DRAFT ENVIRONMENTAL IMPACT STATEMENT

MINNESOTA POWER & LIGHT COMPANY'S PROPOSED UNIT 4 CLAY BOSWELL STEAM ELECTRIC STATION

JULY, 1977

PREPARED BY

MINNESOTA POLLUTION CONTROL AGENCY

VOLUME I

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THIS DOCUMENT IS CONTAINED IN THREE VOLUMES.

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Introduction

Minnesota Power & Light Company (MP&L), the principal electric utility for northeastern Minnesota, has proposed to expand its Clay Boswell Steam Electric Station in Bass Brook Township, Itasca County. Scheduled for start up operation in 1980, the proposed fourth coal-fired steam electric generating unit will add 504 megawatts (MW) of net generating capacity to the approximately 500 MW generated by the 3 existing units. The Clay Boswell Station is one of MP&L's many electric generating facilities which provide power for residential, commercial, and industrial use in 15 counties of northeastern Minnesota and 2 counties of northwestern Wisconsin.

MP&L has proposed to construct and operate Unit 4 at the Clay Boswell Station in response to the rapidly increasing needs for electric energy by the expanding iron taconite mining industry on the Mesabi Iron Range. By 1979, taconite pellet production is expected to increase 60%. Electrical energy requirements for the taconite industry are projected to require electrical generating capacity of approximately 400 MW. MP&L has signed electric service agreements with 7 major taconite producers to provide electrical energy for expansions of their operations. In addition to the expansion of the taconite industry, anticipated expansion of the paper and pulp industries also will result in increased residential and commercial electrical energy needs in northern Minnesota. Until 1980, a portion of MP&L's electric power will be supplied by interconnection with the Manitoba Hydro-electric System and members of the Mid-Continent Area Power Pool. Planning assistance will be provided through the Mid-Continent Area Reliability Coordination Agreement.

Background

Since 1975, MP&L began application procedures for the various Large Electric Power Generating Plant (LEPGP) permits needed for the proposed Unit 4. These procedures result in a sequential process requiring a Certificate of Need, Certificate of Site Compatibility, Environmental Impact Statement, and permits. These steps are respectively the prime responsibility of the Minnesota Energy Agency (MEA), the Minnesota Environmental Quality Board (MEQB), the Minnesota Pollution Control Agency (MPCA), and a number of other governmental regulatory entities. In addition to obtaining the permits for construction of a LEPGP, it also will be necessary to obtain operating permits relating to air emissions, water discharges, and noise.

MP&L was granted a Certificate of Need by the Minnesota Energy Agency on April 6, 1976, and a Certificate of Site Compatibility from the Environmental Quality Council now the Environmental Quality Board (MEQB) on February 11, 1976. The Certificate of Site Compatibility was granted on condition that prior to the start of operation of Unit 4, MP&L should enter into a binding agreement with the MPCA to modify the Clay Boswell Station so that existing Units 1, 2, and 3 are in compliance with all applicable particulate standards, and the Unit 3 stack mist problem is eliminated.

An installation permit for substantial emission control improvements to the existing units was approved by the MPCA on March 23, 1976. A Stipulation Agreement was approved on April 6, 1976. Both agreements required that full compliance for Units 1, 2, and 3 be attained no later than December 31, 1978. On April 13, 1976, the MEQB granted MP&L a Limited Work Authorization to start preparatory work, not including construction of major air and water pollution control systems, on the proposed Unit 4 site. Subsequently, the MPCA Board approved commencement of preliminary site preparation on June 22, 1976. Limited work was started subject to MP&L obtaining appropriate permits from State regulatory agencies, and to a continuing review by the MEQB of the extent and effect of the work. A second Limited Work Authorization was granted by the MEQB on May 24, 1977, which granted MP&L permission to work on the boiler turbine, coal handling system, loop track, administrative and material processing area, and the west parking lot. All work authorized in the first and second Limited Work Authorizations was approved with a provision that MP&L was proceeding at their own risk. Alternatives, mitigating measures, and other considerations in the environmental impact statement process are not to be foreclosed because of construction performed prior to final decisions by the State of Minnesota.

The MEQB determined that construction of proposed Unit 4 at the Clay Boswell Station constituted a major action with the potential for significant environmental effects (Minn. Reg. MEQC 25(c) (1) 1974), and on February 10, 1976, designated the MPCA as the Responsible Agency to prepare an environmental impact statement. This Environmental Impact Statement (EIS) is primarily an informational document designed to provide decisionmakers with information on the proposed action, various alternatives, existing conditions, environmental impacts, possible mitigating measures, and other related concerns. It is not intended as an instrument to justify an action, but rather to assist decision-makers in evaluating the proposed action and its impacts.

MP&L'S PROPOSED UNIT 4

The proposed Unit 4 at the Clay Boswell Steam Electric Station will be a coal-fired steam electric generating unit with a net generating capacity of 504 MW. The projected capacity factor of Unit 4 averaged over its 35 year life is approximately 71.4%.

Unit 4 will be constructed adjacent to the 3 existing units and will share many of the existing facilities. Some facilities will be expanded to accommodate the new unit and others will be modified.

MP&L has acquired 2,880 acres (1,165 hectares) of land to accommodate Unit 4, resulting in a total Station acreage of approximately 3,600 acres (1,457 hectares). This expansion will necessitate the relocation of Minnesota Trunk Highway 6 for a stretch of 2.2 miles. The relocated segment will be constructed by the Minnesota Department of Highways and financed by MP&L.

Coal for the proposed Unit 4 will be western sub-bituminous coal from Peabody's Big Sky Mine near Colstrip, Montana. This same coal is used in Units 1, 2, and 3. The proposed air quality control system for Unit 4 is designed for coal with an upper limit of 2.8% sulfur content. To insure that the "as received" coal does not exceed this upper limit, sampling and analyses will be necessary before the coal is burned. An estimated 2.2 million tons per year (tpy) (2.0 million metric tons per year) (mtpy) will be delivered to the Clay Boswell Station for consumption by Unit 4. This will increase coal deliveries to the Station to approximately 4.5 million tpy (4.1 million mtpy) when Unit 4 goes into operation in 1980. Approximately 4 of the Burlington Northern's unit trains per week will deliver the coal from the Big Sky Mine, using the same route presently used by trains delivering coal for the existing units. MP&L plans to expand the existing coal handling facilities at the Station by installing a new reclaim system to service Unit 4.

The major elements in MP&L's proposed Unit 4 electric generating facility are typical of modern coal-fired steam electric power facilities. The proposed steam generator or boiler will be an indoor-boiler, water cooled furnace, single drum unit and will use pulverized coal. The condenser will utilize 2 condenser shells with a single pass arrangement for each shell.

The proposed water systems for Unit 4 will interface with the existing water systems. All 4 units will use the existing water intake structure, which will be modified to provide for the added demands of the new unit. Total water intake requirements for the entire facility will not increase significantly, but water consumption will be increased because of evaporation from the Unit 4 cooling tower.

As proposed, Unit 4 will utilize an evaporative or wet mechanical draft cooling tower to dissipate waste heat from the main condenser cooling water system. Water for the Unit 4 boiler will be drawn from existing wells supplying Units 1, 2, and 3 boiler makeup and potable water systems. A third well will be added to meet increased requirements. The existing demineralizer system will be used to supply Unit 4 boiler water using an additional 20 gallons per minute (gpm) (76 liters per minute (lpm) for demineralizer regeneration. Regeneration wastes from the demineralizer system will flow to the proposed central waste treatment facility.

The service water system will require an estimated 100 gpm (379 lpm). This water will be supplied from the water intake structure by the makeup and service water pumps serving all 4 units. Service water will be required for bearing cooling, pump seals, cleaning equipment and miscellaneous cleaning. Waste water from this system will be discharged to the floor drainage system and then to the proposed central waste treatment facility.

