926,699	3,902,420	131,257	52,823	3,980,854	(28,361)	921,382	4,873,876	$52,823	
Dec	5,011,198	3,947,807	129,592	58,156	4,019,243	0	933,799	4,953,042	$58,156	
	$64,821,968	$50,177,945	$1,811,165	$772,139	$51,216,971	$278,840	$12,554,017	$64,049,829	$772,139	$0
13 month average	$4,986,305	$3,859,842	$139,320	$59,395	$3,939,767	$21,449	$965,694	$4,926,910	$59,395	$0
Allocation of 154 & 154-01										
Electric 97.32%					$3,834,181			($105,586)		
Gas 0.06%					$2,364				$2,364	
Steam 2.62%					$103,222					$103,222
Allocation of 163										
Electric 97.32%						$20,874		($575)		
Gas 0.06%						$13			$13	
Steam 2.62%						$562				$562
Total								$4,820,749	$61,772	$103,784
Dec 93 Bal								$4,953,042	$58,156	$0
13-Month Average Adjustment								(26,132)	1,239	0
Allocation Adjustment								(106,161)	2,377	103,784
Adjusted Test Period								$4,820,749	$61,772	$103,784

MATERIAL & SUPPLIES

Settlement

ACCOUNT 154-000 Source-Stores Master File (Dec,93)

T & D	
Location 1	$1,565,268
Location 61	$10,322
Edmond Street (Janitorial supplies per R.S.)	
Location 2	$25,489
Lake Road	
Location 3	$2,051,442
Maryville	
Location 6	$201,669
Location 66	$582
Mound City	
Location 8	$92,961
Location 68	$74
Total per ledger	$3,947,807
Overhead Minor Materials 154-01	$129,592
Iatan Material & Supplies	$933,799
Stores Exp-Undistributed 163-000	$0
Total	$5,011,198

	Electric	Gas	Steam	Total
T&D	$1,575,590			$1,575,590
Iatan	933,799			$933,799
North Division	237,130	$58,156		$295,286
Specifically identifiable	$2,746,519	$58,156		$2,804,675
Lake Road(allocated per L.R. adjusted plant balances)	1,950,101		$101,341	$2,051,442
Subtotal	$4,696,620	$58,156	$101,341	$4,856,117
Overhead Minor Material, Stores Exp, & Edmond Street	148,775	2,299	4,007	$155,081
Total	$4,845,395	$60,455	$105,348	$5,011,198
Allocable (Total less North Division gas and Iatan)				$4,019,243
Allocation Percentage	97.32%	0.06%	2.62%	100.00%

Lake Road spare parts inventory (March 1994)		
Electric	$1,237,585	52.14%
Steam	$32,469	1.37%
Allocable	$1,103,747	46.49%
Total	$2,373,801	100.00%

Adjusted L.R. Plant Bal-Dec, 93		
Electric	$53,170,353	92.32%
Steam	$4,420,265	7.68%
Total	$57,590,618	100.00%

	Electric	Steam
Directly assigned	52.14%	1.37%
Allocable-(adjusted L.R. Plant Bal 12-93)	42.92%	3.57%
Lake Road allocation	95.06%	4.94%

Rates & Market Research
March 14, 1994

OFFICE MEMORANDUM

TO: File

FROM: Tim Rush TR

SUBJECT: Allocation Case - Spare Parts Inventory

A review has been made of each spare part item at the Lake Road Plant by unit number. This review identified three categories: 1) electric, 2) steam, and 4) electric/steam. From this evaluation it was determined that at the Lake Road Plant, $1,237,585.26 should be directly assigned to electric, $32,469.04 is steam and $1,103,747.44 is allocable to steam and electric.

Attached is a supporting document by unit number which identifies the three codes assigned to the unit number and the value of the spare parts.

I would recommend that the allocable portion of inventory be assigned based on the allocable plant dollars which ultimately were assigned to steam and electric. This would include the accounts for boilers and 311, 312, 312A, 315 and 316.

Attachment

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

V. OTHER RATE BASE ITEMS

A. PREPAYMENTS

Prepayments which are common to the three departments include prepaid insurance and miscellaneous supplies. Prepaid insurance will be determined by the policy with the basis for the premium being the allocating factor (see G&A allocations below). Miscellaneous prepayments consist primarily of postage, bills and envelopes which are directly related to providing customer services. Therefore, miscellaneous prepayments will be allocated by number of customers.

Prepaid gas for Lake Road and North Division are also included in this account. Lake Road gas is used in the generation of electricity and industrial steam. The percent of gas used for steam production which SOC reports on the December year-to-date fuel rider will be used to allocate Lake Road gas prepayments. North Division gas does not require allocation as it is specifically related to the gas department.

B. DEFERRED TAXES

Deferred taxes on plant accounts are classified by department in Account 282. As general plant and Lake Road plant are included in electric, a portion of electric should be allocated to gas and steam. The ratio of allocated general and Lake Road to electric plant less Iatan is applied to electric deferred taxes less Iatan to determine the portion of deferred taxes to allocate to departments based on adjusted plant percentages.

C. SPECIAL DEPOSITS

Special deposits consist of working funds designated for specific purposes. Funds which are not identifiable by department are allocated based on the general and administrative expense allocation method as they are held for the purpose of providing for these services.

