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ECONOMIC EVALUATION OF LOSSES TO ELECTRIC POWER
UTILITIES CAUSED BY ASH FOULING

Final Technical Report for Period November 1, 1979—April 30, 1980

By
Fred R. Burkhardt
Marvin M. Persinger

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The Virginia Corporation
Richmond, Virginia

U. S. DEPARTMENT OF ENERGY

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FINAL TECHNICAL REPORT

1 November 1979 - 30 April 1980

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Marvin M. Persinger
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THE VIRGINIA CORPORATION
of Richmond

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Richmond, Virginia 23228

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1.0 Introduction

Ash fouling, a phenomena associated with high ash, low rank coals, is in some instances severe enough to force large utility steam generators off line, and to force as high as 20% constant derating of units.

This study was initiated by the Grand Forks Energy Technology Center of the Department of Energy to assess the economic impact of the ash fouling problem to the utility industry.

Seven power stations with twenty three total units were involved in the study; St. Clair station of Detroit Edison Co., Units 1 - 4, 6 and 7; Big Stone station of Otter Tail Power Co., Unit 1; Leland Olds station of Basin Electric Power Cooperative, Units 1 and 2; Jim Bridger station of Pacific Power and Light Co., Units 1 - 4; Four Corners station of Arizona Public Service Co., Units 1 - 5; Big Brown and Monticello stations of Texas Utilities Services, Inc., Units 1, 2 and 3.

Four visits were made to each station for the purpose of data collection and inspection of the steam generators for slagging and fouling conditions. The data collected consisted of the causes and duration for each outage, the duration of each ash fouling related curtailment, and the station coal analyses. The period of data collection was from November, 1979 through April, 1980.

The power stations studied represented Texas and Dakota lignites; and Montana, Wyoming and New Mexico subbituminous coals. Also included are two cyclone fired units, the remainder pulverized coal fired.

As expected, the high sodium ash coals presented the greatest problem. The Leland Olds station and the Big Stone station are the two having the greatest fouling losses.

Jim Bridger, Four Corners, and St. Clair fouling problems would be termed moderate, with substantial but inconsistent problems. Big Brown and Monticello ash fouling problems are virtually nonexistent.

Within this report, outages of all causes are listed and curtailments due to ash fouling and slagging problems are reported. The costs of the outages and curtailments related to ash fouling and slagging problems are computed. These costs vary from need for purchased power, replacement of power from higher cost units, to the firing of oil in the plugged units.

2.0 Acknowledgements

The cooperation of the utility companies involved in the study and of the Grand Forks Energy Technology Center is gratefully acknowledged.

In particular, we wish to thank Dr. Frank Honea of GFETC; Messrs. D. O. Whiddon and Bob Oldani of Detroit Edison; Messrs. Bob Middleton and Nageb Thomas of Otter Tail Power Co.; Messrs. K. Janssen, Richard Fockler, Vernon Laning, Curt Melland, and Doug Rothe of Basin Electric Power Cooperative; Messrs. R. W. Beadnell, Don Vincent, and Steve Wotruba of Pacific Power and Light Co.; Messrs. L. K. Mundth, and Duane Pilcher of Arizona Public Service Co.; Messrs. R. J. Gary, John Dorsett, Steve Payton, Doug Hobbs, and Larry Morris of Texas Electric Service Co.

Without the courtesy and cooperation extended to us by these people the writing of this report could not have been accomplished.

3.0 Unit Operation

The operating records of each unit were reviewed for ash fouling and slagging related outages prior to the study period; and ash fouling and slagging curtailments and all outages during the study period.

This section details the megawatt hour load losses during the study period due to ash fouling and slagging curtailments and due to all outages. Some ash related problems have been excluded from this report because they are not considered to be related to ash properties. They include air preheater fouling; ash conveying system problems; and problems with the soot blowing systems, which can be identified as such. Any pluggage which could not be identified as soot blowing problems would be considered to be ash pluggage problems.

Other information included in this section which is felt to pertain to ash fouling or slagging problems is:

High superheat temperature losses are included because the usual cause is excessive wall slagging, a problem related to ash properties which is significant for many of the units studied.

Low superheat temperature losses are included because, in the cases listed, the cause is generally reluctance to fire in a way which will increase furnace gas exit temperatures because of convection fouling problems.

Supplemental oil firing is included because St. Clair units 1 - 4 fire oil when ash fouling occurs, and Leland Olds 2 fires oil when slag tapping problems occur in the cyclones.

Sootblower cut tube leaks are included for stations which have identified this cutting to be a major problem. It is included because of the excessive blowing requirements of high fouling coals.

Capacity loss is included for the St. Clair station because of a coal conversion to the lower BTU per pound western coals. Detroit Edison has limited loads on the five units studied for a variety of reasons which include high superheat temperatures and fouling. Because the reasons which were given for derating include, but are not limited to, ash problems, the capacity loss is included in this report. It must be emphasized that this is not due solely to ash related reasons, because the boiler was not designed for the low BTU fuel, but ash problems do play a role, not able to be quantitatively defined.

3.1 St. Clair

Units 1 - 4: (See page A-1 in appendix)

These units were designed to burn eastern bituminous coals with an as received higher heating value of 11,700 btu/lb. From September of 1976 through November of 1977, they were converted to burn western subbituminous coals from Decker, Montana. Unit conversion dates:

Unit 1	9/25/76
Unit 2	4/03/77
Unit 3	7/18/77
Unit 4	11/14/77

Units 1 and 4 were rated at 163 megawatts prior to conversion. Units 2 and 3 were rated at 162 megawatts prior to conversion. With all coal mills in service burning Montana coal, the units are now capable of only 135 megawatts. This megawatt load limit is a limitation of the coal mills. These units are capable of oil firing in conjunction with coal firing, and with this supplemental oil firing, can attain the same load as could be attained prior to conversion. The reheat dampers have been pinned open in these units because of consistently low reheat temperatures.

Ash fouling in these units has been a continual problem. Prior to the period which this study details the convection passes were cleaned a total of 24 times. The units were forced off a total of sixteen times for ash pluggage in the convection passes of the unit. Five of these outages occurred in 1977. It appears the operating experience has improved the ash fouling reliability.

Ash related curtailments do not appear in the station records. The capability of the unit to fire oil when convection pluggage occurs eliminates curtailments due to pluggage and instead presents a problem of excessive oil consumption, with its higher cost the principal problem.

Oil is also fired in the units to increase loads above 135 megawatts as the system demand require. Oil is also fired in the units if coal mill problems occur. We have the station data on oil consumption for the study period. With a knowledge of system load demands for the study period, an estimate of oil consumption due to ash fouling will be computed.

Unit 1 (163 megawatts capacity)

Table 3.1 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason For Outage
Date	Hour	Date	Hour			
11/28	23:05	11/29	4:47	5.70	929	Generator exciter brush replacement Boiler inspection license & ins. Turbine governor periodic insp.
2/19	2:53	3/03	22:16	331.37	54013	
4/29	23:57	4/30	3:17	3.33	543	

Unit 1 performed very well through the period of study, with only three outages. Its availability was 92.21%. Two outages were attributed to routine inspections, one to a routine brush replacement.

Curtailments (November, 1979 - April, 1980):

Unit 1 had no ash related curtailments listed.

Unit 2 (162 megawatts capacity)

Table 3.2 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/01	00:01	3/16	24:00	3288	532,656	Turbine dummy ring failure
3/17	00:01	3/31	24:00	359.98	58,317	Inspection, License, Ins.
4/01	00:01	4/28	4:48	652.78	105,750	Turbine dummy ring failure

Unit 2 had one outage due to a turbine dummy ring problem. This outage was relisted in March as a boiler inspection, then relisted again in April as a turbine outage. This outage was very costly during our study. The unit was on line only 67.2 hours during the six month period for an availability of only 1.5%.

Curtailments (November, 1979 - April, 1980):

Unit 2 had no ash related curtailments listed.

Unit 3 (162 megawatts capacity)

Table 3.3 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
1/04	21:33	1/10	12:32	134.98	21,867	Superheater erosion leak
1/10	18:34	1/10	21:40	3.10	502	Differential expansion
1/12	0:28	1/12	16:41	16.22	2,628	electronic problems
1/12	18:51	1/18	2:02	127.18	20,609	Dummy ring seal
2/17	22:09	2/19	6:51	32.7	5,297	Turbine seals
4/06	14:28	4/10	9:30	91.03	14,747	Leaking feedwater heaters
4/10	9:31	4/27	9:27	407.93	66,085	Boiler chemical cleaning
						Boiler periodic insp.

Unit 3 boiler ran well through the study with only one forced outage for a tube leak and one inspection and chemical cleaning outage. The turbine had dummy ring seal problems causing three outages totalling 146.5 hours. One outage was caused by feedwater heater leaks, costing 32.7 hours. Availability for the six months was 81.38% with six total outages.

Table 3.4 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw Curtailed	Hours	Mw Hours	Reason
Date	Hour	Date	Hour				
3/15	21:50	3/17	7:30	25	33.67	843	High superheat temp.

This one high superheat temperature load limitation was most probably due to excessive furnace slagging.

Unit 4 (163 megawatt capacity)

Table 3.5 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
1/19	23:12	1/20	5:10	5.97	973	Exciter brush replacement
1/25	15:44	1/25	20:36	4.87	793	Generator cooling system piping repair
1/25	20:50	1/25	21:10	.33	54	Trip-generator control system
4/11	1:12	4/11	4:54	3.70	603	Exciter brush replacement

Unit four had an extraordinary availability for the six month period of 99.66%. Four generator problems, two brush replacements, one trip, and one piping repair were the only outage causes.

Curtailments (November, 1979 - April, 1980):

Unit 4 had no ash or coal related curtailments listed.

Table 3.6 Oil Consumption (gallons)

Month	Unit 1	Unit 2	Unit 3	Unit 4
November	617,837	x	55,566	1,010,765
December	28,341	x	78,047	653,151
January	1,088,452	x	86,566	1,026,044
February	794,877	x	608,829	413,837
March	778,143	x	821,914	419,641
April	67,003	x	363,728	547,064
Totals	3,374,653	None	2,014,650	4,070,502

Unit 6 (260 megawatts capacity) (See page A-2 in appendix)

As with the other station units, unit 6 was designed to burn 11,700 btu/lb. eastern bituminous coals. It was converted to burn Decker, Montana coal in mid 1977. Since conversion, it has burned a 70% Decker - 30% eastern coal ratio. This ratio is controlled at the coal pile by coal dozer operation and therefore is not totally accurate and leads to stratification in the bunkers. The 70:30 ratio changed during our study to approximately 90:10 at the study end. Unit 6 was rated at 315 megawatts prior to conversion, but is now rated at 260 megawatts due to mill capacity.

Ash fouling has been a problem in this unit from the time of conversion. This was the only station unit with an ash fouling outage during the period of study. Prior to the study period the unit was shut down four times in 1977 and three times in 1978 due to pluggage problems.

Table 3.7 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/20	14:32	11/21	23:09	32.62	8,481	Induced draft fans
12/27	1:32	12/31	4:49	99.28	25,814	Reheater fouling
1/02	18:52	1/04	5:09	34.28	8,913	Superheater erosion leak
1/15	6:30	1/15	10:55	4.42	1,149	Scrubber bypass damper problems
2/03	0:05	2/03	9:20	8.50	2,210	Exciter brush replacement
3/06	9:07	3/06	12:47	3.67	954	Auxiliary transformer failure
3/08	20:53	3/13	15:22	114.48	29,765	Tube leak
3/13	22:40	3/16	15:57	65.28	16,973	Tube leak
4/02	10:17	4/04	16:58	54.68	14,217	Tube leak
4/09	14:17	4/12	10:27	68.17	17,724	Duct system baffle failure

The Unit 6 boiler accounted for the majority of the outage time, with four tube leak outages costing 69,868 hours and ash fouling of the reheater costing 25,814 megawatt hours. Induced draft fan problems, damper and baffle problems, exciter brush replacement, and an auxiliary transformer failure caused five additional outages for a total of 30,518 megawatt hours. Total outage time was 485.38 hour, with ten outages, for an availability of 88.89%.

Ash fouling contributed 99.28 hours or 20.45% of the total outage time.

Table 3.8 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw Curtailed	Mw Hours	Hours	Reason
Date	Hour	Date	Hour				
11/06	5:45	11/06	9:50	40	4.08	163	High superheat temp.
12/02	22:01	12/05	11:35	40	61.57	2463	Reheater fouling
12/05	11:36	12/06	9:32	30	21.93	658	Reheater fouling
12/06	9:33	12/10	7:30	60	93.95	5637	Reheater fouling
12/10	7:31	12/10	10:30	20	2.98	60	Reheater fouling
12/10	10:31	12/19	8:40	60	214.15	12849	Reheater fouling
1/22	19:30	1/25	24:00	10	76.5	765	High superheat temp.
3/08	2:10	3/08	3:15	90	1.08	98	High reheat temp.

During the period of study, high steam temperatures were responsible for three curtailments totalling 1,026 megawatt hours. Because of the lower heating value fuel now burned, the boiler is marginal as to steam temperatures, and furnace slagging considered moderate can give a steam temperature problem. For this study, the high steam temperatures will be considered to be an ash slagging problem.

Reheater fouling started on 12/02 and continued at various load reductions through 12/19. It was responsible for a loss of 21,667 megawatt hours.

Unit 7 (415 megawatt capacity) (See page A-3 in appendix)

This unit, as 1 - 4 and 6, was designed for the 11,700 btu/lb eastern bituminous. It was converted to the Decker, Montana coal in mid-1977 at a blend ratio of 70% Decker-30% eastern. This ratio was changed in December, 1979, to an 85:15 and changed in February, 1980, to 100% Decker operation for a two month test. On April 1, the unit was returned to a 75:25 blend.

Unit 7 was rated at 500 megawatts new, and was rerated at 415 after the Decker conversion. At 100% Decker coal it is load limited (but not officially rerated) at 380 megawatts due to high steam temperatures. Prior to the 100% Decker conversion, the unit was again limited primarily by steam temperatures.

Ash fouling and slagging have been a problem in this unit to a great extent. The station has installed water blowers in the high slagging areas throughout the furnace. Forty-four have been installed from below the burner elevation to the bottom of the upper arch. These were added to remove slag for added furnace heat absorption with lower furnace gas exit temperatures.

Unit 7 had been off line three times in 1978 and twice in 1979, prior to this study period, for ash pluggage problems.

Table 3.9 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason
Date	Hour	Date	Hour			
11/01	0:01	11/01	11:49	11.8	4897	Generator cooling system
11/15	8:30	11/15	16:54	8.5	3528	Electrical precipitator problems
11/15	16:55	11/17	4:54	35.98	14932	Turbine control valve failure
11/17	5:30	11/17	6:49	1.32	548	Light off system
11/17	20:00	11/18	2:37	6.62	2747	Governor tests
11/18	9:03	11/18	10:10	1.12	465	Governor tests
12/23	2:55	12/27	5:16	98.35	40815	Waterwall leak
12/27	22:28	12/28	21:41	23.22	9636	Waterwall leak
1/11	8:25	1/18	16:36	176.18	73115	Cross over piping
1/18	18:45	1/19	4:38	9.88	4100	Light off system
1/19	5:33	1/19	5:53	.33	137	Light off system
1/19	7:23	1/19	12:20	4.95	2054	Light off system
1/19	15:02	1/19	16:20	1.30	540	Light off system
1/30	3:23	1/30	3:40	.28	116	High drum level trip because of pulverizer problem
2/02	0:43	2/02	6:53	6.17	2561	Feedwater heater leaks
2/13	0:09	2/14	3:17	27.13	11259	Precipitator fouling
2/14	3:35	2/14	4:38	1.05	436	Light off system
2/28	23:11	2/29	6:39	7.47	3100	Precipitator fouling
4/12	17:32	4/12	19:52	2.33	967	Feed pump vibration
4/25	4:36	4/25	7:54	3.3	1370	Feedwater heater leaks
4/26	23:05	4/27	3:11	4.1	1702	Feedwater heater leaks

Unit 7 had twenty-one outages during the six month period for a total of 431.38 hours and an availability of 90.12%. Startup problems after outages caused six of these outages for a total of 7814 megawatt hours. Leaking feedwater heaters forced the unit off line three times for a loss of 5633 megawatt hours. Turbine tests, cross over piping problems and a control valve failure caused five outages costing 96156 megawatt hours. Precipitator problems, including pluggage and electrical troubles caused three outages totalling 17,887 megawatt hours. Feedwater heater leaks forced the unit out three times for a total of 5,636 megawatt hours. Boiler feed pump vibration caused one 967 megawatt hour outage. Pulverizer problems caused one 116 megawatt hour trip. Waterwall leaks caused two outages totalling 50,451 megawatt hours.

Table 3.10 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw Curtailed	Hours	Mw Hours	Reason
Date	Hour	Date	Hour				
11/06	0:31	11/07	5:30	75	28.98	2174	HST
11/07	6:31	11/08	0:30	85	17.98	1528	HST
11/08	5:31	11/10	5:55	55	48.40	2662	HST
11/12	8:00	11/12	24:00	65	16.00	1040	HST
11/13	0:01	11/14	4:09	75	28.13	2110	HST
11/18	10:11	11/19	18:40	45	32.48	1462	HST
11/19	18:41	11/19	23:10	75	4.48	336	HST
11/19	23:11	11/22	10:00	45	58.82	2647	HST
11/22	10:01	11/23	0:01	65	14.00	910	HST
11/23	0:02	11/23	7:55	45	7.88	355	HST
11/24	18:30	11/24	20:29	40	1.98	79	HST
11/24	20:30	11/27	10:59	85	62.48	5311	HST
11/27	20:46	11/30	24:00	75	75.23	5642	HST
12/01	0:01	12/01	2:47	75	2.77	208	HST
12/02	11:31	12/03	6:00	60	18.48	1108	HST
12/03	12:00	12/04	0:07	45	12.12	545	HST
12/04	0:08	12/04	23:10	40	23.03	921	HST
12/07	5:18	12/11	8:59	25	99.68	2492	HST
12/11	9:00	12/12	7:00	70	22.00	1540	HST
1/21	0:01	1/26	23:00	30	142.98	4289	HST
1/27	11:05	1/28	7:10	50	20.08	1004	HST
1/28	11:07	1/29	22:50	30	35.72	1072	HST
2/01	0:03	2/01	:41	40	.63	25	HST
2/05	19:00	2/05	23:15	40	4.25	170	HST
2/14	15:01	2/17	8:04	55	65.05	3578	HST
2/17	8:05	2/18	0:01	90	15.93	1434	HST
2/18	6:15	2/18	13:00	75	6.75	506	HST
2/18	13:01	2/18	14:00	85	.98	83	HST
2/18	14:01	2/18	23:00	80	8.98	718	HST
3/08	2:10	3/08	3:15	90	1.08	97	HST
3/20	5:30	3/20	9:00	55	3.5	193	HST
3/20	9:01	3/20	23:45	115	14.73	1694	HST
3/21	6:00	3/23	8:00	95	50	4750	HST
3/23	8:01	3/24	5:00	130	20.98	2727	HST
3/24	5:01	3/24	6:30	85	1.48	126	HST
3/24	6:31	3/24	23:30	100	16.98	1698	HST
3/25	9:20	3/25	18:40	20	9.33	187	HST
4/17	7:30	4/17	23:00	40	15.5	620	HST
4/18	7:30	4/19	7:59	50	24.48	1224	HST
4/30	6:01	4/30	12:20	100	6.32	632	HST

* HST = High superheat temperature

No load limitation due to fouling or pluggage was recorded by the station for Unit 7. The curtailments relating to ash problems were high steam temperatures, due partly to the furnace volume and partly to slagging. Slagging is a problem in this unit as evidenced by the installation of water soot blowers in the combustion zone area.

Load losses due to steam temperatures were 26,256 megawatt hours in November, 5,274 megawatt hours in December, 7,905 megawatt hours in January, 6,514 megawatt hours in February, 11,472 megawatt hours in March, and 2,476 megawatt hours in April, for a total of 59,897 megawatt hours,

It should be noted in this report that the curtailments listed are actual losses incurred by the utility. At times the high steam temperature problem was "masked" by other unrelated problems, and not reported. During the period of 100% Decker coal operation the unit was reduced in load constantly by 50 to 75 megawatts. The actual station losses reflect only 17 - 25% of this loss. Because the report deals with actual losses, this additional loss will not be calculated in the financial analysis.

3.2 Big Stone (399 megawatt capacity) (See page A-4 in appendix)

The Big Stone unit burns North Dakota lignite from the Gascoyne Mine. The percent sodium in ash levels varies with seam depth, which allows the station to average sodium in ash levels to about 4-1/4%.

This unit is capable of attaining 399 megawatts and is usually at that load. It is equipped with water soot blowers, both in the waterwalls and in the convection passes. The convection passes have nine blowers per side before the secondary superheat inlet, and two oscillating blowers per side before the finishing superheater. The waterwalls have six water blowers per wall.

Ash pluggage has been and still remains a severe problem. Two pluggage outages occurred in 1978, one in 1979, prior to the start of this study. During the course of our study, however, the unit was forced off four times due to ash pluggage.

The unit has gas tempering capability which is designed to increase mass flow at the furnace outlet with cooler gas from the economizer outlet. The purpose is to decrease furnace gas exit temperatures to reduce fouling. The station experience has been that it raises the gas temperatures in the rear convection passes and causes fouling in locations where no water blowing capability exists, thus causing more severe fouling problems.

Table 3.11 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
12/16	7:29	12/16	9:18	1.82	726	Electrician error & restart problems
12/17	0:03	12/17	12:58	12.92	5155	Blown control card fuse - delay due to expansion joint repair
1/05	0:03	1/07	15:25	63.37	25285	Primary superheater cleaning followed by tube leak on start up
				36.77*	14670*	Superheater cleaning
				26.60*	10615*	Tube leak
1/14	10:31	1/14	11:12	.68	271	Incorrectly operated breaker
1/20	15:44	1/22	1:04	33.33	13299	Hot reheat pluggage
2/26	23:47	2/28	15:59	40.20	16040	Hot reheat pluggage
3/13	1:05	3/28	15:19	374.23	149318	Cleaning of reheat, primary superheat, and preheater basket repairs
4/15	13:15	4/15	14:23	1.13	451	Intentional trip - boiler feed pump operating problem

- * For this study the outage of 1/05 will be considered to be an ash pluggage outage of 14,670 megawatt hours (the average fouling outage duration), and tube leak outage of 10,615 megawatt hours.

Big Stone Unit 1 had a good availability during our study of 87.92%. Ash fouling of the convection surfaces was responsible for four outages totalling 484.23 hours or an incredible 91.8% of the outage time.

It is interesting to note that the four outages occurred during a two month period. The station finally removed the unit from service for fifteen days and thoroughly cleaned the entire unit of deposits. After this cleanup, the unit ran well and had no ash related curtailments or outages through the months of April, May, and June.

Table 3.12 Curtailments (November, 1979 - April, 1980)

Date	Net Curtailment Loss Mw Hours	Reason
1/03	600	Pluggage
1/04	1010	Pluggage
1/07	1157	Pluggage
1/18	464	Induced draft fan suction
1/19	458	Induced draft fan suction
1/20	832	Induced draft fan suction
1/22	1020	Induced draft fan suction
2/17	586	HGET
2/18	864	HGET
2/19	938	HGET
2/20	1518	HGET
2/21	792	HGET
2/22	908	HGET
2/23	1868	HGET
2/24	1070	HGET
2/25	916	HGET
2/26	1090	HGET
2/28	995	HGET
3/01	194	HGET
3/02	462	HGET
3/03	678	HGET
3/04	598	HGET
3/05	550	HGET
3/06	708	HGET
3/07	1096	HGET
3/08	1166	HGET
3/09	1262	HGET
3/10	2970	HGET
3/11	3332	HGET
3/12	3844	HGET
3/13	302	HGET
3/28	1174	HGET

* HGET = High gas exit temperature

Curtailments at this station usually occur prior to outages. The unit is not generally load limited. During our study, the months of November, December, and April were free of curtailment losses. However, 5541 megawatt hours were lost in January, 11545 in February, and 18,336 in March. These losses are the megawatt hours generated by the station subtracted from the unit's capability (399 megawatt net x 24 hours).

3.3 Leland Olds

Unit 1 (199 megawatt capacity) (See page A-5 in appendix)

This unit burns North Dakota lignite from the Glenharold strip of Mercer County. The mine has no control over sodium levels; therefore the station burns sodium levels as mined. The unit has no water soot blowing capability.

Ash fouling of this unit is severe. In 1979, prior to November, two outages occurred due to fouling. None occurred in 1978; however a secondary effect of the pluggage, the erosion of convection tubing due to excessive soot blowing requirements, forced the unit off seven times out of a total of only twelve outages for a loss of 210.95 hours due to convection tube leaks. This was out of a total of 257.75 hours. So in 1978, soot blower erosion was responsible for 82% of outage time.

In 1979, prior to November 1, six convection leak outages occurred out of 19 total outages. The tube leak outages cost 172.30 hours out of a total of 1180.53 or 14.6% of the outage time.

Unit 1 is limestone injected because of study data indicating that ash deposit strength decreases with increasing percentage of calcium. Lime was injected at the rate of 600 lbs. every two hours prior to 1/10/80, then decreased to 600 lbs. every four hours.

Table 3.13 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/09	22:12	11/11	5:39	31.45	6259	Superheat fouling
11/23	19:19	11/25	1:41	30.37	6044	Furnace tube leak
1/31	7:52	2/01	22:08	38.27	7616 *	Secondary superheat tube rupture
2/16	14:55	2/18	10:25	43.50	8657 *	Reheat superheat tube leaks
3/03	23:34	3/05	3:16	27.70	5512 *	Tube leak
3/26	23:41	3/29	7:33	55.87	11118	Boiler slope leaks, turbine casing steam leak
4/26	5:40	4/26	6:20	.67	133	Reheat valve test failure

Unit 1 had a very good availability during our study period of 94.33%.

* These outages were soot blower cutting initiated.

Out of a total of eight outages, five were tube leaks, costing 38,947 megawatt hours or 86% of the outage time. One outage was due to a reheat valve test failure, costing only 145 megawatt hours, and one was due to a superheat fouling costing 6,793 megawatt hours.

Table 3.14 Curtailments (November, 1979 - April, 1980)

Date	Net Loss	Reason	Date	Net Loss	Reason	Date	Net Loss	Reason
11/01	132	Fouling	12/14	542	Fouling	1/22	616	Fouling
11/02	315	Fouling	12/15	839	Fouling	1/23	730	Fouling
11/03	309	Fouling	12/16	674	Fouling	1/24	167	Fouling
11/04	333	Fouling	12/17	410	Fouling	1/25	44	Fouling
11/05	271	Fouling	12/18	449	Clinkers	1/26	17	Fouling
11/06	497	Fouling	12/19	686	Clinkers	1/28	100	Fouling
11/07	469	Fouling	12/20	1169	Clinkers	1/29	183	Fouling
11/09	646	Fouling	12/21	944	Fouling	1/30	179	Fouling
11/11	1457	Post outage startup	12/22	514	Fouling	1/31	29	Secondary superheat tube leak outage
11/12	997	Post outage startup	12/23	440	Fouling	2/01	222	Post outage startup
11/13	515	Fouling	12/24	613	Fouling	2/02	1032	Post outage startup
11/14	437	Fouling	12/25	1549	Fouling	2/03	227	Post outage startup
11/15	262	Fouling	12/26	776	Fouling	2/04	333	Post outage startup
11/16	242	Fouling	12/27	107	Fouling	2/05	303	Post outage startup
11/17	425	Fouling	12/28	216	Fouling	2/06	335	Post outage startup
11/18	449	Fouling	12/29	266	Fouling	2/07	256	Post outage startup
11/19	438	Fouling	12/30	754	Fouling	2/08	264	Post outage startup
11/20	495	Fouling	12/31	698	Fouling	2/09	144	Post outage startup
11/21	832	Fouling	1/01	377	Fouling	2/10	443	Post outage startup
11/22	2530	Fouling	1/02	240	Fouling	2/11	699	Post outage startup
11/23	2504	Fouling	1/03	214	Fouling	2/12	368	Post outage startup
11/27	498	Fouling	1/04	87	Fouling	2/13	231	Post outage startup
11/28	383	Fouling	1/05	823	Fouling	2/14	375	Fouling
11/29	245	Fouling	1/06	1016	Fouling	2/15	444	Fouling
11/30	115	Fouling	1/07	372	Fouling	2/16	355	Reheat superheat tube leaks
12/01	1360	Fouling	1/08	72	Fouling	2/18	1113	Reheat superheat tube leaks
12/02	1359	Fouling	1/09	86	Fouling	2/19	396	Reheat superheat tube leaks
12/03	1264	Fouling	1/10	125	Fouling	2/20	103	Fouling
12/04	268	Fouling	1/11	111	Fouling	2/21	257	Fouling
12/06	201	Fouling	1/12	1629	Fouling	2/22	157	Fouling
12/07	166	Fouling	1/13	774	Fouling	2/23	117	Fouling
12/08	293	Fouling	1/14	442	Fouling	2/24	396	Fouling
12/09	915	Fouling	1/15	190	Fouling	2/25	432	Fouling
12/10	795	Fouling	1/16	252	Fouling	2/26	383	Fouling
12/11	427	Fouling	1/17	620	Fouling	2/27	345	Fouling
12/12	110	Fouling	1/18	297	Fouling	2/28	279	Fouling
12/13	249	Fouling	1/19	376	Fouling	2/29	209	Fouling
			1/20	407	Fouling	3/01	155	Fouling
			1/21	287	Fouling			

Table 3.14 (cont'd)

Date	Net Loss	Reason	Date	Net Loss	Reason
3/02	165	Fouling	4/17	595	Fouling
3/03	315	Secondary superheat tube leak	4/18	847	Fouling
3/05	978		4/19	628	Fouling
3/06	293	Fouling	4/20	480	Fouling
3/08	157	Fouling	4/21	497	Fouling
3/09	123	Fouling	4/22	252	Fouling
3/10	22	Fouling	4/23	555	Fouling
3/11	198	Fouling	4/24	897	Fouling
3/12	95	Fouling	4/25	926	Fouling
3/13	142	Fouling	4/26	1386	Fouling
3/14	281	Fouling	4/29	686	Fouling
3/15	106	Fouling			
3/16	76	Fouling			
3/17	121	Fouling			
3/18	111	Fouling			
3/19	320	Fouling			
3/20	521	Fouling			
3/21	264	Fouling			
3/22	538	Fouling			
3/23	2160	Fouling			
3/24	888	Fouling			
3/25	427	Fouling			
3/26	345	Fouling			
3/31	836	Fouling			
4/01	111	Fouling			
4/02	183	Fouling			
4/03	739	Fouling			
4/04	954	Fouling			
4/05	872	Fouling			
4/06	919	Fouling			
4/07	441	Fouling			
4/08	483	Fouling			
4/09	320	Fouling			
4/10	370	Fouling			
4/16	428	Clinker			

The curtailments for Unit 1 due to fouling usually occur during the off peak hours. The unit generally drops during the night to provide some relief from plugging conditions. At other times, the unit is load limited throughout the day because of fouling, dropping to lower loads at night. The total curtailments are as follows.

Table 3.15 Leland Olds, Unit 1 Curtailment Summary

Month	Fouling	Soot Blower Cut Tube Leaks	Clinkers
November	15,796		
December	16,749		2,304
January	10,833	29	
February	3,497	6,721	
March	8,344	1,293	
April	13,132		428
	68,351	8,043	2,732

Unit 2 (409 megawatt capacity) (See page A-6 in appendix)

This unit is equipped with water soot blowers in the convection section. Five blowers per side operate ahead of the secondary superheater and two per side operate ahead of the finishing superheater.