Equipment cleaning will include cleaning air preheaters, boiler firesides, and economizers to prevent harmful corrosion. Wastes generated from Units 1, 2, and 3 will be pumped to the Units 1, 2, 3 bottom ash pond and wastes from Unit 4 will be pumped to the Unit 4 bottom ash pond. Periodic internal cleaning of boiler tubes sometimes is necessary to remove boiler scale to maintain efficient performance. Before Unit 4 goes into operation, boiler tubes will be cleaned to remove material left during construction. Wastes will be routed to a holding pond in the fly ash reclamation area until they are collected and hauled off site by a private contractor. Cooling tower wastes generated during cleaning will be removed from the cooling tower basin to a sludge disposal area in the old fly ash pond, and waste water will be routed to the central waste treatment facility.

Potable water for domestic purposes and the demineralizer system will be supplied by existing wells, but another well will be provided to accommodate the increased 10 gpm (318 lpm) for Unit 4.

The sanitary sewer system will be separate from other waste collection systems. A prefabricated sewage treatment facility will be installed to handle sewage for the entire Station. The existing septic tanks for Units 1 and 2 and the holding tank serving Unit 3 will be abandoned. During construction of Unit 4, portable sanitary facilities will be provided, and wastes will be disposed of off site in an appropriate manner.

Rainfall runoff from the coal pile and outdoor coal handling facilities will be collected and treated before discharge. Runoff will flow to a settling pond where solids will be periodically removed and disposed of in the fly ash reclamation area. Effluent from the settling pond will be pumped to the proposed central waste treatment facility for neutralization and equalization for subsequent discharge to the discharge seal well and then to the Mississippi River.

With the exception of cooling tower blowdown, once through cooling water, and sanitary wastes, all wastewater generated at the Clay Boswell Station including Unit 3 fly ash blowdown and Unit 3 fly ash pond overflow will be treated in the proposed central waste treatment facility before discharge. The discharge from all wastewater systems will flow to the discharge seal well which flows to a discharge canal which in turn flows to a backwater of the Mississippi River.

Unit 4 will be equipped with an air quality control system to reduce air pollutant emissions to within regulatory limits. The steam generator or boiler will be equipped with a wet scrubber as the primary collection device for particulate matter, and spray tower absorbers for sulfur dioxide removal. Five percent of the stack gases will bypass the wet scrubber and flow to an electrostatic precipitator for particulate removal. Combustion products will be discharged to the atmosphere from a 600 ft (183 m) stack. To meet MPCA stipulation agreements, the air quality control systems on Units 1 and 2 are being changed from mechanical collectors to baghouse filters (fabric filters) with an estimated collection efficiency of 99.6%. MP&L is trying to solve the stack mist problem in Unit 3 caused by the internal plugging and moisture carryover in the Krebs-Elbair scrubber. A tall, low velocity stack was built in an attempt to solve the problem using the gases from Units 1 and 2 to reheat the gases from Unit 3. The combustion gases from Units 1 and 2 which previously exited through a 250 ft (76 m) stack now exit with gases from Unit 3 through a new 700 ft (213 m) stack. Despite this new air quality configuration, the data submitted to date do not necessarily support the premise regarding the benefits of the low velocity design. It has been assumed that Units 1, 2, and 3 will be in compliance with MPCA air pollution control regulations by the time Unit 4 is placed in operation. Air stipulation agreements between MP&L and the MPCA state that air emission rates of Units 1, 2, and 3 must be in compliance with Minnesota air pollution regulations by December 1978.

The potential for fugitive dust at the Clay Boswell Station will increase as a result of the addition of Unit 4. This is due to the increased handling of raw materials and other activity. Potentially, construction could increase fugitive dust emissions. The Clay Boswell Station is expected to comply with the fugitive dust regulations of the MPCA air pollution control regulations.

Solid waste at the Clay Boswell Station will consist primarily of ash produced from coal burning. The steam generator or boiler in Unit 4, like the boilers for the existing units will produce 15 to 20% of the total ash as bottom ash; most of the remaining ash will be collected as fly ash in the particulate control systems and in the electrostatic precipitators. Unit 4 bottom ash will be sluiced at the rate of 1,233 gpm (4,667 lpm) to a new bottom ash pond to be constructed approximately one mile northwest of the existing electric generating facilities. The Unit 4 bottom ash pond will be one section of the proposed new ash and sulfur dioxide sludge pond to be constructed northwest of the Station. The larger section of the pond will be used for fly ash from Units 1, 2, and 4 and sulfur dioxide absorber sludge from Unit 4.

A fly ash and sulfur dioxide absorber system for Unit 4 will be used to remove particulates and sulfur dioxide from the boiler exhaust gases. The particulates and sulfur dioxide will be pumped in a slurry to the fly ash scrubber sludge disposal pond. Pond effluent will be returned to the system, and there will be no blowdown from the system.

Evaluation of the existing disposal ponds at the Clay Boswell Station indicates that they will have insufficient capcaity to receive all future waste to be produced during the life of Units 1, 2, and 3. MP&L proposes that Units 1 and 2 fly ash produced between 1980 and the retirement date of the 2 units will be deposited in the new ash and sulfur dioxide sludge pond to be located northwest of the Station. No decision has been made as to where to dispose of Unit 3 fly ash after 1994 when it is estimated that the Unit 3 fly ash pond will be full.

Total construction time at the Clay Boswell Station is projected to be approximately 46 months involving about 30,740 person-months of labor. The peak construction period should occur between the 31st and 33rd months of construction during 1979 when about 1,200 workers will be on the job. MP&L plans to observe U.S. Environmental Protection Agency (EPA) erosion control methods during construction. Efforts to ensure that no ground water contamination occurs will include construction of dike cutoffs.

ALTERNATIVES TO MP&L'S PROPOSED UNIT 4

Minnesota Environmental Quality Board regulations require that each environmental impact statement contain an evaluation of all reasonable alternatives to the proposed action, the environmental impact of each, and the reason for their rejection in favor of the ultimate choice. Minn. Reg. MEQC31(f).

Alternatives are considered to be major changes to the proposed action and will require MP&L to make major changes in engineering, construction, equipment, or operating procedures.

Proposed alternatives were assessed using criteria based on the following: anticipated adverse environmental impacts; abatement effectiveness; safety; Federal, State, and local regulations, statutes, and standards; technological and engineering feasibility, reliability, and flexibility; and economic feasibility and cost effectiveness.

Alternatives were considered for the following classifications:

- Primary fuel alternatives,
- Supplemental fuel alternatives,
- Primary fuel processing system alternatives,
- Transportation of primary fuel alternatives,
- Cooling and water supply system alternatives,
- Air quality control system alternatives, and
- Solid waste management system alternatives.

Alternatives not considered were those of alternate sites, since the Certificate of Site Compatibility has been issued, and the alternative of not constructing the facility, because the Minnesota Energy Agency has issued a Certificate of Need for a 500 MW generating facility.

The following are considered to be reasonable alternatives to MP&L's proposed action:

- The use of waste wood residue (hogged fuel) as a supplemental fuel,
- Coal beneficiation as a primary fuel processing system alternative,
- Dry cooling tower as cooling and water supply alternative,
- Wet/dry cooling tower as cooling and water supply alternative, and
- Disposal of solid waste in an abandoned mine as a solid waste management system alternative.

Waste Wood as Supplemental Fuel

Use of waste wood as a supplemental fuel for the production of electricity in a steam-turbine generator is considered a reasonable alternative for several reasons. The Clay Boswell Station is located in a heavily wooded region in northern Minnesota, where timber from the region as well as the west coast is processed into wood products. An excess of waste wood residue is available presently and one large paper company - Blandin Paper Company - intends to utilize their waste wood to supply some of their energy requirements. It is possible that other uses may be found for this waste in the future, such as for building materials, but presently an estimated 110,260 tpy (100,026 mtpy) of waste wood (excluding Blandin Paper Company's waste wood), are available. The waste wood has an average heating value on a dry basis of 4,300 Btu per lb (2,389 kg-cal per kg).