PREPAYMENTS
13 MONTH AVERAGE

MONTH		Insurance 165–01	Postage 165–02	UPS 165–021	Envelopes 165–03	Supplies 165–04	Settlement ELECTRIC	GAS	STEAM
Dec, 1992		329,304	13,834	0	11,902	0	355,040		
Jan. 1993		253,726	18,868	86	10,802	5,447	288,929		
Feb		178,148	13,692	112	9,702	5,375	207,029		
March		102,570	15,013	167	8,602	6,846	133,198		
April		100,928	7,319	221	7,502	6,376	122,346		
May		481,088	11,724	97	6,402	7,918	507,229		
June		829,591	27,914	141	6,189	6,964	870,799		
July		749,366	22,317	113	5,089	2,116	779,001		
Aug		669,441	14,207	63	3,989	5,661	693,361		
Sept		589,215	8,065	93	2,889	3,996	604,258		
Oct		508,990	12,904	142	9,581	3,844	535,461		
Nov		428,764	7,092	64	8,481	4,902	449,303		
Dec		357,042	12,843	0	7,381	0	377,266		
		$5,578,173	$185,792	$1,299	$98,511	$59,445	$5,923,220	$0	$0
13 month average		$429,090	$14,292	$100	$7,578	$4,573	$455,632	$0	$0
Allocation of 165–01									
Electric	89.65%	$384,679					($44,411)		
Gas	3.33%	$14,289						$14,289	
Steam	7.02%	$30,122							$30,122
Allocation of 165–02,165–021,165–03,165–04									
Electric	90.41%		$12,921	$90	$6,851	$4,134	($2,545)		
Gas	9.58%		$1,369	$10	$726	$438		$2,543	
Steam	0.01%		$1	$0	$1	$0			$2
							$408,676	$16,832	$30,124
December 93 Balances							$377,266	$0	$0
13 Month average adjustment							$78,366	$0	$0
Allocation Adjustment							($46,956)	$16,832	$30,124
Adjusted Test Period							$408,676	$16,832	$30,124

Prepaid Insurance–Acct–165–01
12–31–93

Policy	Electric	Gas	Steam	Settlement Premium
Fire and Boiler Machinery (1)	$376,452		$31,317	$407,769
Crime (2)	$5,477	$387	$466	$6,330
Auto Liability (3)	$35,275	$2,796	$1,255	$39,326
Excess Workers Comp (4)	$35,450	$1,992	$1,007	$38,449
General Liability (2)	$294,894	$20,859	$25,086	$340,839
Business Travel (5)	$265	$13	$21	$300
Directors & Officers Liability (2)	$67,390	$4,767	$5,733	$77,889
Iatan Property	$13,467			$13,467
Total	$828,670 89.65%	$30,815 3.33%	$64,884 7.02%	$924,369

Allocations based on:
(1) Adjusted Lake Road Plant Balances
(2) Revenues
(3) Adjusted Vehicle Values
(4) Payroll
(5) G & A

Allocation Factors for Prepayments Settlement

	$	%
Adjusted Lake Road Plant Balances 12-31-93		
Electric	53,170,353	92.32%
Steam	4,420,265	7.68%
Total	57,590,618	100.00%
Revenues (12-mos ended 12-31-93)		
Electric	$74,782,127	86.52%
Gas	5,286,888	6.12%
Steam	6,364,373	7.36%
Total	$86,433,388	100.00%
Vehicle Value (Per C.P.Alloc.)		
Electric	$3,997,490	89.70%
Gas	316,827	7.11%
Steam	141,997	3.19%
Total	$4,456,314	100.00%
Payroll O & M (Form 1)		
Electric	$12,009,800	92.20%
Gas	675,068	5.18%
Steam	341,035	2.62%
Total	$13,025,903	100.00%
G & A (12-31-93)		
Electric		88.38%
Gas		4.46%
Steam		7.16%
Total		100.00%
Customers (12-31-93)		
Electric	60,097	90.41%
Gas	6,370	9.58%
Steam	8	0.01%
Total	66,475	100.00%

PRINT: DEFTAX

Settlement

ST. JOSEPH LIGHT & POWER COMPANY
ALLOCATION OF DEFERRED TAXES

Total Electric Plant in Service–12–31–93		$260,360,771		
Less Non–Depreciable Plant–exlcuding Iatan		($3,345,174)		
Less Iatan plant		(61,792,679)	23.73%	
Total Depreciable Electric plant exl Iatan		$195,222,918		
Lake Road Allocated To Steam	$3,492,988			
General Plant Allocated To Steam	763,796			
Total Lake Road & General Allocated to Steam		$4,256,784	2.18%	
General Plant allocated to gas		$1,339,097	0.69%	
Net electric depreciable plant–excl Iatan		189,627,037	97.13%	
		$195,222,918	100.00%	

		Electric	Gas	Steam
Deferred Tax reserve		$21,352,778	$348,199	$332,771
Less Reserve for Iatan–23.73%		(5,067,014)		
Deferred Taxed after Allocation				
Electric reserve subject to allocation		16,285,764		
L. R. and General Plant allocated to Steam	2.18%	(355,030)		355,030
General Plant allocated to Gas	0.69%	(112,372)	112,372	
Deferred Tax reserve balances after allocations		15,818,362	460,571	687,801

Settlement

ST JOSEPH LIGHT & POWER CO
SPECIAL DEPOSITS
12-31-93

Account	Balance 12-30-93	Electric	Gas	Steam
Group Hospital (135-120) *	$50,000	$44,190	$2,230	$3,580
Iatan (135-130)	150,000	150,000		
S.W. Power (135-140)	1,545	1,545		
Dental (135-170) *	9,548	$8,438	$426	$684
Total	$211,093	$204,173	$2,656	$4,264

*Allocated based on G&A rates

E	88.38%
G	4.46%
S	7.16%

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

VI. EXPENSES - FUEL

A. Fuel and Daily Ash Expense Allocations

SJLP'S procedure outlined in the January 28, 1994, paper entitled "Exergy-Based Electric and Steam Allocation Procedure for Lake Road 900# Plant Fuel and Auxiliary Power" (hereinafter referred to as the "Exergy Approach") should be used for the basis of allocations. (See Attached Report dated January 28, 1994 and marked Schedule 7).

Daily ash removal expenses will be allocated as described on the attached report dated April 14, 1994. (See Operation and Maintenance Expense Allocation. See Attached Report dated April 14, 1994 and marked Schedule 8).

B. Auxiliary Electric Power Allocation

The method of determining the amount of auxiliary electric power to be allocated to industrial steam and to electric users will be that method presented in the January 28, 1994, paper on the "Exergy Approach" (See attached Schedule 7). The auxiliary electric power will be priced using the average system energy cost ($/MWH) for each month, which includes all Lake Road Plant and Iatan generation costs, fuel handling expenses, and all purchased power expenses. Additionally, the Company's average purchased capacity cost ($/MW) will be used to price the demand. An average monthly demand of 2 MW will be used. Billing considerations and accounting for the auxiliary electric power charges will be treated through "steam transfer credits", rather than direct billings.