This unit has the most severe ash fouling problem of any unit included in this study. It is rated at 440 megawatts gross but seldom runs above 380. During this six month study the unit has been out of service five times for cleaning of the superheaters and reheaters.

In 1979, prior to November 1, the unit was removed from service seven times for deslagging for a total of 511.82 hours or 46% of the outage time. Superheat tube leaks were responsible for two outages totalling 78.92 hours or 7.6% of the total outage time.

In 1978, no outages were caused by ash fouling, and only three outages totalling 214.58 hours were caused by convection leaks.

Table 3.16 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/16	21:44	11/18	18:21	44.62	18,250	Precipitator repairs & reheat superheat deslagging
12/01	5:14	12/01	23:03	17.82	7,288	Precipitator repairs
12/21	19:28	12/24	7:55	60.45	24,724	Deslagging, precipitator repairs & reheat superheat leaks
1/13	19:24	1/13	20:54	1.5	614	High conductivity trip
1/19	18:50	1/19	19:27	.62	254	Faulty conductivity device
2/02	1:06	2/11	19:57	234.85	96,054	Superheat fouling & turning gear failure
3/07	22:28	3/09	22:03	47.58	19,460	Deslagging and precipitator repair

Table 3.16 (cont'd)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
3/10	10:36	3/10	11:15	.65	266	480 volt transformer ground fault indication Deslagging Breaker failure Scheduled overhaul
3/29	21:40	4/01	10:15	60.58	24,777	
4/05	22:00	4/06	2:38	4.63	1,894	
4/11	21:45	4/30	24:00	458.25	187.424	

Unit 2 had a rather poor availability during the study period of 78.67%. However a scheduled outage contributed 458.25 hours, and, without the inclusion of these hours, the availability was a good 87.89%. Ash fouling was responsible in part for five outages. The fouling outage times were prolonged for reasons ranging from a turning gear failure to reheat superheat leaks. Time attributed to the ash fouling is computed in the following manner:

Two outages were listed as deslagging and precipitator repairs. Both of these jobs can be worked concurrently. Since one outage for precipitator repairs only took 17.82 hours, these two outages will be attributed in full to deslagging.

Three outages then are attributed in full to deslagging, totalling 152.78 hours for an average deslagging outage time of 50.93 hours.

During one outage, tube leaks in the convection areas were repaired. Since the tube repair and deslagging cannot be worked concurrently, time to repair tube leaks will be subtracted from the beginning of these deslagging outages. The time for this outage was 60.45 hours. Since the average deslagging outage was 50.93 hours, the difference of 9.52 hours will be attributed to tube leak repairs. Based on experience with repairs of this type, this is a reasonable time for repairs.

One outage was attributed to deslagging plus subsequent turning gear failure. Since the reason for outage was initially deslagging, but the outage time was prolonged due to the turning gear failure, the average deslagging time of 50.93 hours will be attributed to ash fouling and the remainder of outage time will be attributed to the turning gear failure.

With this reasoning, the outage table for the purposes of this report will be modified as follows.

Table 3.17 Outages Modified for Ash Fouling

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/16	21:44	11/18	18:21	44.62	18,250	Deslagging Precipitator repair Convection tube leaks
12/01	5:14	12/01	23:03	17.82	7,288	
12/21	19:28	12/24	7:55	9.52	3,894	
				50.93	20,830	Deslagging
1/13	19:24	1/13	20:54	1.5	614	High conductivity trip
1/19	18:50	1/19	19:27	.62	254	Faulty conductivity device
2/02	1:06			50.93	20,830	Deslagging
		2/11	19:57	183.92	75,223	Turning gear failure

Table 3.17 (cont'd)

Time Off		Time On		Total Outage	Mw Hour	Reason for Outage
Date	Hour	Date	Hour	Time (hrs)	Load Loss	
3/07	22:28	3/09	22:03	47.58	19,460	Deslagging
3/10	10:36	3/10	11:15	.65	266	480 volt transformer ground fault indication
3/29	21:40	4/01	10:15	60.58	24,777	Deslagging
4/05	22:00	4/06	2:38	4.63	1,894	Breaker failure
4/11	21:45	4/30	24:00	458.25	187,424	Scheduled overhaul

Using the modified ash fouling table, the ash fouling problem caused four outages costing a total of 254.64 hours or 27.3% of the outage time. Convection tube leaks, a problem resulting from the excessive soot blowing requirements of ash fouling coals, cost only 9.52 hours.

Table 3.18 Curtailments (November, 1979 - April, 1980)

Date	Net Loss	Reason	Date	Net Loss	Reason	Date	Net Loss	Reason
11/01	1344	Fouling	12/16	1933	Fouling	1/30	2566	Fouling
11/02	1265	Fouling	12/17	1286	Fouling	1/31	2958	Fouling
11/03	1320	Fouling	12/18	1383	Fouling	2/01	2965	Fouling
11/04	1388	Fouling	12/19	1353	Fouling	2/02	302	Fouling
11/05	944	Fouling	12/20	1467	Fouling	2/11	1151	Fouling
11/06	794	Fouling	12/21	1846	Fouling	2/12	4917	Fouling
11/07	1015	Fouling	12/24	1886	Fouling	2/13	1785	Fouling
11/08	1178	Fouling	12/25	1550	Fouling	2/14	967	Fouling
11/09	967	Fouling	12/26	1302	Fouling	2/15	617	Fouling
11/10	1265	Fouling	12/27	1494	Fouling	2/16	782	Fouling
11/11	1235	Fouling	12/28	1321	Fouling	2/17	1260	Fouling
11/12	1476	Fouling	12/29	1369	Fouling	2/18	800	Fouling
11/13	950	Fouling	12/30	1546	Fouling	2/19	1437	Fouling
11/14	900	Fouling	12/31	1192	Fouling	2/20	947	Fouling
11/15	1134	Fouling	1/01	1509	Fouling	2/21	1074	Fouling
11/16	1616	Fouling	1/02	1226	Fouling	2/22	1023	Fouling
11/18	1645	Fouling	1/03	945	Fouling	2/23	1007	Fouling
11/19	3661	Fouling	1/04	908	Fouling	2/24	1167	Fouling
11/20	1421	Fouling	1/05	1401	Fouling	2/25	979	Fouling
11/21	1481	Fouling	1/06	1026	Fouling	2/26	1392	Fouling
11/22	792	Fouling	1/07	2380	Fouling	2/27	1261	Fouling
11/23	1445	Fouling	1/08	1959	Fouling	2/28	1231	Fouling
11/24	1261	Fouling	1/09	926	Fouling	2/29	1796	Fouling
11/25	1592	Fouling	1/10	685	Fouling	3/01	2170	Fouling
11/26	953	Fouling	1/11	778	Fouling	3/02	1811	Fouling
11/27	1041	Fouling	1/12	1067	Fouling	3/03	1986	Fouling
11/28	1301	Fouling	1/13	1709	Fouling	3/04	1682	Fouling
11/29	1326	Fouling	1/15	721	Fouling	3/05	1219	Fouling
11/30	1220	Fouling	1/16	1170	Fouling	3/06	1577	Fouling
12/03	1213	Fouling	1/17	1190	Fouling	3/07	627	Fouling
12/04	902	Fouling	1/18	1217	Fouling	3/09	505	Fouling
12/05	764	Fouling	1/19	1459	Fouling	3/10	2687	Fouling
12/06	500	Fouling	1/20	1292	Fouling	3/11	1445	Fouling
12/07	677	Fouling	1/21	1004	Fouling	3/12	1112	Fouling
12/08	654	Fouling	1/22	584	Fouling	3/13	1317	Fouling
12/09	1102	Fouling	1/23	936	Fouling	3/14	1697	Fouling
12/10	1935	Fouling	1/24	1789	Fouling	3/15	1699	Fouling
12/11	1957	Fouling	1/25	1036	Fouling	3/16	1698	Fouling
12/12	1659	Fouling	1/26	639	Fouling	3/17	1517	Fouling
12/13	2023	Fouling	1/27	873	Fouling	3/18	1964	Fouling
12/14	1505	Fouling	1/28	1351	Fouling	3/19	2066	Fouling
12/15	1630	Fouling	1/29	1858	Fouling	3/20	1778	Fouling

Table 3.18 (cont'd)

Date	Net Loss	Reason
3/21	1804	Fouling
3/22	1839	Fouling
3/23	2804	Fouling
3/24	2387	Fouling
3/25	1985	Fouling
3/26	1528	Fouling
3/27	2180	Fouling
3/28	3078	Fouling
3/29	2857	Fouling
4/01	2400	Fouling
4/02	1978	Fouling
4/03	1255	Fouling
4/04	1268	Fouling
4/05	2057	Fouling
4/06	2970	Fouling
4/07	1425	Fouling
4/08	1540	Fouling
4/09	1374	Fouling
4/10	1215	Fouling
4/11	1974	Fouling

Unit 2 is the most severely curtailed of any unit studied. The average daily load loss is 1,494 megawatt hours, or 62.25 megawatts lost capacity. This is a loss of 15.2% of the unit's net generation capability. If the deslagging outage hours are considered, the average loss is 2,068 megawatt hours, or 86 megawatts for a loss of 21.1% of the unit's net generation capability. The unit is constantly curtailed, having attained full load only one day during the study period for a full load test. The load swings due to load requirements, the station preferring to keep the gross load at about 380 megawatts, but the load demand often forces the unit over 410 megawatts. Very seldom is the night load over 370 megawatts.

3.4 Jim Bridger

Units 1 - 4: (See page A-7 in appendix)

These units burn coal mined at the station site in Sweetwater County near Rock Springs, Wyoming. The primary station curtailment problem is one of ash pluggage in the air preheater. The station feels that this is caused by large clumps of ash carrying over from the economizer hoppers. The only other cause of preheater pluggage possible is a condensation problem within the preheater. Either cause is unrelated to the ash fouling problem under investigation in this study and will not be reported.

The station has had problems with fouling in the past, but for the most part, these have been eliminated. The station had problems with the soot blowing steam supply system and the individual blowers. The station has made steam supply modifications and a concentrated effort on blower maintenance. The results below are reported as per station records. Most occurrences of furnace slagging, however, appear to be reheat fouling. Unit 4 was not started until the end of August, 1979.

Megawatt Hour Load Losses - Jim Bridger

	Unit 1		Unit 2	Unit 3
	Furnace Slagging	Reheat Pluggage	Furnace Slagging	Furnace Slagging
1978	11,468	86,985	77,103	28,818
1979 (prior to November)	2,324	93,147	9,786	1,994
Study Period (Nov '79 - Apr. '80)	0	15	6,911	1,499

Unit 1 (510 megawatt capacity)

Table 3.19 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/03	22:20	11/06	9:21	59.02	30,100	Tube leak economizer
11/09	11:53	11/09	14:49	2.93	1,494	DC power failure
11/13	1:04	11/18	19:54	138.83	70,803	Flyash silo pluggage
12/11	8:19	12/11	13:38	5.32	2,713	Power supply failure - turbine control loss causing trip
12/20	19:33	12/20	22:28	2.92	1,489	Boiler circulating pump
12/20	22:58	12/21	4:31	5.55	2,831	Electrical trouble
1/02	9:10	1/02	18:17	9.12	4,651	Manual-removal coal coal supply limited
1/06	14:36	1/06	15:21	.75	383	Manual trip - full arc switch by operator
1/08	18:53	1/10	4:53	34.00	17,340	Tube leak
1/14	2:08	1/14	2:46	.63	321	Trip - hi back pressure, # 11 circulating water pump discharge valve failed to close
1/24	13:22	1/24	16:20	2.97	1,515	Manual

Table 3.19 (cont'd)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
1/24	18:07	1/24	20:52	2.75	1,403	Manual - economizer inlet valve yoke assembly came apart
2/09	1:31	2/09	4:37	3.10	1,581	Transmission system lost Kinport & Goshen lines
2/13	20:37	2/14	6:18	9.68	4,937	Manual-repair economizer inlet valve
2/14	7:10	2/14	8:00	.83	423	Lo vacuum trip, # 11 circulating water screen collapsed
2/14	8:59	2/18	14:20	101.35	51,683	Lo vacuum trip, # 11 circulating water pump suction screen condenser pluggage
2/28	3:31	2/29	16:21	36.83	18,783	Reheat tube leak
3/08	0:54	3/11	19:38	90.73	46,272	Reheat tube leak-manual
3/13	20:06	3/14	20:49	24.72	12,607	Reheat tube leak
3/16	7:38	3/16	9:26	1.80	918	Trip
3/16	10:18	3/16	18:53	8.68	1,255	Induced draft fan silica
3/31	11:00	4/01	14:21	27.35	13,949	Waterwall tube leak
4/01	14:59	4/01	16:07	1.13	576	Flame failure
4/14	16:30	4/15	5:08	12.63	6,441	Boiler circulating pump Delta P - lost drum pressure transmitter
4/17	1:44	4/17	5:42	3.97	2,025	Lost central air compressor
4/22	0:15	4/22	12:29	12.23	6,237	Trip - transmission line load unbalance (Borah Line)
4/22	13:51	4/22	16:55	3.07	1,566	Turbine trip - auxiliary relay breakers burned up

Tube leaks were responsible for six outages costing 272.65 hours. Two startup problems cost 6.68 hours. Eight trips due to various causes cost a total of 44.00 hours. Economizer inlet valve problems cost two outages totalling 12.43 hours, flyash silo pluggage forced the unit off line for 138.83 hours. Five outages of various causes cost 25.49 hours. Circulating water problems cost 102.81 hours. Availability for the unit was 86.2%.

Table 3.20 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw Curtailed	Hours	Mw Hours	Reason
Date	Hour	Date	Hour				
12/29	16:55	12/29	17:15	50	.33	17	Economizer pluggage
3/30	0:00	3/30	24:00	230	24.00	5520	Economizer pluggage

The economizer pluggage listed will not be included in the analysis as it is not considered an ash fouling problem as studied in this report.

Unit 2 (510 megawatt capacity)

Table 3.21 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/01	5:41	11/08	14:40	176.98	90,260	Boiler feed pump valves
11/08	15:13	11/08	19:60	3.88	1,979	Lost ignition energy
11/08	22:27	11/08	23:08	.68	347	Ignitors remover prematurely
11/08	23:38	11/09	9:40	10.03	5,115	Low fuel oil supply header pressure low
11/09	11:53	11/10	8:51	20.97	10,695	Control power loss
11/16	10:43	11/16	19:04	8.35	4,259	Lo vacuum trip - lost main air compressor
11/23	5:01	11/25	8:50	51.82	26,428	Tube leak-reheater
12/05	21:39	12/08	5:21	55.70	28,407	Flame failure
12/20	21:40	12/22	15:42	42.03	21,435	Manual - waterwall tube leak
1/09	0:58	1/09	3:52	2.90	1,479	Boiler circulating pump Delta P - feeder plugged
1/10	9:20	1/10	9:49	.48	245	Trip-system fault - generator dropping scheme
1/11	7:08	1/13	5:32	46.40	23,664	Manual-tube leak - superheater tube
1/18	22:31	1/19	0:42	2.18	1,112	Back press trip - circulating water pump motor
1/29	14:52	1/31	14:47	47.92	24,439	No makeup water - manual out of condensate
2/01	11:16	2/01	12:22	1.10	561	Boiler circulating pump Delta P
2/06	12:01	2/09	2:56	62.92	32,089	Repair circulating water trash screens
2/09	11:59	2/11	2:06	38.12	19,441	Reheat-waterwall spacer tube
2/11	9:18	2/13	5:18	44.00	22,440	Reheat-waterwall spacer tube - three tubes
2/20	23:54	2/21	2:22	2.47	1,260	Lost Kingsport line - transmission system
2/21	2:24	2/21	2:57	.55	281	Flame failure low oil press to warm up guns
4/07	17:46	4/07	20:32	2.77	1,413	Flame failure - low load 2 mills - primary air fans problems
4/08	9:17	4/08	12:42	3.42	1,744	Flame failure
4/17	1:44	4/17	5:58	4.23	2,157	Lost central air compressor
4/17	6:11	4/17	7:32	1.35	689	Flame failure
4/17	7:55	4/17	9:22	1.45	740	Ignition failure
4/25	21:49			122.18	62,312	Annual overhaul - planned outage

Flame failures and startup problems accounted for nine outages totalling 79.83 hours. Tube leaks caused five outages totalling 222.37 hours. Loss of air compressors caused two outages totalling 12.58 hours. Trips due to various causes were responsible for six outages totalling 30.10 hours. Inability to isolate a boiler feed pump and need for repairs caused one 176.97 hour outage. No makeup water caused a 47.92 hour shutdown. Repair of a trash screen cost 62.92 hours. Finally, one scheduled outage cost 122.18 hours.

Availability, discounting the outage, was 85.1% and overall was 82.7%.

Table 3.22 Curtailments (November, 1979 - April, 1980)

Time Off		Time On		Mw Curtailed	Hours	Mw Hours	Reason
Date	Hour	Date	Hour				
1/05	10:20	1/05	10:40	65	.33	22	Soot blowing-slag
1/05	15:00	1/06	24:00	150	33	4950	Furnace slagging south reheat area
1/07	0:00	1/07	15:30	125	15.5	1938	Furnace slagging south reheat area

The period from 1/5 through 1/7 is the only listed curtailment due to ash or slag problems. It was initiated by a soot blowing problem and is not considered to be the type of fouling investigated in this report.

Unit 3 (510 megawatt capacity)

Table 3.23 Outages (November, 1979 - April, 1980)

Time Off		Time On ,		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/15	22:27	11/18	8:53	58.43	29,799	Tube leak-boiler
11/26	9:08	11/26	19:38	10.50	5,355	Lost ignition energy
12/04	6:34	12/04	9:55	3.35	1,709	Flame failure
12/04	9:56	12/04	10:40	.73	372	Furnace pressure - high & warmup gun trouble
12/10	1:56	12/10	11:08	9.20	4,692	Boiler feed pump Delta P
12/20	21:40	12/21	7:44	10.07	5,136	Tripped gen. - dropping scheme
12/21	8:43	12/21	17:07	8.40	4,284	Manual trip-cooling tower bypass would not close
12/22	17:08	12/22	17:31	.38	194	Furnace pressure high
1/01	8:29	1/03	13:11	52.70	26,877	Phase leads burnt at cooling tower terminal
1/03	13:25	1/03	18:51	5.43	2,769	Turbine control system line broken - manual
1/03	19:59	1/03	20:52	.88	449	Turbine trip by boiler
1/03	20:53	1/04	2:54	6.02	3,070	Flame failure
1/20	19:19	1/20	20:01	.70	357	Trip-back pressure lost two cooling tower fans

Table 3.23 (cont'd)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
1/24	13:57	1/24	15:02	1.08	551	Trip - back pressure level control gauge bad
1/24	15:19	1/24	18:04	2.75	1,403	Ignitor trouble - manual
1/29	17:19	1/30	21:17	27.97	14,265	Trip-back pressure ran out of circulating water
1/20	21:25	1/31	1:03	3.63	1,851	Flame failure
1/31	1:15	3/31	2:12	.95	485	Lost ignition energy
1/31	8:40	1/31	9:05	.42	214	Unit trip - cause unknown
2/14	2:30	2/15	9:26	30.93	15,774	Waterwall tube leak
2/23	0:49	2/25	14:44	61.92	31,579	Safety valves - leak in packing at steam drum
2/25	15:00	2/25	18:27	3.45	1,760	Warmup gun problem flame failure
2/25	18:53	2/25	19:34	.68	347	No ignition-flame failure
3/15	3:54	4/14	9:57	726.05	370,286	Planned outage - annual overhaul (4 weeks)
4/14	11:07	4/14	19:08	8.02	4,090	Test reverse power relay, antimotor protection
4/17	1:45	4/17	13:12	11.45	5,840	Lost central air compressor
4/17	14:00	4/17	16:49	2.82	1,438	Flame failure ignition problem
4/22	13:05	4/22	16:00	2.92	1,489	Boiler trip primary air duct pressure transmitter
4/22	16:00	4/25	11:48	67.80	34,578	Maintenance boiler feed pump valve remained off after trip
4/25	21:39	4/27	14:08	40.48	20,645	Boiler trip - 2200 - 480 transformers burned up

Tube leaks were responsible for two outages totalling 89.36 hours. Ten instances of startup troubles and flame failures caused ten outages totalling 34.88 hours. Cooling tower and circulating water problems caused four outages totalling 89.77 hours. Nine trips for various reasons cost 73.45 hours. Four maintenance outages cost 146.60 hours, and one planned outage cost 726.05 hours.

The availability was 88.1%, discounting the outage, and 73.4% overall.

Table 3.24 Curtailments (November, 1979 - April, 1980)

Time Off		Time On		Mw Curtailed	Hours	Mw Hours	Reason
Date	Hour	Date	Hour				
1/01	0:00	1/01	6:00	250	6	1500	Slagging

This is the only recorded instance of fouling or slagging curtailments and was an apparent load drop to shed wall slag.

Unit 4 (510 megawatt capacity)

Table 3.25 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage	Mw Hour	Reason for Outage
Date	Hour	Date	Hour	Time (hrs)	Load Loss	
11/08	14:50	11/08	15:28	.63	321	Furnace pressure low
11/08	16:22	11/08	16:47	.42	214	Flame failure
11/16	10:46	11/16	14:51	4.08	2,031	Back pressure
11/16	14:53	11/16	15:28	.58	296	345 breaker trip when released
11/22	12:47	11/24	2:16	37.48	19,115	Manual-clinker in bottom of boiler
11/30	0:33	12/03	4:29	75.93	38,724	Scheduled outage prior to performance tests
12/12	14:05	12/12	15:48	1.72	877	Boiler circulating pump Delta P low
12/20	6:57	12/20	11:26	4.48	2,285	Furnace pressure
1/14	10:49	1/14	11:49	1.00	510	Primary air duct pressure
1/18	10:09	1/18	11:24	1.25	638	Furnace pressure trip
1/18	11:41	1/18	12:19	.63	321	Lost ignition energy
1/18	12:28	1/18	19:42	7.23	3,687	Lost ignition energy
1/18	22:13	1/19	5:05	6.87	3,504	Trip-boiler circulating pump Delta P - frozen drum level sensing line
1/21	14:11	1/21	17:14	3.05	1,556	Boiler circulating pump Delta P
1/28	15:19	1/28	16:55	1.60	816	Turbine control system fluid press low
1/28	18:06	1/28	22:05	3.98	2,030	Operator trip - frozen drum level lines
1/29	9:33	1/29	12:36	3.05	1,556	Turbine control system pressure low - trip
1/29	17:37	1/30	7:53	14.27	7,278	Out of condensate - manual removal
1/30	8:10	1/30	9:07	.95	485	Flame failure-lost ignitors
1/30	15:48	1/30	16:53	1.08	551	Boiler circulating pump Delta P - lost boiler feed pump
2/03	8:14	2/03	9:22	1.13	576	Flame failure
2/10	0:11	2/10	3:58	3.78	1,928	Boiler circulating pump Delta P-fault relays tripped
2/21	0:36	2/22	24:00	47.40	24,174	Waterwall tube leak
2/22	24:00	2/29	15:29	159.48	81,335	Scrubber maintenance
3/03	11:52	3/03	20:42	8.83	4,503	Induced draft fan dampers - no control manual removal
3/12	4:02	3/13	12:47	32.75	16,703	Flame failure trip
3/14	17:38	3/14	19:00	1.37	699	Trip-loss of fuel - primary air duct pressure
4/10	4:59	4/11	3:36	22.62	11,536	Waterwall tube leak
4/15	16:52	4/15	24:00	7.13	3,636	Back pressure - low condensate storage level
4/16	0:00	4/21	21:12	141.20	72,012	Flue gas damper maintenance scheduled off before trip

Two instances of turbine control oil pressure problems cost 4.65 hours. Boiler circulating pump differential (control system) problems caused six outages totalling 20.48 hours. Waterwall tube leaks cost 70.02 hours. Startup problems, principally flame failures, caused six outages totalling 43.11 hours. Furnace pressure problems caused three outages costing 6.36 hours. Seven outages of varying causes cost 37.26 hours. Scheduled flue gas damper maintenance continued a trip outage to account for 141.20 hours. Scrubber maintenance continued a waterwall tube leak outage to account for 159.48 hours. One scheduled pre-performance test outage cost 75.93 hours. Finally, a boiler clinker cost 37.48 hours.

Without the two scheduled outages taken into consideration, the availability was 90.9% and overall was 86.4%.

Table 3.26 Curtailments (November '79 - April '80)

Begin		End		Mw		Mw	Reason
Date	Hour	Date	Hour	Curtailed	Hours	Hours	
3/11	0:00	3/11	2:15	150	2.25	338	Boiler slagging
3/11	13:00	3/11	24:00	100	11	1100	Boiler slagging, reheat plugging
3/12	0:00	3/12	4:00	120	4	480	Boiler slagging
3/18	9:14	3/18	10:40	45	1.43	65	Slagging, soot blowing
3/18	10:40	3/18	18:20	230	7.67	1763	Slagging, soot blowing

These are the only reported instances of curtailments listed. The curtailments of 3/11 and 3/12 appear to be a reheat pluggage problem listed as boiler slagging. The instance on 3/18 was listed as a soot blowing problem and will not be included in the financial analysis.

3.5 Four Corners

Coal for Four Corners is a high ash subbituminous mined at the site near Fruitland, New Mexico. Problems at Four Corners include fouling and, in particular, slagging. With regard to slagging, some load limitation is generally incurred due to high steam temperatures. The excess slag can usually be shed by an abrupt load drop. However, in the case of Units 4 and 5, the slagging problem results in clinkers which force the unit off line. These units have center walls in the furnace with no blowing capability. The slagging on the curtain wall drops to the lower slope and apparently sticks, causing clinker formation in the center of the furnace. Since these units are forced draft (positive furnace gas pressure) the observation ports on the furnace bottom are small and do not allow on line cleaning of the clinkers. The units do have a tendency to foul, but soot blower effectiveness is far greater than with the Dakota lignites. Soot blowing at the station is primarily done by air, with steam used only on Unit 4 IK soot blowers because of a lower failure rate, and occasional steam use on Unit 3 when air supply problems exist.

In 1978, slagging was responsible for megawatt hour losses of 76,540 for Unit 1: 11,741 for Unit 2: 30,946 for Unit 3: and 5,285 for Unit 4. In 1978, clinkers were responsible for megawatt hour losses of 432 for Unit 1: 755 for Unit 3: 89,514 for Unit 4: and 41,575 for Unit 5.

Prior to the study in 1979, slagging was responsible for megawatt hour losses of 2,527 for Unit 1: 10,448 for Unit 2: and 1,721 for Unit 3. Clinkers cost 2,340 megawatt hours for Unit 2: 21,402 for Unit 3: 157,596 for Unit 4: and 990 for Unit 5. Convection fouling cost 8,916 megawatt hours for Unit 1: 8,076 for Unit 2: and 15,219 for Unit 3.

Units 1 and 2 had been modified prior to this study by shielding the finishing superheater with 2/3 of the upper slope tubes.

Unit 3 was modified during the study to remove a steam cooled curtain wall and replace it with radiant panels.

Unit 1 (175 megawatt capacity) (See page A-8 in appendix)

Table 3.27 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/10	3:33	11/12	6:44	51.18	5,957	Waterwall tube leak
1/20	2:10	1/22	3:11	49.02	8,597	Screen tube leak
2/13	0:21	3/05	18:37	522.27	91,397	Minor overhaul
3/15	23:23	3/06	2:31	3.13	548	Routine turbine test

Unit 1 had an outstanding availability of 85.7% considering a scheduled outage lasting 522 hours. Discounting this outage, the availability was 97.3%. Tube leaks accounted for over 100 hours of outage time.

Table 3.28 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	
Date	Hour	Date	Hour	Curtailed	Hours	Hours	Reason
12/01	21:00	12/01	24:00	10.7	3	32	Superheat fouling
12/06	4:00	12/06	8:00	41.3	4	165	Clinker
12/07	16:00	12/07	24:00	10.6	8	85	Superheat fouling
12/10	21:00	12/10	24:00	10.7	3	32	Superheat fouling
12/12	11:00	12/14	3:00	10.6	40	500	Superheat fouling
12/16	4:00	12/19	14:00	10.6	82	872	Superheat fouling
12/25	1:00	12/25	3:00	10.5	2	21	Superheat fouling
1/01	1:00	1/01	7:00	25.3	6	152	Superheat fouling
1/02	22:00	1/03	7:00	25.2	9	227	Superheat fouling
1/09	1:00	1/09	9:00	25.3	8	202	Superheat fouling
1/12	12:00	1/15	6:00	25.3	66	1668	Superheat fouling
3/16		3/17		5.8		139	High reheat temp.
3/26	14:00	3/26	24:00	4.8	10	48	Reheat fouling

Ash fouling cost the station a total of 3,839 megawatt hours, a clinker cost 165 megawatt hours, and high reheat temperatures cost 139 megawatt hours.

Unit 2 (175 megawatt capacity) (See page A-8 in appendix)

Table 3.29 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage	Mw Hour	
Date	Hour	Date	Hour	Time (hrs)	Load Loss	Reason for Outage
11/09	0:44	11/10	14:46	38.03	6,655	Superheater tube leak
11/14	12:15	11/16	10:33	46.30	8,103	Waterwall tube leak
11/24	22:23	11/26	20:30	46.12	8,071	Waterwall tube leak
12/03	20:04	12/06	3:17	25.22	4,414	Waterwall tube leak
1/20	1:23	2/12	0:17	550.90	96,408	Minor overhaul
2/12	8:30	2/12	11:05	2.58	452	Routine turbine test
2/12	19:11	2/13	18:28	23.28	4,074	Low vacuum trip
2/13	23:02	2/14	0:04	1.70	298	Low vacuum trip
2/23	21:33	2/24	3:42	6.15	1,076	Turbine vibration trip
3/01	8:30	3/03	6:07	45.62	7,984	Reheat tube leaks
3/16	3:40	3/16	5:17	1.62	284	Low vacuum trip
4/17	11:34	4/17	12:13	.65	114	Turbine vibration false alarm
4/22	16:53	4/24	16:50	47.95	8,391	Economizer tube leak

Tube leaks cost 249.24 hours, vacuum problems cost 26.6 hours, and trips and tests cost 9.38 hours for a total forced outage time of 285.22 hours or 92.5% availability of the non-outage hours. A scheduled outage cost 550.90 hours for an overall availability of 80.9%. No ash or coal related outages occurred.

Table 3.30 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	
Date	Hour	Date	Hour	Curtailed	Hours	Hours	Reason
11/01	2:00	11/01	11:00	11.6	9	104	Superheat fouling
11/02	23:00	11/03	10:00	122.4	11	1346	Superheat fouling
11/05	8:00	11/05	15:00	122.4	7	857	Superheat fouling
11/08	17:00	11/08	24:00	122.4	7	857	Superheat fouling
12/06	16:00	12/14	7:00	34.8	183	6371	Superheat fouling
12/18	8:00	12/19	6:00	34.8	22	766	Superheat fouling
12/21	23:00	12/24	4:00	34.8	53	1845	Superheat fouling
12/27	17:00	12/30	7:00	34.8	62	2159	Superheat fouling
1/08	8:00	1/09	5:00	24.1	21	507	Superheat fouling
1/11	1:00	1/11	16:00	24.2	15	363	Superheat fouling
1/16	17:00	1/19	8:00	24.2	63	1522	Superheat fouling
2/20	24:00	2/21	1:00	15.0	1	15	Superheat fouling
3/15	1:00	3/15	5:00	14.5	4	58	Superheat fouling
3/21	15:00	3/21	23:00	19.9	8	159	Reheat fouling

Most ash fouling occurred in the superheater, costing a total of 16,770 megawatt hours; one instance occurred in the reheater costing 159 megawatt hours.