The use of waste wood, which is compatible with MP&L's proposed steam-turbine generator could displace approximately 55,000 tons (49,895 mt) of coal per year. This will result in an estimated cost savings of approximately $544,500 annually. The amount of ash and SO_2 scrubber sludge generated by Unit 4 will be reduced with the use of waste wood, as will air emissions. Waste wood could be transported to the Clay Boswell Station by either rail or truck. Waste wood handling costs, which include the cost of "retrofitting" the steam-turbine generator, wood storage costs, auxiliary power costs, and annual wages for 2 wood handlers, will be approximately $940,150 per year.

Coal Beneficiation

Beneficiation, or cleaning, of the sub-bituminous coal from the Big Sky Mine near Colstrip, Montana, will result in reduced air emissions and reduced solid waste production at proposed Unit 4. These reductions may cause operation of SO_2 spray tower absorbers to be unnecessary for compliance with Federal new source performance standards and also may allow a substantial reduction in the size of the proposed new ash and SO_2 sludge disposal pond.

A coal preparation plant could be built and operated at either the coal's source, the Big Sky Mine, or at the Clay Boswell Station. Because the potential for surface and ground water contamination is less in Montana's arid climate, only a coal preparation plant at the Big Sky Mine was considered. A complete testing program, which will take about 12 months to complete, is needed to determine fluctuations in coal quality and washability and to perform pilot plant testing of bulk samples from the McKay and Rosebud coal seams and boiler burning studies. Another 6 months will be required for coal preparation plant engineering, and the plant itself will take 2 years to construct. The capital cost for the coal preparation plant is estimated to be $38 million.

The coal preparation plant will have adequate capacity to beneficiate up to 6.0 million tons (5.4 million mt) of raw coal annually, resulting in 5.3 million tons (4.3 million mt) of cleaned coal. Some coal will be dried to avoid the possibility of the coal freezing during transport in the winter months. Beneficiated coal could be transported from the Big Sky Mine to the Clay Boswell Station in the same unit trains which MP&L intends to use for the proposed action and on the same route. The beneficiated coal will use the same handling and storage facilities as the proposed action of using raw coal.

MP&L possibly could realize cost savings with the use of beneficiated coal if the sulfur content of the cleaned coal were low enough to make the use of the spray tower SO_2 absorbers unnecessary. However, costs associated with coal cleaning and drying are estimated to offset these savings and the alternative of coal beneficiation is estimated to cost MP&L an additional $1,959,000 annually.

Dry Cooling Towers

Use of dry cooling towers will reduce Unit 4 water consumption to about 1% of the water consumption for MP&L's proposed action. Water consumption is reduced by eliminating the water loss which occurs with the use of evaporative cooling systems. Dry cooling systems have a higher cost than evaporative systems, but offer some environmental advantages such as minimal water consumption, elimination of visible vapor plumes, icing problems, and salt deposition, which may outweigh their economic disadvantages.

There are 2 types of dry cooling towers; direct and indirect. The direct dry cooling tower system is considered most economical for small and intermediate size steam turbines in cool climates. In steam-turbine generators of the 300 to 800 MW capacity, the indirect system becomes more economically attractive.

Energy requirements for the dry cooling tower system will be greater than for MP&L's proposed action, ranging from 1 to 10% of the proposed Unit 4 net generating capacity. This could increase the coal requirements of the proposed Unit 4 by 10,000 to 100,000 tpy (9,072 to 90,178 mtpy).

Lime consumption will increase by approximately the same proportion as coal consumption. Chlorine consumption, however, will be reduced substantially. Increased lime and coal consumption will mean increased handling of these materials, but MP&L's facilities appear to be adequate to handle these increases.

Dry cooling towers will have major effects on MP&L's proposed steam condenser and steam-turbine generator. However, the condenser and generator could be designed to minimize these effects. Use of dry cooling towers could result in a reduction of Unit 4 net generating capacity. This lost capacity probably will have to be made up by a different generating unit and will consume additional coal.

Use of dry cooling towers will have a minimal effect on air emissions when compared with the proposed Unit 4 wet cooling towers. Ash and scrubber waste production will be increased slightly with increased coal consumption, but the sediment which accumulates in wet cooling towers will be eliminated with the use of dry cooling towers.

Wet/Dry Cooling Towers

Wet/dry cooling towers incorporate a radiator-type heat exchanger in a dry section as well as a conventional evaporative wet cooling tower section. The ratio of wet to dry cooling depends on the design parameters for a particular operation. Some wet/dry cooling towers have been designed for water conservation and generally have small wet sections. Others, designed for plume abatement or to reduce fogging, generally have a small dry section. Wet/dry towers of the size necessary for proposed Unit 4 are in operation in the U.S. However, these towers have not been designed for fog control.

Installation of a wet/dry cooling tower could result in some reduction in Unit 4 generating capacity. However, if the tower were designed for the wet tower to meet the unit's maximum cooling requirements, and only enough dry to eliminate fogging, capacity reduction will not occur.

A wet/dry cooling tower will cost approximately $17 to $19 million, compared with a capital cost of $15 million for MP&L's proposed wet cooling tower. In addition, reduced generating capacity will have to be made up by another generating unit which will increase coal consumption. Lime consumption will increase in the same proportion as coal consumption. Chlorine consumption will be decreased slightly with a wet/dry cooling tower. MP&L's existing facilities are considered adequate to handle increased lime and coal handling requirements.

The effects of wet/dry cooling towers on water systems for the proposed Unit 4 depend on the cooling tower design. The dry portion of the tower reduces total water consumption, and water intake quantities will be reduced accordingly. For instance, for wet/dry cooling towers with 80% wet and 20% dry, the water quantities would be reduced by 20%. If the wet/dry cooling towers were designed to eliminate capacity reductions and provide for approximately the same evaporative cooling as MP&L's proposed wet cooling towers, then no change in water consumption will occur.

Emissions of SO_2 and particulates could increase if extra energy generation were necessary to make up reduced capacity. These are expected to have little effect on MP&L's proposed air quality control system (AQCS). In addition, bottom ash production as well as fly ash and SO_2 scrubber sludge will increase for the same reason.

Wet/dry cooling towers will reduce waste water effluent by reducing cooling tower blowdown. Fogging and drift will be nearly eliminated from Clay Boswell Unit 4 with use of wet/dry cooling towers.

Disposal of Solid Waste in an Abandoned Mine

Disposal of the solid waste generated by the proposed Unit 4 at the Clay Boswell Station in abandoned open pit iron mines will eliminate the need for MP&L's new ash and SO_2 sludge pond and eliminate the potential for seepage from this pond.

Disposal in an abandoned open pit iron mine of the bottom ash, fly ash, and SO_2 scrubber waste will require dewatering, chemical fixation, and curing of the waste before transporting it to the mine site by rail. After arrival at the mine, the waste may be stockpiled before being placed in the mine and compacted. Eventually, the material will be revegetated.

Coal and lime handling are not expected to be affected by this alternative. However, 23,000 to 32,000 tpy (20,865 to 29,030 mtpy) of chemical reagents will be required annually for fixation of the solid waste.

Water systems will be essentially the same as for the proposed action, except that the bottom ash, fly ash, and SO_2 sludge handling systems will be modified to incorporate dewatering processes.

The disposal of chemically fixed solid waste in an abandoned iron mine may cause ground water contamination through permeable sections of the Biwabik Iron Formation. It is believed that this seepage will be less than the estimated seepage for the new ash and SO_2 sludge pond. However, a detailed site specific investigation at the mine site will be necessary to determine seepage potential. Surface water pollution may be greater with this solid waste disposal alternative than with MP&L's proposed action because of increased solid waste handling and storage. However, handling the waste in a dry or nearly dry state, as in this alternative, minimizes transport and disposal difficulties.