ST. JOSEPH LIGHT & POWER COMPANY

Exergy-Based Electric and Steam Allocation Procedure for Lake Road 900# Plant Fuel and Auxiliary Power

January 1995

The Lake Road 900# Plant fuel allocation is performed between steam and electric constituencies based upon the amount of fuel energy required to supply each on a daily basis. To determine this allocation, the fuel energy is tracked on an exergy[1] basis through the 900# plant. The fuel "cost" per unit of exergy of flow streams within the plant are determined by the "cost" of input streams and second law efficiencies of plant equipment. The use of this method is strongly supported in technical literature dealing with the allocation of costs in cogeneration facilities.[2]

Fuel energy is based upon the "higher heating value" of the fuels and is considered to be 100% available to the boilers. That is, the exergy content and heating value of the fuels are assumed to be equal. One mmBtu[3] of fuel is defined as one cost unit. By tracking the exergy flow and its "cost" through the plant, the quantity of fuel energy required to supply a given flow stream is simply the exergy flow of the stream multiplied by the unit cost of that stream. Exergy is measured relative to the reference state of water at 14.3 psia (corresponding to the plant elevation of 812 feet above sea level) and the plant well water temperature, typically 60° F.

The procedure begins with total daily fuel, steam, water, and electricity flows to, from, and within the 900# plant, along with average thermodynamic conditions. Using heat and mass balance equations, an approximate daily 900# plant heat balance is determined. The major components in the heat balance are: 900# boilers (1 - 5, 7), 900# turbines and condensers (1 - 3), industrial steam system (high pressure and low pressure), pressure reducing valves, attemperating equipment, flash tanks, water treatment plant, general plant (pumps, feedwater heaters, 900# auxiliary steam loads), and Unit 4/6 (auxiliary steam). The daily total

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[1] See "Definition of Exergy" on page 5.

[2] See Reference List on page 5.

[3] mmBtu = one million British thermal units = 10^6 Btu.

mass and exergy flows in and out of the above components are determined. After these quantities are known, a set of simultaneous equations is solved to determine the cost of the various flow streams. These equations are determined by equating the total costs in and out of the individual components. That is, the following equation is solved for each component.

$$\sum (E_i \; c_i) = \sum (E_e \; c_e) \tag{1}$$

The above equation states that the sum of the products of incoming exergy flows (E_i) and their respective unit costs (c_i) is equal to the sum of the products of the exiting exergy flows (E_e) and their respective unit costs (c_e). Generally equation (1) has the following form.

$$\sum (M_i \; \epsilon_i \; c_i) = \sum (M_e \; \epsilon_e \; c_e) + W_e \; c_e \tag{2}$$

In equation (2), the M's represents flow in pounds per day, ϵ's represents exergy content of the fluid in Btu per pound, the W represents work generated by the device in Btu/day (i.e. turbine shaft work to a generator) and the c's represent the unit cost in Btu's of fuel per Btu of exergy.

As an example, consider a boiler consuming 100 mmBtu of fuel per hour at a cost of 1 (fuel Btu per exergy Btu), with a feedwater flow and exergy content of 100,000 lb/hr and 75 Btu/lb at a cost of 5, and delivering 100,000 lb/hr of steam with an exergy content of 600 Btu/lb. The cost of the steam would be determined from the following equation.

$$\begin{aligned} &[100(10^6)\ \frac{Btu}{hr} \times 1\ \frac{fuel\ Btu}{exergy\ Btu}]_{fuel} + \\ &[100(10^3)\ \frac{lb}{hr} \times 75\ \frac{Btu}{lb} \times 5\ \frac{fuel\ Btu}{exergy\ Btu}]_{feedwater} \\ &\quad = 100(10^3)\ \frac{lb}{hr} \times 600\ \frac{Btu}{lb} \times c_{stm} \end{aligned} \tag{3}$$

Solving for c_{stm}, the steam cost is 2.29 fuel Btu per exergy Btu. The total cost of the steam is 137 mmBtu of fuel per hour (100,000 lb/hr x 600 Btu/lb x 2.29 Btu fuel/Btu exergy).

In the case of multiple outputs from a plant component, it is necessary to establish one or more auxiliary equations which relate to the costs of the exergy flows. Usually, this consists of simply equating the exiting costs ($c_{e1} = c_{e2} = c_{e3} \ldots$). That is, the output streams all share the incoming costs in proportion to their exergy contents. This is approach is used for Lake Road Turbine 1: the cost per unit of exergy of the extraction steam is set equal to the cost of the shaft work developed in the high pressure turbine section (shaft work is considered 100% available to the generator).

In some cases it is necessary to apply different costs to the output flows. This is true with a low pressure turbine and condenser combination. The two outputs are the shaft work to the generator and the condensate returning to the plant. If these two outputs were assigned the same cost, the condensate would become quite expensive as it would be charged with much of the exergy destruction and rejection in the condenser and cooling tower. However, these losses were incurred so that electric generation could take place, not for production of condensate. Therefore, the cost of the condensate should not reflect these losses. Generally in this situation the condensate "by-product" is priced at zero or is assigned a cost per unit of exergy equal to that of the steam to the turbine. This shifts the cost of losses to the electric generation function, where it belongs. In the Lake Road Plant fuel allocation calculations, condensate is priced at the same cost per unit of exergy as the incoming steam.