Unit 3 (225 megawatt capacity) (See page A-9 in appendix)

Table 3.31 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage	Mw Hour	
Date	Hour	Date	Hour	Time (hrs)	Load Loss	Reason for Outage
11/01	0:00	11/02	13:25	37.42	8,420	Primary superheat tube leak
11/20	1:45	11/24	23:42	117.95	26,539	Waterwall tube leak
11/25	0:00	11/25	12:08	12.13	2,729	Low boiler pressure
12/03	16:02	12/04	5:28	13.43	3,022	Low boiler pressure
12/07	20:40	12/11	12:35	87.92	19,782	Waterwall tube leak
12/23	5:08	12/24	14:29	33.35	7,504	Waterwall tube leak
12/28	22:54	12/31	7:31	56.62	12,740	Superheater ash pluggage
12/31	9:30	12/31	12:50	3.33	749	Low vacuum trip
1/03	12:31	1/06	4:42	64.18	14,441	Waterwall tube leak
1/20	2:44	1/20	9:05	6.35	1,429	Switch yard upset
2/05	13:02	2/07	12:58	47.93	10,784	Superheat ash pluggage
2/07	15:25	2/07	16:45	1.33	299	Low vacuum trip
2/08	6:07	2/08	14:18	8.18	1,841	Low throttle pressure
2/23	8:52	2/23	16:19	7.45	1,676	Low throttle pressure
3/10	0:56	3/12	6:06	53.17	11,963	Reheat tube leak
3/12	14:57	3/12	16:22	1.42	320	Low vacuum trip
3/14	10:23	3/14	11:59	1.60	360	Low boiler pressure
3/20	4:44	3/20	12:21	7.62	1,715	Low boiler pressure
3/20	13:35	3/20	18:12	4.62	1,040	Low boiler pressure
3/21	19:45	3/22	18:00	22.25	5,006	Primary air fan duct explosion
3/22	18:00	4/30	24:00	942.00	211,950	Major overhaul

A major scheduled outage cost the majority of outage time with 942.00 megawatt hours lost. Tube leaks cost 393.99 megawatt hours, and superheat ash fouling cost 104.55 hours. Other causes were responsible for 89.71 hours. The primary duct explosion was followed by an outage, which reduced the severity of the megawatt loss due to the explosion.

The availability was 82.8% discounting the scheduled outage or 65% overall.

Table 3.32 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw Curtailed	Hours	Mw Hours	Reason
Date	Hour	Date	Hour				
11/03	20:00	11/04	7:00	47.9	11	527	Superheater ash fouling
11/16	17:00	11/20	2:00	10.3	81	838	Clinkers
12/28	8:00	12/28	22:54	46.3	14.9	690	Pre-outage fouling loss
12/31	7:31	12/31	15:00	46.4	7.48	347	Post outage startup loss
1/31	7:00	1/31	10:00	85.7	3	257	Clinker
2/04	20:00	2/05	13:02	99.4	17.03	1,692	Pre-outage fouling loss
2/07	16:45	2/08	1:00	99.3	8.25	819	Post outage fouling loss

Ash fouling caused curtailments totalling 4,075 megawatt hours. Clinkers cost 1,095 megawatt hours. The ash fouling curtailments were generally limited to the time prior to and after the two fouling outages, with one eleven hour exception, when the unit got out of trouble without a shutdown.

Unit 4 (755 megawatt capacity) (See page A-10 in appendix)

Table 3.33 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/01	0:00	11/04	1:01	73.02	55,130	Clinker
11/19	12:03	11/22	15:43	75.67	57,131	Waterwall tube leak
12/01	9:29	12/06	17:16	127.78	96,474	Loss of control power trip - secondary preheater repairs
12/26	10:36	12/26	22:54	12.3	9,287	Loss of 4160 reserve trip
1/31	15:26	2/05	14:59	119.55	90,260	Clinker
2/22	12:58	2/24	2:52	37.9	28,615	Clinker
2/24	6:46	2/24	11:05	4.32	3,262	Loss of auxiliary steam
3/24	12:55	3/26	6:58	42.05	31,748	Tube leak-economizer enclosure
4/06	1:43	4/29	1:04	551.35	416,269	Minor overhaul
4/29	7:13	4/29	22:37	15.40	11,627	Repair to turbine controls
4/30	19:40	4/30	24:00	4.33	3,269	Tube leaks-secondary superheater

Clinkers caused three outages totalling 230.47 hours, tube leaks caused three outages totalling 122.05 hours, preheater repairs after a trip cost 127.78 hours, and outages of other causes cost 32.02 hours. A minor overhaul cost 551.35 hours. The availability, discounting the outage, was 86.6% and overall was 75.7%

Table 3.34 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	Reason
Date	Hour	Date	Hour	Curtailed	Hours	Hours	
11/04	1:01	11/05	24:00	285.5	46.98	13,413	Startup loss from clinker outage
1/09	7:00	1/09	15:00	288.6	8	2,309	Clinker
1/25	20:00	1/26	17:00	361.9	21	7,600	Clinker
1/31	2:00	1/31	15:26	361.8	13.43	4,859	Pre-outage loss clinker
2/05	14:59	2/07	9:00	116.6	42.02	4,900	Post outage startup loss
2/22	9:00	2/22	12:58	147.4	3.97	585	Pre-outage loss clinker
2/24	2:52	2/24	16:00	147.3	13.13	1,934	Post outage loss
2/27	18:00	2/28	8:00	116.6	14.00	1,633	Clinker
2/29	4:00	2/29	16:00	147.3	12.00	1,767	Clinker
3/01	21:00	3/03	11:00	76.5	38.00	2,908	Clinker

Clinkers caused curtailments totalling 41,908 megawatt hours. Some clinkers were formed which did not force the unit off line totalling 16,217 megawatt hours, the remaining attributed to losses prior to and on startup from an outage.

Unit 5 (755 megawatt capacity) (See page A-10 in appendix)

Table 3.35 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage	Mw Hour	Reason for Outage
Date	Hour	Date	Hour	Time (hrs)	Load Loss	
11/01	5:05	11/08	5:25	168.33	127,089	Reheat tube leak
11/08	22:55	11/10	3:40	28.75	21,706	Low main steam temp. trip
12/10	7:29	12/15	19:06	131.62	99,373	Reheat tube leak
12/26	10:36	12/28	15:02	52.43	39,585	Loss of 4160 reserve trip
2/24	6:35	2/27	5:09	70.57	53,280	Trip-turbine trip system failure
2/27	7:52	2/27	11:24	3.53	2,665	Low main steam temp. trip
3/02	22:56	3/04	7:00	32.07	24,212	Clinker
3/04	7:00	3/06	12:33	53.55	40,430	Waterwall tube leak
4/12	20:47	4/15	17:54	69.12	52,186	Clinker
4/15	21:44	4/16	3:15	5.52	4,168	Low main steam temp. trip
4/16	5:00	4/16	8:07	3.12	2,356	High main steam temp. trip
4/30	15:25	4/30	24:00	8.58	6,478	Minor overhaul

Clinkers were responsible for two outages costing 101.19 hours. Tube leaks caused two outages and extended one clinker outage for a total of 353.5 hours. Various trips cost 163.92 hours, and the beginning of an outage cost 8.58 hours.

The availability was 85.8%, discounting the outage, and 85.6% overall.

Table 3.36 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	Reason
Date	Hour	Date	Hour	Curtailed	Hours	Hours	
2/14	20:00	2/16	24:00	294.9	52	15,337	Clinkers
2/29	15:00	2/29	24:00	218.6	9	1,967	Clinkers
3/01	21:00	3/02	22:56	390.4	25.93	10,123	Loss prior to clinker outage
3/08	18:00	3/08	24:00	390.3	6	2,342	Clinkers
3/10	8:00	3/10	20:00	390.0	12	4,685	Clinkers
4/10	9:00	4/12	20:47	223.4	59.78	13,352	Loss prior to clinker outage
4/15	17:54	4/15	24:00	223.3	6.1	1,362	Startup loss after clinker
4/16	24:00	4/19	4:00	223.3	52	11,614	Clinkers
4/21	15:00	4/30	14:00	223.0	215	48,020	Clinkers

Clinkers in this unit were not a problem until February. Two outages and several severe curtailments then occurred, with a curtailment loss of 108,802 megawatt hours.

3.6 Big Brown

These units burn Texas lignite mined near the plant site in Freestone County, Texas. The most serious ash related problem in these units is boiler slagging. The boilers are the most heavily slagged viewed in this study. Although this is a serious problem, the units have not suffered extreme load loss because of it. The desuperheat sprays are usually in use because of high temperatures, but the slagging is within the unit control range.

Poor fuel quality quite often degrades the unit's performance, accounting for a 13,894 megawatt hour load loss in Unit 1 and a 9,600 megawatt hour load loss in Unit 2 during the study period.

Unit 1 (575 megawatt capacity) (See page A-11 in appendix)

Table 3.37 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/04	10:45	11/04	19:25	8.67	4,985	Operator error-tap test
11/04	19:40	11/04	22:07	2.45	1,409	Plugged gas strainer
11/04	22:35	11/05	5:20	6.75	3,881	Boiler feed pump recirculation valve
1/17	21:00	1/18	23:41	26.69	15,341	Low waterwall pressure trip
1/19	0:54	1/19	3:47	2.88	1,656	High waterwall pressure trip
1/28	5:41	1/28	16:25	10.73	6,170	AC power loss
1/28	16:52	1/28	18:48	1.93	1,110	High waterwall pressure trip
1/28	19:35	1/28	20:54	1.32	759	Low waterwall pressure trip
2/02	4:09	2/02	7:09	3.00	1,725	High waterwall pressure trip
2/02	8:17	2/02	9:15	.97	558	Boiler feed pump turbine
2/02	11:59	2/02	13:03	1.07	615	High waterwall pressure
2/02	13:42	2/02	14:35	.88	506	High waterwall pressure
2/15	23:05	3/19	23:18	792.22	455,527	Semi-annual spring overhaul
3/19	23:30	3/20	6:35	7.08	4,071	Anti-motoring pressure switch
3/20	6:52	3/20	7:05	.22	127	Anti-motoring pressure switch
3/20	7:17	3/20	10:30	3.22	1,852	Anti-motoring pressure switch
3/20	10:41	3/20	12:27	1.77	1,018	Anti-motoring pressure switch
3/20	13:47	3/20	18:40	4.88	2,806	Manual trip to locate hydrogen leak

Waterwall pressure trips accounted for seven trips costing 37.76 megawatt hours. An anti-motoring pressure switch caused four trips on startup totalling 12.29 hours. Five variously caused outages totalled 34.45 hours. One scheduled outage cost 792.22 hours.

Discounting the outage, availability was 97.64% and 79.93% overall.

Table 3.38 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	Reason
Date	Hour	Date	Hour	Curtailed	Hours	Hours	
11/07	22:35	11/08	6:15	100	7.67	767	High heat rate/ bottom ash clinkers
11/10	6:20	11/10	17:55	125	11.58	1,448	Boiler slagging, soot blowing, air compressor out of service
1/07	1:42	1/08	10:51	25	33.15	829	High heat rate/dirty boilers
4/23	1:25	4/23	5:30	40	4.08	163	Boiler slagging

The second curtailment was caused by soot blower problems and will not be financially analyzed. The other three occurrences will be treated as boiler slagging.

Unit 2 (575 megawatt capacity) (See page A-11 in appendix)

Table 3.39 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage	Mw Hour	Reason for Outage
Date	Hour	Date	Hour	Time (hrs)	Load Loss	
11/07	10:39	11/07	19:32	8.88	5,106	High furnace pressure trip
12/06	20:42	12/07	1:17	4.58	2,634	Wiped primary fan bearing unit trip
1/03	10:24	1/05	6:57	52.93	30,435	BTB valve repair
1/05	10:06	1/05	15:20	5.23	3,007	Trip-feeders
1/19	12:57	1/19	14:58	2.02	1,162	Instrument problem
1/20	11:58	1/29	19:12	223.23	128,357	Boiler feed pump-low recirculation flow/bearing vibration No. 3 turbine bearing
3/03	21:58	3/04	7:01	9.05	5,204	Manual trip-turbine control system fluid leak
3/21	18:56	3/28	4:42	153.77	88,418	Semi annual spring overhaul

The principal outages were due to a BTB (Boiler Throttle Bypass) valve repair costing 52.93 hours, a low recirculation flow, a No. 3 turbine bearing problem costing 223.23 hours, and an overhaul costing 153.77 hours. Other various causes were responsible for four outages costing 29.76 hours. Discounting the annual, availability was 92.7%, and 89.5% overall.

Table 3.40 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	Reason
Date	Hour	Date	Hour	Curtailed	Hours	Hours	
12/28	5:38	12/28	9:35	20	3.95	79	High heat rate/boiler slagging
1/17	16:40	1/18	0:01	65	7.35	478	Boiler slagging
4/21	10:30	4/25	6:30	90	92	8,280	Bridge in #3 ash hopper

All listed curtailments will be treated as slagging losses.

3.7 Monticello

The coal burned in the Monticello units is mined near the plant site in Titus County, Texas.

These three units have had the least problem with ash of any studied. Slag is minimal and fouling is unknown. The units resemble oil fired units in ash deposits.

Fuel related curtailments occur due to the design of the boiler being based on higher quality fuel than is received. Through the study, limitations occurred due to fuel quality)pulverizers at maximum capacity), induced draft fans out of capacity, or fuel delivery equipment at maximum capacity. The breakdown of megawatt hour losses was as follows:

	<u>Unit 1</u>	<u>Unit 2</u>	<u>Unit 3</u>
Fuel quality	1,799	1,272	1,103
ID fans	55	894	-
FD fans	-	-	727.5
Fuel delivery equipment at maximum capacity	133.5	5,918.5	727.5

The other significant problem was lignite feeder pluggage (due to wet coal handling problems). This pluggage accounted for 19,597 megawatt hours for Unit 1; 16,476 megawatt hours for Unit 2; and 6,036 megawatt hours for Unit 3; during the six month study.

Unit 1 (575 megawatt capacity) (See page A-11 in Appendix)

Table 3.41 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/01	0:00	11/09	21:14	213.23	122,607	Overhaul
11/10	9:01	11/10	18:53	9.87	5,675	Turbine control system fluid leak
11/21	9:20	11/21	15:04	5.73	3,295	Boiler feed pump turbine low oil pressure
11/21	15:30	11/21	15:33	.05	29	High waterwall pressure trip
11/30	13:30	11/30	16:22	2.87	1,650	Low turbine control system pressure trip
12/07	10:59	12/07	17:21	6.37	3,663	Generator connection insp.
12/25	2:47	12/25	11:54	9.12	5,244	Boiler feed pump low lube pressure
12/26	14:49	12/28	13:34	46.75	26,881	345 KV breaker
12/28	13:51	12/28	16:32	2.68	1,541	Low waterwall flow trip
2/19	7:09	2/19	20:47	13.63	7,837	Loss of AC power trip
2/19	21:03	2/20	3:31	6.47	3,720	Boiler circulating pump trip - unit trip
3/04	19:00	3/05	1:27	6.45	3,709	Low furnace pressure
4/03	6:47	4/03	14:09	7.37	4,238	Loss of vital AC trip
4/13	2:48	4/15	1:15	46.45	26,709	Waterwall and reheat tube leaks
4/15	5:45	4/15	14:05	8.33	4,792	Boiler feed pump turbine overspeed trip-unit trip

Tube leaks caused one 46.45 hour outage, one breaker failure caused a 46.75 hour outage, ten trips of various causes cost 62.70 hours, two small maintenance outages cost 16.24 hours, and a scheduled outage cost 213.23 hours.

Availability, discounting the outage, was 95.9% and overall was 91.2%.

Table 3.42 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	Reason
Date	Hour	Date	Hour	Curtailed	Hours	Hours	
2/01	11:55	2/01	12:20	140	.42	58	Clinker in bottom ash hopper
4/05	13:25	4/05	13:45	80	.33	27	Load reduction to inspect ash hopper for clinkers

These two instances of clinkers were of such short duration that they will be considered to be related to grinding equipment problems rather than actual clinkers due to slagging, and they will not be included in the financial analysis.

Unit 2 (575 megawatt capacity) (See page A-11 in appendix)

Table 3.43 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage	Mw Hour	Reason for Outage
Date	Hour	Date	Hour	Time (hrs)	Load Loss	
11/24	23:11	1/07	18:40	1051.49	604,607	Planned outage
1/07	18:41	1/08	6:52	12.18	7,004	Main transformer relay trip
1/08	16:34	1/10	1:20	32.77	18,843	345 KV disconnect repairs
1/15	22:48	1/16	2:35	3.78	2,174	Loss of vital AC trip
1/16	4:03	1/16	4:13	.17	98	Turbine vibrations
1/16	17:48	1/19	22:29	76.68	44,091	Turbine vibrations
1/31	23:43	2/01	2:15	2.53	1,455	High waterwall temperature trip
2/01	3:20	2/01	5:13	1.88	1,081	High waterwall temp. trip
2/04	1:10	2/04	3:32	2.37	1,363	Loss of vital AC trip
2/16	11:03	2/17	17:58	30.92	17,779	Low primary air duct pressure
3/01	22:55	3/02	2:23	3.47	1,995	Trip-frozen waterwall pressure transmitter
3/02	4:06	3/02	23:18	19.2	11,040	Trip - frozen waterwall pressure transmitter
4/03	0:47	4/04	3:19	26.53	15,255	High generator stator differential temperature
4/28	8:05	4/30	24:00	63.92	36,754	Planned outage

Generator stator differential temperature problems cost 26.53 hours. Repairs to a 345 KV disconnect cost 32.77 hours, primary air problems cost 30.92 hours, seven various trips cost 45.41 hours, turbine vibration problems caused two outages totalling 76.85 hours and two scheduled outages cost 1115.41 hours.

Availability, discounting the outages, was 93.5%, and 69.6% overall.

Curtailments (November, 1979 - April, 1980)

No ash fouling or slagging curtailments were noted.

Unit 3 (790 megawatt capacity) (See page A-12 in appendix)

Table 3.44 Outages (November, 1979 - April, 1980)

Time Off		Time On		Total Outage Time (hrs)	Mw Hour Load Loss	Reason for Outage
Date	Hour	Date	Hour			
11/11	6:10	11/30	5:41	455.52	359,861	Overhaul
11/30	5:44	11/30	19:40	13.93	11,005	Low turbine control fluid pressure trip
12/02	9:13	12/04	3:13	42.00	33,180	Thrust bearing wear trip
12/04	7:07	12/04	19:41	12.57	9,930	Fuel run back trip
12/05	2:15	12/05	21:10	18.92	14,947	Boiler feed pump trip - unit trip
12/14	22:54	12/16	22:39	47.75	37,723	Boiler feed pump discharge valve repair
12/24	7:27	12/27	16:41	81.23	64,172	Primary air fan failure
1/11	1:00	1/12	7:25	30.42	24,032	Loss of control power
1/25	23:35	2/03	22:16	214.68	169,597	Boiler feed pump discharge valve
2/09	6:25	2/10	0:41	18.27	14,433	Boiler feed pump turbine trip - unit trip
2/10	18:42	2/12	7:25	36.72	29,009	Boiler feed pump turbine trip - unit trip
2/12	21:14	2/13	2:06	4.87	3,847	Primary fan vibration - unit trip
2/17	8:20	2/17	13:13	4.88	3,855	Primary air fan surge approach trip - unit trip
2/18	3:34	2/19	3:01	23.45	18,526	Safety would not reseal - unit taken off
2/27	4:11	3/01	3:47	71.60	56,564	Primary air heater pin rack repairs
3/02	3:03	3/02	15:13	13.17	10,404	Flame out trip
3/14	6:23	3/17	23:35	89.2	70,468	Trip - cause unknown
3/29	6:20	4/27	12:43	702.38	554,880	Major overhaul

Two boiler feed pump discharge valve repairs cost 262.43 hours, a primary air fan failure cost 81.23 hours, air heater repairs cost 71.60 hours, safety valve repairs cost 23.45 hours, eleven various trips cost 284.95 hours, and two scheduled outages cost 1157.9 hours.

Discounting the scheduled outages, availability was 77.5% and 56.9% overall.

Table 3.45 Curtailments (November, 1979 - April, 1980)

Begin		End		Mw		Mw	
Date	Hour	Date	Hour	Curtailed	Hours	Hours	Reason
1/10	14:30	1/10	16:00	20	1.5	30	High reheat temp.
3/03	9:45	3/03	12:15	20	2.5	50	High reheat temp.

These two outages will be attributed to excess slagging, as high steam temperatures are most often caused by wall slagging.

4.0 Financial Loss

Financial analysis for a utility system is a difficult task.. Curtailment or outage costs are contingent upon many factors, some of which are; season of the year, time of day, cost of the unit curtailed, the generation make up of the system, and the philosophy concerning reserve.

The methodology used to arrive at costs for generation lost in this study is an averaging technique based on 1979 statistics. This methodology is used in most cases, with the Basin Electric Power cooperative the only exception. The technique applies only to system megawatt load and ignores system reserve. System reserve is a variant that depends upon philosophy, cooperative arrangements, sharing agreements, etc., and will be neglected in this study.

A precise cost analysis would have required extensive daily load data from the power supply departments of each of the sixteen utilities, a data gathering task with a very high cost-benefit ratio in our opinion.

The methodology was basically as follows: The 1979 generation statistics were tabulated on a monthly basis; both the monthly peak and the output were tabulated for each month of the year. Because of a generally low load growth throughout the country (as demonstrated by the St. Clair statistics), the 1979 data was applied to 1980 without any changes. The monthly peaks, compared to the system yearly peak, was used as a criterion of generation available for scheduled maintenance. Throughout this study, the assumption is made that 10% of the system generation is lost to unscheduled outage. The expression 20%, 25%, etc. in the cost tabulation simply means that this percent of the generation, related to the yearly peak load, is out for scheduled and unscheduled maintenance

A very simple averaging approach was used to establish the system load for each day in the year. The monthly megawatt output was divided by the number of days in the month to establish daily megawatt production. The daily production was subdivided to express "day load" and "night load"; day load is the period from 6:00 AM to 10:00 PM and night load is the period 10:00 PM to 6:00 AM.. It is impossible to use the same percentage criteria for all of the utilities involved due to the difference in geographic location and the nature of the respective loads; however, a night load of 65% of day load, and a weekend load of 70% of weekday load served as a base for adjustment. With the above calculations completed for each month of the year, an average was assigned to weekday load, week night load, weekend day load, and weekend night load for each month. This approach enables the actual cost of an outage or curtailment to be established within reason.

The system costs and capabilities table was developed for each utility in terms of ascending costs; generation was added to system capability in relation to cost of generation per megawatt hour. A reference to the table (4.3) of average daily load and table (4.5) of unit costs and capabilities enables one to reasonably assign an economic penalty to an ash related outage or curtailment. For example, assume a weekday curtailment of 100 Mw at St. Clair Station of the Detroit system in the month of February. The average daily load in this month is 6100 Mw. A loss of 100 Mw at a cost of \$16.21 per Mwh would necessitate generating the curtailment with Conners Creek steam at a cost of \$30.96 per Mwh.. The information is obtained from the 20% section since this reflects generation out for scheduled and unscheduled maintenance. Should the outage extend to the "night" section of generation, the average load of 3965 Mw would require additional generation at Trenton Channel and River Rouge, with respective costs of \$20.85 and \$22.25.

It is recognized that the needs for reserve will have an influence on cost which is not computed in our analysis. To have included reserve would have necessitated the knowledge of corporate reserve policies, reserve agreements with neighboring utilities, and would have complicated the analysis considerably. For example, the need for reserve would necessitate the running of a high cost unit at minimum load and backing lower cost units down to make up the difference. This would necessitate the inclusion of a minimum load table of each unit to be used in conjunction with the cost and capability table. It is our opinion that the accuracy of inclusion of reserve costs does not warrant the effort.

The methods applied here are certainly not ideal, but extended over the entire study period of six months, the summation of results reflects a reasonably accurate assessment of the total economic penalty.

4.1 St. Clair

Detroit Edison

The following 1978 and 1979 statistics are presented as the basis of our financial analysis.

Table 4.1 Detroit Edison Peak Demand Statistics

Month	Monthly Peak (megawatts)		% of High Peak		% of Change 1978 - 1979
	1978	1979	1978	1979	
January	6157	6247	84.2	91.5	1.5
February	6019	6081	82.3	89.0	1.0
March	5490	5859	75.1	85.8	6.7
April	5513	5617	75.4	82.3	1.9
May	6487	6386	88.7	93.5	-1.6
June	6781	6532	92.7	95.7	-3.7
July	7120	6724	97.4	98.5	-5.6
August	6785	6829	92.8	100.0	.6
September	7312	6436	100.0	94.2	-12.0
October	5595	5441	76.5	79.7	-2.8
November	6003	5742	82.1	84.1	-4.3
December	6138	5792	83.9	84.8	-5.6
Overall Average					-2.0

Table 4.2 Detroit Edison Output Statistics

Month	Monthly Output Megawatt Hours		% of High		% of Change 1978 - 1979
	1978	1979	1978	1979	
January	3,454,918	3,662,944.3	95.6	100.0	6.0
February	3,099,357.2	3,310,817.4	85.8	90.4	6.8
March	3,289,243.2	3,453,672.3	91.0	94.3	5.0
April	3,075,544.9	3,126,903.1	85.1	85.4	1.7
May	3,210,721.7	3,296,242.8	88.8	90.0	2.7
June	3,315,460.6	3,397,637	91.7	92.8	2.5
July	3,455,387.8	3,458,327	95.6	94.4	0.1
August	3,613,792.4	3,400,053.2	100.0	92.8	-5.9
Sept.	3,408,088.9	3,067,205.8	94.3	83.7	-10.0
October	3,325,020.6	3,211,606.5	92.0	87.7	-3.4
November	3,291,424.6	3,103,108	91.1	84.7	-5.7
December	3,391,252.6	3,103,983.2	93.8	84.7	-8.5
Overall					-0.7%

Assumptions based on this data and on general electrical consumption are as follows:

1. The overall electrical consumption both in output and peak have not changed significantly. Because of this, the January through April data of 1979 will be applied for the 1980 period under study.
2. The generation assumed to be out of service for scheduled repairs will be 10% in November, December, January, and February, 15% in March, and 20% in April.
3. The generation assumed to be out of service for unscheduled repairs will be 10% during the entire study.
4. Both of the percentages assumed to be out of service will be equally applied to all units.
5. The average weekend load will be 70% of the weekday load.
6. The daily loads will be assumed to be as follows:
 - a. Sixteen hours (6:00 AM - 10:00 PM) will be considered to be the day load.
 - b. Eight hours (10:00 PM - 6:00 AM) will be considered to be off hours at 65% of the base daily load.

The following equations will be used to derive Table 4.3, Detroit Edison average daily load statistics:

$$\text{Average Weekly Load} = \frac{\text{Monthly Total (7 days/week)}}{\text{Number of days in the month}}$$

$$\text{Average Weekly Load} = 5y + 2(.7y) = 6.4y$$

where y = average weekday load, .7y = average weekend load

$$\text{Average Weekday/weekend load} = 16x + 8(.65x) = 21.2x$$

where x = day load, .65x = night load

Table 4.3 Detroit Edison Average Daily Load

Month	Weekday Day Load	Weekday Night Load	Weekend Day Load	Weekend Night Load
November	5337	3469	3736	2428
December	5166	3358	3616	2350
January	6096	3962	4267	2774
February	6100	3965	4270	2776
March	5748	3736	4023	2615
April	5377	3495	3764	2447

The Detroit Edison system has a pumped storage unit capable of 917.3 megawatts. This unit is used to supply power by using low cost night generation for pumping to a storage reservoir for daytime peak use. This pumped storage unit will be applied to the peaks as follows:

- a. The unit will be derated by 20% in November, December, January, and February, 25% in March, and 30% in April.
- b. The unit will be assumed to run for a total of sixteen hours during the day load periods for output and eight hours during the night load periods for input.
- c. The unit takes 1.393 megawatts of pumping power for each megawatt generated. (71.8% efficient).

For the eight hour pumping period the total capacity would be:

$$917.3 \text{ megawatts (8 hours)} = 7338.4 \text{ megawatt hours.}$$

Only 71.8% is available for production during the 16 hour day load:

$$7338.4 \text{ megawatt hours } 71.8\%/16 \text{ hours} = 329 \text{ megawatts during the 16 hour day load}$$

$$\text{At 20\% reduction, night load required is } 917.3 - 20\% = 734 \text{ megawatts; day load is } 329 - 20\% = 263 \text{ megawatts}$$

$$\text{At 25\%, night load} = 688; \text{ day load} = 247$$

$$\text{At 30\%, night load} = 642; \text{ day load} = 230$$

Using these figures to adjust the generation required yields Table 4.4, the loads adjusted for the pumped storage capability.

Table 4.4 Detroit Edison Daily Average Loads Modified for Pumped Storage

Month	Weekday Day Load	Weekday Night Load	Weekend Day Load	Weekend Night Load
November	5008	4203	3407	3162
December	4837	4092	3287	3084
January	5767	4696	3938	3508
February	5771	4699	3941	3510
March	5501	4424	3776	3303
April	5147	4137	3534	3089

The Detroit Edison system is comprised of six major fossil fired plants and one major pumped storage plant. The total system is comprised of generation as follows:

- Coal fired steam turbine - 10 units
- Oil fired steam turbine - 4 units
- Coal and oil fired steam turbine - 10 units
- Oil and gas fired steam turbines - 8 units
- Coal and gas fired steam turbines - 3 units
- Coal, oil, and gas fired steam turbines - 10 units
- Pumped storage - 6 units
- Oil fired combustion turbines - 3 units
- Gas fired combustion turbines - 4 units
- Oil and gas fired combustion turbines - 1 unit
- Oil fired diesel generators - 14 units

These units are installed at twenty-two different power plants.

In Table 4.5 the power plants are listed with total capacity and production expense figures for 1979. Also included is the average cost of purchased power, broken down by utility. The amount of purchased power will be averaged on a yearly basis. This table is the basis for the economic evaluation.