The dewatering, chemical fixation, rail transport, and handling of the solid waste for this alternative will consume more energy and incur additional capital and operating costs than MP&L's proposed solid waste handling and disposal systems.

Several guidelines were used to determine the feasibility of mines for this alternative: surface or open pit mines only were considered; rail transport is the only feasible transport method for the solid waste to the mine, and therefore, the mine must be served by existing rail trackage; the mine site must be less than 20 miles (32.2 km) by rail from the Clay Boswell Station; the mine must have a volume equal to or greater than 5,900 acre ft (7,277,543 cu m) either individually or in combination with adjacent sites; and the mine must be exhausted or mined out to the extent that solid waste disposal will not interfere with future ore extraction. Data showed that there are no exhausted mines within 20 miles (32.2 km) of the Clay Boswell Station which have the capacity required for disposal of the solid waste produced by the proposed Unit 4. There are some mines near the Clay Boswell Station, however, which may be exhausted or nearly exhausted by 1980 and which have, alone or in combination, more than adequate capacity.

ENVIRONMENTAL SETTING

The Clay Boswell Steam Electric Station is situated in the southwest corner of Itasca County in north central Minnesota, 5 miles west of Grand Rapids on the upper Mississippi River. This heavily forested area with numerous lakes is characterized by long severe winters and temperate summers.

Located at the southwest tip of the Mesabi Iron Range, the Clay Boswell Station lies in a region abundantly supplied with resources which constitute major elements of northern Minnesota's economy. The Arrowhead Region, the largest of the 13 Planning and Development Regions in Minnesota, includes Itasca County. Bordering Ontario, Canada, to the north, and Lake Superior to the east, the Arrowhead Region has a land area of 18,000 square miles (46,620 square kilometers) (sq km) and holds a large share of Minnesota's natural resources, including 56% of the forests, 37% of the water surface area, and 20% of the marshlands. Much of the land in the Arrowhead Region is publicly owned with up to 64% being owned by the State or Federal Government. The region supports several major industries including forestry, recreation, agriculture, and the rapidly expanding taconite mining industry. The possibility of a copper-nickel mining industry developing is still uncertain, but the State of Minnesota will determine whether to proceed after completion of studies.

The Clay Boswell Station is surrounded by forest, much of which is managed by the State, County, and Federal governments. Of the land in Itasca County, 54% is publicly owned. Situated on the western suburban fringe of Grand Rapids, the Clay Boswell Station site will occupy 3,600 acres (1,456.9 hectares) when complete. The site is predominantly wooded land interspersed with cultivated and pasture land. At present, 38 dwellings are located on the land already acquired or to be acquired for MP&L's proposed Unit 4.

The present Clay Boswell Station, consisting of Units 1, 2, and 3, is a complex of several tall buildings, 4 tall smoke stacks, solid waste disposal ponds, fly ash reclamation areas, an electrical switching yard, and a railroad yard. The stacks are visible from distances of 6 miles (9.6 km) and the smoke and vapor plumes are visible from greater distances. Fly ash from stack emissions have settled on everything within a radius of approximately 1 mile (1.61 km) of the Station, giving the area a white cast.

Noise from the Clay Boswell Station is generated by operating equipment and external sources such as coal trains and delivery trucks. Noise measurements taken at the Station did not include coal train unloading operations. This causes some uncertainty in determining ambient noise levels.

The background air quality in the vicinity of the Clay Boswell Station is fairly good. There are 5 principal air pollutants associated with coal-fired steam electric stations: particulates, nitrogen oxides (NO_x), sulfur dioxides (SO_2), trace elements, and sulfates. Diffusion modeling was conducted to calculate the dispersion of Units 1, 2, and 3 emissions for both before and after modifications to the air quality control system. Results of modeling for emissions from the premodified units indicated that the 24-hr maximum ambient air quality standard (AAQS) for particulates was being exceeded by 76%. The 3-hr maximum concentration allowed for SO_2 was being exceeded by 61%. The annual geometric mean particulate concentration was in compliance, as was the annual arithmetic mean concentration for NO_x and SO_2. The 24-hr maximum concentration for SO_2 was marginally in compliance.

According to the 1976 Stipulation Agreement between MP&L and the MPCA, Units 1, 2, and 3 must comply with all air quality standards by December 31, 1978. It is expected that after modifications, pollutant concentrations resulting from Units 1, 2, and 3 will not exceed the AAQS with the exception of SO_2 emissions, which are expected to exceed the 3-hr maximum AAQS by 34%. Analyses conducted to determine particle size distribution of particulates from Units 1, 2, and 3 indicate that most particles emitted will be of the size thought to be most hazardous to human health (less than 5 microns). Fogging, icing, and salt deposition resulting from the Unit 3 cooling tower probably does not cause any problems beyond the MP&L property line.

The vegetation in the region and around the Clay Boswell Station is primarily forested, but areas of natural and man-caused openings also exist. Presently, northern Minnesota contains a mosaic of vegetative types, both forest and non-forest, occurring on widely ranging topographic sites, from wet to dry and from thin rocky soils to deep loams and clays. Forest types within a radius of 12 miles (19.3 km) of the Clay Boswell Station include hardwood forest, northern lowland forest, northern mesic forest, northern xeric forest, boreal forest, open bog and tall shrub communities, and fens and sedge meadows. Both pasture and crop land exist in the vicinity of the Clay Boswell Station. Operation of Units 1, 2, and 3 already has affected vegetation within the vicinity of the Station. A preliminary plant pathology survey conducted near the Station in 1974 found severe air pollution damage to vegetation within a 4 mile (6.44 km) radius of the Station. Preliminary observations showed first, visible deposition of particulate matter on foliage to a distance of approximately 1 mile (1.6 km) radius of the stack with deposition closely related to prevailing winds. Second, leaf damage by deposition of an aerosol fine mist was found to extend approximately to a radius of 4 miles (6.4 km) from the stack. The leaf damage also was closely related to prevailing wind direction. It has been determined that the current knowledge of the terrestrial vegetation and soils in the area around the Clay Boswell Station is inadequate. Additional data will be gathered in a supplemental study in summer 1977 and the scope and severity of past and present phytotoxic and soils impacts will be examined. There is a possibility that more rare and endangered plant species exist in Itasca County than have been found to date and that they may well be growing in areas likely to be affected by the Clay Boswell Station. During the summer 1977 study, a detailed search for endangered and rare species of plants will be conducted.

Terrestrial wildlife is governed by habitat type which, in turn, governs wildlife species distribution and populations. Age of vegetation, dispersion, and vegetative type determine the suitability of habitat for wildlife species. Most wildlife inhabit distinct vegetative types. A few species such as the larger herbivores and carnivores range over several vegetative types. Near the Clay Boswell Station, the terrestrial wildlife includes amphibians, reptiles, birds and mammals. The bird community of north central Minnesota ranges from the inconspicuous warblers to the bald eagle. The largest remaining concentrations of bald eagles nesting in the continental United States is centered in the Chippewa National Forest, the eastern border of which is only 9 km west of the Clay Boswell Station. The mammal community in the vicinity of the Clay Boswell Station includes both herbivores and carnivores. These include mice, snowshoe hare, chipmunks, beaver, white-tailed deer, long-tailed weasel, coyote, and the endangered timber wolf. Up to 56 species of mammals are likely to exist in the area near the Clay Boswell Station. Important wildlife resources in the vicinity of the Clay Boswell Station include white-tailed deer, beaver, otter, and coyote. Waterfowl populations in the Game Management Area near the Clay Boswell Station are relatively abundant, particularly on Blackwater, Little White Oak, Shoal, Rice, Bass, and Little Drum Lakes. The terrestrial wildlife in the vicinity of the Clay Boswell Station will be studied during the summer 1977 field study.