Another special case in costing exergy flows at Lake Road is due to Boiler 7. Boiler 7 is a heat recovery steam generator (HRSG) that supplies steam to the 900 psi header using the exhaust of Turbine 5, a 60 megawatt combustion turbine, as its heat source. The fuel burned in Turbine 5 is charged totally to the electric system. Therefore, the Turbine 5 exhaust and the Boiler 7 steam exergy that it generates "belong" to the electric system. To handle this situation, Boiler 7 steam exergy is assigned a cost of zero and is computationally provided only to Turbines 1 and 2 (Turbine 3 uses lower pressure steam). This mathematically reduces the amount of exergy provided to these turbines from Boilers 1 - 5 and consequentially the amount of Boiler 1-5 fuel charged to electric. This approach properly assigns to the electric system the full benefit of all fuel burned in Turbine 5. Further, this approach is consistent with the 100% electric allocation of Boiler 7 capital, operating, and maintenance expenses.

Exergy flows which are consumed in the general plant for the benefit of both steam and electric (e.g. 900# auxiliary steam) are assigned a cost of zero. This effectively "raises the price" of those exergy flows which are ultimately delivered to the steam or electric consumers and forces all fuel costs to be charged to these consumers in proportion to the exergy used by them.

Fuel Energy Charged to Electric

The daily fuel energy charged to electric is the total cost (mmBtu of fuel) of the turbine shaft work which drives the 900# plant generators plus the total cost of steam and condensate transferred to Unit 4/6.

Fuel Energy Charged to Industrial Steam

The daily fuel energy charged to industrial steam is the total cost (mmBtu of fuel) delivered to the industrial steam system. This includes the steam supplied through the 12" and 16" header meters, the attemperating water supplied to the customer steam lines, and the steam delivered to the high pressure steam customer plus the cost of exergy losses between the plant and the high pressure customer meter.

The daily steam fuel allocation factor, x_s, is determined by dividing the mmBtu's of fuel charged to industrial steam from the above procedure by the total 900# boiler fuel mmBtu's consumed. This factor is used in the allocation of auxiliary power, described later.

FUEL ALLOCATION PROCEDURE REFERENCE LIST

Gaggioli, R. A., and El-Sayed, Y. M., "A Critical Review of Second Law Costing Methods" presented at the Fourth International Symposium of on Second Law Analysis of Thermal Systems; Rome, Italy; May 25 - 29, 1987.

Gaggioli, R. A., "Proper Evaluation and Pricing of 'Energy'"

Gaggioli, R. A., El-Sayed, Y. M., El-Nashar, A. M., Kamaluddin, B., "Second Law Efficiency and Costing Analysis of a Combined Power and Desalination Plant"; Journal of Energy Resources Technology, Vol. 110, pp 114-118, June, 1988.

Lang, Fred D., Horn, Ken F., "Make Fuel-Consumption Index Basis of Performance Monitoring"; Power, Vol. 134, No. 10, pp 19-22, October 1990.

Moran, M. J., Availability Analysis, pp 206-210, ASME Press, 1989.

Reistad, G. M., and Gagglioli, R. A., "Available-Energy Costing", October 30, 1979.

Sandage, P.E., "Turbine By-pass System Evaluation & Costing", Sega, Inc., October 18, 1990.

"Exergy Costing in Multi-Product Plants"

DEFINITION OF EXERGY

Exergy is 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". Total exergy is measured in Btu and is often called "availability" or "available energy." (Note that these terms are easily confused with other plant performance and thermodynamic quantities; "exergy" is more specific.) 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, E, of a fluid stream is usually calculated as the total mass flow, M, times specific exergy, or $E = M\epsilon$.

AUXILIARY POWER ALLOCATION

The allocation of auxiliary power is performed in the following manner. First, the auxiliary power which can be attributed directly to industrial steam or electric is subtracted from the total 900 psi plant metered auxiliary power, leaving an allocable quantity. Auxiliary power which is metered elsewhere in the plant, but benefits the 900 psi plant is added to the allocable amount. This result is then allocated by the fuel allocation factor (x, see the fuel allocation procedure). Auxiliary power which is directly attributed to each demand is then added to the allocated quantities.

Included in the auxiliary power attributed directly to each constituency is a daily base power consumption. The base usage for the total 900 psi plant is approximately 7.5 MWhr per day. This corresponds to an idle but ready plant (no industrial steam sales and no electric generation). The 7.5 MWhr is allocated between steam and electric using the Steam Demand Allocation Factor, which is defined in Appendix II of the Plant and O & M Allocation Procedure.

The process is summarized in the following steps.

1. Meter the daily auxiliary power (kwhr) used by the 900 psi plant via house service transformers #1 and #2, and #3 standby transformer, call this P_{900}.

2. Determine the 900 psi auxiliary power which is 100% electric (e.g. condensate and circulating water pump motors, cooling tower fans, substation power, and base station power for electric), call this P_{e1}. These auxiliaries are estimated from hourly motor current readings, test data, and the allocation of the total base station power.

3. Determine the 900 psi auxiliary power which is chargeable directly to the industrial steam system, P_{s1}. This quantity is the sum of the base station power for steam and the power consumed by various pumps for the benefit of industrial steam. The pump power consumption is that required for well

water pumps, softener booster pumps, treated water make-up pumps, and attemperating water pumps. The total pumping energy quantities are calculated from water flows, pressures, and appropriate test data. Pumping energy for the water treatment function is allocated 96% to industrial steam, based on the 1994 plant water use study prepared for the MPSC Case EO-94-36.

4. Determine the portion of P_{900} which can be allocated, $P'_{900} = P_{900} - P_{e1} - P_{s1}$.

5. Determine the auxiliary power consumed by Boiler 5 precipitator (supplied from the Unit 5 auxiliary transformer), P_{5p} = K1 x number hours Boiler 5 is on burning coal, where K1 is the average kilowatt load drawn by the Boiler 5 precipitator.

6. Estimate the power consumed by #3 and #8 coal belts to deliver coal to the Boiler 5 coal bunkers, P_{38} = K2 x number of tons of coal delivered to Boiler 5 bunkers. K2 is the average kwh required to transport one ton of coal from the reclaim pit to the Boiler 5 bunkers.

7. Meter the daily auxiliary power used by the rotary dumper, #6 and #7 coal belts, and related equipment supplied by #7 auxiliary transformer. Determine the amount allocated to steam by multiplying by the Plant Coal Burn Allocation Factor. Designate this power as P_{sc}.