The cost of St. Clair generation, to be included in the table, as reported in 1979 was as follows:

- Coal cost - \$1.243/mbtu
- # 6 oil cost - \$2.870/mbtu
- Heat rate - \$10.589/mbtu

$$\text{Coal cost} - \$1.243/\text{mbtu} \left(10.589 \frac{\text{mbtu}}{\text{Mwh}} \right) = \$13.16/\text{Mwh}$$

$$\# 6 \text{ oil cost} - \$2.870/\text{mbtu} \left(10.589 \frac{\text{mbtu}}{\text{Mwh}} \right) = \$30.39/\text{Mwh}$$

Operation and maintenance cost - \$3.05/Mwh

Coal generation cost - $13.16 + 3.05 = 16.21$

Oil generation cost - $30.39 + 3.05 = 33.44$

Capacities are:

	Coal	Oil
Units 1,3	135	28
Units 2, 4	135	27
Unit 5	-	315
Unit 6	260	-
Unit 7	<u>415</u>	<u>-</u>
Totals	1215	425

Table 4.5 Detroit Edison Unit Costs and Capabilities (1979)

Source	Megawatt	\$/Mw Hour	Total Load Capability		
			@20%	@25%	@30%
St. Clair Coal (S)	1215	16.21	972	911	851
Monroe (S)	3000	16.39	3372	3161	2951
Harbor Beach (S)	110	20.36	3460	3244	3028
Trenton Channel (S)	668	20.85	3994	3745	3495
River Rouge (S)	776	22.25	4615	4327	4038
Indiana & Michigan Electric Co. (P)	262.5	23.39	4825	4524	4222
Ludington Operations (P)	782	24.92	5451	5110	4769
Ontario Hydro (P)	505	25.53	5855	5489	5123
Wyandotte City (P)	1.9	25.98	5856	5490	5124
Marysville (S)	146	27.19	5973	5600	5226
Connors Creek (S)	395	30.96	6289	5896	5503
St. Clair Oil (S)	425	33.44	6629	6215	5800
Greenwood (S)	725	37.29	7209	6759	6308
Hancock (CT)	194	42.80	7364	6904	6444
St. Clair (CT)	23	43.74	7383	6921	6460
Northeast (CT)	154	45.16	7506	7037	6568
Delray (S)	235	49.11	7694	7213	6732
Putnam	14	49.81	7705	7224	6742
Dayton (D)	10	50.74	7713	7231	6749
Consumers Power Co. (P)	14.8	50.96	7725	7242	6759
Monroe (D)	14	52.15	7736	7253	6769
River Rouge (D)	11	52.34	7745	7261	6777
Colfax (D)	14	54.27	7756	7271	6787
Slocum (D)	14	55.43	7767	7282	6796
Pennsalt (S)	14	56.09	7779	7292	6806
Enrico Fermi (T)	79	61.65	7842	7352	6862
Superior (CT)	80	70.12	7906	7412	6912
Toledo Edison (P)	3.7	77.80	7909	7414	6920
Wilmot (D)	14	129.3	7920	7425	6930
Oliver (D)	14	132.99	7931	7435	6940
Placid (D)	28	138.33	7953	7456	6959

S - Steam Plant (Detroit Edison Owned)

CT - Combustion Turbine (Detroit Edison Owned)

D - Diesel (Detroit Edison Owned)

P - Purchased Power from outside sources.

Note: Other sources of interchanged power are outputs, included in the monthly load figures.

For an example of the derivation of Table 4.6, select the first incident in the table. 3/15 was a Saturday, the outage started about 22:00, the night weekend load. It lasted for 33.37 hours broken down as follows:

	Saturday	Sunday	Monday	Total
Day load weekday			1.5	1.5
Night load weekday			6	6
Day load weekend	.17	16		16.17
Night load weekend	2	8		10

The severity was 25 megawatts. Therefore the load required was:
(Table 4.4)

	5501 + 25 = 5526	Day load weekday
March load	4424 + 25 = 4449	Night load weekday
	3776 + 25 = 3801	Day load weekend
	3303 + 25 = 3328	Night load weekend

This would be the system load required if St. Clair was down 25 megawatts in load.

The 5526 megawatt load level in Table 4.5 for the March (25%) level is at the Marysville cost level of \$27.19/Mwh; the 4449 represents Indiana & Michigan cost levels of \$23.39/Mwh; the 3801 represents River Rouge at \$22.25/Mwh; and the 3328 represents Trenton Channel at \$20.85/Mwh cost.

Costs are calculated as follows:

1.5 hours	X (27.19 - 16.21 \$/Mwh)	X 25 megawatts	= 412
6 hours	X (23.39 - 16.21 \$/Mwh)	X 25 megawatts	= 1077
16.17 hours	X (22.25 - 16.21 \$/Mwh)	X 25 megawatts	= 2442
10 hours	X (20.85 - 16.21 \$/Mwh)	X 25 megawatts	= 1160
Total cost			\$5091

Table 4.6 Ash Related Costs St. Clair Station

Unit	Starting Time		Reason	Cost
	Date	Hour		
3	3/15	21:50	High superheat temp	\$ 5,091
6	12/27	1:32	Reheater fouling	142,082
6	11/06	5:45	Reheater fouling	1,012
6	12/02	22:01	Reheater fouling	18,422
6	12/05	11:36	Reheater fouling	5,090
6	12/06	9:33	Reheater fouling	21,969
6	12/10	7:31	Reheater fouling	519
6	12/10	10:31	Reheater fouling	78,377
6	1/22	19:30	High superheat temp	6,573
6	3/08	2:10	High superheat temp	451
7	11/06	0:31	High superheat temp	16,331
7	11/07	6:31	High superheat temp	12,862
7	11/08	5:31	High superheat temp	18,869
7	11/12	8:00	High superheat temp	8,711
7	11/13	0:01	High superheat temp	15,947
7	11/18	10:11	High superheat temp	8,820
7	11/19	18:41	High superheat temp	2,265
7	11/19	23:11	High superheat temp	20,313
7	11/22	10:01	High superheat temp	7,576
7	11/23	0:02	High superheat temp	2,375
7	11/24	18:30	High superheat temp	329

Table 4.6 (cont'd.)

Unit	Starting Time		Reason	Cost
	Date	Hour		
7	11/24	10:30	High superheat temp	30,007
7	11/27	20:46	High superheat temp	43,938
7	12/01	0:01	High superheat temp	37
7	12/02	11:31	High superheat temp	2,309
7	12/03	12:00	High superheat temp	4,496
7	12/04	0:08	High superheat temp	7,273
7	12/07	5:18	High superheat temp	10,355
7	12/11	9:00	High superheat temp	11,918
7	1/21	0:01	High superheat temp	34,186
7	1/27	11:05	High superheat temp	5,697
7	1/28	11:07	High superheat temp	9,418
7	2/01	0:03	High superheat temp	113
7	2/05	19:00	High superheat temp	1,477
7	2/14	15:01	High superheat temp	23,913
7	2/17	8:05	High superheat temp	8,415
7	2/18	6:15	High superheat temp	4,946
7	2/18	13:01	High superheat temp	814
7	2/18	14:01	High superheat temp	12,730
7	3/08	2:10	High superheat temp	451
7	3/20	5:30	High superheat temp	2,009
7	3/20	9:01	High superheat temp	23,770
7	3/21	6:00	High superheat temp	34,553
7	3/23	8:01	High superheat temp	17,844
7	3/24	5:01	High superheat temp	1,219
7	3/24	6:31	High superheat temp	23,910
7	3/25	9:20	High superheat temp	1,739
7	4/17	7:30	High superheat temp	6,656
7	4/18	7:30	High superheat temp	10,668
7	4/30	6:01	High superheat temp	9,322

No load limitation due to fouling or pluggage was recorded by the station for Unit 7. The curtailments relating to ash problems were high steam temperatures, due in part to the furnace volume and in part to slagging. Slagging is a problem in this unit as evidenced by the installation of water soot blowers in the combustion zone area.

Load losses due to steam temperatures were 26,256 Mwh in November, 5,274 Mwh in December, 7,905 Mwh in January, 6,514 Mwh in February, 11,472 Mwh in March, and 2,476 in April, for a total of 59,897 Mwh.

The breakdown of losses is as follows:

Reheater fouling - \$267,471
 High superheat temperatures - \$470,696

Units 1 - 4 at St. Clair have additional load capacity due to oil firing capabilities. Oil is fired for three reasons:

1. Load requirements
2. Mill problems plus load requirement
3. Convection pass pluggage

The best estimate arrived at by station personnel for oil use due to ash fouling problems is 25% of the total oil used. Using this consumption, and 1979 cost statistics, the cost of supplemental oil firing caused by ash fouling is:

Unit 1

3,374,653 gallons (149,557 BTU/gallon) = 504,703 MBTU

504,703 MBTU (2.870 \$/MBTU oil cost - 1.243 \$/MBTU coal cost) = \$821,152

For the 25% ash fouling; \$821,152 (25%) = \$205,288

Unit 2

No oil consumption utilized.

Unit 3

2,014,650 gallons (149,557 BTU/gallon) = 301,305 MBTU

301,305 MBTU (2.870 \$/MBTU - 1.243 \$/MBTU) = \$490,223 X 25% = \$122,556

Unit 4

4,070,502 gallons (149,557 BTU/gallon) = 608,772 MBTU

608,772 MBTU (2.870 \$/MBTU - 1.243 \$/MBTU) = \$990,472 x 25% = \$247,618

Another factor which costs St. Clair a sizable sum is the derating of the units while burning the low heating value Western coal. The boilers were not designed for this low heating value fuel and the furnace volumes are too small.

Limiting factors for coal operation are mill capabilities for all the units. If more mill capacity were added, the problems would become either superheat temperatures or ash fouling, as both are now marginal problems. It is impossible to put a dollar amount on ash fouling vs. the high superheat temperatures, but it is a factor which should be noted.

Table 4.7 St. Clair Capacity Loss due to Low Rank Coal Firing

Deratings	Unit 1, 4	163-135 =	28
	Unit 2, 3	162-135 =	27
	Unit 6	315-260 =	55
	Unit 7	500-415 =	85
Total			250 Mw

Applying a total reduction of 250 megawatts to the load requirements in Table 4.4, the monthly replacement cost levels are listed in Table 4.8.

Table 4.8 Replacement Cost/Mhr of St. Clair Lost Capacity

	Weekday		Weekend	
	Day load	Night load	Day load	Night load
November:				
Load	5258	4453	3657	3412
Replacement cost diff.	8.71	6.04	4.64	4.15
December:				
Load	5087	4342	3537	3334
Replacement cost diff.	8.71	6.04	4.64	.18
January:				
Load	6017	4946	4188	3758
Replacement cost diff.	14.75	8.71	6.04	4.64
February:				
Load	6021	4949	4191	3760
Replacement cost diff.	14.75	8.71	6.04	4.64
March:				
Load	5751	4674	4026	3553
Replacement cost diff.	14.75	8.71	6.04	4.64
April:				
Load	5397	4387	3784	3339
Replacement cost diff.	14.75	8.71	6.04	4.64

To calculate the cost, the megawatt loss is multiplied by the number of hours in the month at a particular load multiplied by the cost at that load.

For example:

November peak weekday load -

250 megawatts lost (30 days) $\left(\frac{5 \text{ weekdays}}{7 \text{ days}}\right)$ (16 hours per weekday) (8.71/Mwh)=\$941,143

Using this logic, Table 4.9 was developed.

Table 4.9 Dollar Losses of St. Clair Lost Capacity

	November	December	January	February	March	April
Weekday						
Day Load	746,571	771,457	1,306,429	1,180,000	1,306,429	1,264,286
Weekday						
Night Load	258,857	267,486	385,729	348,400	385,729	373,286
Weekend						
Day Load	159,086	164,389	213,989	193,280	213,989	207,086
Weekend						
Night Load	71,143	3,189	82,194	74,240	82,194	79,543
	1,235,657	1,206,521	1,988,341	1,795,920	1,988,341	1,924,201

Total cost of replacement power because of unit derating was \$10,138,981 for the six month period.

Financial Summary

Financial losses for the St. Clair station are summarized as follows.

Table 4.10 St. Clair - Detroit Edison
 Summary of Ash Related Fouling Losses

Unit	High Steam Temperature	Ash Fouling	Oil Firing Caused by Ash Fouling
1	-	-	205,288
2	-	-	-
3	5,091	-	122,556
4	-	-	247,618
6	7,024	267,471	-
7	458,581	-	-
Totals	470,696	267,471	575,462
Station loss due to derating because of low rank coal firing - \$10,138,981			

4.2 Big Stone

The Big Stone Station is owned in part by three companies. Otter Tail Power Co. operates the plant and has 47.5% ownership. Northwestern Public Service Co. owns 32.5% and Montana-Dakota Utilities owns 20%.

To provide an accurate economic assessment, the financial losses will be computed for each of the different utilities.

Otter Tail Power Co.

The 1979 statistics will be used as a basis of the study as was done for the Detroit Edison Financial Analysis. The Otter Tail system loads for 1979 are summarized in Table 4.11.

Table 4.11 Otter Tail Demand Statistics (1979)

Month	Peak(Mw)	% of High Peak	Output (Mw, Hr)	% of High Demand
January	450.319	100	333,213	100
February	446.028	99	314,553	94
March	381.516	85	240,734	72
April	376.215	84	263,268	79
May	316.881	70	243,131	73
June	307.852	68	248,815	75
July	328.207	73	257,131	77
August	286.652	64	312,653	94
September	272.159	60	218,678	66
October	322.399	72	287,840	86
November	396.123	88	289,408	87
December	427.557	95	332,554	100

The reported peaks are low for this utility, presumably because purchased power was not included.

The assumption for the derivation of Table 4.12 Otter Tail Average Daily Load Statistics are as follows:

1. 1980 loads are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of December, January, and February is 0%; in November, March and April is 10%.
3. The generation assumed to be out of service for unscheduled maintenance will be assumed to be 10%.
4. Both out of service percentages will be applied to all units.
5. The average weekend load will be 70% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6 AM to 10 PM) will be the day load.
 - b. Eight hours (10 PM to 6 AM) will be the night load at 65% of the day load.

The equations used for derivation of Table 4.12 are:

$$\text{Average weekly load} = \frac{\text{Monthly Megawatt Hours} \times 7 \text{ day week}}{\text{No. of days in month}}$$

$$\text{Average weekly load} = 5y + 2(.7y) = 6.4y$$

where y = average weekday load

.7 y = average weekend load

$$\text{Average weekday/weekend load} = 16x + 8(.65)x = 21.2x$$

where x = average day load

.65 x = average night load

Table 4.12 Otter Tail Daily Average Load Statistics

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	498	324	348	228
December	553	360	387	252
January	555	360	388	252
February	580	377	406	264
March	401	260	280	182
April	453	294	317	206

The Otter Tail system is comprised of five steam units, twenty-two diesel units, eight hydro units, three combustion turbines, and two gasoline engines. All steam units are coal fired and all combustion turbines are diesel fuel fired. The megawatt capabilities of the generation is as follows:

Steam - 339 megawatts

Diesel & Gasoline Engine - 19.2 megawatts

Combustion Turbine - 72.3 megawatts

Hydro - 4.19 megawatts

This utility purchases about 35% of its power from fifteen different sources, in different categories.

These categories will be averaged for the financial analysis as follows:

Scheduled outages purchased power - as needed @ 14.19 \$/Mwh

Economy & operational control power - 81 Mw @ 13.79 \$/Mwh

Emergency power purchased was insignificant

Table 4.13 represents the cost of power for the utility, including the purchases. The cost of scheduled outage power will be excluded from the table and applied only during the outages.

Table 4.13 Otter Tail Unit Costs and Capabilities

Source	Megawatt Capacity	\$/Mwh	Total Capability	
			@10%	@20%
Hydro Power	4.19	4.35	3.8	3.4
Big Stone (S)	197	9.99	181	161
Hoot Lake (S)	148	13.71	314	279
Economy Purchase	81	13.79	387	344
Scheduled Outage	-	14.19	-	-
Ortonville (S)	15	17.29	401	356
Jamestown 1 (CT)	29.4	54.01	427	380
Jamestown 2 (CT)	29.4	56.05	454	403
Lake Preston (CT)	29.4	57.89	480	427
Diesel & Gasoline	19.2	605.18	497	442

The following example is used to show how Table 4.14 was developed for outages.

On 1/5 at about 0:00 hours, the unit came off for ash fouling for 36.77 hours, the hourly breakdown was as follows:

All were weekend hours, with 14 night hours and 22.77 day hours.

Because this is an outage, it is assumed that power costs are contracted at costs of 14.19 \$/Mwh for loads above 368 Mw during January. The lowest load, the weekend night load, is 252 Mw, with the lost capacity of Big Stone, the generation required is 452, in excess of the 368 Mw.

Therefore, the cost is:

$$36.77 \text{ hours } (14.19 \text{ $/Mwh} - 9.99 \text{ $/Mwh}) (197 \text{ Mw}) = \$30,423$$

For curtailments, the loss was assumed to have occurred evenly over the 24 hour period. This is a reasonable assumption at Big Stone, as the unit is usually derated a certain Mw load when plugging occurs, and run at that load continually. The curtailment loss in Table 3.12 was actual operating data subtracted from the megawatt hour generation figures.

As an example of cost calculation, the loss of 1/3 is used:

$$600 \text{ Mwh/24 hours } (47.5\% \text{ ownership}) = 11.9 \text{ Mw}$$

The January load levels are:

$$\text{Day } 555 + 12 = 567 \text{ Mw}$$

$$\text{Night } 360 + 12 = 372 \text{ Mw}$$

This utility is difficult to analyze as the purchases are cheaper than their gas turbine power, and are such a high percentage of total power. If purchases were available at any time, the gas turbines would never be run. This is not true; however, Jamestown 1 ran .75 hours per day average, Jamestown 2 ran 0.48 hours per day, and Lake Preston ran 0.54 hours per day. This is a great deal of operating hours considering that these units should run only during the system peaks when cheaper outside power cannot be purchased.

In order to present a fair evaluation of replacement power costs, considering that this period of study occurred during the system peak, it will be assumed that power requirements in excess of system capability at the Lake Preston power levels, are purchased at Lake Preston costs.

Therefore, the costs of this incident are:

$$16 \text{ hours } (57.89 \text{ $/Mwh} - 9.99 \text{ $/Mwh}) (11.9 \text{ Mw}) = 9120$$

$$8 \text{ hours } (13.79 \text{ $/Mwh} - 9.99 \text{ $/Mwh}) (11.9 \text{ Mw}) = 362$$

Total \$9,482

Table 4.14 Ash Related Costs - Big Stone Station
Otter Tail Power Co.

Starting Time Date	Reason	Cost
1/05	Ash fouling outage	30,423
1/20	Ash fouling outage	27,577

2/26	Ash fouling outage	33,261
3/13	Ash fouling outage	309,638
1/03	Pluggage	9,482
1/04	Pluggage	15,936
1/07	Pluggage	18,247
1/18	Induced draft fan suction	7,331
1/19	Induced draft fan suction	7,251
1/20	Induced draft fan suction	13,147
1/22	Induced draft fan suction	16,095
2/17	High gas exit temperature	8,515
2/18	High gas exit temperature	14,104
2/19	High gas exit temperature	15,341
2/20	High gas exit temperature	33,557
2/21	High gas exit temperature	12,500
2/22	High gas exit temperature	14,331
2/23	High gas exit temperature	28,369
2/24	High gas exit temperature	15,562
2/25	High gas exit temperature	14,410
2/26	High gas exit temperature	17,197
2/28	High gas exit temperature	15,684
3/01	High gas exit temperature	344
3/02	High gas exit temperature	824
3/03	High gas exit temperature	9,837
3/04	High gas exit temperature	8,662
3/05	High gas exit temperature	8,001
3/06	High gas exit temperature	10,277
3/07	High gas exit temperature	15,930
3/08	High gas exit temperature	2,092
3/09	High gas exit temperature	2,264
3/10	High gas exit temperature	46,852
3/11	High gas exit temperature	52,509
3/12	High gas exit temperature	60,636
3/13	High gas exit temperature	4,404
3/28	High gas exit temperature	17,031

All curtailments listed were directly attributable to correction ash fouling. Total cost is \$917,621 for Otter Tail Power Co.

Montana - Dakota Utilities

Again, the 1979 data will be the basis of the study.

Table 4.15 Montana - Dakota Demand Statistics (1979)

Month	Peak Mw	% of High Peak	Output (Mwh)	% of High Output
January	299.7	100	180,484	100
February	284.9	95.1	148,985	82.5
March	246.0	82.1	139,877	77.5
April	209.2	69.8	121,186	67.1
May	241.8	80.7	127,608	70.7
June	279.4	93.2	136,808	75.8
July	282.9	94.4	150,997	83.7
August	279.1	93.1	149,956	83.1
September	253.2	84.5	128,276	71.1
October	235.9	78.7	137,755	76.3
November	239.9	96.7	165,328	91.6
December	298.9	99.7	171,706	95.1

The assumptions for the derivation of Table 4.16 Montana-Dakota Average Daily Load Statistics are:

1. 1980 loads are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November, December, January and February is 0%, in March is 15%, and in April is 25%.
3. The generation assumed to be out of service for unscheduled maintenance will be 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 70% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6 AM to 10 PM) will be the daily load.
 - b. Eight hours (10 PM to 6 AM) will be the night load at 65% of the day load.

The equations used for derivation of Table 4.16 are:

$$\text{Average Weekly Load} = \frac{(\text{Monthly Mwh}) (7 \text{ days/week})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5 y + 2 (.70y) = 6.4 y$$

where y is the average weekday load
where .70 y is the average weekend load

$$\text{Average weekday/weekend load} = 16 x + 8 (.65 x) = 21.2 X$$

where x = average day load
.65 x = average night load

Table 4.16 Montana - Dakota Average Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	284.3	184.8	199.0	129.4
December	285.8	185.7	200.0	130.0
January	300.4	195.2	210.3	136.7
February	274.5	178.4	192.2	124.9
March	232.8	151.3	163.0	105.9
April	208.4	135.5	145.9	94.8

The Montana-Dakota system is comprised of three coal fired steam plants (one the 20% ownership of Big Stone), two small gas or oil fired steam plants, two gas turbines, and two diesel engines.

Capacities are distributed as follows:

Coal fired steam - 237 Mwh
 Oil fired steam - 7 Mwh
 Oil fired combustion turbine - 63.5 Mwh
 Diesel - 3.4 Mwh

Purchased power accounts for 16.6% of total energy. One large power block from Pacific Power & Light will be treated as an entity, other purchased power will be averaged.

This system goes outside for Big Stone replacement power. Since requirements sometimes exceed the system average capabilities in Table 4.17, it will be assumed that the excess power replacement costs during an outage are no higher than the \$49.29 operating costs of the Glendive combustion turbine.

Table 4.17 Montana - Dakota Unit Costs and Capabilities

Source	Mwh	\$/Mwh	Total Load Capability		
			@10%	@25%	@35%
Other (P)	23.2	9.34	20.9	17.4	15.1
Big Stone (S)	83	9.80	95.6	79.7	69
Pacific Power & Light (P)	18.2	9.97	112	93.3	80.9
Neskitt (S)	103	10.16	204.7	170.6	147.8
Lewis & Clark(S)	51	12.73	250.6	208.8	181.0
Other (S)	7	27.8	256.9	214.1	185.5
Miles City (CT)	28	29.82	282.1	235.1	203.7
Glendive	35.5	49.29	314.0	261.7	226.8

S - steam (M-D - owned) P - Purchases (outside)

CT - Combustion turbine (M-D - owned)

Table 4.18 is derived as per the following example:

The first incident, an ash fouling outage lasted 36.77 hours. It was a weekend outage with 14 hours at night and 22.77 hours during the day.

The January weekend loads are 210.3 Mw day and 136.7 Mw night (Table 4.16).

$$210.3 + 83 \text{ Mw (Big Stone @ 20\%)} = 293.3 \text{ Mw}$$

$$136.7 + 83 \text{ Mw (Big Stone @ 20\%)} = 219.7 \text{ Mw}$$

The cost levels in January (10% loss) month are 49.29 at 293.3 Mw and 12.73 at 219.7 Mw.

Costs are:

$$83 \text{ Mw (22.77 hours) (49.29 - 9.80 \$/Mwh)} = 74,632$$

$$\text{and } 83 \text{ Mw (14 hours) (12.73 - 9.80 \$/Mwh)} = 3,404$$

$$\text{Total Cost } \$78,036$$

Table 4.18 Montana-Dakota Utilities - Big Stone Ash Fouling Losses

Start Date	Reason	Cost
1/05	Superheat Pluggage	\$ 78,036
1/20	Reheat Pluggage	88,098
2/26	Reheat Pluggage	109,138

Table 4.18 (cont'd.)

3/13	Superheat & Reheat Cleaning	972,384
1/03	Pluggage	3,173
1/04	Pluggage	5,331
1/07	Pluggage	6,291
1/18	Induced draft fan suction	2,475
1/19	Induced draft fan suction	189
1/20	Induced draft fan suction	343
1/22	Induced draft fan suction	5,395
2/17	High gas exit temperature	42
2/18	High gas exit temperature	2,327
2/19	High gas exit temperature	4,950
2/20	High gas exit temperature	8,061
2/21	High gas exit temperature	5,141
2/22	High gas exit temperature	2,456
2/23	High gas exit temperature	776
2/24	High gas exit temperature	77
2/25	High gas exit temperature	2,456
2/26	High gas exit temperature	5,776
2/28	High gas exit temperature	5,268
3/01	High gas exit temperature	14
3/02	High gas exit temperature	34
3/03	High gas exit temperature	3,617
3/04	High gas exit temperature	3,173
3/05	High gas exit temperature	2,919
3/06	High gas exit temperature	3,745
3/07	High gas exit temperature	5,776
3/08	High gas exit temperature	483
3/09	High gas exit temperature	522
3/10	High gas exit temperature	1,625
3/11	High gas exit temperature	1,822
3/12	High gas exit temperature	2,096
3/13	High gas exit temperature	1,587
3/28	High gas exit temperature	6,220

All curtailments listed were directly attributable to ash pluggage. The total cost is \$1,375,315 for the Montana-Dakota Utilities Co.

Northwestern Public Service Co.

The 1979 statistics will be used as the basis for the study.

Table 4.19 Northwestern Public Service Co. 1979 Operating Statistics

Month	Peak Mw	% of High Peak	Output Mwh	% of High Output
January	152.5	78.7	88,364	100.0
February	152.5	78.7	75,369	85.3
March	127.6	65.9	70,657	80.0
April	126.7	65.4	62,552	70.8
May	121.6	62.6	60,079	68.0
June	176.1	90.9	63,798	72.2
July	184.6	95.3	74,281	84.1
August	193.7	100.0	70,768	80.1
September	192.3	99.3	60,034	67.9
October	132.0	68.1	63,258	71.6
November	142.7	73.7	68,120	77.1
December	145.0	74.9	71,584	81.0

The assumptions for the derivation of Table 4.20 Northwestern Public Service Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November and December is 25%, in January and February is 20%, and in March and April is 30%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources except Big Stone. Big Stone is excluded in this case because of the system importance and because of its remarkable performance during the study with non-ash related problems.
5. The average weekend load will be 60% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10PM) will be the daily load.
 - b. Eight hours (10PM - 6AM) will be the night load at 55% of the day load.

The equations used for derivation of Table 4.20 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5 y + 2 (.60) y = 6.2 y$$

where y is the average weekday load
and .6 y is the average night load

Table 4.20 Northwestern Average Daily Load

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	125.7	69.1	75.4	41.5
December	127.8	70.3	76.7	42.2
January	157.8	86.8	94.7	52.1
February	149.0	81.9	89.4	49.2
March	126.1	69.4	75.7	41.6
April	115.4	63.5	69.2	38.1

The Northwestern system is comprised of 24 diesel engines, one steam turbine, two gas turbines, 10% ownership in Neal #4, and 32.5% ownership in Big Stone.

Steam turbine (owned) - 7.5 Mw Combustion Turbine - 35.1 Mw
 Diesel engine - 46.7 Mw
 Steam Turbine - 35.1 Mw
 (Big Stone)

W. Neal Station was under startup in 1979, not in commercial status, and is included in the purchased power category.

The utility sells a substantial amount of power amounting to 30% of their generation. In order to calculate their financial loss, this sales factor must be taken into account.

This utility is in a position to buy and sell power to absorb its peaks. Other generation (combustion turbines and diesels) accounted for only 1.4% of the utilities total generation. Because of the utility's small size

and the inaccuracies presented by using an averaging technique applied to its purchased power, the following assumptions will be utilized in the financial analysis:

1. The utility has a summer peak, and it will be assumed that the 1.4% other generation was used only in the summer months.
2. All power needed in excess of system capabilities can be purchased at 21.19 \$/Mwh, the average cost of 1979 purchased power.
3. All power generated in excess of system demand can be sold at \$18.40/Mwh, the average cost of power sold by the utility in 1979.

Table 4.21 represents the system capabilities with these assumptions in mind.

Table 4.21 Northwestern Unit Costs and Capabilities

Source	Megawatts	\$/Mwh	@30%	@35%	@40%
Big Stone	135	9.80	135	135	135
Other Steam	7.5	19.58	140	140	140
Purchased	as needed	21.19			

An example of the derivation of Table 4.22 is as follows:

The first incident was an ash fouling outage lasting 36.77 hours. It was a weekend outage with 14 hours at night and 22.77 hours during the day.

The lowest January load levels at night are 52.1 megawatts. Without Big Stone all power would be purchased at a cost of 21.19 \$/Mwh.

Costs are:

$$36.77 \text{ hours } (21.19 - 9.80 \text{ $/Mwh}) (135 \text{ Mw}) = \$56,539$$

Table 4.22 Northwestern Public Service Co. - Big Stone Ash Fouling Losses

Start Date	Reason	Cost
1/5	Superheat pluggage	56,539
1/20	Reheat pluggage	51,250
2/26	Reheat pluggage	61,813
3/13	Superheat and reheat	575,435
1/3	Pluggage	2,033
1/4	Pluggage	3,434
1/7	Pluggage	3,934
1/18	Induced draft fan suction	1,576
1/19	Induced draft fan suction	1,280
1/20	Induced draft fan suction	2,326
1/22	Induced draft fan suction	3,467
2/17	High gas exit temperature	1,639
2/18	High gas exit temperature	2,937
2/19	High gas exit temperature	3,188
2/20	High gas exit temperature	5,162
2/21	High gas exit temperature	2,693
2/22	High gas exit temperature	3,088

Table 4.22 (cont'd.)

2/23	High gas exit temperature	5,222
2/24	High gas exit temperature	2,991
2/25	High gas exit temperature	3,113
2/26	High gas exit temperature	3,705
2/28	High gas exit temperature	3,382
3/1	High gas exit temperature	543
3/2	High gas exit temperature	1,292
3/3	High gas exit temperature	2,068
3/4	High gas exit temperature	1,672
3/5	High gas exit temperature	1,548
3/6	High gas exit temperature	2,162
3/7	High gas exit temperature	3,715
3/8	High gas exit temperature	3,261
3/9	High gas exit temperature	3,529
3/10	High gas exit temperature	10,092
3/11	High gas exit temperature	11,322
3/12	High gas exit temperature	9,853
3/13	High gas exit temperature	844
3/28	High gas exit temperature	3,992

Total losses for Northwestern Public Service Co. are estimated to be \$856,100.

Station Loss

Another loss at Big Stone is the problem the station has with main steam temperatures. In order to prevent fouling, the boiler is operated in ways to lower the furnace gas exit temperatures. This is accomplished by allowing no furnace wall slag to form and by not running the gas recirculation capabilities to their fullest extent. There is a very solid reason for this -- if the furnace gas exit temperatures increase, experience has proven that the units will foul more severely.

The penalty for this low temperature operation is low steam temperatures. This raises the turbine heat rate and lowers overall plant efficiency.

During the period of study, main steam temperatures were low a total of fifty-five days, when the unit was at full load operation. The average temperature for these days was 961° F.

The change in heat rate for this temperature is about 423 BTU/Kwh. The 1979 Lignite cost was .694 \$/MBTU.

The cost is:

$$55 \text{ days (24 hours/day) (423 BTU/Kwh) (.694 $/MBTU) (420,000 Kw)} \\ (\text{MBTU}/10^6 \text{ BTU}) = \$162,751$$

Taking into account the percent ownership:

$$\begin{aligned} \text{Otter Tail Power Co.} &- \$162,751 (.475) = \$77,307 \\ \text{Montana-Dakota Utilities} &- \$162,751 (.325) = \$52,894 \\ \text{Northwestern Public Service Co.} &- \$162,751 (.20) = \$32,550 \end{aligned}$$

4.3 Leland Olds

Basin Electric Cooperative

Basin is a power supplier to seventeen cooperatives in eight different states.

They own three stations -- Leland Olds, J. W. Neal, and Spirit Mound.