Much of the electrical energy generated by the MP&L system meets the demands of the rapidly expanding taconite mining industry. In 1976, annual electrical energy consumed by the industrial and mining sector of the service area was 72% of the total electrical energy consumed, while electrical energy for agriculture was less than 1% of the total electrical energy consumed. Based on commitments from the taconite industry, MP&L's electrical energy sales have been projected to increase by more than 79%, or from 4.4 billion to 7.8 billion kw hr during the years 1975 to 1979. Projected expansion of the paper and pulp industries also will increase electrical energy demand as employment opportunities become available and the area's population is increased. To meet these additional demands, MP&L proposes to increase its generating capacity by adding Unit 4 at the Clay Boswell Station and by constructing other facilities within the service area.

Itasca County, with a 1970 population of 36,000, is one of 7 counties in the Arrowhead Region. Itasca County and the Arrowhead Region have experienced declining population since 1960. However, Grand Rapids, which is the largest city in the County, has shown a steady population increase in the last 3 decades. This seems to demonstrate the relative economic strength of Grand Rapids compared with the surrounding area. Grand Rapids had total retail sales of $43.7 million in 1972.

Itasca County supports a variety of potentially conflicting economic functions such as ore extraction and tourism-recreation. The combination of a large land area with a small and dispersed population reduces the opportunity for conflict.

The industry of Itasca County is resource-oriented. The taconite and timber industries are the County's largest employers and expansion of these industries has increased the County's labor force by 18% since 1970. Itasca County had an unemployment rate of 10.9% in 1974, which exceeds the State's average. Per capita income in 1973 for Itasca County was $3,500, which is 32% below the State's average.

Agriculture and agricultural employment have dropped dramatically in Itasca County since 1959. The number of farms declined 57% between 1959 and 1969 and farm employment declined 47% in the same period.

Itasca County and the Arrowhead Region have a healthy tourism industry. Resorts and accommodations are available in the area, as well as tourist-oriented services.

The Clay Boswell Station presently employs 102 people and generates $2.7 million in annual revenues to Itasca County, Bass Brook Township, and School District 318. Employee earnings annually generate $176,000 in Federal taxes and $69,000 in State income taxes. Direct and secondary employment earnings at the Clay Boswell Station accounted for 1% of Itasca County total retail sales. There is an acute housing shortage in Itasca County, which has been made more severe by a recent influx of construction workers.

Itasca County has 4 school districts with 9,354 students. County school enrollments are predicted to follow the State and national trends and decline dramatically by 1980. Among elementary schools, only Deer River is near capacity. Secondary schools in both Grand Rapids and Deer River are currently above capacity.

For Itasca County, doctors, police officers, and health care facilities per thousand population are below the State average. However, the County has more fire fighters than the State's average.

Situated on the Canadian Shield in the Chisholm Embarrass area between the eastern arm of Lake Agassiz and the Mesabi (Giants) Range, the Clay Boswell Station is in an area reflecting a complex geologic history. The bedrock characteristics of the region consist of folded and faulted Precambrian rocks.

The faults, now generally inactive, were formed during a mountain-building and granite-forming episode approximately 2.5 billion years ago. The bedrock is overlain by a glacial landscape characterized by morainal till plain and glacial deposits left during the last million years (Quarternary period). Landforms and surficial deposits in the area reflect only the last glaciation (Wisconsin Stage) which began some 40,000 years ago and ended 10,000 years ago. Wisconsin Stage drifts (soils) in Minnesota have a highly varied lithology and stratigraphy, which reflect the configuration of the several lobes that protruded from the ice sheet margin during various intervals of advance and retreat.

Abundant mineral deposits associated with Precambrian bedrock and Quarternary glacial and alluvial deposits are present in northern Minnesota. These include iron, dimension stone, and gold resources. The Mesabi Iron Range has been the major iron ore source for the nation's steel industry, 3.0 billion tons (3.1 billion mt) of iron ore and pellets having been shipped from the Mesabi Range singe 1890. The iron mines of the Mesabi range are primarily producing low grade iron ore which is concentrated to produce high grade iron or taconite pellets.

No economically recoverable mineral deposits are known to exist on the Clay Boswell Station site, with the possible exception of sand and gravel in the northwest corner.

The Clay Boswell Station is in an area which has an abundance of lakes. Located on Blackwater Lake (part of the Mississippi River), the Station is downstream from the major reservoirs in the Mississippi Headwaters region. Water levels in Blackwater Lake are controlled by the water levels at the Pokegama Dam and the upstream reservoirs in accordance with the reservoir manual compiled by the Minnesota Department of Conservation (now Minnesota Department of Natural Resources). Approximately 115,000 gpm (435,310 lpm) of water is pumped into Units 1, 2, and 3 through the intake structure on Blackwater Lake and approximately 112,000 gpm (423,954 lpm) is discharged to an embayment of the Mississippi River. Approximately 3,000 gpm (11,355 lpm) is lost by evaporation from the Unit 3 cooling tower. The annual average Mississippi River flow is 1,144 cfs (32.39 cu m per sec). In the 1976 to 1977 period, low flows dropped to approximately 200 cfs (5.66 cu m per sec).

Ground water in the vicinity of the Clay Boswell Station exists in bedrock and glacial drift aquifers.

Surface water quality data gathered at various sampling stations near and at the Clay Boswell Station indicate that the water quality of the Mississippi River is very good, with few indications of significant municipal or industrial pollution. This water has been classified 2B, 3B, 4A, 4B, 5, and 6, indicating that the water is suitable for fish habitation and propagation, and is suitable for aquatic recreation and industrial consumption. Water quality meets or surpasses applicable criteria for all parameters except copper. In this stretch of the Mississippi River, a diverse selection of biota exists. Data gathered from sampling stations upstream and downstream from the Clay Boswell Station discharge indicated the presence of phytoplankton, periphyton, aquatic macrophyte, zooplankton, macroinvertebrate, and fish populations. No aquatic species considered by the U. S. Fish and Wildlife Service to be endangered or threatened are known to occur in north central Minnesota.

The Mississippi headwaters region, including the area around the Clay Boswell Station, was extensively explored and charted in the late eighteenth and early part of the nineteenth centuries. Remains of ancient Indian habitations were discovered at various locations near the Clay Boswell Station. A historically significant site, including ancient burial mounds dating back to between 100 BC to 1,700 AD (late Woodland Indian Period), was discovered at White Oak Point, a few miles up river from the Clay Boswell Station. An Indian trail, connecting Pokegama Falls downstream from the Clay Boswell Station and White Oak Point, was found to cross the northwest corner of the Clay Boswell Station site.

ENVIRONMENTAL IMPACTS

MP&L's Proposed Unit 4 - Clay Boswell Steam Electric Station

Construction and operation of Unit 4 at the Clay Boswell Steam Electric Station inevitably will result in some significant impacts, both beneficial and adverse. The most obvious impact of Unit 4 will be the additional generating capacity available for the rapidly expanding taconite industry. The expansion of the Clay Boswell Station will require appropriation of 2.3% of agricultural land in Itasca County. This constitutes a significant impact. Similarly, the influx of up to 1,200 construction workers during the estimated 46 month construction period will have significant socio-economic impacts on the area near the generating facility and on Grand Rapids and its environs.

The pollutant emissions from proposed Unit 4 will increase the ambient concentrations of particulates, nitrogen oxides, sulfur dioxide, trace elements, and sulfates in the vicinity of the Clay Boswell Station. These emissions will cause meteorological and climatological impacts which will be negligible beyond the boundaries of MP&L's property, except to the extent that they contribute to global climatic changes associated with air pollution.