8. Total auxiliary power charged to steam is calculated as $P_s = x_s(P'_{900} + P_{5p} + P_{38}) + P_{s1} + P_{sc}$, where x_s is the fuel allocation factor for steam.

9. Total auxiliary power charged to electric is the difference between the total plant auxiliary power and P_s.

5/13/93
Revised 4/14/94

ST. JOSEPH LIGHT & POWER COMPANY
CALCULATION OF ALLOCATION FACTORS FOR
LAKE ROAD DAILY ASH REMOVAL EXPENSES
Acct. 141-2501-119

Expenses to be allocated with these factors include the removal cost of all ash material sent to the ash tank; it does not include costs associated with cleaning of material sluiced to the ash ponds, or removal of materials temporarily stored at the west coal yard area.

It is assumed that the amount of removal cost incurred is directly proportional to the amount of ash material sent to the ash tank, on a moisture-free, carbon-free basis. This material includes all coal ash from Boiler 5 (including bottom ash and fly ash) and 17.7 percent of the fly ash from Boiler 6 (the remaining 82.3 percent of Boiler 6 fly ash is sluiced to the ash ponds). The percentage split for Boiler 6 fly ash is based on assuming that no Boiler 6 fly ash can be sent to the tank during winter months January, February, November, and December, when vacuum system freezing problems occur, and that only one-third of the Boiler 6 fly ash can be sent to the tank during other months when dust-pulling equipment capacity is limiting. The 17.7 percent value was determined by analysis of the past three years' operations based on these assumptions. For Boiler 6, thirty percent of the total ash produced is fly ash and the remaining seventy percent is bottom ash (slag). All bottom ash for Boiler 6 is sluiced to the slag pond where it is removed by a contractor, for beneficial use, at no cost to the Company.

The total amount of ash material produced in Boilers 5 and 6 is directly proportional to the amount of coal burned in each boiler. Presently, the same type of coal (approximately 12% ash) is burned in both boilers. This allows a steam/electric allocation factor for ash to be calculated using coal burn (mmBtu) data currently available in the Lake Road Monthly Results Summary. The factors are based on a three year rolling average; this is consistent with other factors used in our allocation procedures.

The calculations are as follows:

AAFS = ASH ALLOCATION FACTOR FOR STEAM
AAFE = ASH ALLOCATION FACTOR FOR ELECTRIC

Eq.

(1) $$\text{AAFS} = \frac{[\text{Total Coal mmBtu to Steam}]}{[\text{Boiler 5 Coal mmBtu}] + (0.177) \times (0.30) \times [\text{Boiler 6 Coal mmBtu}]}$$

(2) AAFE = 1 - AAFS

W/ NEW ASH SYSTEM THIS FACTOR IS 1.00

3-Year Coal Burn (mmBtu) Data from Results Summary

Year	Boiler 5 Coal Burn (mmBtu)*	Boiler 6 Coal Burn (mmBtu)	Coal Btu To Steam (mmBtu)*
1991	1,457,777	1,971,238	1,088,477
1992	1,296,644	2,123,212	1,130,221
1993	1,940,561	2,816,719	1,528,054
TOTAL	**4,694,982**	**6,911,169**	**3,746,752**

*Figures used in these columns are adjusted values to account for the effect of Monfort Pork leaving.

(1) $$\text{AAFS} = \frac{3{,}746{,}752}{4{,}694{,}982+(0.177)\times(0.30)\times(6{,}911{,}169)} = 0.740$$

(2) AAFE = 1 - 0.740 = 0.260

6/15/93
Revised 4/14/94

Calculations to Determine Allocation Factors for expenses associated with Ash Pond Cleaning and West Coal Yard Material Removal

These calculations determine the factors to be used in allocating expenses associated with cleaning the ash ponds at Lake Road Plant and removing temporarily stored material from the West Coal Yard area. Two separate allocation factors are determined: The factor for allocating the total of these expenses between the appropriate ash handling and feedwater accounts, and the factor for allocating the ash handling portion of these expenses between the steam and electric jurisdictions. The feedwater portion of these expenses should be allocated between the steam and electric jurisdictions in accordance with the existing feedwater expense allocation factor.

It is assumed that the annual cost associated with these activities is directly proportional to the total weight (including moisture and unburned carbon) of material temporarily placed in the West Coal Yard storage area each year. The greatest portion of this material is that which is sluiced to the settling pond system and subsequently cleaned from the ponds and spread out over the West Coal Yard area for drying. A smaller amount of material is also placed in the West Coal Yard area each year from various cleaning operations around the plant. The following is a list of the different materials placed in the West Coal Yard area.

- That portion of Boiler 6 fly ash which is sluiced to the ponds
- Sediment from river water used to sluice Boiler 6 fly ash to the ponds
- Water softener blowdown sludge sent to the ponds
- Fly ash carryover from the ash tank dust-pulling system which is sent to the ponds
- Material from cleaning the coal yard runoff ditch system
- Boiler 5 coal mill-reject material
- Ash cleaned up from around the ash tank

The allocation factors are determined as follows: (1) Determine the total weight (including moisture and unburned carbon) of each material placed in the West Coal Yard area on an annual basis, (2) calculate the weight-ratio of softener sludge material to total material placed in the West Coal Yard area; this will provide the allocation factor for the split between ash handling and feedwater expenses, (3) determine the jurisdictional weight-split for each individual material associated with ash handling, (4) calculate a composite steam/electric allocation factor for ash handling expenses based on the total annual weight of ash-related material attributed to each jurisdiction, (5) use the existing feedwater expense allocation factor to allocate the feedwater portion of these expenses. As with other allocations, the factor will be based on a three year rolling average.

Boiler 6 Fly Ash

Lake Road Boiler 6 is a cyclone boiler. This means when coal is burned in Boiler 6, about 30 percent of the total ash produced is fly ash and the remaining 70 percent is bottom ash. The present coal burned at Lake Road has approximately 12 percent total ash content. With current operations, 82.3 percent of the total fly ash from Boiler 6 is sent to the ash ponds and the remaining 17.7 percent is sent to the ash tank (as explained in the Daily Ash Removal Expenses Allocation Procedure for account 141-2501-119). All bottom ash (slag) from Boiler 6 is sluiced to the slag pond where it is removed by a contractor at no cost to the Company.