Generation costs for the period of study averaged:

Leland Olds 1 - 9.26
Leland Olds 2 - 12.39
W. J. Neal - 20.48
Spirit Mound - 76.92 (Unit was only run .2 hours during the study.
The 76.92 was 1979 average cost.)

As a bulk power supplier, the financial analysis is rather uncomplicated. It is assumed that all power generated could be sold at the average power cost sold by the utility. This cost for the study period was 21.45 \$/Mwh. The analysis is limited to multiplying this power cost by the Mwh loss.

Leland Olds 1

Total fouling loss (outages) - 6259 Mwh
Total fouling loss (curtailments) - 68,351 Mwh
Total clinker loss (curtailments) - 2732 Mwh
Total sootblower cutting loss (outages) - 21,785 Mwh
Total sootblower cutting loss (curtailments) - 8043 Mwh

Cost:

Fouling - 74,610 Mwh (21.45 \$/Mwh - 9.26 \$/Mwh) = \$909,496
Clinkers - 2732 (21.45 \$/Mwh - 9.26 \$/Mwh) = \$33,303
Tube Cutting - 29,828 (21.45 \$/Mwh - 9.26 \$/Mwh) = \$363,603

Leland Olds 2

Total fouling loss (outages) - 104,147 Mwh
Total fouling loss (curtailments) - 213,876 Mwh
Total sootblower cutting loss - 3894 Mwh

Cost:

Fouling - 318,023 Mwh (21.45 \$/Mwh - 12.39 \$/Mwh) = \$2,881,288
Sootblower cutting loss - (3894 Mwh) (21.45 \$/Mwh - 12.39 \$/Mwh) = \$35,280

Leland Olds 2 sustains another loss due to ash related problems. Tapping problems in the cyclones due to the characteristics of the ash cause the unit to use great amounts of oil.

Total oil consumption for the study was 1,842,235 gallons. Eleven startups were required costing 20,000 gallons of oil apiece. The oil fired for slag tapping purposes was 1,622,235 gallons.

The average oil cost was 6.04 \$/MBTU. The average coal cost was .4993 \$/MBTU.

The BTU/gallon of oil was 140,000. Total cost was:

Difference in coal & oil: 6.04 - .4993 = 5.5407 \$/MBTU

$5.5407 \text{ $/MBTU} \left(140,000 \frac{\text{BTU}}{\text{gal.}}\right) (1,622,235 \text{ gal.}) \left(\frac{\text{MBTU}}{[10]6 \text{ BTU}}\right) = \$1,258,364$

4.4 Jim Bridger

The owners of Jim Bridger, Pacific Power and Light Co., have requested that they not be included in the financial analysis. The Pacific Northwest is blessed with abundant hydro, with lower generation costs than the coal fired units. It is also penalized with long transmission distances.

Because of the complexities of weather, hydro storage, high summer California peaks, and the limitations of wheeling capacity from Wyoming, Pacific Power and Light Co. does not feel that the technique of averaging power capabilities and demands accurately reflect the true cost of Jim Bridger lost generation.

The computation of actual cost data by investigation of the power supply information would require extensive data from Pacific Power and Light and data analysis which is beyond the scope of this study.

We will take the liberty of pointing out that the low incidence of fouling or slagging related losses in the units amounted to only 3418 megawatt hours, and at replacement power cost levels considered high, would not in all probability have exceeded cost levels at Big Stone, Leland Olds, St. Clair, or Four Corners.

4.5 Four Corners Power Plant

Units 1, 2 and 3 of the Four Corners Units are wholly owned by Arizona Public Service Co.

Units 4 and 5 ownership is split six ways: Arizona Public Service owns 15%, Southern California Edison owns 45%, El Paso Electric Co. owns 7%, Public Service Co. of NM owns 13%, Tucson Electric Power Co. owns 7%, and the Salt River Project owns 10%.

The financial analysis will consider Units 1, 2 and 3 separately from Units 4 and 5.

Arizona Public Service Co.

Table 4.23 Arizona Public Service 1979 Operating Statistics

Month	Peak Mw	% of High Peak	Output Mwh	% of High Output
January	1789	68.5	1,014,670	71.4
February	1654	63.3	866,687	61.0
March	1629	62.4	940,745	66.2
April	1713	65.6	909,531	64.0
May	2028	77.7	1,049,424	73.9
June	2521	96.6	1,237,464	87.1
July	2611	100.0	1,420,723	100.0
August	2590	99.2	1,340,265	94.3
September	2579	98.77	1,279,590	90.1
October	2128	81.5	1,027,988	72.4
November	1642	62.89	921,969	64.9
December	1643	62.93	996,117	70.1

The assumptions for the derivation of Table 4.24 Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November - April is 30%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 70% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM to 10PM) will be the day load.
 - b. Eight hours (10PM to 6AM) will be the night load at 65% of the day load.

The equations for derivation of Table 4.24 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5 y + 2 (.7) y = 6.4 y$$

where y = average weekday load
(.7) y = average weekend load

Average weekday/weekend load = $16x + 8(.65)x = 21.2x$.
 where x is the average day load
 $(.65)x$ is the average night load

Table 4.24 Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	1586	1031	1110	721
December	1658	1078	1160	754
January	1689	1098	1182	768
February	1597	1038	1118	727
March	1566	1018	1096	712
April	1564	1017	1095	712

The APS system is comprised of eight coal fired steam units, eleven gas and oil fired combustion turbines, three combined cycle units, and three small hydro units.

The capacities are as follows:

Coal fired steam - 1478.0 Mw
 Oil & gas fired steam - 576.7 Mw
 Oil & gas fired combustion turbine - 510.9 Mw
 Oil combined cycle - 225 Mw
 Hydro - 4.9 Mw

About 9% of the utility's power is purchased, an average of 130 Mw at a cost of 33.9 \$/Mwh.

25% of the utility's power is interchanged. The average cost of interchange power purchased is about equal to the cost of power supplied. The average amount interchanged is 418 Mw. Power costs for this interchanged power are about the same at an average of 30.66 \$/Mwh. Most of the power does not involve a monetary transaction, but is paid back in power. This interchange power will be assumed to be available as required at the aforementioned costs and capabilities. The paybacks will not affect this study, as it is assumed to be paid back only when power is available at lower cost.

Table 4.25 Arizona Public Service Unit Cost and Capabilities

Source	Mw	\$/Mwh	Total Load Capabilities 40%
Hydro Power	4.9	1.40	29
Four Corners 4, 5 (S)	240	7.00	147
Navajo (S)	315	9.04	336
Four Corners 1, 2, 3 (S)	572	11.59	679
Cholla (S)	351	13.22	890
Octillo	229.4	27.55	1027
Yuma	25	27.65	1042
Octillo (CT)	111.8	30.08	1109
Interchanged	418	30.66	1360
Saguaro (S)	214	31.26	1489
Saguaro (CT)	109	31.56	1554
West Phoenix (CT)	112.4	33.84	1622
Purchases	130	33.90	1700

Table 4.25 (cont'd.)

Yucca (CT)	157.2	36.63	1794
West Phoenix (CC)	225	38.00	1929
West Phoenix (S)	108.3	44.59	1994
Douglas (CT)	20.7	55.8	2006

S - Steam Plant CT - Combustion Turbine CC - Combined Cycle

An example of the derivation of Table 4.26 is as follows: The first incident, a three hour superheat fouling incident cost three hours of 12/1, one hour during day load and two hours during night load. The curtailment was 10.7 Mw.

The December Load Levels are 1160 for a weekend day and 754 for a weekend night (Table 4.24). Adding the 10.7 Mw lost capacity, the night load is 1171 Mw and the day load is 765 Mw.

The cost levels at this load are 30.66 \$/Mwh for day load and 13.22 \$/Mwh for a night load (Table 4.25).

10.7 Mw (1 hour) (30.66 - 11.59 \$/Mwh)	\$ 204
10.7 Mw (2 hours) (13.22 - 11.59 \$/Mwh)	35
Total Cost	\$ 239

Table 4.26 Ash Related Losses - Four Corners, Arizona Public Service

Date	Reason	Cost
Unit 1		
12/1	Superheat fouling	239
12/6	Clinker	3,687
12/7	Superheat fouling	1,833
12/10	Superheat fouling	647
12/12	Superheat fouling	9,073
12/16	Superheat fouling	17,313
12/25	Superheat fouling	473
1/1	Superheat fouling	2,980
1/2	Superheat fouling	4,433
1/9	Superheat fouling	4,280
1/12	Superheat fouling	28,780
3/16	High reheat temperature	2,907
3/26	Reheat fouling	980
Unit 2		
11/1	Superheat fouling	1,987
11/2	Superheat fouling	28,618
11/5	Superheat fouling	21,489
11/8	Superheat fouling	21,489
12/6	Superheat fouling	126,674
12/18	Superheat fouling	16,113
12/21	Superheat fouling	25,367
12/27	Superheat fouling	34,880
1/8	Superheat fouling	10,700
1/11	Superheat fouling	7,640
1/16	Superheat fouling	29,200
2/20	Superheat fouling	293
3/15	Superheat fouling	93
3/21	Reheat fouling	3,507

Table 4.26 (cont'd.)

Unit 3		
12/28	Superheater ash pluggage	237,718
2/5	Superheater ash pluggage	258,388
11/3	Superheater ash fouling	3,831
11/16	Clinkers	12,960
12/28	Pre-outage fouling loss	17,191
12/31	Post-outage startup loss	8,705
1/31	Clinker	6,448
2/4	Pre-outage fouling loss	35,190
Unit 4		
11/1	Clinker	178,754
1/31	Clinker	328,403
2/22	Clinker	114,036
1/4	Startup loss from clinker outage	41,491
1/9	Clinker	10,264
1/25	Clinker	17,211
1/31	Pre-outage loss clinker	20,311
2/5	Post-outage startup loss	20,420
2/22	Pre-outage loss clinker	2,355
2/24	Post-outage loss	7,057
2/27	Clinker	5,724
2/29	Clinker	6,844
3/1	Clinker	8,297
Unit 5		
3/2	Clinker	58,247
4/12	Clinker	163,507
2/14	Clinkers	50,675
2/29	Clinkers	7,724
3/1	Loss prior to clinker outage	26,765
3/8	Clinkers	6,261
3/10	Clinkers	18,916
4/10	Loss prior to clinker outage	55,351
4/15	Startup loss after clinker outage	5,272
4/16	Clinkers	42,320
4/21	Clinkers	172,824

Tucson Electric Power Co.

The 1979 operating statistics are presented in Table 4.27 as the basis of the study.

Table 4.27 Tucson Electric Power Co. 1979 Operating Statistics

Month	Peak	% of High Peak	Output (Mwh)	% of High Output
January	890	71.1	503,082	74.9
February	875	69.9	461,253	68.7
March	928	74.1	520,778	77.5
April	971	77.6	535,600	79.8
May	1051	83.9	517,903	77.1
June	1211	96.7	600,697	89.4
July	1252	100.0	671,585	100.0

Table 4.27 (cont'd.)

August	1229	98.2	614,145	91.4
September	1214	97.0	619,154	92.2
October	1098	87.7	553,806	82.5
November	986	78.8	497,751	74.1
December	925	73.9	482,197	71.8

Tucson Electric Service Co. owns 7% of Four Corners 4 and 5.

The assumptions for the derivation of Table 4.28 Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November and April is 20%, December through March is 25%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 65% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 60% of the day load.

The equations for derivation of Table 4.28 are:

$$\text{Average Weekly Load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average Weekly Load} = 5 y + 2 (.65) y = 6.3 y$$

where y = average weekday load
 (.65) y = average weekend load

$$\text{Average Weekday/Weekend Load} = 16 x + 8 (.60) x = 20.8 x$$

where x is the average day load
 (20.8) x is the average night load

Table 4.28 Tucson Electric Power Co. Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	886	532	576	346
December	831	499	540	324
January	867	520	564	338
February	880	528	572	343
March	897	538	583	350
April	954	572	620	372

Tucson Electric's generation is comprised of eight gas, heavy oil or light oil fired steam turbines, eight combustion turbines, 7% ownership of Four Corners 4 and 5, 50% ownership of San Juan, and 7.5% ownership of Navajo.

Total generation is:

Coal fired steam - 845.3 Mw
 Gas oil fired steam - 609 Mw
 Combustion turbine - 254.5 Mw

Power was purchased from two sources which will be itemized in Table 4.29.

Interchanged power amounted to 32.5 megawatt average into the utility and 27.2 megawatt average out of the utility. This power will be treated as a separate source. The output will not be considered in the financial analysis.

Table 4.29 Tucson Electric Power Co. Unit Costs and Capabilities

Source	Mw	\$/Mwh	@30%	@35%
Cortaro Marana				
Irrigation District (P)	1.8	5.55	1.3	1.2
Four Corners 4 & 5 (S)	112	7.00	80	74
Navajo (S)	168	9.11	197	183
San Juan (S)	550	12.47	582	541
U. S. Bureau of				
Reclamation (P)	8.8	12.61	588	546
Irvington (S)	422.1	26.73	884	821
Interchange (P)	82.5	28.42	942	874
DeMoss Petri (S)	97.8	35.93	1010	974
DeMoss Petri (CT)	47.1	41.41	1043	969
North Loop (CT)	97.4	48.23	1111	1032
Irvington (CT)	73.1	62.83	1162	1079

S - Steam Plant P - Purchases CT - Combustion Turbine

An example of the development of Table 4.30 is as follows: Select the first incident, a clinker with 32 weekday hours, 16 night hours, 16 weekend day hours, and 9.02 weekend night hours. It occurred in November

The loads from Table 4.28 are:

Day	886 + 53 = 939
Night	532 + 53 = 585
Weekend Day	576 + 53 = 629
Weekend Night	346 + 53 = 399

53 Mw is the Tucson 7% share of the outage.

The costs of Table 4.29 are:

Day	28.42 \$/Mwh
Night	14.61 \$/Mwh
Weekend Day	26.73 \$/Mwh
Weekend Night	12.47 \$/Mwh

Cost of Four Corners Power is 7.00 \$/Mwh; therefore, the loss is:

32 hours (28.42 - 7.00 \$/Mwh)	5 x 3 Mw = 36,328
16 hours (14.61 - 7.00 \$/Mwh)	5 x 3 Mw = 6,453
16 hours (26.73 - 7.00 \$/Mwh)	5 x 3 Mw = 16,731
9.02 hrs. (12.47 - 7.00 \$/Mwh)	5 x 3 Mw = 2,615
Total:	62,127

Table 4.30 Four Corners 4 & 5, Tucson Electric Power Co.
Ash Related Costs

Start Date	Reason	Cost
Unit 4		
11/1	Clinker	62,127
1/31	Clinker	136,105
2/22	Clinker	50,251
1/4	Startup loss from clinker outage	14,807
1/9	Clinker	4,675
1/25	Clinker	5,986
1/31	Pre-outage loss clinker	7,642
2/5	Post-outage startup loss	7,463
2/22	Pre-outage loss clinker	1,183
2/24	Post-outage loss	2,782
2/27	Clinker	1,782
2/29	Clinker	3,092
3/1	Clinker	3,076
Unit 5		
3/2	Clinker	22,911
4/12	Clinker	69,913
2/14	Clinker	22,196
2/29	Clinker	3,702
3/1	Loss prior to clinker outage	10,529
3/8	Clinker	2,462
3/10	Clinker	9,592
4/10	Loss prior to clinker outage	19,336
4/15	Startup loss after clinker outage	2,088
4/16	Clinker	16,683
4/21	Clinker	4,356

El Paso Electric Co.

The 1979 statistics are presented in Table 4.31 as the basis of the study.

Table 4.31 El Paso Electric Co.

Month	Peak Mw	% of High Peak	Output (Mwh)	% of High Output
January	526	76.5	299,452	81.6
February	523	76.0	262,097	71.4
March	504	73.3	285,030	77.7
April	553	80.4	281,404	76.7
May	601	87.4	301,184	82.1
June	668	97.1	326,374	88.9
July	688	100.0	367,059	100.0
August	660	95.9	343,783	93.7
September	663	96.4	315,879	86.1
October	590	85.8	301,845	82.2
November	522	75.9	278,760	75.9
December	528	76.7	289,005	78.7

El Paso owns 7% of Four Corners 4 & 5.

The assumptions for the derivation of Table 4.32 El Paso Electric Co. Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November - February is 20%, March is 25%, and April is 15%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 65% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM to 10 PM) will be the day load.
 - b. Eight hours (10PM to 6 AM) will be the night load at 60% of the day load.

The equations for derivation of Table 4.32 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

$$\begin{aligned} \text{Average Weekly Load} &= 5 y + 2 (.65) y = 6.3 y \\ \text{where } y &= \text{average weekday load} \\ (.7) y &= \text{average weekend load} \end{aligned}$$

$$\begin{aligned} \text{Average weekday/weekend load} &= 16 x + 8 (.60) x = 20.8 x \\ \text{where } x &= \text{the average day load} \\ (.60) x &= \text{the average night load} \end{aligned}$$

Table 4.32 El Paso Electric Co. Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	496	298	323	194
December	498	299	324	194
January	516	310	335	201
February	500	300	325	195
March	491	295	319	192
April	501	301	326	195

El Paso Electric Co. is comprised of twelve gas and oil steam plants, and 7% ownership in Four Corners.

Very little power was purchased in 1979, but a great amount was sold. Average sales accounted for \$27.42/Mwh. The sales volume amounted to an average of 14.7 Mw. This sale will be treated as follows in the financial report:

If the units at Four Corners suffer a curtailment when the megawatt demand levels are confined to Four Corners' cost, the megawatt curtailment loss will be charged at a loss against the 27.42 \$/Mwh loss.

Table 4.33 El Paso Unit Costs and Capabilities

Source	Total Load Capability				
	Megawatts	\$/Mwh	@25%	@30%	@35%
Four Corners 4 & 5	112	7.686	84	78	72
Newmann	504	24.48	462	431	400
Rio Grande	360	27.36	732	683	634

An example of the derivation of Table 4.34 is as follows:

The first incident, a clinker outage, had 32 weekday hours, 16 night hours, 16 weekend day hours, and 9.02 weekend night hours.

The loads from Table 4.32 are:

Day	$496 + 52.9 = 549$
Night	$298 + 52.9 = 351$
Weekend Day	$323 + 52.9 = 376$
Weekend Night	$194 + 52.9 = 247$

52.9 Mw is 7% of the actual outage loss.

The costs from Table 4.33 are:

Day	27.36 \$/Mwh
Night	24.48 \$/Mwh
Weekend Day	24.48 \$/Mwh
Weekend Night	24.48 \$/Mwh

Cost of Four Corners power is 7.686 \$/Mwh; therefore, the loss is:

32 hours	$(27.36 - 7.686 \text{ $/Mwh}) (52.9 \text{ Mw}) = 33,304$
16 hours	$(24.48 - 7.686 \text{ $/Mwh}) (52.9 \text{ Mw}) = 14,214$
16 hours	$(24.48 - 7.686 \text{ $/Mwh}) (52.9 \text{ Mw}) = 14,214$
9.02 hrs.	$(24.48 - 7.686 \text{ $/Mwh}) (52.9 \text{ Mw}) = 8,013$

Total Cost = 69,746

Table 4.34 Four Corners 4 & 5, El Paso Electric Co.
Ash Related Costs

Date	Reason	Cost
Unit 4		
11/1	Clinker	69,746
1/31	Clinker	113,428
2/22	Clinker	37,547
11/4	Startup loss from clinker outage	16,697
1/9	Clinker	3,179
1/25	Clinker	9,066
1/31	Pre-outage loss clinker	6,392
2/5	Post-outage startup loss	6,467
2/22	Pre-outage loss clinker	687
2/24	Post-outage loss	4,029
2/27	Clinker	2,069
2/29	Clinker	2,372
3/1	Clinker	3,523

Table 4.34 (cont'd.)

Unit 5		
3/2	Clinker	28,484
4/12	Clinker	64,000
2/14	Clinkers	19,054
2/29	Clinkers	2,620
3/1	Loss prior to clinker outage	12,013
3/8	Clinkers	2,780
3/10	Clinkers	6,444
4/10	Loss prior to clinker outage	17,047
4/15	Startup loss after clinker outage	1,788
4/16	Clinkers	15,058
4/21	Clinkers	61,593

Southern California Edison

The 1979 operating statistics are presented in Table 4.35 as the basis of the study.

Table 4.35 Southern California Edison 1979 Operating Statistics

Month	Peak	% of High Peak	Output Mwh	% of High Output
January	9,756	77.1	5,599,082	90.7
February	9,275	73.3	4,734,431	76.7
March	8,980	71.0	5,142,414	83.3
April	8,977	70.9	4,934,383	79.9
May	10,291	81.2	5,407,979	87.6
June	12,649	100.0	5,721,828	92.7
July	11,837	93.6	6,134,712	99.4
August	11,766	93.0	6,098,869	98.8
September	12,653	100.0	6,172,027	100.0
October	10,499	83.0	5,646,623	91.5
November	9,467	74.8	5,293,691	85.8
December	9,437	74.6	5,330,863	86.4

The assumptions for the derivation of Table 4.36 Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November - January is 20%, February - April is 25%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 70% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10 PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 65% of the day load.

The equations for derivation of Table 4.36 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

Average weekly load = $5y + 2(.70)y = 6.4y$
 where y = average weekday load
 $(.70)y$ = average weekend load

Average weekday/weekend load = $16x + 8(.65)x = 21.2x$
 where x is the average day load
 $(.65)x$ is the average night load

Table 4.36 Southern California Edison Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	9104	5917	6373	4142
December	8872	5767	6210	4037
January	9318	6057	6523	4240
February	8724	5670	6107	3969
March	8558	5563	5991	3894
April	8486	5516	5940	3861

Southern California Edison's generation is comprised of forty-nine oil and gas fired steam plants, six oil and gas fired combustion turbines, 80% of San Onofre Nuclear Plant, 48% of Four Corners 4 & 5, 56% of Mohave, 33.3% of Yuma Axis, and eighty-three hydro units at 28 sites.

The capabilities are:

Nuclear - 344 Mw
 Coal fired steam - 1678 Mw
 Gas and oil fired steam - 9348 Mw
 Gas turbine - 550 Mw
 Hydro - 1173.3 Mw

Purchased power was received from several sources. It was economy power averaging only 16.2 \$/Mwh. It will be treated as a single source at an average load of 682 Mw.

Incoming interchanged power accounted for an average of 55 Mw at a cost of 7.89 \$/Mwh.

The hydro power will be considered as one source, as it will always be run if available. The highest cost is 2.28 \$/Mwh, the average is 1.74 \$/Mwh.

Table 4.37 Southern California Edison Unit Costs and Capabilities

Source	Mw	\$/Mwh	Total Load Capabilities	
			@30%	@35%
System Hydro	1173	1.74	821	762
Interchange (P)	55	7.89	860	798
Four Corners 4 & 5 (S)	768	8.02	1397	1297
San Onofre (N)	349	8.14	1642	1524
Purchased Power	682	16.20	2119	1968
Mohave (S)	851	22.18	2715	2521
Ellwood (CT)	54	25.36	2752	2556

Table 4.37 (cont'd.)

San Bernadino (S)	126	27.45	2841	2638
Mandalay (S-CT)	551	29.15	3226	2996
Redondo Beach (S)	1602	29.57	4348	4037
Yuma Axis (S)	33	30.33	4371	4059
Huntington Beach (S-CT)	991	31.71	5065	4703
Etiwanda (S-CT)	1025	32.56	5782	5369
El Segundo (S)	1020	32.65	6496	6032
Alamitos (S-CT)	2071	32.93	7946	7378
Ormond Beach (S)	1500	34.21	8996	8353
Coolwater (S)	506	34.26	9350	8682
Long Beach (S-CT)	686	35.70	9830	9128
Highgrove (S)	154	40.14	9938	9228
Garden State (CT)	12	57.49	9946	9236

S - Steam

P - Purchases

CT - Combustion Turbine

As an example of the derivation of Table 4.38 select the first incident, a clinker with 32 weekday hours, 16 night weekday hours, 16 weekend day hours, and 9.02 weekend night hours. It occurred in November.

The loads from Table 4.36 are:

Day	$9104 + 362 = 9466$ Mw
Night	$5917 + 362 = 6279$ Mw
Weekend Day	$6373 + 362 = 6735$ Mw
Weekend Night	$4142 + 362 = 4504$ Mw

362 Mw is the SCE 48% share of the outage loss.

The costs from Table 4.37 are:

Day	35.70 \$/Mwh
Night	32.65 \$/Mwh
Weekend Day	32.93 \$/Mwh
Weekend Night	31.71 \$/Mwh

Cost of Four Corners replacement power is:

32 hours	$(35.70 - 8.02 \text{ $/Mwh}) (362 \text{ Mw}) = 320,645$
16 hours	$(32.65 - 8.02 \text{ $/Mwh}) (362 \text{ Mw}) = 142,657$
16 hours	$(32.93 - 8.02 \text{ $/Mwh}) (362 \text{ Mw}) = 144,279$
9.02 hrs.	$(31.71 - 8.02 \text{ $/Mwh}) (362 \text{ Mw}) = 77,354$
Total	\$684,934

Table 4.38 Four Corners 4 & 5, Southern California Edison
Ash Related Costs

Date	Reason	Cost
Unit 4		
11/1	Clinker	684,934
1/31	Clinker	1,117,447
2/22	Clinker	363,799
1/4	Startup loss/clinker outage	160,599
1/9	Clinker	30,669
1/25	Clinker	89,398
1/31	Pre-outage loss clinker	62,453
2/5	Post-outage startup loss	62,883
2/22	Pre-outage loss clinker	7,780
2/24	Post-outage loss	39,937
2/27	Clinker	20,335
2/29	Clinker	23,085
3/1	Clinker	33,485
Unit 5		
3/2	Clinker	283,210
4/12	Clinker	631,113
2/14	Clinker	185,029
2/29	Clinker	24,435
3/1	Loss prior to clinker outage	119,003
3/8	Clinker	27,552
3/10	Clinker	62,247
4/10	Loss prior to clinker outage	161,307
4/15	Startup loss/clinker outage	16,814
4/16	Clinker	141,500
4/21	Clinker	582,508

Public Service Co. of New Mexico

The 1979 Operating Statistics are presented in Table 4.39 as the basis of the study.

Table 4.39 Public Service Co. of New Mexico 1979 Operating Statistics

Month	Peak	% of High Peak	Output Mwh	% of High Output
January	761	89.0	449,511	93.5
February	731	85.5	391,266	81.4
March	686	80.2	414,325	86.2
April	701	82.0	409,547	85.2
May	714	83.5	419,524	87.2
June	846	98.9	432,636	90.0
July	855	100.0	480,888	100.0
August	837	97.9	451,065	93.8
September	812	95.0	448,753	93.3
October	720	84.2	425,960	88.6
November	771	90.2	425,709	88.5
December	761	89.0	474,124	98.6

Public Service Co. of New Mexico has a 13% ownership in Four Corners 4 & 5.

The assumptions for the derivation of Table 4.40 Public Service Co. of New Mexico Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November is 0%, December, January and February is 10%, March and April is 15%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 75% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 70% of the day load.

The equations for derivation of Table 4.40 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5 y + 2 (.75) y = 6.5 y$$

where y = average weekday load
(.75) y = average weekend load

$$\text{Average weekday/weekend load} = 16 x + 8 (.70) x = 21.6 x$$

where x is the average day load
(.70) x is the average night load

Table 4.40 Public Service Co. of New Mexico Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	707	495	531	371
December	763	534	572	400
January	723	506	542	380
February	697	488	523	366
March	666	466	500	350
April	681	476	510	357

Public Service Co. of New Mexico's generation is comprised of ten gas fired steam units; 50% of the San Juan coal fired units 1, 2 and 3; 13% of Four Corners coal fired units 4 and 5, and one gas turbine. The system's capacities are:

Gas fired steam - 293 Mw
Coal fired steam - 803 Mw
Gas fired combustion turbine - 20 Mw

Power was purchased from four sources which will be itemized in Table 4.41. Interchanged power into the system amounted to about 9.81% of the power supply. Interchanged power out of the system accounted for 12.25% of the

supply. Most of the output was power banked for future need. It will not be considered for financial analysis, as it would only be sold if the system capability permitted. The interchanged power averaged 69.9 Mw and the cost averaged 16.53 \$/Mwh. This will be treated as another power source.

Table 4.41 Public Service Co. of New Mexico Unit Costs and Capabilities

Source	Mw	\$/Mwh	@10%	@20%	@25%
Four Corners 4 & 5 (S)	208	7.00	187	166	156
San Juan (S)	550	12.38	682	606	569
Interchanged (P)	69.9	16.53	745	662	621
Tucson (P)	57.5	28.40	797	708	664
El Paso (P)	10.8	30.80	807	717	672
Tucson (P)	29.4	33.00	833	740	694
Persons (S)	96	33.96	919	817	766
Reeves (S)	175	36.69	1077	957	897
Prayer (S)	21.4	73.68	1096	974	914
Salt River (P)	2.1	73.90	1098	976	915
Las Vegas (CT)	20	76.25	1116	992	930

P - Purchases S - Steam Plant CT - Combustion Turbine

An example of the development of Table 4.42 is as follows: Select the first incident. It was a clinker with 32 weekday hours, 16 night weekday hours, 16 weekend day hours, and 9.02 weekend night hours. It occurred in November.

The loads from Table 4.40 are:

Day	707 + 98.2 = 805
Night	495 + 98.2 = 593
Weekend Day	531 + 98.2 = 629
Weekend Night	371 + 98.2 = 469

98.2 Mw is the 13% share of the outage.

The costs from Table 4.41 are:

Day	30.80
Night	12.38
Weekend Day	12.38
Weekend Night	12.38

Cost of Four Corners power is 7.00 \$/Mwh; therefore, the loss is:

32 hours (30.80 - 7.00 \$/Mwh) (98.2 Mw)	= 74,789
16 hours (12.38 - 7.00 \$/Mwh) (98.2 Mw)	= 8,453
16 hours (12.38 - 7.00 \$/Mwh) (98.2 Mw)	= 8,453
9.02 hrs. (12.38 - 7.00 \$/Mwh) (98.2 Mw)	= 4,765

Total 96,460

Table 4.42 Four Corners 4 & 5, Public Service Co. of New Mexico
Ash Related Costs

Date	Reason	Cost
Unit 4		
11/1	Clinker	96,460
1/31	Clinker	192,856
2/22	Clinker	74,062
11/4	Startup loss from clinker outage	12,434
1/9	Clinker	6,420
1/25	Clinker	7,339
1/31	Pre-outage loss clinker	12,960
2/5	Post-outage startup loss	11,554
2/22	Pre-outage loss clinker	1,814
2/24	Post-outage loss	2,407
2/27	Clinker	2,498
2/29	Clinker	4,776
3/1	Clinker	3,045
Unit 5		
3/2	Clinker	25,541
4/12	Clinker	96,605
2/14	Clinkers	24,930
2/29	Clinkers	5,474
3/1	Loss prior to clinker outage	7,087
3/8	Clinkers	1,640
3/10	Clinkers	16,435
4/10	Loss prior to clinker outage	27,476
4/15	Startup loss after clinker outage	3,518
4/16	Clinkers	28,139
4/21	Clinkers	103,010

Salt River Project

Detailed monthly peaks and outputs are not available. Its proximity to Arizona Public Service Co., however, would be a good basis for comparison. In Table 4.43, the yearly output for Salt River is compared with the monthly APS percentages, and the monthly Salt River totals are derived.