With respect to the applicable Prevention of Significant Deterioration (PSD) regulations, the proposed action is projected to contribute 2.0% of the annual geometric mean particulate increment, 12.6% of the 24-hr maximum particulate increment, 13.3% of the annual arithmetic mean sulfur dioxide increment, 66% of the 24-hr maximum sulfur dioxide increment, and 36% of the 3-hr maximum sulfur dioxide increment. These contributions effectively will limit new construction of major air polution sources in the region of the Clay Boswell Station. The ambient pollutant concentrations resulting from emissions of the proposed Unit 4 are not projected to exceed the Ambient Air Quality Standards (AAQS). However, the combined emissions of modified Units 1, 2, 3 and proposed Unit 4 will cause the 24-hr maximum sulfur dioxide AAQS to be exceeded by 21%, and the 3-hr maximum sulfur dioxide AAQS to be exceeded by 72%. In addition, the emissions will cause high ambient sulfate concentrations. The AAQS violations and high sulfate concentrations are due primarily to the high sulfur content and low heating value of the coal which MP&L has proposed to burn at the Clay Boswell Station. The coal analyses which will result in compliance with the AAQS have been computed and the resultant pollutant concentrations have been projected.

The high ambient sulfur dioxide concentrations projected to be caused by the emissions from modified Units 1, 2, and 3, and proposed Unit 4 probably will cause some damage to terrestrial vegetation in the vicinity of the Clay Boswell

Station and may result in some long-term soils impacts. The extent of these potential impacts cannot be estimated until after the summer 1977 field studies have been completed. The terrestrial wildlife impacts of the Clay Boswell Station emissions will be transmitted primarily through wildlife food sources and cannot be predicted accurately. The terrestrial wildlife impacts will be only subtle and probably minor if the Clay Boswell Station complies with the AAQS. The terrestrial ecology impacts associated with construction of the proposed action will be due principally to the excavation and construction of the borrow area and the ash and SO_2 sludge pond. These impacts will be significant but highly localized.

With the addition of Unit 4, water consumption at the Clay Boswell Station will increase by 4,075 gallons per minute (15,425 lpm), an increase of 120% over the consumption for the existing units. The likely impacts which may result include the possible reversal of flow between the intake on Blackwater Lake and the discharge on the Mississippi River if the river flow were to drop to a critical low flow of 100 cfs (2.83 cu m per sec). This condition could prevail during a drought, such as that which occurred in the summer of 1976. The reversal of flow would cause a water temperature rise both upstream and downstream from the Station. Mississippi River levels are regulated by reservoir releases from Winnibigoshish and Leech Lakes, both managed by the U. S. Army Corps of Engineers. The additional water consumption at the Clay Boswell Station could affect water users as far downstream as Minneapolis/St. Paul. If enough water were released from the upstream reservoirs to compensate for the reduced flow, the water levels would drop 0.04 ft (0.012 m) in Winnibigoshish Lake and 0.02 ft (.006 m) in Leech Lake. This lowering of lake levels does not appear to be a significant impact.

It is unlikely that there will be any significant impacts on ground water at the Clay Boswell Station. However, possible impacts may result from construction of the proposed new ash and scrubber sludge disposal pond. These include possible accidental spills of liquid fuels, lubricants, and chemicals, and possible disruption of the ground water recharge area. Potential leakage from the sludge disposal pond may be a problem unless more positive control measures are taken. Possible leakage control measures include:

1. Chemical stabilization of fly ash and SO_2 scrubber sludge;

2. Lining the pond with an impervious material; and

3. Revision of present leakage control measures to increase their effectiveness.

The same petrochemical wastes which may contaminate ground water may also run off in surface waters, resulting in adverse impacts. This could be minimized by maintenance of construction equipment and the installation of waste sumps to contain spills. Excavations and construction of Unit 4 and the sludge disposal pond may result in the potential for soil erosion and sediment deposition, which could result in elevated turbidity and suspended solids in water near the construction site.

The principal impact on water quality will result from the chemical discharges during operation of Unit 4 and, to a lesser extent, from the thermal effluents. It is projected that under worst case conditions some water quality standards may be exceeded. This stretch of the Mississippi River is classified as suitable for fishing and other aquatic recreation and for general industrial consumption. Effluents are produced by the cooling tower effluent discharge system and the air quality control system. The cooling water will be withdrawn from the Mississippi River and will be concentrated by evaporation. This will cause increased concentrations of sulfates and total hardness in the cooling tower effluent. Chlorine will be added to the circulating water to control biological fouling. This will result in elevated levels of chlorine in the cooling tower effluents. Other pollutants in the cooling tower effluents will include trace elements and related compounds. Concentrations of many of these compounds have been measured and found to range from undetectable levels to levels which approach the applicable water quality standards. The effluents produced by the air quality control system are principally associated with fly ash and SO_2 slurry disposal. These effluents contain significant quantities of sulfates and contribute significantly to the total hardness of the effluent. MP&L has proposed various methods to control these pollutants.

The expected changes in the thermal effects on the water quality due to Unit 4 are estimated to be negligible because these changes are small compared with diurnal temperature variations under normal operating conditions. However, under worst case conditions when a reversal of flow may occur between the intake and discharge points, the consequent elevated temperature may have adverse effects on aquatic biota upstream and downstream from the Station.

Aquatic biota in the vicinity of the Clay Boswell Station may be affected by construction and operation of Unit 4. Construction may cause temporary habitat modification in the vicinity of the Station because of local increases in total suspended solids from construction area runoff and other sources. Runoff will be treated to reduce total suspended solids concentrations and no serious impacts to aquatic biota should result.

Operation of Unit 4 may result in possible impacts from the intake system, effluent cooling water and discharge systems, and the air quality control system. Impingement of aquatic biota on the intake screens will be minimal as the additional water withdrawal rates for Unit 4 are not much in excess of those for the existing units. Impingement rates may slightly increase or decrease depending on water velocity. Entrainment of organisms in the intake system will increase mortality rates of icthyoplankton, phytoplankton, and zooplankton. Under most operating conditions, replacement of entrainment losses will be compensated for by the stimulating effect of the chemical and thermal effluents on the environment of the discharge embayment. Discharges from Unit 4 will increase nutrient concentrations, sulfates, and chlorides, especially under worst case conditions. The increased nutrients could stimulate algal growth if worst case conditions persist. Elevated sulfate concentrations should not adversely affect wild rice production in the Mississippi River. Under worst case conditions, sensitive species of fish (e.g., lake whitefish and cisco herring) may be forced to move away from the chloride concentrations and may be damaged by them. Heavy metal concentrations may increase due to evaporative losses from Unit 4. In addition, copper from condenser tubing erosion and corrosion will be present. This could be toxic to copper sensitive species such as the fathead minnow. Under normal operating conditions, no impacts on aquatic biota are expected from the thermal effluent. Increases in sulfur dioxide and nitrogen oxide emissions could increase the potential for acid rain and possibly lower the pH of surrounding lakes which could result in adverse impacts on aquatic biota.

No adverse effects on the bedrock geology at the Clay Boswell Station are expected because construction of Unit 4 will entail excavation of the ground surface to only shallow depths. With varying degree, construction of the new generating facilities and the proposed new fly ash and scrubber sludge pond will disturb the natural processes of erosion, deposition, and soil formation of the glacial deposits common to the area. Clearing, excavation, and construction will affect about 17% or 620 acres (250 hectares) of the total site. Construction of the proposed new fly ash and scrubber sludge pond will result in adverse conditions until a stable vegetative cover is established. Construction of the dike for the proposed pond may cause stability problems. It has been suggested that the maximum height dike section may have marginal stability during and immediately after construction, but it is expected to increase in stability provided there is no foundation failure during or immediately after the construction period. Once the disposal pond has been filled, it probably will be covered with soil and then vegetated.

Proposed Unit 4 will increase MP&L's electric generating capability to 1,760 MW. The Clay Boswell Station will provide 57% of the total MP&L generating capability, with Unit 4 alone providing 29% of the total. Approximately 1,867,239 tons (1,693,931 mt) of sub-bituminous coal from the Big Sky Mine will be consumed annually by MP&L's proposed Unit 4.