Material sluiced to the ash ponds is typically cleaned out twice each year and placed in the West Coal Yard area for drying. A multiplier of 1.3299 is applied to the dry-weight tonnage of fly ash placed in the West Coal Yard area to account for moisture (21.14%) and unburned carbon (11.85%).

Using the above information, the total amount of Boiler 6 fly ash sent to the West Coal Yard area can be calculated from annual coal burn results.

Year	Boiler 6 Coal Burned	Boiler 6 Ash Content
1991	83,075 Tons	12.30 %
1992	89,524 Tons	12.07 %
1993	120,666 Tons	12.98 %

The annual fly ash tonnage (including moisture and unburned carbon) sent to the ponds, and subsequently placed in the West Coal Yard area (assuming 99% precipitator efficiency) is calculated as follows:

Year		Tonnage
1991	(83,075)x(.1230)x(.3)x(.99)x(.823)x(1.3299)	= 3322 Tons
1992	(89,524)x(.1207)x(.3)x(.99)x(.823)x(1.3299)	= 3513 Tons
1993	(120,666)x(.1298)x(.3)x(.99)x(.823)x(1.3299)	= 5091 Tons

Since this material is produced solely from burning coal in Boiler 6, the total weight is attributed to the electric jurisdiction.

Sediment from Boiler 6 Fly Ash Sluicing Water

As mentioned above, during 82.3 percent of Boiler 6 operating time, water from the Missouri River is used to sluice Boiler 6 fly ash to the ash ponds. Since river water is typically very muddy, it represents another source of material input to the ash ponds. Sluicing water discharged back into the river after flowing through the pond system is much cleaner than incoming river water. The settling ponds allow suspended river silt in the sluicing water to drop out and accumulate in the pond floor along with other materials intentionally pumped into the ponds.

The sluicing pumps take their suction from the Turbine 4 condenser water box where they tap into the circulating water supply pumped in from the river for condenser cooling. Circulating water pumps located at the river pump circulating water into the plant where the water flows through the condenser and then back out to the river. The Company has an NPDES permit which allows it to discharge this water back into the Missouri River. This discharge is referred to as the "003" discharge. Permit requirements dictate that we monitor and record total suspended solids in the 003 discharge. This provides the necessary field information to calculate the amount of river sediment accumulated in the ponds.

Average Total Suspended Solids in 003 Discharge:

Year	TSS	TSS
1991	245 ppm	0.002042 lbs/gal
1992	351 ppm	0.002925 lbs/gal
1993	558 ppm	0.004650 lbs/gal

Note, the multiplying factor to convert ppm (parts per million) to lbs/gallon is 1/120,000.

The sluicing water system is used for fly ash removal for 82.3 percent of the total Boiler 6 operating time. During this time, the sluicing water is actually used for dust pulling about 50 percent of the time; during the remaining 50 percent, the system is used for bottom ash removal.

Boiler 6 Operating Hours/Sluicing Time (minutes):

Year	Boiler Operating Hours		Sluicing Time (Min)
1991	4802 hrs x 60 x 0.823 x 0.50	=	118,561 min
1992	4210 hrs x 60 x 0.823 x 0.50	=	103,945 min
1993	5212 hrs x 60 x 0.823 x 0.50	=	128,684 min

The sluicing water flow rate is estimated to be 750 gpm. Also, it is assumed that all of the river sediment is filtered out in the ponds, and the moisture content of the sediment material after it is placed in the West Coal Yard area is estimated to be 24.0 percent.

Using the above information, the annual tonnage of river sediment material placed in the West Coal Yard area is calculated as follows:

Year		Tonnage
1991	(118,561) x (750) x (0.002042) x (1.24) / 2000 =	113 tons
1992	(103,945) x (750) x (0.002925) x (1.24) / 2000 =	141 tons
1993	(128,684) x (750) x (0.004650) x (1.24) / 2000 =	278 tons

All of this material is attributable to the electric jurisdiction.

Softener Blowdown Sludge

The quantity of softener sludge material sent to the ash ponds and subsequently placed in the West Coal Yard area is determined as follows:

- First, the hardness constituents of the processed well water are identified and measured (in parts per million or ppm) before and after it flows through the lime softeners to determine the "net" hardness removed in the softening process. These hardness concentrations are measured, on an "as CaCO3" basis, by Laboratory Technicians on a regular basis throughout the year and records are maintained in laboratory files. Average values for the year 1992 will be used in these calculations. These data would not vary significantly from year to year.

- For the 1992 data, calculate the average "net" hardness concentration removed for each hardness constituent and then convert these values to "lbs/1000 gallon" terms on a "per substance" basis.

- Determine the primary chemical reactions which take place in the hot lime softening process. These are reactions involving the use of lime [$Ca(OH)_2$] and/or soda ash (Na_2CO_3) to remove calcium bicarbonate [$Ca(HCO_3)_2$], magnesium bicarbonate [$Mg(HCO_3)_2$] and magnesium sulfate ($MgSO_4$) from the incoming well water. The end result of the chemical reactions is to remove the unwanted hardness constituents by causing them to precipitate out of solution. The reaction products are calcium carbonate ($CaCO_3$), magnesium hydroxide [$Mg(OH)_2$], sodium sulfate (Na_2SO_4) and water (H_2O). Calcium carbonate and magnesium hydroxide are both insoluble precipitates which drop out of solution inside the softener to form sludge. This sludge must then be drained from the softener on a regular basis for the process to continue. After leaving the softeners, the sludge is pumped to the ash ponds where it becomes mixed with other materials sent to the ponds. The reaction product, sodium sulfate, remains in solution and flows on through the softener system along with any water formed in the reaction. The chemical reactions are as follows:

(1) $Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3\downarrow + 2H_2O$

(2) $Mg(HCO_3)_2 + 2Ca(OH)_2 \rightarrow Mg(OH)_2\downarrow + 2CaCO_3\downarrow + 2H_2O$

(3) $MgSO_4 + Ca(OH)_2 + Na_2CO_3 \rightarrow Mg(OH)_2\downarrow + CACO_3\downarrow + Na_2SO_4$

A downward arrow indicates the reaction product is a precipitate.