Salt River yearly Mw production (1979) - 11,149,686,231

APS yearly Mw Production (1979) - 13,005,174,276

Table 4.43 Salt River Estimated 1979 Operating Statistics

Month	APS Prod. (Mw)	APS % of Total	Salt River Prod. (Mw)	% of High Output
January	1,014,670.5	7.8	869,904	71.4
February	866,686	6.7	743,034	61.0
March	940,745	7.2	806,526	66.2
April	909,531	7.0	779,765	64.0
May	1,049,424	8.1	899,699	73.9
June	1,237,464	9.5	1,060,911	87.1
July	1,420,723	10.9	1,218,024	100.0
August	1,340,265	10.3	1,149,045	94.3
September	1,279,590	9.8	1,097,027	90.1
October	1,027,988	7.9	881,322	72.4
November	921,117	7.1	789,698	64.9
December	996,117	7.7	853,998	70.1

The assumption for the derivation of Table 4.44 Salt River Project Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November - April is 30%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 70% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM to 10PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 65% of the day load.

The equations for derivation of Table 4.44 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production}) (7 \text{ days})}{\text{No. of days in the month}}$$

$$\begin{aligned} \text{Average weekday/weekend load} &= 5 y + 2 (.7) y = 6.4y \\ \text{where } y &= \text{average weekday load} \\ (.7) y &= \text{average weekend load} \end{aligned}$$

$$\begin{aligned} \text{Average weekday/weekend load} &= 16 x + 8 (.65) x = 21.2 x \\ \text{where } x &= \text{the average day load} \\ (.65) x &= \text{the average night load} \end{aligned}$$

Table 4.44 Salt River Project Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	1324	860	927	602
December	1421	924	995	647
January	1448	941	1013	659
February	1369	890	958	623
March	1342	872	940	611
April	1341	872	939	610

Salt River's generation is comprised of nine oil and gas fired steam units, seven gas and oil fired combustion turbines, four oil and gas fired combined cycle units, seven hydro units, two pumped storage hydro units, and partial ownership in eight coal fired steam units.

Capacities are:

Coal fired steam - 1060.5
 Oil and gas fired steam - 528.5
 Oil and gas fired combustion turbine - 450
 Oil and gas fired combined cycle - 414
 Conventional hydro - 88.3
 Pumped storage hydro - 137

Pumped storage will be used to adjust Table 4.44. The day load will be decreased to reflect the output of pumped storage during the day and increased to reflect the input to the storage units.

The following assumptions will be made for evaluation:

- Unit efficiency is 70%.
- The unit will be derated for maintenance the same percentage as the other generation units (in this case 40%).
- The unit will be run 16 hours during the day for output and 8 hours during the night for input.

For the eight hour pumping period, the total capacity would be: 137 megawatts x (8 hours) = 1096 megawatt hours.

Only 70% of this power is available for day use:

1096 megawatt hours (.7) (12 hours) = 48 megawatts available for day load

@ a 40% reduction:

Night load - 137 - 40% = 82
 Day load - 48 - 40% = 29

Using these figures to adjust the generation required in Table 4.44 yields Table 4.45 Salt River Project Average Daily Loads modified for pumped storage.

Table 4.45 Salt River Project Average Daily Loads Modified for Pumped Storage

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	1242	942	845	684
December	1339	1006	913	729
January	1366	1023	931	741
February	1287	972	876	705
March	1260	954	858	693
April	1259	954	857	692

Purchased power amounted to 17% of the system's energy sources. The major suppliers will be detailed in the financial analysis. Interchange power into the system accounted for only 3% of the sources, and will be treated as an average.

Table 4.46 Salt River Project Unit Costs and Capabilities

Source	Mw	\$/Mwh	@40% Reduction
Other Hydro	46	4.84	28
Craig Trial Generation (S)	18	5.30	38
Coronado Trial Generation (S)	27	6.40	55
Haydon (S)	210	6.63	181
Parker-Davis (P)	17	6.80	191
Four Corners 4 & 5 (S)	160	7.39	287
CRSP (P)	49	7.60	316
Navajo (S)	488	8.63	609
Coronado Trial Generation (S)	20	14.10	621
Navajo (P)	86	14.30	673
Roosevelt Hydro	36	16.77	694
Mohave (S)	158	20.41	789
Stewart Mountain Hydro	13	27.36	797
Aqua Fria (S)	402	28.35	1038
Interchange (P)	41	30.80	1063
Kyrene (S)	104	37.44	1125
Kyrene (CT)	196	49.36	1243
Santan (CC)	288	57.34	1415
Aqua Fria (CT)	197	171.21	1534

P - Purchased Power

S - Steam Power

CC - Combined Cycle

CT - Combustion Turbine

An example of the derivation of Table 4.47 is as follows: The first incident is a clinker with 32 weekday hours, 16 night hours, 16 weekend day hours, and 9.02 weekend night hours. It occurred in November.

The loads from Table 4.47 are:

Day	$1242 + 76 = 1318$
Night	$942 + 76 = 1018$
Weekend Day	$845 + 76 = 921$
Weekend Night	$684 + 76 = 760$

76 Mw is the SRP portion of Four Corners 4 & 5.

The costs (Table 4.46) are:

Day	$57.34 - 7.39 = 49.95$
Night	$28.35 - 7.39 = 20.96$
Weekend Day	$28.35 - 7.39 = 20.96$
Weekend Night	$20.41 - 7.39 = 13.02$

7.39 is SRP cost of Four Corners Power.

Cost of the outage is:

Day	76 Mw (49.95 \$/Mwh) (32 hrs.) = 121,478
Night	76 Mw (20.96 \$/Mwh) (16 hrs.) = 25,487
Weekend Day	76 Mw (20.96 \$/Mwh) (16 hrs.) = 25,487
Weekend Night	76 Mw (13.02 \$/Mwh) (9.02 hrs.) = 8,925

Total 181,377

Table 4.47 Four Corners 4 & 5, Public Service Co. of New Mexico Unit Costs and Capabilities

Date	Reason	Cost
Unit 4		
11/1	Clinker	181,377
1/31	Clinker	352,356
2/22	Clinker	125,965
11/4	Startup loss from clinker outage	39,117
1/9	Clinker	26,995
1/25	Clinker	20,337
1/31	Pre-outage loss clinker	45,857
2/5	Post-outage startup loss	20,136
2/22	Pre-outage loss clinker	2,915
2/24	Post-outage loss	4,915
2/27	Clinker	5,468
2/29	Clinker	7,959
3/1	Clinker	6,192

Table 4.47 (cont'd.)

Unit 5		
3/2	Clinker	42,358
4/12	Clinker	138,460
2/14	Clinker	45,672
2/29	Clinker	8,575
3/1	Loss prior to clinker outage	18,431
3/8	Clinker	4,285
3/10	Clinker	23,377
4/10	Loss prior to clinker outage	45,627
4/15	Startup loss after clinker outage	5,502
4/16	Clinker	44,284
4/21	Clinker	169,419

4.6 Big Brown

Big Brown is owned by three utility companies: Dallas Power & Light owns 33-1/3%, Texas Electric Service Company owns 33-1/3%, and Texas Power and Light Company owns 33-1/3%.

Dallas Power & Light

The 1979 Operating Statistics are presented in Table 4.48 and is the basis of the economic study.

Table 4.48 Dallas Power & Light 1979 Operating Statistics

Month	Peak	% of High Peak	Output (Mwh)	% of High Output
January	1696	68.58	967,905	74.0
February	1705	68.94	834,593	63.8
March	1418	57.34	838,533	66.4
April	1667	67.41	802,460	61.3
May	1920	77.64	977,086	74.7
June	2457	99.31	1,149,003	87.8
July	2466	99.72	1,308,354	100.0
August	2473	100.0	1,298,099	99.2
September	2447	98.95	1,057,282	80.8
October	2189	88.52	924,691	70.7
November	1539	62.23	808,357	61.8
December	1698	68.66	889,232	68.0

The assumptions for the derivation of Table 4.49 Dallas Power & Light Co. Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November ~ April is 30%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 65% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 60% of the day load.

The equations for derivation of Table 4.49 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production})(7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5 y + 2 (.65) y = 6.3 y$$

where y = average weekday load
(.65) y = average weekend load

$$\text{Average weekday/weekend load} = 16 x + 8 (.6) x = 20.8 x$$

where x is the average day load
(.6) x is the average night load

Table 4.49 Dallas Power & Light Co. Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	1439	864	936	561
December	1532	919	996	598
January	1668	1001	1084	650
February	1592	955	1035	621
March	1497	898	973	594
April	1429	857	929	557

The Dallas Power & Light system is comprised of fifteen gas fired steam plants, 33-1/3% of Big Brown, 20% of Monticello 1 & 2, and 21.7% of Martin Lake.

Capabilities are:

Gas fired steam - 3089 Mw

Lignite fired steam = 1071 Mw

Purchased power accounted for an average of 18.6 Mw at a cost of 12.30 \$/Mwh.

Interchanged power averaged 1259 Mw at no cost (repayment in kind). Since this interchange power was with the same associated utilities as the purchased power, this power will be priced the same as the purchased power for the purposes of this study.

Table 4.50 summarizes the sources of generation and the costs.

Table 4.50 Dallas Power & Light Co. Unit Costs and Capabilities

Source	Mw	\$/Mwh	Total Load Capability
			@40%
Big Brown	383	7.64	230
Monticello	238	10.38	373
Martin Lake	488	11.25	665
Interchange & Purchase	1278	12.30	1432
North Lake	700	23.49	1852
Lake Hubbard	890	24.00	2386
Mountain Creek	893	31.96	2922
Parkdale	327	34.24	3118
Dallas	145	39.67	3205

Big Brown Costs:

As an example of the development of Table 4.51, select the first incident, a bottom ash clinker costing 100 Mw for 7.67 hours. The entire loss occurred during off peak hours. $100 \text{ Mw} (.333) = 33 \text{ Mw}$ loss for Dallas Power & Light Co. The load levels for November were 864 Mw (Table 4.49).

$$864 + 33 = 897 \text{ Mw}$$

The cost levels for this load in November were 12.30 \$/Mwh. (Table 4.50)

$$12.30 \text{ \$ /Mwh} - 7.64 \text{ \$ /Mwh} = 4.66 \text{ \$ /Mwh}$$

$$33 \text{ Mw} (4.66 \text{ \$ /Mwh}) (7.67 \text{ hours}) = \$1179$$

Table 4.51 Big Brown, Dallas Power & Light Co. Ash Related Costs

Date	Time	Reason	Cost
Unit 1			
11/7	22:35	Bottom ash clinkers	1179
1/7	1:42	Dirty boiler	3260
4/23	1:25	Boiler slagging	254
Unit 2			
12/28	5:38	Boiler slagging	417
1/17	16:40	Boiler slagging	1954
4/21	10:30	Bridge in ash hopper	33,034

Texas Electric Service Co.

The 1979 Operating Statistics are presented in Table 4.52 as a basis for the study.

Table 4.52 Texas Electric Service Co. 1979 Operating Statistics

Month	Peak	% of High Peak	Output	% of High Output
January	2938	78.94	1,930,809	92.75
February	2932	78.77	1,644,760	79.01
March	2541	68.27	1,678,869	81.08
April	2682	72.06	1,514,899	72.77
May	2755	74.02	1,541,777	74.06
June	3643	97.93	1,800,555	86.49
July	3722	100.00	2,081,796	100.00
August	3634	97.64	2,010,097	96.56
September	3610	96.99	1,906,687	91.59
October	3292	88.45	1,615,000	77.58
November	2764	74.26	1,509,840	72.53
December	2955	79.32	1,588,819	76.32

The assumptions for the derivation of Table 4.53 Texas Electric Service Co. Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the months of November - February is 20%, March and April is 25%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.

4. Both out of service percentages will apply to all power sources.
5. The average weekend load will be 75% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 70% of the day load.

The equations for derivation of Table 4.53 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production})(7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5 y + 2 (.75) y = 6.5 y$$

where y = average weekday load
 (.75) y = average weekend load

$$\text{Average weekday/weekend load} = 16 x + 8 (.70) x = 21.6 x$$

where x is the average day load
 (.70) x is the average night load

Table 4.53 Texas Electric Service Co. Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	2509	1756	1882	1317
December	2555	1789	1916	1342
January	3105	2174	2329	1630
February	2929	2050	2197	1538
March	2700	1890	2025	1418
April	2518	1762	1888	1322

Texas Electric Service Co.'s generation is comprised of twenty-three gas and oil fired steam units, 28.3% of Martin Lake Lignite fired, 33-1/3% of Big Brown, 30% of Monticello 1 & 2, and 50% of Monticello 3.

Capabilities are:

Gas and oil fired steam - 4412 Mw
 Lignite fired steam - 1466 Mw

Purchased power averaged 50 Mw at a cost of 11.83 \$/Mwh.

Interchanged power averaged 1144 Mw at no cost. (Repayment in kind.)

Since no cost was listed, and interchange was among associated utilities, the loss will be assumed to be the same as purchased power.

Table 4.54 summarizes the unit costs and their capabilities.

Table 4.54 Texas Electric Service Co. Unit Costs and Capabilities

Source	Mw	\$/Mwh	Total Load Capabilities	
			@30%	@35%
Big Brown	383	7.64	268	249
Graham	615	8.51	699	649
Morgan Creek	813	8.73	1268	1177
Handley	1375	9.80	2230	2071
Permian Basin	708	9.90	2726	2531
Monticello	753	10.38	3253	3021
Martin Lake	637	11.25	3699	3435
Interchanged and Purchased Power	1194	11.83	4535	4211
Eagle Mountain	665	12.32	5000	4643
North Main	80	21.57	5056	4695

Big Brown Costs:

As an example of the development of Table 4.55, select the first incident, a bottom ash clinker costing 100 Mw for 7.67 hours. The entire loss occurred during off peak hours. $100 \text{ Mw} (.333) = 33 \text{ Mw}$ loss for TESC. The load levels for November were 1756 Mw (Table 4.60).

$$1756 + 33 = 1789 \text{ Mw}$$

The cost levels at this load in November were 9.80 \$/Mwh.

$$9.80 - 7.64 = 2.16 \text{ $/Mwh}$$

$$33 \text{ Mw} (7.67) (2.16) = \$546$$

Table 4.55 Big Brown, Texas Electric Service Co. Ash Related Costs

Date	Hour	Reason	Cost
Unit 1			
11/7	22:35	Bottom Ash Clinker	546
1/7	1:42	Dirty boiler	699
4/23	1:25	Boiler slagging	118
Unit 2			
12/28	5:38	Boiler slagging	59
1/17	16:40	Boiler slagging	407
4/21	10:30	Bridge in ash hopper	7006

Costs of curtailments for this station are low due to the excellent reserve position of this utility and the low costs of all of their generation.

Texas Power & Light Co.

The 1979 Operating Statistics are presented in Table 4.56 as the basis of the economic study.

Table 4.56 Texas Power & Light Co. 1979 Operating Statistics

Month	Peak	% of High Peak	Output (Mwh)	% of High Output
January	4099	80.9	2,342,141	69.0
February	4150	81.9	1,998,875	58.9
March	3357	66.3	1,972,876	58.1
April	3352	66.2	1,876,603	55.3
May	3572	70.5	1,953,978	57.6
June	5037	99.4	2,390,343	70.5
July	5052	99.7	2,775,836	81.8
August	5067	100.0	2,825,628	83.3
September	4957	97.8	3,392,787	100.0
October	4410	87.0	2,161,467	63.7
November	3834	75.7	1,888,517	55.7
December	4088	80.7	2,102,399	62.0

The assumptions for the derivation of Table 4.57 Texas Power & Light Co. Average Daily Load Statistics are:

1. 1980 load levels are unchanged from the 1979 levels.
2. The generation assumed to be out of service for scheduled maintenance in the month of November is 15%, in December - February is 20%, and in March and April is 30%.
3. The generation assumed to be out of service for unscheduled maintenance is 10%.
4. Both the out of service percentages will apply to all power sources.
5. The average weekend load will be 65% of the weekday load.
6. The daily loads will be divided as follows:
 - a. Sixteen hours (6AM - 10PM) will be the day load.
 - b. Eight hours (10PM - 6AM) will be the night load at 60% of the day load.

The equations for derivation of Table 4.57 are:

$$\text{Average weekly load} = \frac{(\text{Monthly Mwh Production})(7 \text{ days})}{\text{No. of days in the month}}$$

$$\text{Average weekly load} = 5y + 2(.65)y = 6.3y$$

where y = average weekday load
(.65) y = average weekend load

$$\text{Average weekday/weekend load} = 16x + 8(.6)x = 20.8x$$

where x is the average day load
16 x is the average night load

Table 4.57 Texas Power & Light Co. Average Daily Loads

Month	Weekday		Weekend	
	Day Load	Night Load	Day Load	Night Load
November	3363	2018	2186	1311
December	3623	2174	2355	1413
January	4036	2422	2623	1574
February	3813	2288	2479	1487
March	3400	2040	2210	1326
April	3342	2005	2172	1303

The Texas Power & Light Co. system is comprised of fourteen gas fired steam units, 33-1/3% of Big Brown, 50% of Martin Lake, and 50% of Monticello.

System capabilities are:

Lignite fired steam - 2458 Mw
Gas fired steam - 4780 Mw

Purchased power amounted to 88 Mw average at a cost of 6.13 #/Mwh.

Interchanged power averaged 2232 Mwh. No costs were involved.

91% was interchanged between associated utilities (Dallas Power & Light and Texas Electric Service Co.)

In order to place a cost on the power for evaluation, the costs of the associated utilities' interchanges and purchases will be used. This average cost is 12.07 \$/Mwh.

Table 4.58 Texas Power & Light Co. Unit Costs and Capabilities

Source	Mw	\$/Mwh	Total Load Capabilities		
			@25%	@30%	@40%
Purchases	88	6.13	66	62	53
Big Brown	383	7.64	353	330	283
Stryker Creek	685	8.62	867	809	694
Monticello	950	10.38	1580	1474	1264
Mountain Lake	1125	11.25	2423	2262	1939
Interchanges	2232	12.07	4097	3824	3278
DeCordova	775	21.25	4679	4367	3743
Tradinghouse	1340	21.74	5684	5305	4547
Valley	1100	21.83	6509	6075	5207
Lake Creek	323	24.92	6751	6301	5401
Collin	153	28.65	6866	6408	5492
River Crest	110	35.75	6948	6485	5558
Trinidad	314	37.94	7184	6705	5747

Big Brown Costs:

As an example of the development of Table 4.59, select the first incident, a bottom ash clinker costing 100 Mw for 7.67 hours. The entire loss occurred during off peak hours. $100 \text{ Mw} (.333) = 33 \text{ Mwh}$ loss for Texas Power & Light Co.

The load levels for November were 2018 Mw (Table 4.58).

$$2018 + 33 = 2051 \text{ Mw}$$

The costs at this load level are 11.25 \$/Mwh.

$$11.25 - 7.64 = 3.61 \text{ $/Mwh}$$

$$33 \text{ Mw} (3.61 \text{ $/Mwh})(7.67 \text{ hours}) = \$914$$

Table 4.59 Big Brown, Texas Power & Light Co. Ash Related Costs

Date	Hour	Reason	Cost
Unit 1			
11/7	22:35	Bottom ash clinkers	914
1/7	1:42	Dirty boiler	2842
4/23	1:25	Boiler slagging	241
Unit 2			
12/28	5:38	Boiler slagging	117
1/17	16:40	Boiler slagging	705
4/21	10:30	Bridge in ash hopper	28,751

4.7 Monticello

The Monticello units are owned jointly by three utility companies; Dallas Power & Light Co. owns 20% of units 1 & 2, Texas Electric Service Co. owns 30% of units 1 & 2 and 50% of unit 3, Texas Power and Light Co. owns 50% of units 1, 2 and 3.

Referencing the appropriate tables in section 4.6 for the three utilities, the following cost tables are developed:

Dallas Power & Light Co.

Unit three, the only Monticello unit with slagging costs, is not owned by Dallas Power & Light Co.

Texas Electric Service Co.

Only two curtailments were found which could be construed as ash problems. Because of the utility's reserve position and because of Monticello's position in the utility for generation costs, these curtailments were without cost to the utility.

Texas Power & Light Co.

Referencing Tables 4.57 and 4.58, and utilizing the techniques developed for Texas Power and Light Co. Big Brown Costs, Table 4.60 was developed.

Table 4.60 Monticello, Texas Power & Light Co. Ash Related Costs

Date	Hour	Reason	Cost
Unit 3			
1/10	14:30	High reheat temperature	25
3/3		High reheat temperature	65

These costs at Monticello are very low, principally because the curtailments were very small (10 Mw) and very short (2-1/2 hours the longest).

4.8 Financial Summary

Table 4.61 details the costs associated with each ash related problem encountered in the six month study.

Table 4.68 Summary of Ash Related Costs

Unit	High Superheat Temperature	Low Superheat Temperature	Clinkers	Convection Fouling	Supplemental Oil Firing	Sootblower Cut Tube Leaks	Capacity Loss	Total
<u>St. Clair</u>								
Detroit Edison								
1		--	--	--	205,288	--	1,135,566	1,340,854
2	--	--	--	--	--	--	1,095,010	1,095,010
3	5,091	--	--	--	122,556	--	1,095,010	1,222,657
4	--	--	--	--	247,618	--	1,135,566	1,383,184
6	7,024	--	--	267,471	--	--	2,230,576	2,505,071
7	458,581	--	--	--	--	--	3,447,254	3,905,835
St. Clair Total	470,696	--	--	267,471	575,462	--	10,138,982	11,452,611
<u>Big Stone</u>								
Otter Tail Power Co.								
1	--	77,307	--	917,621	--	--	--	994,928
Montana-Dakota Utilities								
1	--	52,894	--	1,375,315	--	--	--	1,428,209
Northwestern Public Service Co.								
1	--	32,550	--	856,100	--	--	--	888,650
Big Stone Total	--	162,751	--	3,149,036	--	--	--	3,311,787
<u>Leland Olds</u>								
Basin Electric Power Cooperative								
1	--	--	33,303	909,496	--	363,603	--	1,306,402
2	--	--	--	2,881,288	1,258,364	35,280	--	4,174,932
Leland Olds Total	--	--	33,303	3,790,784	1,258,364	398,883	--	5,481,334

Four Corners

Arizona Public Service Co.

1	2,907	--	3,687	71,031	--	--	--	77,625
2	--	--	--	328,050	--	--	--	328,050
3	--	--	19,408	578,335	--	--	--	597,743
4	--	--	752,870	--	--	--	--	752,870
5	--	--	616,159	--	--	--	--	616,159

Total	2,907	--	1,392,124	977,416	--	--	--	2,372,447
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Tucson Electric Power Co.

4	--	--	393,795	--	--	--	--	393,795
5	--	--	90,864	--	--	--	--	90,864

Total	--	--	484,659	--	--	--	--	484,659
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El Paso Electric Co.

4	--	--	367,686	--	--	--	--	367,686
5	--	--	138,397	--	--	--	--	138,397

Total	--	--	506,083	--	--	--	--	506,083
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Southern California Edison Co.

4	--	--	2,696,804	--	--	--	--	2,696,804
5	--	--	2,234,718	--	--	--	--	2,234,718

Total	--	--	4,931,522	--	--	--	--	4,931,522
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Public Service Co. of New Mexico

4	--	--	428,625	--	--	--	--	428,625
5	--	--	339,855	--	--	--	--	339,855

Total	--	--	768,480	--	--	--	--	768,480
-------	----	----	---------	----	----	----	----	---------

Salt River Project

4	--	--	1,020,407	--	--	--	--	1,020,407
5	--	--	365,172	--	--	--	--	365,172

Total	--	--	1,385,579	--	--	--	--	1,385,579
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Four Corners

Total	2,907	--	9,468,447	977,416	--	--	--	10,448,770
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Big Brown

Dallas Power & Light Co.

1	3,514	--	1,179	--	--	--	4,693
2	2,371	--	33,034	--	--	--	35,405
Total	5,885	--	34,213	--	--	--	40,098

Texas Electric Service Co.

1	817	--	546	--	--	--	1,363
2	466	--	7,006	--	--	--	7,472
Total	1,283	--	7,552	--	--	--	8,835

Texas Power & Light Co.

1	3,083	--	914	--	--	--	3,997
2	822	--	28,751	--	--	--	29,573
Total	3,905	--	29,665	--	--	--	33,570

Big Brown

Total	11,073	--	71,430	--	--	--	82,503
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Monticello

Dallas Power & Light Co.

No Costs

Texas Electric Service Co.

No Costs

Texas Power & Light Co.

1	--	--	--	--	--	--	--
2	--	--	--	--	--	--	--
3	90	--	--	--	--	--	90

Monticello

Total	90	--	--	--	--	--	90
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Total Study
Costs

484,766	162,751	9,573,180	8,184,707	1,833,826	398,883	10,138,982	30,777,095
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5.0 Coal Analyses

In addition to review of the units performance, coal samples were delivered to GFETC for analysis. The GFETC analysis consisted of percent sulphur, ash, and moisture analysis, plus an ash constituent analysis.

Data was also gathered from the station coal analyses and presented in section 5.2.

This section details the methods of sample gathering by the stations and the results of all analyses.

5.1 Sampling Systems

St. Clair Station

(See pages 102 and 111 for analysis results.)

The samples analyzed by the GFETC are daily grab samples from the plant belts. These are not mixed with other samples.

The station analysis is weekly composite samples analyzed by the Detroit Edison system laboratory. This sample comes from an elaborate sampling system comprised of primary samplers taking 35 cuts per 1000 tons (.125%), a sample crusher, a secondary sampler taking a 3.84% cut, and a storage bin and tertiary sampler for taking samples during the last 15 minutes of each day.

Big Stone Station

(See pages 103 and 112 for analysis results.)

Both the plant samples and those sent to GFETC for analysis were samples taken from the plant conveying system.

This system is comprised of a device which enters the hopper into which the plant conveyors empty. This device has an opening of approximately 3" x 3". It enters the duct slowly, extending in about 12". The device is triggered once every 10 minutes. It can sample from either plant conveyor, these samples being separately collected.

It was noted that the sample collected appeared to contain a disproportionate amount of fines as compared to the coal on the plant belt. The system is simple, but only draws from one small area on only one side of the duct.

Leland Olds

(See pages 104 and 113 for analysis results.)

Both the plant samples and those taken to GFETC are taken from the plant sampling system.

This system draws 1.3 tons per hour from the mine conveyors. This is fed to a sample crusher into a secondary sampler feeding 10.5 lb./hour into a sample container. This is an excellent sampling system, but two problems exist in determining the sample actually fired in the boiler.

1) The sample is taken from the stack out conveying system. If mine deliveries are low, some coal will be taken from the dead storage pile for burning in the unit. During the study period deliveries were low; therefore, this is a significant factor.

2) About 20% of the coal supply has been taken from a neighboring utility. Although samples are taken, these are the utility's mine samples. Coal is removed from their storage pile and placed in the Leland Olds dead storage pile to be dozed into the live storage as required. It is impossible to determine when this coal was burned in the boiler. GFETC did not analyze this coal as it was not included in the sample sent. Data does exist for this sample, and will be included in this report.

Jim Bridger

(See pages 105 and 114 for analysis results.)

The sampling system was not in operation during this study. Both the samples analyzed by GFETC and the station were daily grab samples.

Four Corners

(See pages 106 and 115 for analysis results.)

The station sampling system takes one 400 lb. cut every 28 tons of coal conveyed. Thirty-five cuts go into a bin which is riffled into one sample. One of these daily samples was sent in every week to the GFETC for analysis.

Big Brown

(See pages 107-108 and 116-117 for analysis results.)

A daily grab sample was taken at the tripper conveyor. This sample was mixed weekly and sent to GFETC. This sample was also used for station analysis. One such sample was taken for each unit.

Monticello

(See pages 109-110 & 118-120 for analysis results.)

Grab samples are taken once per shift from the tripper belt of each unit. A weekly composite is made of these three samples and used for station analysis and was sent to the GFETC.

5.2 Coal Analysis Data

In this section, the GFETC results are listed, along with station data of a similar date, if available.