The construction of Unit 4 will use energy in the form of materials personnel. Approximately 50 MW will be required for operation of auxiliary electrical equipment at proposed Unit 4, including the approximately 7.1 MW required to operate pollution control equipment.

Although the number of the construction force for Unit 4 is expected to be 1,200 at its peak in 1979, it is difficult to accurately predict the socio-economic impacts. Two possible situations were hypothesized.

Case A assumes that 70% of the peak construction force will commute daily to the Clay Boswell Station, 15% will commute weekly, and 15% will move to the area. Case B assumes that 50% of the construction labor force will commute daily, 25% will commute weekly, and 25% will move to the area. Certain criteria were used to measure impacts. The following impacts are expected to occur with construction and operation of the Clay Boswell Station.

- Housing demand in all incorporated communities in the area except Cooley will increase more than 5% due to the construction labor force.

- Housing demand will increase 14% in the community of Cohasset and 8% in the City of Deer River due to increased permanent operational employment at the Clay Boswell Station.

- No significant impact on elementary school enrollments are projected, but secondary school enrollments will exceed school capacity in the Grand Rapids School District 318.

- The proposed action will increase property taxes paid by the Clay Boswell Station by 41% over those currently being paid. This will result in an increase of 16% in school taxes being paid in School District 318.

- Police service per 1,000 population in the City of Grand Rapids is expected to decrease by 13.3 to 20%.

- Public revenues will increase by less than 10% as a result of the proposed action in the cities of Coleraine, Deer River, Marble, and Taconite and in Itasca County.

With construction of proposed Unit 4, the present 12.5% unemployment rate in Itasca County will be reduced by 30.4 to 33.6%. A dramatic 50% decrease in unemployment is expected among craftsmen and foremen. The addition of 170 employees for operation of Unit 4, although small, will decrease Itasca County unemployment by 6.4 to 12.0%, for a net rate of approximately 11.7%. The increased population in the area will, in turn, spur business activity which is predicted at the peak construction year of 1979 to increase dollar volume by 2.7 to 4.1% in Grand Rapids, and by 8.7 to 12.2% in the surrounding communities. The added need for housing will not create a demand that requires the extension of sewer and water service in incorporated areas of Itasca County. The aesthetic impact of the additional structure of Unit 4 will increase the already severe aesthetic impact of the existing facilities. Although no feature of Unit 4 will be visible from any distance greater than the existing structures, there will be additional plumes from the proposed Unit 4 stack and wet cooling towers.

Noise levels resulting from construction of the new ash and scrubber sludge pond for proposed Unit 4 are expected to violate Minnesota noise standards at MP&L's northern property line, near the community of Cohasset. This impact will be exacerbated by traffic noise from nearby U.S. 2. Extended work days may be needed for concrete pours, during which time noise levels may exceed nighttime standards. Noise levels may exceed Minnesota noise regulations during steam piping blowout, a temporary procedure. Limiting levels of impulsive noise, such as pile driving, are not addressed by Minnesota standards. General noise levels resulting from the operation of the Clay Boswell Station probably will fall within the levels provided in Minnesota noise standards for residential areas, except for certain activities such as replacement of machinery parts.

It should be noted that noise measurements do not include coal train unloading operations. This causes some uncertainty in determining ambient noise levels and compliance with regulations.

There will be no significant impacts on either the geography of the area around the Clay Boswell Station, or on any of the archeological sites near the facility.

Alternatives

Waste Wood as Supplemental Fuel

The principal difference between the environmental impacts resulting from the alternative of using waste wood as a supplemental fuel and the proposed action are related to surface and ground waters and air quality. The burning of 132,260 tpy (119,984 mtpy) of waste wood in the proposed Unit 4 could have beneficial impacts on surface and ground water quality. Possible surface and ground water contamination by seepage from surface and landfill disposal sites for waste wood and wood processing facilities is a present environmental concern. Reducing the waste wood volume in central Minnesota by using waste wood as a supplemental fuel in Unit 4 will reduce the potential for surface and ground water contamination by present waste wood disposal methods.

The burning of waste wood in the proposed Unit 4 could have beneficial impacts on air quality. Much of the waste wood produced in northern Minnesota presently is burned in incinerators and other facilities without removal of particulates from emission gases. If the waste wood were burned in Unit 4, 99.7% of the particulates in the stack gases will be recovered by the air quality control system.

The major difficulty with utilizing waste wood as a supplemental fuel is the assurance of supply and increased capital costs. Presently, substantial quantities of waste wood are available in close proximity to the Clay Boswell Station. However, Blandin Paper Company plans to use their waste wood as a fuel in their operations. Consequently, their waste wood probably will not be available in the future. Because of recent fuel price increases, it is reasonable to assume that other wood processors will burn waste wood as a replacement for other energy sources. It also is possible that other beneficial uses, such as particle board, will be found for the waste wood. The capital costs of waste wood processing and handling facilities is estimated to be approximately $6.5 million. When balancing the savings due to decreased coal consumption with the increased costs due to waste wood handling and processing, operating costs for Unit 4 are expected to increase slightly.

Coal Beneficiation

The principal differences between the impacts resulting from the alternative of using beneficiated or cleaned coal and those resulting from the proposed action of using raw coal are related to surface and ground waters and air quality. The cleaned coal has a lower ash and sulfur content than the raw coal. This results in reduced solid waste production and reduced production of particulates, sulfur dioxide, sulfates, and possibly trace elements by the proposed Unit 4.

The solid waste production will be reduced 37%, resulting in a significant reduction in the land area and volume required for MP&L's proposed new ash and sulfur dioxide sludge pond. Thus, potential leachate seepage into surface and ground waters from the disposal pond and possible adverse surface and ground water contamination will be reduced by using beneficiated coal. However, coal beneficiation could have possible adverse impacts on surface and ground waters in the vicinity of the Big Sky Mine in Montana. These adverse impacts would result from the disposal of coal cleaning rejects or waste at the mine.

The use of beneficiated coal at the Clay Boswell Station will reduce particulate emissions by less than 1% and sulfur dioxide emissions by 34%. The substantial reduction in sulfur dioxide emissions results in lower ambient sulfur dioxide concentrations. Thus, any potential adverse public health, water quality, terrestrial vegetation, and terrestrial wildlife impacts will be reduced by using beneficiated coal.

Because of the coal lost in the coal rejects and the necessity to partially dry the beneficiated coal for unit train transport during winter months, the alternative of using beneficiated coal will increase the total raw coal consumption. Based on using beneficiated coal for all 4 units at the Clay Boswell Station, total raw coal consumption will increase 11 million tons (10.0 million mt) or 9% during the estimated life of the Station. The estimated coal consumption data include coal for Units 1, 2, 3, and 4 as well as coal received at the Clay Boswell Station for transfer to MP&L's Syl Laskin Station.

The estimated capital cost to construct the proposed coal preparation plant is $38,000,000. The estimated annual incremental cost increase incurred by MP&L is $1,959,000. This cost considers the cost savings incurred by not needing to continuously operate the sulfur dioxide absorber and cost increases incurred by coal cleaning and drying.

Dry Cooling Towers

The principal differences between the environmental impacts resulting from using dry cooling towers rather than MP&L's proposed wet cooling towers relate to water consumption and generating efficiency. The use of dry cooling towers essentially eliminates the consumptive use of water by Unit 4. Thus, any adverse impacts on surface water hydrology and surface water quality essentially will be eliminated by using dry cooling towers. The dry cooling tower also will eliminate the cooling tower plume, since there will be no evaporation of cooling tower water.