- Using the above chemical equations and "net" hardness concentrations "removed", calculate the concentration of each precipitate formed in the reactions in "lbs/1000 gallons" on a "per substance" basis.

- Calculate the total precipitate concentration, in lbs/1000 gallons, by summing all the precipitate concentrations from all reactions.

- Determine the total gallons of well water processed through the softeners during the year. These data are available from the Lake Road Results Summary, but must be adjusted to account for Monfort Pork leaving.

- Multiply the total precipitate concentration (in lbs/1000 gal) by the total annual amount of well water processed (in gallons) to obtain the total amount of softener sludge produced each year on a dry basis (in pounds).

- Calculate the total amount of sludge produced for each of the past three years using this method.

- Determine the total weight (including moisture) of sludge material placed in the West Coal Pile area for each of the past three years.

The calculations are as follows:

(1) Average measured hardness concentrations for 1992:

	$Ca(HCO_3)_2$	$Mg(HCO_3)_2$	$MgSO_4$
Before	244 ppm	12 ppm	78 ppm
After	48 ppm	3 ppm	7 ppm
Net	196 ppm	9 ppm	71 ppm

The Net value equals the Before value minus the After value.

(2) Calculate the net concentration of each hardness component in lbs/1000 gallons on a "per substance" basis.

To convert ppm to lbs/1000 gallon, multiply ppm by (1/120).
To convert "as $CaCO_3$" concentrations to "per substance" concentrations, multiply the "as $CaCO_3$" values as follows:

$Ca(HCO_3)_2$ (as $CaCO_3$) x 1.62
$Mg(HCO_3)_2$ (as $CaCO_3$) x 1.46
$MgSO_4$ (as $CaCO_3$) x 1.20

These are standard factors from chemistry tables.

The following calculations determine the average net hardness "removed" for each constituent in 1992 in terms of lbs/1000 gallons on a "per substance" basis.

Net Hardness Removed
(lbs/1000 gal. on per substance basis)

$Ca(HCO_3)_2$: (196 ppm) x (1/120) x (1.62) = 2.646 lbs/1000 gal

$Mg(HCO_3)_2$: (9 ppm) x (1/120) x (1.46) = 0.110 lbs/1000 gal

$MgSO_4$: (71 ppm) x (1/120) x (1.20) = 0.710 lbs/1000 gal

(3) Referring to the three chemical equations stated earlier, calculate the precipitate concentrations which are formed in the process of removing the "net" hardness concentrations calculated above.

Equation 1
$Ca(HCO_3)_2$ to $CaCO_3$: (2.646) x (200/162)* = 3.27 lbs/1000 gal

Equation 2
$Mg(HCO_3)_2$ to $Mg(OH)_2$: (0.110) x (58/146)* = 0.04 lbs/1000 gal

$Mg(HCO_3)_2$ to $CaCO_3$: (0.110) x (200/146)* = 0.15 lbs/1000 gal

Equation 3
$MgSO_4$ to $Mg(OH)_2$: (0.710) x (58/120)* = 0.34 lbs/1000 gal

$MgSO_4$ to $CaCO_3$ (0.71) x (100/120)* = 0.59 lbs/1000 gal
TOTAL PRECIPITATE CONCENTRATION = 4.39 lbs/1000 gal

* Multiplier equals the ratio of the molecular weight of the precipitate to the molecular weight of the hardness component being removed in each equation.

(4) Total softener well water flow for each of the last three years is as follows (1 gallon = 8.337 lbs):

1991	1,840,686,000 lbs = 220,785 (1000 gal) *	
1992	1,867,956,000 lbs = 224,056 (1000 gal) *	
1993	1,894,434,000 lbs = 227,232 (1000 gal) *	

*Data taken from Lake Road Results Summary, and ajusted downward by 14.3 percent (3-year weighted average) to account for Monfort leaving.

(5) Multiply the total precipitate concentration (found in step 3) by the total annual well water flow (found in step 4) to obtain the total quantity of sludge produced for each of the three years. Multiply this result by 1.24 to include 24 percent moisture.

Year		Tonnage
1991:	(4.39) x (220,785) x (1.24) x (1/2000) =	601 tons
1992:	(4.39) x (224,056) x (1.24) x (1/2000) =	610 tons
1993:	(4.39) x (227,232) x (1.24) x (1/2000) =	618 tons

The softener sludge portion of the total material tonnage placed in the West Coal Yard area should be allocated in accordance with the existing feedwater expense allocation factors.

Ash Carryover from Ash Tank

A small amount of the ash pulled to the ash tank carries over past the cyclone separators on top of the tank and flows into a steam condensing/water wash chamber located immediately before the steam exhaust for the vacuum system (the system uses a steam exhauster-type vacuum system for pulling ash.) Water flowing through the wash chamber catches any carried over ash and sends it to the sludge tank in the water softener department where it is pumped to the ash pond along with the softener sludge. This carried over ash thus comprises another input to the ash ponds.

An investigation was conducted to determine the amount of material involved with ash carryover. It was concluded the amount of material is relatively small and does not vary substantially from year to year. Therefore, a fixed amount of 60 tons per year (including moisture and unburned carbon), as determined from the investigation, is used for purposes of these calculations.

Since this material is the result of ash tank carryover, it should be proportioned between the two jurisdictions in accordance with the Daily Ash Removal Expense Allocation Factor.

Material Cleaned from Coal Yard Runoff Ditches

The Coal Yard at Lake Road Plant has a ditch system surrounding it to collect rain-water runoff material and prevent it from encroaching on neighboring property. The layout of the ditch system directs all flow to the south side of the coal yard where it is eventually pumped into the ash ponds. Through the course of a year, a considerable amount of material settles out in the ditches and must be cleaned out. Also, part of the runoff material settles out in the ash ponds and must be cleaned out, similar to other pond inputs.