Table 5.1 Coal Analyses Data

St. ClairGFETC Analysis

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TiO2</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>NA2O</u>	<u>K2O</u>	<u>SO3</u>
11/29/79	.35	4.0	24.2	28.8	15.1	6.8	1.7	1.0	15.0	3.2	7.4	0.3	20.3
11/26/79	.25	3.3	23.5	26.6	17.8	5.5	1.7	.9	16.4	3.5	6.7	0.6	19.7
12/02/79	.36	4.3	23.3	30.6	16.9	6.5	1.7	1.0	13.9	3.5	6.2	0.5	18.7
12/05/79	.32	3.8	24.9	24.1	16.2	6.9	1.7	1.3	16.3	4.0	7.2	0.4	21.6
12/09/79	.39	4.5	21.8	31.8	17.3	6.5	1.6	1.0	13.7	3.2	6.1	0.4	17.8
12/13/79	.32	3.6	22.9	28.7	17.0	5.7	2.0	1.2	15.6	3.7	7.7	0.4	18.0
12/17/79	.34	3.3	23.4	34.4	14.2	6.3	0.8	0.6	21.3	3.9	1.2	0.4	16.7
12/19/79	.32	4.0	21.6	27.5	17.3	7.0	1.8	1.1	15.0	3.2	7.3	0.6	18.8
12/24/79	.22	3.9	22.2	30.8	17.2	5.4	1.9	1.1	17.3	3.7	7.3	0.3	14.3
1/01/80	.73	5.8	21.2	36.3	17.8	9.0	1.3	0.9	10.2	2.7	4.8	0.9	15.7
1/04/80	.31	3.8	25.7	25.2	16.9	6.3	1.8	1.1	15.8	3.7	8.7	0.3	19.5
1/09/80	.25	3.4	25.9	26.1	14.9	6.9	1.8	1.1	16.7	3.5	8.1	0.5	20.0
1/12/80	.28	3.6	26.3	26.5	16.0	5.9	1.6	1.1	15.2	3.5	7.9	0.3	21.4
1/16/80	1.21	5.7	20.0	35.9	17.9	11.3	1.1	0.8	9.9	2.6	3.7	1.0	15.4
1/20/80	.33	4.9	27.1	36.4	17.7	5.8	1.7	0.8	12.8	3.3	5.7	0.6	14.9
1/29/80	.72	5.4	22.4	30.9	17.8	10.3	1.5	0.9	10.9	2.8	5.7	0.9	18.0
2/01/80	.47	5.0	23.5	26.5	16.3	9.9	1.6	1.0	13.1	3.5	6.3	0.6	20.5
2/02/80	.61	5.3	21.8	27.7	17.0	9.4	1.5	1.1	11.9	2.7	5.8	0.8	21.5
2/03/80	.60	4.9	19.2	26.1	17.3	9.5	1.6	1.0	13.1	3.0	6.5	0.5	20.9
2/04/80	1.13	7.4	17.6	33.4	18.1	12.2	1.3	0.8	10.2	2.7	4.1	1.0	15.7
2/10/80	.51	4.7	23.9	31.9	17.0	7.8	1.5	0.8	12.8	3.0	6.7	0.6	17.4
2/12/80	.51	4.5	24.6	27.7	16.2	9.3	1.6	1.1	13.2	3.1	7.1	0.6	19.7
2/13/80	.3	5.0	23.0	32.6	16.5	6.3	1.6	1.1	11.8	3.3	6.5	0.3	19.2
2/14/80	.39	4.4	23.3	28.3	17.1	6.9	1.7	1.1	14.1	3.4	7.7	0.5	18.8
2/15/80	.31	4.0	24.3	24.3	16.8	6.7	1.8	1.2	15.9	3.6	8.5	0.3	20.5
2/16/80	.29	3.6	23.8	21.8	16.6	6.8	1.8	1.1	16.2	4.2	9.1	0.4	21.6
2/17/80	.46	3.9	20.7	25.7	17.0	7.9	1.7	1.2	14.3	3.4	6.5	0.6	21.3
2/18/80	.32	3.8	24.0	23.8	17.4	7.1	1.9	1.1	15.7	3.5	7.4	0.6	20.9
2/19/80	.36	4.3	22.4	28.1	17.0	7.1	1.7	1.0	13.5	3.3	7.4	0.6	19.7
2/20/80	1.46	6.2	17.1	31.6	18.4	15.3	1.2	0.8	8.7	2.6	5.3	1.0	14.6
2/21/80	.36	4.3	23.3	25.4	17.2	8.1	1.7	1.1	14.0	3.3	7.3	0.5	20.9
2/22/80	.56	4.5	24.4	29.3	16.7	9.1	1.5	1.1	12.0	2.9	6.3	0.6	19.9
2/23/80	.42	3.5	24.6	25.0	11.7	7.2	1.0	1.0	17.8	6.3	4.9	0.4	24.1
2/24/80	.58	4.6	25.6	24.7	16.1	6.0	1.9	1.2	16.3	3.5	8.5	0.2	21.1

Station AnalysisAs Received

<u>Week Ending</u>	<u>Moisture</u>	<u>Ash</u>	<u>Sulphur</u>	<u>BTU</u>	<u>Week Ending</u>	<u>Moisture</u>	<u>Ash</u>	<u>Sulphur</u>	<u>BTU</u>
11/06/79	22.09	4.74	.51	9856	2/19/80	23.82	4.08	.38	9643
11/13/79	21.66	4.63	.45	9800	2/26/80	24.67	4.62	.56	9616
11/27/79	21.91	4.66	.58	9896	3/04/80	24.46	4.61	.51	9520
12/04/79	23.44	4.63	.47	9566	3/11/80	24.58	4.70	.55	9495
12/11/79	22.47	4.51	.44	9732	3/18/80	25.15	4.06	.39	9425
12/28/79	21.34	4.84	.72	10012	3/28/80	24.42	4.93	.63	9294
1/08/80	22.87	4.67	.52	9794	4/08/80	23.45	4.67	.55	9550
1/15/80	20.91	5.32	.77	10079	4/15/80	24.13	5.13	.53	9681
1/22/80	22.25	5.01	.70	9904	4/27/80	22.30	4.92	.60	9844
1/28/80	23.53	4.39	.47	9799	5/06/80	21.00	4.88	.60	9856
2/05/80	22.60	4.90	.58	9901	5/13/80	22.78	4.79	.49	9721
2/12/80	24.75	4.68	.51	9572					

Big Stone
GFETC Analysis

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TiO2</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>NA2O</u>	<u>K2O</u>	<u>SO3</u>
10/28/79	1.16	10.7	16.8	26.5	10.5	6.5	1.1	0.7	21.5	7.7	3.4	0.2	21.2
11/05/79	1.43	11.6	13.8	22.7	8.8	9.1	1.0	0.9	20.1	7.6	3.0	0.1	25.6
11/11/79	1.53	11.0	10.8	17.1	8.9	8.7	0.8	0.9	23.7	8.2	3.3	0.9	27.9
11/18/79	1.64	12.1	11.2	21.1	9.3	9.8	1.1	0.8	20.0	7.7	3.8	0.1	25.9
11/25/79	1.33	12.0	13.2	23.2	9.7	4.7	1.0	0.8	22.7	8.1	3.9	0.1	25.0
12/02/79	1.36	11.0	10.3	24.5	10.0	5.0	1.0	0.9	21.1	8.1	3.6	0.2	25.0
12/09/79	1.32	11.8	9.5	27.0	9.2	4.8	1.2	0.8	20.1	7.9	4.1	0.2	24.0
12/16/79	1.21	11.2	10.8	21.9	9.6	5.4	0.9	0.9	22.0	8.5	4.1	0.1	26.0
12/23/79	1.31	11.1	9.9	22.2	9.9	6.0	1.1	0.9	22.6	8.1	3.6	0.1	24.9
12/30/79	1.46	11.8	10.3	22.6	9.5	7.4	1.6	0.9	20.2	7.2	3.7	0.1	26.2
1/13/80	1.57	12.5	10.8	21.0	9.5	5.7	4.4	0.9	19.6	7.5	3.8	0.2	27.0
1/20/80	1.30	12.9	9.9	29.5	11.5	5.2	1.4	1.0	20.2	6.9	2.1	0.2	21.4
1/27/80	1.35	12.7	8.9	28.6	12.1	4.9	1.1	0.9	19.6	6.9	3.3	0.2	21.5
2/03/80	1.37	11.3	9.6	22.4	12.2	6.1	0.9	0.9	20.7	7.8	4.6	0.1	23.6
2/10/80	1.39	13.2	9.3	27.1	11.6	6.3	1.1	0.9	18.2	6.9	3.9	0.3	22.9
2/17/80	1.19	12.6	10.9	30.5	11.8	5.2	1.1	0.8	18.4	6.3	5.1	0.3	19.9
3/02/80	1.28	12.9	8.9	30.6	10.9	5.5	1.0	0.6	19.4	6.9	4.1	0.4	20.0
3/09/80	1.23	12.0	10.5	27.9	10.4	5.1	1.3	0.7	21.0	7.1	5.4	0.2	20.3
3/30/80	1.29	12.8	9.8	26.9	10.2	5.2	1.0	0.8	19.2	7.0	5.6	0.3	23.3
4/06/80	1.20	12.5	12.5	27.9	11.7	5.1	1.0	0.7	20.4	7.2	3.8	0.3	21.3
4/20/80	1.10	9.5	41.4	26.8	11.8	6.6	2.0	1.0	16.5	6.6	5.0	0.4	22.9
4/27/80	.83	8.7	39.9	29.0	16.3	6.0	1.7	1.1	15.0	3.5	7.0	0.4	19.6
5/04/80	.70	9.0	40.1	35.7	11.8	4.2	1.3	0.7	16.3	6.1	3.1	0.3	19.9
5/11/80	.86	9.1	40.4	31.1	11.9	6.0	1.1	0.8	17.1	6.4	3.7	0.3	21.0
5/18/80	.90	8.1	33.9	29.3	11.7	6.9	1.1	0.9	17.0	5.7	4.6	0.3	22.0

Station Analysis

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>Sulphur</u>	<u>% NA2O in Ash</u>	<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>Sulphur</u>	<u>% NA2O in Ash</u>
10/28/79	5997	43.88	7.08	.65	3.73	12/30/79	5964	45.08	7.02	.70	2.87
11/05/79	6189	43.36	7.01	.55	4.11	1/13/80	6080	44.00	6.35	.68	3.71
11/11/79	6080	42.08	6.55	.86	3.20	1/20/80	6145	42.38	8.05	.74	2.67
11/19/79	6640	32.65	9.58	.93	3.20	1/27/80	6115	44.06	6.94	.66	2.78
11/25/79	6475	44.73	7.93	.71	3.20	2/03/80	6206	44.20	6.48	.84	2.61
12/02/79	6252	42.21	6.91	.71	3.83	2/10/80	6165	43.79	7.15	.61	2.84
12/09/79	6274	40.66	6.53	.74	3.89	2/17/80	5380	51.10	6.11	.63	3.68
12/16/79	5942	44.40	6.39	.59	3.92	4/06/80	6273	41.47	7.66	.80	4.04
12/23/79	6126	43.47	6.71	.50	3.62	4/20/80	6021	44.16	6.99	.58	6.40

Monthly Averages

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>Sulphur</u>	<u>% NA2O in Ash</u>
Nov.	6128	42.60	7.71	.75	3.09
Dec.	6124	43.23	7.03	.68	3.73
Jan.	6076	43.65	7.39	.67	3.07
Feb.	5949	44.30	7.04	.82	3.27
April	6243	41.78	7.28	.68	4.42
June	6096	40.56	8.28	.79	3.46

Leland Olds

GFETC Analysis

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TiO2</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>NA2O</u>	<u>K2O</u>	<u>SO3</u>
11/06/79	.32	10.8	30.5	40.4	13.2	5.8	0.9	0.3	14.8	4.6	6.3	1.5	11.6
11/14/79	.41	8.8	35.6	39.3	13.4	5.8	1.0	0.3	15.7	4.9	5.7	1.7	12.0
11/26/79	.46	10.1	36.4	39.3	14.2	6.5	0.8	0.4	11.9	4.2	7.3	1.7	13.2
12/03/79	.54	8.1	35.6	35.3	12.3	7.7	0.9	0.4	16.2	4.6	6.1	1.4	14.7
12/10/79	.47	8.4	36.2	33.1	10.5	7.2	0.9	0.4	17.2	5.3	8.7	0.9	15.6
12/17/79	.50	8.4	36.1	37.3	12.5	6.3	0.9	0.5	13.4	4.4	6.8	1.5	15.8
12/26/79	.40	9.2	35.6	36.4	12.0	6.4	0.9	0.5	14.4	4.9	7.7	1.5	15.0
12/31/79	.48	9.2	37.2	38.0	12.6	6.0	0.9	0.4	13.5	4.6	8.4	1.3	13.8
1/07/80	.43	9.0	36.6	38.9	13.2	6.8	0.9	0.4	13.7	4.7	6.2	1.6	13.4
1/14/80	.37	7.2	37.2	31.9	11.8	7.2	1.0	0.4	17.7	5.6	8.0	1.1	15.0
1/15/80	.40	7.8	36.8	34.4	12.0	7.6	0.9	0.4	15.5	5.0	7.4	1.4	15.0
1/23/80	.36	11.6	35.3	40.5	14.4	5.6	0.9	0.3	13.1	5.0	6.2	1.6	11.6
1/29/80	.54	11.6	35.3	40.5	14.4	6.4	0.8	0.4	10.7	4.7	5.9	1.7	14.1
2/07/80	.44	10.7	34.2	43.7	12.8	6.3	1.0	0.4	12.9	4.4	4.3	1.2	12.2
2/13/80	.42	11.8	34.4	41.5	14.3	6.1	1.0	0.3	12.3	4.8	5.2	2.0	12.2
2/18/80	.5	10.8	34.4	39.2	14.5	6.3	0.9	0.4	12.9	4.6	4.9	1.7	14.1
2/29/80	.51	10.8	36.6	40.9	14.2	6.7	0.8	0.3	12.2	3.8	4.8	1.4	13.9

Station Analysis

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>% NA2O in Ash</u>	<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>% NA2O in Ash</u>
11/06/79	6490	36.92	9.36	4.17	12/10/79	6600	38.18	7.42	4.47
11/14/79	6750	36.13	8.50	4.00	12/17/79	6720	35.80	8.74	4.47
11/26/79	6260	36.43	11.83	3.75	12/26/79	6600	36.73	8.62	3.05
12/03/79	6730	37.07	7.99	3.75	12/31/79	6640	36.41	9.06	2.95

Monthly Averages

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>% NA2O in Ash</u>	<u>% of Total</u>
Nov.					
Consolidation	6422	33.6	9.63	4.09	39.16
UPA	7194	31.58	9.77	3.79	10.34
Dec.					
Consolidation	6629	36.89	8.41	3.37	89.45
UPA	7210	32.74	8.44	2.81	10.55
March					
Consolidation	6590	37.16	8.66	4.98	96.17
UPA	6919	32.93	10.18	4.51	3.83
April					
Consolidation	6649	37.01	8.44	6.17	96.62
UPA	7224	31.91	9.46	5.73	3.33

Jim Bridger

GFETC Analysis

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>Al2O3</u>	<u>Fe2O3</u>	<u>TiO2</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>Na2O</u>	<u>K2O</u>	<u>SO3</u>
11/28/79	.6	9.6	8.8	53.3	15.5	5.4	1.1	0.4	8.0	3.0	1.4	0.3	11.1
12/10/79	.29	17.3	20.0	75.9	15.5	2.0	1.6	0.3	0.9	1.3	0.7	0.2	1.2
12/21/79	.50	19.9	9.6	65.1	12.9	3.4	1.0	0.3	6.0	2.1	1.3	0.4	7.2
12/27/79	.57	11.5	13.6	59.8	14.8	4.2	1.1	0.4	6.4	2.5	1.5	0.3	8.6
1/03/80	.47	5.1	20.9	46.3	20.9	1.4	1.4	0.6	9.3	5.2	0.9	0.1	13.4
1/14/80	.38	6.0	23.9	39.4	16.0	7.1	1.0	0.4	12.7	6.0	2.6	0.1	13.9
1/22/80	.50	10.7	16.1	57.7	15.8	3.4	1.2	0.4	5.8	2.8	2.9	0.6	8.9
2/25/80	.78	11.1	24.3	37.7	14.8	7.3	1.2	0.5	15.8	3.9	0.5	0.6	17.2

Station Analysis

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>	<u>Sulphur</u>
12/10/79	9120	20.02	9.9	.49
12/22/79	9607	14.92	9.81	.61
12/27/79	9562	17.0	10.6	.51
1/03/80	9093	19.5	10.1	.73
1/14/80	9398	17.92	13.63	.57
1/22/80	9531	19.13	17.4	.19
2/25/80	10297	14.46	12.29	.60

Monthly Averages

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
Dec.	9370	18.02	12.40
Jan.	9260	13.28	12.03
Feb.	9549	18.04	11.66
March	9273	19.42	11.23
April	9846	19.0	10.27

Four Corners

GFETC Analysis

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TiO2</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>NA2O</u>	<u>K2O</u>	<u>SO3</u>
12/09/79	.80	22.8	5.4	56.5	25.2	4.8	0.9	0.2	3.6	2.0	2.2	0.9	3.3
12/23/79	1.00	23.4	5.2	57.5	23.9	5.5	0.9	0.1	4.1	1.8	1.4	0.9	3.3
12/30/79	.84	24.5	5.5	57.7	25.1	4.6	0.9	0.2	3.3	1.9	2.1	0.9	2.8
1/06/80	.87	24.6	5.2	56.5	25.8	4.9	0.9	0.2	3.5	1.8	2.0	0.8	3.0
1/13/80	.87	24.1	4.9	56.9	25.5	4.8	1.0	0.2	3.4	2.0	2.0	0.8	3.5
1/20/80	.83	25.5	5.8	56.3	25.2	5.0	1.0	0.1	3.9	2.1	1.8	0.9	3.5
2/03/80	.86	23.7	5.7	57.1	25.3	4.5	0.9	0.2	4.1	1.8	1.4	0.8	3.5
2/10/80	.81	23.3	5.6	56.8	25.7	4.7	1.0	0.1	3.4	1.9	2.0	0.8	3.1
2/24/80	.88	24.8	4.6	57.3	25.9	4.1	0.9	0.2	3.5	2.0	1.5	0.7	3.4
3/09/80	.84	24.2	4.5	59.2	26.0	4.0	1.0	0.1	3.0	1.8	1.0	0.8	2.7
3/16/80	.84	24.5	4.4	58.9	25.9	4.1	0.9	0.1	2.9	1.9	1.3	1.0	2.6
3/24/80	.82	24.0	4.3	56.7	26.4	3.9	0.9	0.2	3.4	2.0	1.7	0.9	3.3
3/30/80	.85	23.6	4.3	58.1	25.8	4.3	1.0	0.2	3.3	1.8	1.4	1.0	2.8
4/06/80	.83	24.0	4.4	56.0	25.8	4.2	0.9	0.2	4.0	2.1	1.7	0.8	3.8
4/13/80		21.9	11.2	60.1	23.3	4.4	0.9	0.1	3.2	1.9	1.6	0.9	3.1
4/20/80		22.7	11.6	59.3	23.1	4.5	0.9	0.2	3.5	1.9	1.9	0.9	3.4
4/27/80		22.6	11.7	58.6	23.4	4.4	1.0	0.2	3.7	1.7	1.7	0.9	4.0
5/04/80		23.0	11.3	58.1	23.7	4.0	0.9	0.2	4.1	1.8	1.8	0.8	4.1
5/11/80		22.2	10.7	57.3	23.2	4.9	1.0	0.2	4.2	2.1	1.6	0.9	4.3
6/01/80		21.7	11.5	60.5	23.0	4.4	0.9	0.2	3.3	1.9	1.2	0.9	3.3
6/08/80		23.0	10.8	60.4	22.8	4.3	0.9	0.2	3.5	1.9	1.1	0.9	3.7
6/ /80		22.6	10.3	26.1	10.7	10.9	1.0	0.7	16.6	4.6	7.1	0.2	21.2
6/22/80		22.6	9.8	59.0	24.4	4.2	0.9	0.2	3.2	2.1	1.7	0.9	3.2

Station Analysis

No station analysis data was obtained.

Big Brown

GFETC Analysis

Composite

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SI02</u>	<u>AL203</u>	<u>FE203</u>	<u>Ti02</u>	<u>P205</u>	<u>CAO</u>	<u>MGO</u>	<u>NA20</u>	<u>K20</u>	<u>S03</u>
12/28/79	.96	17.8	10.2	43.3	16.0	9.8	1.0	0.4	10.9	3.1	0.0	0.9	14.2
2/20/80				54.0	19.9	4.5	1.5	0.2	8.3	2.8	0.0	0.7	7.4

Unit 1

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SI02</u>	<u>AL203</u>	<u>FE203</u>	<u>Ti02</u>	<u>P205</u>	<u>CAO</u>	<u>MGO</u>	<u>NA20</u>	<u>K20</u>	<u>S03</u>
10/23/79	1.02	13.2	11.8	37.8	14.0	6.7	1.2	0.6	17.4	3.6	0.3	0.6	17.1
12/13/79	.85	15.1	11.3	34.7	12.8	7.1	1.2	0.5	15.5	11.1	0.0	0.5	16.3
1/03/80	.73	14.3	9.3	39.9	15.7	7.8	1.5	0.4	15.8	3.2	0.3	0.6	14.3
1/09/80	1.10	15.8	11.9	39.4	15.7	6.7	1.4	0.5	16.0	3.4	0.5	0.8	15.5
1/16/80	.90	16.3	11.2	44.5	13.9	7.9	1.2	0.4	12.3	2.9	0.6	0.6	15.3
1/30/80	1.22	14.9	10.0	33.9	14.4	9.6	1.3	0.6	17.8	3.3	0.7	0.4	17.6
2/06/80	1.02	15.9	9.7	12.6	15.5	7.3	1.3	0.5	13.2	3.3	0.5	0.7	14.6
2/13/80	1.01	15.4	17.8	39.9	15.5	6.2	1.4	0.4	15.9	3.6	0.7	0.5	15.4
3/26/80	.97	13.4	11.7	38.6	14.7	6.7	1.4	0.5	17.4	3.8	0.0	0.4	16.2
4/02/80	.89	11.7	11.8	38.7	14.4	9.0	1.4	0.6	15.9	3.7	0.0	0.5	16.5
4/09/80	1.14	14.2	10.6	11.6	11.0	9.9	1.2	0.4	12.6	2.9	0.6	0.7	15.5
4/16/80	.62	11.2	32.4	42.4	15.8	4.1	1.4	0.3	17.6	3.6	0.8	0.5	12.9
4/23/80	.83	13.0	32.2	43.7	14.9	7.9	1.1	0.4	11.3	3.1	1.5	0.9	14.9
4/30/80	.73	12.0	32.6	40.9	15.0	8.7	1.2	0.4	13.3	3.3	0.3	0.7	15.6
5/07/80	.55	10.6	32.8	37.2	16.4	6.6	1.2	0.5	15.3	3.7	1.1	0.6	17.0
5/14/80	1.00	11.7	30.9	39.4	15.4	9.2	1.2	0.5	13.1	3.0	0.4	0.7	16.5

Unit 2

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SI02</u>	<u>AL203</u>	<u>FE203</u>	<u>Ti02</u>	<u>P205</u>	<u>CAO</u>	<u>MGO</u>	<u>NA20</u>	<u>K20</u>	<u>SO3</u>
12/13/79	.87	13.3	15.5	41.4	16.4	6.7	1.2	0.4	14.4	3.6	1.2	0.6	13.7
1/03/80	.81	17.2	12.1	12.8	16.9	7.3	1.5	0.5	13.6	3.3	0.0	1.0	12.9
1/09/80	1.02	15.1	9.3	37.6	14.7	7.1	1.2	0.5	18.7	0.0	2.8	0.5	16.1
1/16/80	.98	15.1	12.9	39.5	14.1	9.3	1.1	0.5	13.6	3.1	1.1	0.8	16.1
1/30/80	.92	14.5	11.3	37.3	17.9	5.9	1.6	0.4	15.5	3.9	1.0	0.4	15.5
2/06/80	.79	15.8	11.9	11.2	16.3	8.2	1.2	0.4	13.4	3.3	0.0	0.5	14.5
2/13/80	.97	14.7	9.1	38.3	15.1	6.4	1.3	0.5	17.3	3.6	0.6	0.5	15.9
2/27/80	.81	11.3	12.1	54.7	21.6	3.7	1.5	0.3	6.6	2.8	0.5	0.7	7.2
3/05/80	.88	15.1	9.0	11.8	16.0	7.7	1.2	0.4	13.8	3.7	0.0	0.7	14.3
3/12/80	1.11	15.9	10.6	10.1	15.8	7.4	1.3	0.5	14.2	3.7	0.8	0.6	15.1
3/19/80	.93	13.7	10.2	38.2	15.0	7.3	1.4	0.5	16.1	3.3	0.5	0.5	16.7
4/02/80	.84	15.0	11.6	12.3	15.7	7.0	1.4	0.4	13.5	3.5	0.6	0.6	14.5
4/16/80	.91	13.3	31.1	42.0	15.7	5.7	1.3	0.4	13.9	3.2	1.3	0.6	15.5
4/23/80	.74	12.0	32.5	40.7	14.5	7.8	1.1	0.5	13.6	3.3	1.5	0.7	15.6
4/30/80	.92	13.0	31.9	42.7	14.8	8.3	1.2	0.4	13.2	3.0	1.0	0.5	14.4
5/07/80	.43	9.7	27.4	63.0	14.3	3.4	1.1	0.3	5.3	2.3	1.9	0.7	7.3
5/14/80	.99	10.9	31.8	40.0	15.8	8.3	1.1	0.5	12.9	2.9	0.3	0.6	16.9

Station Analysis
Unit 1

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
11/04/79	6838	32.36	12.99
11/11/79	6660	29.19	16.78
11/18/79	6978	37.95	13.65
11/25/79	7048	31.2	9.0
12/09/79	5335	28.74	40.0
12/16/79	6674	30.75	14.70
1/06/80	6737	31.96	13.95
1/13/80	6833	30.28	14.57
1/20/80	7206	29.72	10.04
1/27/80	7068	31.14	12.26

Unit 2

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
11/04/79	6847	32.00	13.63
11/11/79	7018	28.63	12.73
11/18/79	5110	31.50	14.38
11/25/79	6968	30.9	19.5
12/09/79	8361	32.12	10.86
12/16/79	7096	32.73	10.41
1/06/80	6712	29.96	15.59
1/13/80	7015	29.15	13.74
1/20/80	7179	29.60	11.20
2/03/80	7150	31.87	7.75
2/10/80	7003	32.21	11.79

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
2/03/80	6848	32.63	10.09
2/10/80	7200	32.0	10.2
2/17/80	6880	30.16	14.2
3/30/80	6902	29.95	15.15
4/06/80	6951	30.05	13.31
4/13/80	6911	31.42	14.24
4/20/80	6834	30.35	14.61
4/27/80	3666	30.74	15.60
5/04/80	6582	30.78	16.03

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
2/17/80	6677	31.92	13.89
3/02/80	7058	31.09	12.53
3/09/80	6345	33.36	15.76
3/16/80	6398	30.52	16.96
3/23/80	7202	31.18	10.81
4/06/80	6643	30.01	15.77
4/13/80	6575	30.14	17.17
4/20/80	6690	30.43	15.59
4/27/80	3437	30.83	11.02
5/04/80	6041	30.46	14.01

Monticello

GFETC Analysis

Unit 1

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TI02</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>Na2O</u>	<u>K2O</u>	<u>SO3</u>
1/17/80	.66	19.9	18.8	51.2	20.4	3.7	1.8	0.3	9.9	3.2	0.9	0.7	7.7
1/24/80	.64	22.5	15.8	53.1	20.4	3.9	1.6	0.3	8.2	3.2	0.7	0.7	7.7
2/01/80	.67	27.1	15.6	54.7	21.3	3.4	1.5	0.2	7.5	3.1	0.7	0.9	6.4
2/07/80	.61	19.3	18.9	50.6	20.3	4.3	1.6	0.2	9.7	3.1	0.8	0.7	8.0
2/20/80	.63	21.3	18.9	52.6	19.7	3.7	1.5	0.3	8.9	3.2	0.7	0.7	8.6
2/21/80	.68	23.9	23.2	53.4	21.3	3.7	1.4	0.2	7.9	2.9	0.6	0.9	7.1
3/06/80	.69	19.4	9.3	48.4	20.1	4.0	1.6	0.3	11.5	3.2	0.0	0.6	9.8
3/01/80	.61	26.7	9.4	55.4	20.6	3.3	1.3	0.2	7.4	3.0	0.8	0.7	7.0
3/27/80	.74	26.4	7.2	55.0	20.8	3.4	1.5	0.2	7.9	3.0	0.8	0.8	6.2
4/02/80	.61	30.2	6.8	58.0	20.3	3.3	1.3	0.1	7.8	2.5	0.0	0.9	5.3
4/10/80	.44	20.6	29.9	57.6	19.6	3.2	1.3	0.2	6.5	2.8	1.1	0.8	6.3
4/18/80	.54	19.8	32.1	54.8	21.4	3.0	1.4	0.2	7.3	2.8	0.8	1.0	6.8
4/24/80	.49	17.0	32.8	51.5	20.2	3.8	1.6	0.3	9.7	3.2	0.5	0.7	8.2
5/03/80	.46	10.9	38.7	54.3	20.2	3.1	1.5	0.1	8.7	3.1	1.0	0.8	6.5

Unit 2

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TI02</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>NA2O</u>	<u>K2O</u>	<u>SO3</u>
1/09/80	.65	20.3	16.6	50.4	20.8	3.9	1.7	0.3	9.9	3.0	0.7	0.8	8.5
1/17/80	.57	23.2	17.0	53.0	22.0	3.3	1.5	0.2	8.1	3.0	1.0	0.7	6.8
1/24/80	.66	11.3	25.4	54.5	21.2	3.7	1.3	0.3	6.9	2.8	0.8	0.9	7.2
2/01/80	.67	26.2	14.9	54.0	21.8	3.5	1.4	0.2	7.4	3.0	1.0	1.0	6.3
2/01/80	.64	19.3	18.5	50.8	19.7	4.7	1.6	0.3	9.7	3.2	0.9	0.7	8.1
2/07/80	.66	22.4	17.0	51.4	21.1	3.9	1.5	0.3	8.6	3.1	1.0	0.8	7.9
2/21/80	.62	22.5	15.9	54.0	21.1	3.6	1.5	0.2	8.0	3.2	1.3	0.7	6.2
2/28/80				56.3	19.2	3.3	1.5	0.2	8.5	3.0	0.9	0.9	5.3
3/06/80	.63	24.0	9.5	52.3	20.0	3.3	1.6	0.3	8.9	3.3	0.8	0.7	8.4
3/14/80	.69	27.5	7.7	55.2	21.5	3.2	1.3	0.2	7.6	3.1	0.7	0.8	5.9
3/27/80	.65	27.3	7.2	54.9	20.3	3.1	1.4	0.2	7.7	3.0	0.8	0.9	7.3
4/02/80	.72	26.9	6.0	55.1	19.9	3.3	1.3	0.3	7.6	3.0	1.1	0.8	7.2
4/08/80	.44	19.4	32.6	55.8	20.7	3.1	1.5	0.2	8.3	2.9	0.5	0.8	5.9
4/10/80	.49	22.0	26.4	56.6	20.0	3.4	1.3	0.2	7.4	3.1	0.0	0.7	6.8
4/24/80	.47	17.3	31.6	54.1	19.9	3.4	1.5	0.2	9.8	3.2	0.5	0.7	6.2
5/09/80	.43	23.7	30.0	57.6	21.2	2.7	1.4	0.1	6.7	2.7	0.5	1.0	5.5

Unit 3

<u>Date</u>	<u>Sulphur</u>	<u>Ash</u>	<u>Moisture</u>	<u>SiO2</u>	<u>AL2O3</u>	<u>FE2O3</u>	<u>TI02</u>	<u>P2O5</u>	<u>CAO</u>	<u>MGO</u>	<u>NA2O</u>	<u>K2O</u>	<u>SO3</u>
1/17/80	.83	25.2	12.4	53.0	22.0	3.6	1.5	0.3	7.5	3.0	0.9	0.6	7.1
1/24/80	.73	25.9	11.9	56.3	25.4	4.8	1.0	0.2	3.2	2.0	2.3	0.9	3.7
2/20/80	.67	24.7	17.8	53.7	20.6	3.9	1.5	0.2	8.4	2.9	1.0	1.0	6.2
2/21/80	.85	25.0	15.0	53.0	20.8	1.4	1.7	0.2	7.2	2.6	0.8	0.5	8.2
3/06/80	.80	25.0	16.7	53.1	22.1	3.8	1.7	0.3	7.3	2.8	0.5	0.7	7.3
3/14/80	.80	28.4	7.4	53.0	20.1	3.2	1.3	0.2	9.3	3.3	0.5	0.9	7.9
4/02/80	.66	30.3	7.0	58.9	18.9	1.8	1.3	0.2	5.9	2.5	0.5	0.9	5.6
5/03/80	.47	19.4	31.0	54.1	19.7	3.6	1.6	0.2	8.1	2.9	0.4	0.7	8.4
5/09/80	20.50	21.1	30.1	55.3	21.7	3.3	1.6	0.2	7.4	2.9	0.4	0.8	6.0
6/02/80				39.5	14.0	5.6	2.0	0.5	17.8	2.6	4.6	0.5	12.8

Station Analysis

Unit 1

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
11/16/79	6002	31.22	18.56
11/30/79	5880	30.89	20.02
12/07/79	6417	28.68	16.13
12/14/79	6456	33.13	15.07
12/21/79	5863	30.17	19.99
12/28/79	6400	29.99	15.53
1/04/80	6088	29.48	17.47
1/10/80	5854	30.37	20.66
1/17/80	5916	30.83	19.84
1/24/80	6388	30.64	17.22
2/01/80	5875	29.28	21.24
2/08/80	5740	30.48	20.89

Unit 2

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
11/02/79	6484	20.24	23.58
11/08/79	6396	36.63	15.23
11/16/79	5959	31.16	18.52
1/10/80	6365	30.89	15.77
1/17/80	6220	30.85	16.92
1/24/80	6235	32.84	16.99
2/01/80	5970	30.21	20.14
2/08/80	5855	32.21	18.46
2/15/80	5889	30.44	18.53

Unit 3

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
11/02/79	5937	30.42	18.94
11/08/79	6070	29.25	17.85
11/16/79	6161	32.65	16.13
12/14/79	6406	31.39	16.98
12/21/79	6174	29.52	13.56
12/28/79	6116	29.31	18.84
1/04/80	5891	28.53	20.43
1/10/80	6122	30.36	18.62
1/17/80	6171	31.13	18.68
1/24/80	5915	31.86	19.39

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
2/15/80	6468	30.47	14.40
2/22/80	6252	30.80	17.04
2/29/80	5952	29.52	19.11
3/14/80	6244	32.27	17.13
3/21/80	6217	31.43	16.53
3/27/80	5895	30.37	21.65
4/03/80	5379	28.83	25.15
4/11/80	6634	31.37	19.20
4/18/80	6200	30.57	18.17
4/25/80	6321	28.47	18.59
5/02/80	5953	26.15	19.61

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
2/22/80	6248	31.88	15.51
2/29/80	6045	30.50	17.98
3/14/80	6241	32.29	17.08
3/21/80	6128	31.60	17.3
3/27/80	6025	31.31	18.93
4/03/80	5776	32.46	19.13
4/11/80	5742	29.52	22.99
4/18/80	6305	31.09	17.02
4/25/80	5905	32.56	10.47

<u>Date</u>	<u>BTU</u>	<u>Moisture</u>	<u>Ash</u>
2/01/80	6357	31.42	15.97
2/08/80	5855	32.21	18.46
2/15/80	6171	30.05	17.24
2/22/80	6589	30.81	18.06
2/29/80	5787	29.98	21.01
3/14/80	6152	31.50	18.77
3/21/80	6041	31.20	18.95
3/27/80	6003	30.78	20.25
4/03/80	5792	34.79	17.71
5/12/80	5959	22.72	21.91

Big Stone Coal Analyses

Ash data through 4/6 taken from station analyses.

Sodium and the remainder of ash data taken from GFETC analyses.

Leland Olds Coal Analyses

All data from GFETC analyses.

Jim Bridger Coal Analyses
All data from GFETC analyses.

Big Brown Unit 1 Coal Analyses
 Ash data through 4/9 taken from station analyses.
 Sodium and the remainder of ash data taken from GFTC analyses.

Big Brown Unit 2 Coal Analyses

Ash data through 4/2 taken from station analyses.

Sodium and the remainder of ash data taken from GFETC analyses.

Monticello Unit 1 Coal Analyses

Ash data through 4/2 taken from station analyses.

Sodium and the remainder of ash data taken from GFETC analyses.

Monticello Unit 2 Coal Analyses

Ash data through 4/2 taken from station analyses.

Sodium and the remainder of ash data taken from GFETC analyses.

Monticello Unit 3 Coal Analyses

Ash data through 4/2 taken from station analyses.

Sodium and the remainder of ash data taken from GFETC analyses.

6.0 Boiler Observations

During the power station visits, all the units involved in the study were "walked down" and inspected for fouling and slagging conditions. This section details the conditions as found in the boilers and other general observations made about the units' operation.

One shortcoming must be noted when inspecting these boilers for fouling conditions. Observation ports are generally placed in the soot blowing pass before and after each tube bank. Generally, no ports are located in such a manner that the convection banks can be observed for pluggage in the direction of gas flow. Because of this, fouling severity has to be judged by the amount of ash deposit on the leading edge of each bank. This deposit is not a direct cause of an outage or curtailment, as only the ash within the tube banks impede gas flow. It is, however, an excellent indication of rate of deposit buildup, the hardness of the deposit, and the effectiveness of the unit's soot blowers.

6.1 St. Clair Station

The St. Clair station did show signs of ash adherence to the tube leading edges. In one case, where a soot blower was out of service, ash was stuck to the leading edges in great amounts. The deposits were generally soft, coming off the tube surfaces very easily when rodded. Only in a few instances was any difficulty encountered in rodding deposits. Soot blower effectiveness in these units was very great.

Unit 1

The convection surfaces generally had no leading edge deposit, but had deposits between tubes. This unit can be observed from the back of the unit forward. The leading edge deposit was no greater than 1/2". The walls of the unit were generally clean with only one instance of coverage as high as 40% at top levels. On one trip the level at the top of burners was 100% covered in places. No molten slag was seen. The curtain wall on units 1 - 4 has a trap which collects ash at the high levels, but this is not construed as an ash problem, but a design problem.

Unit 2

Unit 2 was running during only one trip. The convection surfaces were generally clean, with the worst deposit 1/2 - 1" thick. This deposit was fairly hard to remove.

The only significant wall deposit was 40 - 50% coverage through the burner zone. It appeared to be sticky.

Unit 3

The convection surfaces were generally clean except for one area of the pendant superheater on all three trips. On one trip it was as deep as 1 foot. It appeared that a soot blower was possibly out of service.

The wall near the convection deposit was heavily slagged, but the remainder of the walls were clean except at the top of the burner zone, where it became as high as 80% covered with a great percentage molten.

Unit 4

The convection surfaces were generally clean with about a 1/2" deposit. One location had a deposit as deep as 1-1/2".

The walls were about 50% covered at convection surface levels, then cleaning up until the top burner elevation, where 100% molten coverage existed.

Unit 6

The convection surfaces had a general coverage about 1" thick.

The radiant superheater and reheat panels had a deposit on the rear edge about 4" thick. The bottom of these panels was generally covered.

The walls were heavily slagged. The coverage ranged from 30 - 100% at high elevations, with slag about 4" thick; to 60 - 100% coverage at levels just below the radiant panels, starting to get molten; to 40 - 100% coverage above the burners, all molten; to 100% at the top burner elevation, all molten; to 0 - 100% through the remainder of the burner zone, not molten.

Unit 7

The convection surfaces had only 1" thick deposits at worst until the last visit where they were about 8" thick. The bottom of the radiant division panels was always 40 - 100% covered with ash as thick as 12".

The walls were generally clean with deposits ranging from full coverage to immaculate. The water blowers in this unit appear to remove all ash from the section blown. The covered sections were generally 1 - 2" thick. The curtain wall was always 100% covered. Through the burner zone, the ash became molten.

6.2 Big Stone

The secondary superheater leading tubes were generally clean during all visits. The other elements were heavily fouled during the first two visits, deposits as deep as 1 foot. During the second visit the unit came off line for cleaning. An internal inspection showed the reheat section about 40% plugged to gas flow. This was widely scattered through the section, not in only one particular location.

The convection surfaces during the third visit had only 1 - 2" thick deposits.

The walls on the first two trips were 5 - 40% ash covered. The third trip were about 10 - 20% covered. None appeared to be molten.

The steam soot blower effectiveness on the deposits appears to be nil. Blowers were seen to change color of the deposit without removal. They must aid in removal, as it is obvious that without them the unit could not be run, but when watching them work, their effectiveness cannot be seen. The water blowers can be seen effectively removing the ash.

Rodding these deposits was very difficult. Rods most often poked holes in the deposit rather than break it from the tubes.

6.3 Leland Olds

Slag in both boilers at Leland Olds came off the tubes more easily when rodded than at Big Stone. Steam soot blower effectiveness, however, was equivalent to Big Stone in its apparent inability to remove deposits.

Unit 1

Lime is added in this boiler at the rate of 600 lb. every two hours prior to 1/10/80 and 600 lb. every 4 hours after 1/10/80. This is fed into the pulverizers at one time every interval.

The convection surfaces were not badly built up. Only a few places had areas one foot deep. Generally the slag was only 1 - 2" thick.

It must be noted that not a great deal of the convection surface can be seen in this unit.

The walls at high elevations were generally clean ranging from 0 - 60% coverage.

The walls became generally dirtier down toward the burners. At the top of burners the walls were 80 - 100% covered on one trip, and 10 - 50% on the other two trips. The slag was molten at the burners.

Unit 2

The convection surfaces were the worst at high elevations, up to one foot thick deposit, then gradually tapering down at lower elevations. The leading element was clean. The last trip was after an annual over-haul and all convection surfaces were clean.

The walls at top elevations (no soot blowers) were 80 - 100% covered with deposits as deep as one foot.

The walls became cleaner at the lower levels, the rear wall usually heavily slagged, the front cleaner. Above the lower slope the slag became molten.

6.4 Jim Bridger

Units 1 - 4

All these units are identical. The fouling deposits were easily rodded and soot blower effectiveness was excellent. The slagging patterns in these units were very similar.

The convection surfaces were generally clean with only 2 - 4" deposits at the deepest. These deposits were easily blown and generally the convection surfaces were clean.

The walls throughout the unit ranged from clean to fully slag covered. The wall coverage averaged about 60% down through the top burner elevation. Through the burners and below, the walls were generally clean. The slag was most often molten at and just above the top burner elevation, but not always.

The division panels were heavily slagged, as deep as one foot.

6.5 Four Corners

Unit 1

The convection surfaces were generally immaculate at the bottom levels with as much as six inch deep deposits at high levels on one visit.

The walls through the burner zones were heavily slag covered 100% at top levels, down to 10 - 50% at the bottom burner level. The slag did not appear to be molten, but, when covering an observation port, was plastic when rodded.

Unit 2

Convection passes were generally immaculate, with only 1 - 3" deposit on some forward surfaces.

The burner zone slagging was not as severe as Unit 1. The average at top of burners was about 50%, at mid burner was 30%, and the bottom burner was about 20%. No molten slag was seen.

Unit 3

The convection passes were again clear with the only significant deposit a six inch on the leading edge of the pendant superheater.

The walls of this unit were fairly clean, with an estimate of 40% coverage. No molten slag was seen.

Units 4 and 5

These units were very difficult to observe. They are forced draft units, with small observation ports. If a seal air problem exists at the ports, the port cannot be opened. The observation glass is usually black so the ports must be opened for viewing. The convection surface has only one observation port per side.

The convection surface (the leading edge of the pendant superheater at low levels) had a 4 - 6" deposit. The rear wall was generally covered, as was No. 4 curtain wall. The walls in unit four averaged about 60%, the walls in unit five about 70%.

6.6 Big Brown

Units 1 and 2

These units were the most heavily slagged of any involved in the study. In the worst case the walls were 100% covered at the rear of the furnace from the elevation below the convection levels to the bottom of the burner levels. Slag was molten from the elevation below the convection surfaces to the bottom burner levels. The worst case probably averages 70% wall coverage, the best case probably about 50%.

From viewing these boilers, it is difficult to understand why high steam temperatures are not a problem. The desuperheat sprays were generally wide open, but high temperatures seldom limited load.

The convection surfaces were generally clean with the pendant superheater having the worst deposit, about 3" thick. The division panels and platen superheaters had 2 - 6" thick coverage, generally on the hot side.

6.7 Monticello

Units 1, 2 and 3

These units were the cleanest seen. The slag was seen falling off of its own weight. Some parts of portions of the walls had 100% coverage but generally the walls were immaculate. The ash never was seen running, but it did get sticky near the burner zone. The coverage was generally less than 10% of the wall surface.

The convection surfaces did deposit a small amount, the worst spot built up 4" thick. Units 1 and 2 were generally clean. Unit 3 had a general 3" thick deposit on the leading edge of the secondary superheater and a 1" deposit on the leading edge of the reheater.

7.0 Observations and Conclusions on Ash Fouling and Slagging

Listed below are several facts from the study which deserve consideration:

1. The fouling problems corresponded well to sodium levels in ash. The Texas lignites were low in sodium and had no fouling losses. Jim Bridger subbituminous was low in sodium and low in fouling losses. Four Corners subbituminous was a bit higher in sodium levels than Jim Bridger and had significant fouling losses. Leland Olds and Big Stone are high sodium coals and fouling losses at these stations are great, and in proportion to the sodium levels (i.e. Leland Olds with higher sodium levels suffers the greater loss). The one notable exception is St. Clair. With the highest sodium levels of any coal studied, the fouling losses are roughly in a category with Four Corners. Unit seven at St. Clair suffered no fouling loss throughout the entire study. This may be attributable in part to ash levels, the lowest in the study.
2. The soot blower effectiveness in the convection surfaces of all the units was good except for Big Stone and Leland Olds. Observation and operating records confirm this. The only units with water convection blowers are Big Stone and Leland Olds Unit 2.
3. The pendant superheater and reheater spacing on St. Clair units one through four is 4", the tightest of any pendant convection surface in this study. This may account for the greater fouling problems incurred by these units than in units 6 and 7.
4. Leland Olds unit two has a higher percentage fouling loss than unit 1. The size difference is 206%, the fouling loss difference is 317%.
5. The only units with water blowers on the waterwalls are Unit 7 at St. Clair and Unit 1 at Big Stone.
6. Big Stone ash and sodium levels trended up throughout the study period. After a fifteen day outage period for thorough fireside boiler washing the unit did not suffer an ash fouling related curtailment as late as June.
7. Four Corners 4 and 5 swapped slagging problems about mid study period. Unit 4 had problems until early March, when they stopped. Unit 5 had no problems until early February, when they continued until the end of the study.
8. Four Corners 4 and 5 were the only positive draft pressure units in the study. The observation ports at the furnace bottom are small and preclude on line clinker cleaning.
9. The following units have radiant surface superheat or reheat in the furnace:
Jim Bridger 1 - 4
Four Corners 1, 2 and 3
Big Brown 1 and 2
Monticello 1, 2 and 3.

10. Jim Bridger had considerable problems in the past with fouling. A concentrated effort has been made by the station to improve the steam supply reliability and the operation of the individual blowers. During this study period fouling has virtually been eliminated. It is the utility opinion that convection pass pluggage in the past was due to hot furnace gas exit temperatures and the low ash fusion temperatures of their coal ash, not in total to the fouling problem as experienced with high sodium coals. The utility feels that before past problems occurred the sodium levels were below 3%. The improvement of soot blower reliability helped reduce wall slagging which lowered furnace gas exit temperature, and, of course, assisted in removal of convection deposits.
11. When a unit becomes fouled severely enough to affect load, it is usually found that most of the convection elements are heavily fouled. This is apparently due to the fact that the temperature increases back through the unit as the fouled area loses heat transfer capability. This pushes the "fouling temperature" zone back through the unit until back end temperature or draft losses force a curtailment. Because of this mechanism, fouling is generally a slow process, and units can be load reduced and cleaned up to a small degree by soot blowing and hand lancing while on line.

These facts led to the following conclusions concerning ash fouling and slagging problems.

1. The study results corresponded with the conclusions advanced by the GFETC concerning sodium and ash levels and their effect on fouling. In all cases but St. Clair, the losses were in agreement with the sodium levels. At St. Clair, although sodium levels were high, the amount of ash in the coal again supported the GFETC's contention that low ash, high sodium coals have low fouling potentials.
2. More attention should be paid to the susceptibility of the ash to soot blowing in research data. All the units in this study experienced ash clinging to convection surfaces to some degree. If no soot blowing was done in any of these units, they would eventually plug. All the deposits were fairly easily blown except for Big Stone and Leland Olds. The problem at these stations is not strictly the rate of deposit, but the strength with which it adheres to itself and to the boiler tubing. Possibly a soot blowing test could be performed at GFETC in conjunction with the deposition rate studies.
3. It appears from the data in this study that pulverized coal firing is preferable to cyclone firing for high fouling coals. Unit 2 at Leland Olds had a greater percentage loss than unit 1, and

both units burn identical fuels. Unit 2 has water soot blowers in the convection areas while unit 1 survives with only steam blowing. Leland Olds unit 1 had less fouling problems than Big Stone unit 1, even though Big Stone operates on lower sodium coals.

4. Furnace exit gas temperatures are very important in practical operation of a high fouling coal fired boiler. If gas exit temperatures are allowed to get high, fouling will become a problem. Two examples stress this importance. Before this study began, St. Clair unit 7 had such a fouling problem that Detroit Edison commissioned a task force to solve the problem. The task force recommendations included load limitations and water blowers in the furnace. This unit has the most water blowers of any in the study. There are no water blowers in the convection passes. Because of these attempts to lower furnace gas exit temperature, unit 7 at St. Clair did not suffer any fouling related curtailments during the study. All the other units at St. Clair which ran an appreciable length of time suffered some fouling related losses.

Another striking example is Big Stone. The unit was plagued with ash fouling outages for the initial period of the study. The unit was out for fouling four times from November through mid-March. In March the unit was taken off line and thoroughly cleaned of deposits. After this thorough cleaning, it ran until at least mid-June without any fouling problems even though ash and sodium levels trended upward. It should be noted that this unit also has water blowers on the walls.

5. Slagging is highly contingent on firing techniques. Units 4 and 5 at Four Corners are identical, burning identical fuel. During the beginning of the study unit 4 had a great deal of clinker problems. Unit 5 then developed a great deal of clinker problems while unit 4 became free of clinkers. This is unexplainable except that the firing techniques were changed. Excess air was lowered in both units during this period, and much attention was paid to burner register settings. One problem the station has is the registers sticking when closed off during a mill shutdown. Because of this, the registers are left open when a mill is out of service causing air lean firing at the other burners and air rich firing when the fuel comes in contact with this air source.
6. Four Corners units 4 and 5 have a very high incidence of clinker outages and curtailments as opposed to Big Brown which has slagging problems greater than those seen at Four Corners. This cannot be blamed entirely on ash problems as Big Brown fights clinkers to a great extent. Big Brown is more successful at fighting clinkers

while the unit is on line without the need for curtailments. The reason is simple and must be considered when reviewing the performance at the two stations. Four Corners is a positive draft pressure system. The access ports to Four Corners 4 and 5 in the ash pit area are virtually useless for fighting clinkers. It is hard to see the clinkers through these ports much less water lance them.

7. Because of the time duration associated with the fouling of operating boilers, the correlation of a curtailment or outage with a particular coal analysis is impossible. The best results that can be hoped for in a study of this type are long term trends such as observed at Big Stone, which showed that even though sodium levels trended up about 60% and ash levels trended up about 20%, the boiler cleanliness reduced ash losses to zero.

8.0 Summary and Recommendations

Problems with convection ash fouling and wall slagging were considerable during our study. The Dakota lignites posed the greatest problems, particularly with fouling. The subbituminous coals had considerable problems, related mostly with wall slagging.

The Texas lignites had few problems, and those were only associated with wall slagging. The generation losses were as follows:

The Dakota lignite burning stations averaged an overall availability of 87.13%. Convection fouling outages were responsible for 57.75% of this outage time for a decrease in availability of 7.43%. Fouling was responsible for curtailment losses of 317,649 Mwh or 8.25% of the remaining available generation. Slagging was responsible for losses of 2732 megawatt hours or .07% of the remaining available generation. Total ash related losses amounted to 16.08% of the total available generation.

The subbituminous burning stations averaged an overall availability of 78.36%. Convection fouling outages were responsible for 1.43% of this outage time for a decrease in availability of 0.31%. Slagging losses accounted for 2.60% of this outage time for a decrease in availability of 0.56%. Fouling was responsible for curtailment losses of 48,428 Mwh or 0.26% of the remaining available generation. Slagging was responsible for curtailment losses of 220,895 Mwh or 1.18% of the remaining available generation. Total ash related losses amounted to 1.54% of the total available generation.

The Texas lignite burning stations averaged an overall availability of 80.63%. No ash related outage losses occurred. Slagging curtailments accounted for 10,676 hours or 0.10% of the remaining generation or 0.08% of the total available generation.

Costs due to ash fouling and slagging related curtailments are a tremendous sum. Seven power stations were studied for a six month period to assess costs. During this six months, fouling of convection surfaces cost the utilities which owned these stations \$8,184,707; clinkers from slagging problems cost \$9,573,180; high steam temperatures because of slagging cost \$484,766; low steam temperatures because of fouling conditions cost \$162,751; need for oil firing caused by fouling and slag tapping problems cost \$1,833,826; tube leaks caused by the extreme soot blowing demand of high fouling coals cost \$398,883; and finally lost capacity suffered by Detroit Edison for burning the low heating value, high fouling coal cost \$10,138,982.

The total cost directly attributable to ash slagging and fouling condition is \$20,638.113.

This study has shown that slagging is as great a monetary loss factor as is fouling.

Some recommendations which could help the problems are:

1. Testing should be performed which evaluates soot blower effectiveness at the deposit temperatures.
2. In units which have fouling problems, utmost importance should be placed on controlling furnace gas exit temperatures.
3. It is felt that water blowers on furnace walls are the most cost effective measure for controlling furnace exit temperatures. Water blowers should be considered for Leland Olds 1 and 2 on the waterwalls, and should possibly be increased at Big Stone to numbers approximating St. Clair.
4. Convection water blowers seem very effective for removing deposits. It would appear that both the Big Stone and Leland Olds units could greatly improve their performance with water blowers in all the convection surfaces. Steam blowing appears to be fruitless when being observed, while water blowers appear to work successfully.
5. Slagging problems most often cause the most monetary damage as clinkers. It would appear that water blowers should be tried on the lower slope at Four Corners 4 and 5, as clinkers caused tremendous losses of these units.
6. Water blowers would probably be cost effective on all units involved in our study to some degree excepting Jim Bridger and Monticello. These stations were relatively free of ash related problems.
7. We think that success in burning these poorer grades of coal is largely dependent upon the conservatism exercised in the initial design of the boiler. A conservative approach concerning heat release in the furnace is certainly a requirement. The above factors increase initial unit cost, but are easily recoverable in more reliable operation.

St. Clair Units 1 - 4

These units are of the same design. They feature a horizontal reheater section, division walls, and gas recirculation entering the bottom of the unit. The unit is front fired. Steam temperatures are controlled by gas dampers, exhaust gas recirculation, and desuperheat sprays. Soot blowing is done by air.

Unit Specifications:

Capacity - 1,070,000 lb./hr.
Superheat Outlet Pressure - 1850 psi
Main Steam Temperature - 1000^o F
Reheat Steam Temperature - 1000^o F
Heat Release - 89,800 BTU per hour per sq. ft.
 - 19,000 BTU per hour per cu. ft.

Element Spacings:

Primary Superheater - 4"
Primary reheater - 3"
Secondary superheat first pass - 12"
Secondary superheat second pass - 6"
Finishing superheat - 4"
Finishing reheater - 4"

Coal Design Criteria (as received):

Heating Value - 11,700 BTU/lb.
Moisture - 8.9%
Volatile - 33.7%
Fixed Carbon - 46.5%
Ash content - 10.9%
Ash softening temperature - 2200^o F
Margrove grindability - 55

St. Clair Unit 6

This unit features two separate furnaces. One furnace contains all superheat convection elements, the other contains primary superheat and reheat convection elements. The unit is corner fired from eight corners. Steam temperatures are controlled by burner tilts, desuperheat sprays, and the separate firing of the two furnaces. Soot blowing is done by air.

Unit Specifications:

Capacity - 2,100,000 lb./hr.
Superheat outlet pressure - 2450 psi
Main steam temperature - 1050° F
Reheat steam temperature - 1000° F
Heat release - 142,500 BTU/hr/ft.²
 - 26,100 BTU/hr/ft.³

Element Spacings:

Primary superheater - 3 1/4"
Radiant pendant superheater - 15 5/32"
Secondary superheater - 15 5/32"
Finishing superheater inlet - 4 35/64"
Finishing superheater outlet - 9 3/32"
Radiant pendant reheater - 15 5/32"
Secondary reheater - 15 5/32"
Finishing reheat inlet - 4 35/64"
Finishing reheat outlet - 9 3/32"

Coal design criteria (as received)

Heating value - 11,700 BTU/lb.
Moisture - 8.9%
Volatile - 33.7%
Fixed carbon - 46.5%
Ash content - 10.9%
Ash softening temperature -
 2200° F
Hargrove grindability - 55

St. Clair Unit 7

This unit features a radiant wall reheater, division panel, superheaters, and a water cooled division wall. It is corner fired from eight corners. The boiler feed pumps are auxiliary turbine driven. Steam temperatures are controlled by burner tilts and desuperheat sprays. Soot blowing is done by air and water.

Unit Specifications:

Capacity - 3,124,000 lb./hr.
Superheat outlet pressure - 2641 psi
Main steam temperature - 1000⁰ F
Reheat steam temperature - 1000⁰ F
Heat release - 68,700 BTU/hr/ft²
- 17,200 BTU/hr/ft³

Element Spacings:

Primary superheater -
4 1/8"
Vertical primary superheater
4 1/8"
Finishing superheater -
4 3/4"
Finishing reheat outlet -
9 1/2"
Finishing reheat inlet -
9 1/2"
Superheater platen - 19"

Design Criteria (as received)

Heating value -
11,700 BTU/lb.
Moisture - 9%
Volatile - 40%
Fixed carbon - 40%
Ash content - 11%

Big Stone

This unit features front and rear cyclone firing, gas recirculation and gas tempering. The unit features auxiliary turbine driven feed pumps and forced draft fans. Steam temperatures are controlled by gas recirculation and desuperheat sprays. Soot blowing is done by steam and water.

Unit Specifications:

Capacity - 3,250,000 lb/hr
Superheat outlet pressure - 2620 psi
Main steam temperature - 1005° F
Reheat steam temperature - 1005° F

Element Spacings:

Primary superheater - 4 1/2"
Reheater - 9"
Secondary superheater - 24"
Finishing superheater - 12"

Coal Design Criteria (as received):

Heating value - 6255 BTU/lb.
Moisture - 41.3%
Volatile - 25.24%
Fixed carbon - 27.0%
Ash content - 6.46%
Softening temperature - 2060°-
2570° F

Leland Olds Unit 1

This unit is a pulverized coal, with front and rear firing, and a water cooled division wall. Steam temperature is controlled with desuperheat sprays. Soot blowing is done with steam.

Unit Specifications:

Capacity - 1,570,000 lb/hr.
Superheat outlet pressure - 2475 psi
Main steam temperature - 1005⁰ F
Reheat steam temperature - 1005⁰ F

Element Spacings:

Superheater outlet - 18"
Superheater inlet - 9"
Reheat outlet - 6"
Reheat inlet - 6"

Coal Design Criteria (as received):

Heating value - 6754 BTU/lb.
Moisture - 36.4%
Volatile - 28.8%
Ash content - 6.8%

Leland Olds Unit 2

This unit features front and rear cyclone firing, gas recirculation and tempering, and auxiliary turbine driven feed pumps. Steam temperatures are controlled by gas recirculation and desuperheat sprays. Soot blowing is done by steam and water.

Unit Specifications:

Capacity - 3,000,000 lb/hr.
Superheat outlet pressure - 2640 psi
Main steam temperature - 1005° F
Reheat steam temperature - 1005° F

Element Spacings:

Primary superheater - 4 1/2"
Reheater - 9"
Secondary superheater - 24"
Finishing superheater - 12"

Coal Design Criteria (as received):

Heating value - 6523 BTU/lb
Moisture - 39.6%
Volatile - 27.4%
Fixed carbon - 26.5%
Ash content - 6.5%
Softening temperature - 1950° -
2400° F

Jim Bridger Units 1 - 4

The units are all of the same design, featuring a radiant reheater, a vertical primary superheater, superheat division panels, and pulverized coal firing from four corners. Steam temperature is controlled by burner tilts and desuperheat sprays. Soot blowing is done by steam.

Unit Specifications:

Capacity - 3,980,000 lb/hr.

Superheat outlet pressure -
2660 psi

Main steam temperature -
1005° F

Reheat steam temperature -
1005° F

Heat release - 72,700 BTU/hr/ft²
12,200 BTU/hr/ft³

Element Spacings:

Primary superheater - 4 1/4"

Finishing superheater - 4 3/4"

Finishing reheater - 9 1/2"

Pendant platen superheater - 19"

Coal Design Criteria (as received)

Heating value - 10,239 BTU/lb.

Moisture - 16.69%

Ash content - 8.0%

Hargrove grindability - 53.6

Ash fusion temperature - 2160° F

Four Corners Units 1 & 2

These are identical units featuring water cooled platens, primary reheater and superheater, and a superheat bypass system, which diverts furnace gas from the primary superheater and primary reheater, through an area with additional primary reheat surface and economizer surface. The units are pulverized coal front fired. Steam temperatures are controlled by bypass dampers and desuperheat sprays. Soot blowing can be either air or steam.

Unit Specifications:

Capacity - 1,270,000 lb/hr.
Superheat outlet pressure - 1925 psi
Main steam temperature - 1005°F
Reheat steam temperature - 1005°F
Heat release - 80,000 BTU/hr/ft²
 - 17,900 BTU/hr/ft³

Element Spacings:

Economizer - $5\frac{1}{8}"$
Primary reheater - $5\frac{1}{8}"$
Primary superheater - $5\frac{1}{8}"$
Finishing reheater - $5\frac{1}{8}"$
Finishing superheater - $10\frac{1}{4}"$
Pendant platen superheater - $3'5"$

Coal Design Criteria (as rec'd):

Heating value - 9200 BTU/lb.
Volatile - 31.32
Fixed carbon - 35.93%
Moisture - 12.33%
Ash content - 20.42%
Hargrove grindability - 49
Ash softening temperature - 2485°F

Four Corners Unit 3

This unit features separate reheater and primary superheater gas passes, gas flow controlled by dampers, and a main steam cooled furnace division wall. This wall was replaced by four division panels during a scheduled outage which occurred during this study. The unit is pulverized coal front fired. Steam temperatures are controlled by gas dampers and superheat sprays. Soot blowing is done by either air or steam.

Unit Specifications:

Capacity - 1,613,000 lb/hr.
Superheat outlet pressure - 2125 psi
Main steam temperature - 1005°F
Reheat steam temperature - 1005°F
Heat release - $93,900 \text{ BTU/hr/ft}^2$
 - $16,000 \text{ BTU/hr/ft}^3$

Element Spacings:

Primary superheater - $5 \frac{1}{8}"$
Primary reheater - $5 \frac{1}{8}"$
Finishing reheater - $5 \frac{1}{8}"$
Pendant superheater - $41"$

Coal Design Criteria (as received):

Heating value - 9200 BTU/lb.
Volatile - 31.32%
Fixed carbon - 35.93%
Moisture - 12.33%
Ash content - 20.42%
Hargrove grindability - 49
Ash fusion temperature - 2485°F

Four Corners Units 4 & 5

These are identical units featuring gas recirculation and tempering, a water cooled division wall, and supercritical pressure operation. The units are pulverized coal front and rear fired. Soot blowing is by either steam or air.

Unit Specifications:

Capacity - 5,582,000 lb/hr.
Superheat outlet pressure - 3600 psi
Main steam temperature - 1004° F
Reheat steam temperature - 1000° F

Element Spacings:

Primary reheater - 4 1/2"
Primary superheater -
4 1/2"
Finishing reheater - 9"
Platen superheater - 18"
Finishing superheater - 9"

Coal Design Criteria (as rec'd)

Heating value - 8900 BTU/lb
Volatile - 31.32%
Fixed carbon - 35.93%
Moisture - 12.33%
Ash content - 20.42%
Hargrove grindability - 49
Ash softening temperature -
2485° F

Big Brown and Monticello Units 1 and 2

These four units are identical. They feature a horizontal primary reheater, superheat division panels, auxiliary turbine driven feed pumps, furnace division walls, and supercritical pressure design. The unit is pulverized coal fired from eight corners. Steam temperatures are controlled by burner tilts and desuperheat sprays. Soot blowing is done by air.

Unit Specifications:

Capacity - 4,025,000 lb/hr.
Superheat outlet pressure - 3825 psi
Main steam temperature - 1005° F
Reheat steam temperature - 1005° F

Element Spacings:

Primary reheater - 4 3/8"
Finishing superheater - 6 9/16"
Finishing reheater - 17 1/2"
Platen superheater 21 7/8"
Division panel superheater - 9' 1 3/8"

Coal Design Criteria (as received):

	Big Brown Monticello	
Heating value	7591 BTU/lb	6767 BTU/lb
Moisture	31.74%	31.27%
Ash content	10.44%	14.31%
Ash fusion temperature	- 2220° F

Monticello Unit 3

This unit features entirely pendant superheaters and reheaters, and supercritical pressure design. It is a pulverized coal front and rear fired. Steam temperatures are controlled by desuperheat sprays. Soot blowing is done by air.

Unit Specifications:

Capacity - 5,524,000 lb/hr.
Superheat outlet pressure - 3850 psi
Main steam temperature - 1010° F
Reheat steam temperature - 1005° F

Element Spacings:

Reheater - 9"
Economizer - 4"
Division panel superheater - 6"
Secondary superheater - 24"

Coal Design Criteria (as rec'd)

Heating value - 6767 BTU/lb
Volatile - 31.40%
Fixed carbon - 23.02%
Moisture - 31.27%
Ash content - 14.31%
Ash fusion temperature (H=W) - 2328° F