The total annual weight (including moisture, unburned carbon, dirt, and some coal) of this material which is cleaned out and placed in the West Coal Yard area is estimated to be approximately 300 tons. This value is based on weigh-ticket results from trucks hauling an observed amount of material cleaned from the ditches.

Since the activity associated with accumulating this material is related to the coal pile itself, it should be allocated in accordance with the Plant Coal Burn Allocation Factor.

Boiler 5 Coal Mill Reject Material

A small amount of material is rejected from coal mills during the grinding process, and placed into a special chamber in the mill for periodic emptying. At Lake Road, operators empty these chambers on the coal mills for Boiler 5 and haul the material by wheelbarrow to a collecting point outside the plant between 5 & 6 Boilers.

Every 3 - 4 weeks, coal handlers load this material on a dump truck and haul it to the West Coal Yard area where it is mixed in with other temporarily stored material. Typically, they fill a dump truck during each of these cleanings. Based on this, the total annual weight of this material placed in the West Coal Yard area is estimated to be approximately 150 tons.

This material should be allocated according to the ratio of steam coal Btu's to total coal Btu's on Boiler 5.

Ash Cleaned from Around the Ash Tank

Approximately once every two weeks, coal handlers clean up the area around the ash tank. Typically, they get about half of a dump truck load each time they clean and haul it to the West Coal Yard area. Based on this, the total annual weight of this material placed at the West Coal Yard area is estimated to be 150 tons.

This material should be allocated in accordance with the Daily Ash Removal Expense Allocation Factor.

Calculation of Allocation Factors

Two new allocation factors are needed for the overall objective: One to allocate total pond cleaning/West Coal Yard material removal expenses between ash handling expenses (acct. 501) and feedwater expenses (acct. 502), and one to allocate the ash handling portion of these expenses between the steam and electric jurisdictions. A new jurisdictional- split allocator is not needed for the feedwater portion of these expenses; the existing factor can be used for this purpose. Three account numbers will be utilized: One for initial collection of all pond cleaning/West Coal Yard material removal expenses (this acct. will be allocated between acct.'s 501 & 502), one for the feedwater portion of these expenses (to be allocated between steam and electric using the existing factor), and one for the ash handling portion (to be allocated between steam and electric using the new factor determined in these calculations.)

The following tabular information is used to determine the ash handling/feedwater allocation factor.

Year	Material Type	Tons	Tons	Tons
1991	Total Fuel/Ash-Related	4095		
	Softener Sludge		601	
	TOTAL			4696
1992	Total Fuel/Ash-Related	4314		
	Softener Sludge		610	
	TOTAL			4924
1993	Total Fuel/Ash-Related	6029		
	Softener Sludge		618	
	TOTALS			6647
TOTALS		**14,438**	**1,829**	**16,267**

The ash handling/feedwater expense allocation factors "AH" and "FW" are calculated as follows:

$$\text{Feedwater:} \quad FW = \frac{1,829}{16,267} = 0.112$$

$$\text{Ash Handling:} \quad AH = 1 - 0.112 = 0.888$$

Use these factors to allocate total expenses (acct. 141-2501-219) between feedwater expenses (acct. 141-2502-019) and ash handling expenses (acct. 141-2501-319).

The attached Table 1 includes tabular information and calculations to determine the jurisdictional-split allocators for the ash handling portion of the total expenses. The steam/electric allocation factors "AHS" and "AHE" for the ash handling portion of the total expense are as follows:

Steam: AHS = 0.077

Electric: AHE = 0.923

Use these factors to allocate acct. 141-2501-319 between the steam and electric jurisdictions.

Use the existing feedwater allocation factor for acct. 141-2502-010 to allocate acct. 141-2502-019 between the steam and electric jurisdiction. Presently, this factor is 90% steam/10% electric.

ALLOCATION OF ASH HANDLING PORTION
(Acct. 141-2501-319)

Table 1

Year	Description	Total Tons	Steam Factor	Steam Tons	Electric Factor	Electric Tons
1991	Boiler 6 Fly Ash	3322	(0%)	0	(100%)	3322
	Sluicing Sediment	113	(0%)	0	(100%)	113
	Ash Tank Carryover	60	(74.0%)*	44	(26.0%)*	16
	Coal Pile Runoff	300	(32.3%)**	97	(67.7%)**	203
	Coal Mill Rejects	150	(79.8%)***	120	(20.2%)***	30
	Ash Clean up	150	(74.0%)*	111	(26.0%)*	39
	TOTAL	4095		372		3723
1992	Boiler 6 Fly Ash	3513	(0%)	0	(100%)	3513
	Sluicing Sediment	141	(0%)	0	(100%)	141
	Ash Tank Carryover	60	(74.0%)	44	(26.0%)	16
	Coal Pile Runoff	300	(32.3%)	97	(67.7%)	203
	Coal Mill Rejects	150	(79.8%)	120	(20.2%)	30
	Misc. Ash Cleanup	150	(74.0%)	111	(26.0%)	39
	TOTAL	4314		372		3942
1993	Boiler 6 Fly Ash	5091	(0%)	0	(100%)	5091
	Sluicing Sediment	278	(0%)	0	(100%)	278
	Ash Tank Carryover	60	(74.0%)	44	(26.0%)	16
	Coal Pile Runoff	300	(32.3%)	97	(67.7%)	203
	Coal Mill Rejects	150	(79.8%)	120	(20.2%)	30
	Misc. Ash Cleanup	150	(74.0%)	111	(26.0%)	39
	TOTAL	6029		372		5657
	GRAND TOTALS	14,438		1116		13,322

Steam: AHS = 1116 ÷ 14438 = 0.077

Electric: AHE = 1 - 0.077 = 0.923

* Daily Ash Removal Expense Allocation Factors

** Total Plant Coal Burn Allocation Factors (with Monfort removed)

*** Ratio of steam coal Btu's to total coal Btu's on Boiler 5 for past 3 years (with Monfort removed)