The use of dry cooling towers will decrease the net generating capacity of Unit 4 because of a decrease in the unit's overall efficiency. This decrease occurs because the dry cooling towers require 5 to 50 MW additional power to operate cooling tower fans and pumps. If this reduction in net generating capacity were replaced by increasing the capacity factors for Units 1, 2, and 3, there will be additional adverse impacts from the operation of these units. Coal consumption will increase 0.5 to 5.0% with a resultant increase in diesel fuel consumption for unit trains transporting the coal, solid waste production, and air pollutant emissions. These increase the potential for adverse impacts to public health, water quality, and terrestrial ecosystems.

In addition to the increased operating cost due to lower unit generating efficiency, dry cooling towers will result in a capital cost increase of $15 to $25 million when compared with the capital cost of the proposed wet cooling towers.

Wet/Dry Cooling Towers

The principal differences between the environmental impacts resulting from using wet/dry cooling towers relate to water consumption. Based on a cooling tower designed for 80% wet (or evaporative) and 20% dry, water consumption will be reduced an average of 693 gpm (2,623 lpm) or approximately 20%. The wet/dry cooling tower will result in a substantial decrease in the cooling tower plume caused by the evaporation of cooling tower water. Wet/dry cooling towers will have a slightly lower generating efficiency than MP&L's proposed wet cooling tower. However, this decrease will not significantly increase adverse environmental impacts.

Wet/dry cooling towers will slightly increase operating costs. Capital cost is estimated to increase $2 to $4 million when compared with the capital cost of the proposed wet cooling towers.

Disposal of Solid Waste in an Abandoned Mine

The disposal of Unit 4 solid waste in an abandoned open pit iron mine, rather than in MP&L's proposed new ash and sulfur dioxide scrubber sludge pond, will decrease land required for solid waste disposal, probably decrease adverse impacts on surface and ground waters, decrease adverse impacts on terrestrial vegetation and wildlife, increase energy consumption, and increase noise impacts. This alternative will eliminate the need for the new ash and sulfur dioxide scrubber sludge pond. Thus, the 420 acres (170 hectares) required for the solid waste disposal pond will be available for agricultural production or other uses.

Using an abandoned mine for solid waste disposal will decrease the potential for surface and ground water contamination in the vicinity of the Clay Boswell Station, but increase the potential of possible surface and ground water contamination at the abandoned mine site. The degree of impact will be determined largely by the geologic structure of the abandoned mine disposal area. The use of an abandoned mine for solid waste disposal essentially will eliminate the terrestrial vegetation and wildlife impacts related to the clearing of 420 acres (170 hectares) for construction of the new solid waste disposal pond.

The disposal of solid waste in an abandoned mine will increase energy consumption for solid waste handling, processing, and transport. Noise impacts will be greater because of rail transport of the solid waste. The noise impacts are expected to have the greatest impact in the City of Grand Rapids, where the trains pass through residential areas.

MITIGATING MEASURES

Mitigating measures are those actions which reduce or eliminate environmental impacts associated with the proposed action. Several mitigating measures have been proposed for Unit 4 at the Clay Boswell Station. Measures to mitigate construction impacts include the following.

- Erosion and sedimentation could be reduced by minimizing the length of time bare earth will be exposed, stabilizing new road surfaces, and limiting construction traffic. Use of filtering networks could reduce sediment concentrations by reducing runoff velocity. Water used in dewatering operations could be routed to the sedimentation basin before discharge to Blackwater Lake or the Mississippi River.

- Discharge of petrochemical wastes can be controlled by restricting the equipment maintenance area, keeping vehicles in good working order, and by providing containment facilities at the site. Waste sumps can be installed in storage and maintenance areas.

- Ground water contamination can be minimized with the use of dike cutoffs.

- Fugitive dust may become a problem. Application of water or suitable chemicals for dust control could minimize dust, as would covering vehicles when transporting materials which could become airborne. Prompt removal of earth deposited by truck, earth-moving equipment, or erosion would also be beneficial.

- Vacant housing is very limited in the 22 township area. Housing will be necessary for the proposed Unit 4 construction labor force. Construction and operation of a mobile home park by MP&L, or an MP&L financed apartment complex are options. A search program for local housing by MP&L is another option. These options also would benefit new permanent operational employees.

- Secondary school capacity will be exceeded in District 318 by 68 to 112 students due to the construction labor force at Unit 4, creating the need for 3 to 5 new classrooms. Temporary classrooms, shifting students to districts with excess capacity, or renting a vacant school building from another district are all possible solutions. School District 318 will have 16% more revenue to help pay for additional classrooms and teachers.

- The ratio of police officers to population will drop by more than 10% in Grand Rapids. This could be mitigated by hiring additional officers or financing overtime for the existing force. A third option would be to utilize volunteer auxiliary police on a temporary basis.

The following are measures which could mitigate the environmental impacts of the operation of Unit 4 at the Clay Boswell Station.

- Sulfur dioxide scrubber sludge possibly could be used in the future as a building material such as gypsum.

- Ash pond water and dissolved solids can be contained by utilizing an impermeable liner of natural clay, rubber, or asphalt in the new ash and sulfur dioxide sludge pond.

- The potential for leachate could be reduced by dry disposal of scrubber sludge or by chemical fixation of the sludge.

- The new ash and sulfur dioxide scrubber sludge pond could be reclaimed and revegetated, with farming or silviculture as a future possibility.

- Wastewater discharges can be recycled to other Clay Boswell Station water systems to decrease makeup water requirements and water discharge volumes.

- Sewage effluent could be discharged to the ash ponds instead of to the proposed central wastewater treatment facility.

- Alternatives to the use of chlorine as a biocide include ozone, ultraviolet light, and nonoxidizing biocides.

- Chlorine-reducing agents can be used to reduce chlorine in cooling tower blowdown.

- Cooling towers can be designed to reduce or eliminate the use of chlorine.

- Mechanical condenser cleaning systems could replace the use of chlorine.

- Local governmental officials should anticipate population increases in Deer River and the community of Cohasset and plan to expand facilities and services accordingly.

- Land use impacts could be mitigated by returning a portion of the land acquired for the proposed Unit 4 to agricultural use.

- Clay Boswell Station buildings could be painted in natural tones to reduce their visibility.

- Trees could be planted between the proposed Unit 4 facilities and the shore of the Mississippi River to minimize the visual impact of the proposed action.

SHORT-TERM VERSUS LONG-TERM

Short-term is defined as the 46 month construction period plus the estimated 35 year lifetime of the proposed Unit 4 at the Clay Boswell Station. MP&L proposes to construct Unit 4 to meet rising energy demands in their service area. The rising energy demands are due primarily to the expansion of the taconite mining industry and, to a lesser extent, the expansion of the wood products industry. Expansion of these industries, facilitated by an available energy supply, will in turn bring both the problems and benefits of economic growth by providing new jobs and stimulating the area's economy while creating new demands for more energy.

Short-term and long-term benefits to the natural environment, if there are any, are minimal. There will be no long-term productivity since energy production will end when Unit 4 ceases operation at the end of its optimal lifetime. The only clearly defined benefits associated with construction and operation of proposed Unit 4 are short-term economic benefits related to the expansion of the taconite industry.

The Environmental Impact Statement is not a decision-making document, but presents information on which to base decisions. Short and long-term benefits and losses as well as beneficial and adverse impacts must be balanced by the decision-makers.

IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

The construction and operation of MP&L's proposed Unit 4 will result in the irretrievable and irreversible commitment of energy resources, materials, land, and human resources.

- o Consumption of 65 million tons (59 million mt) of coal as the primary fuel during the life of the proposed Unit 4 represents a major commitment of a finite resource.
- o Consumption of 1.12 million tons (1.02 million mt) of limestone will be required for the air quality control systems during the life of the proposed Unit 4.
- o Consumption of 83.3 million gallons (315.35 liters) of diesel oil will be required to transport the coal from the Big Sky Mine in Colstrip, Montana, to the Clay Boswell Station during the life of the proposed Unit 4.
- o While some of the construction materials such as sand, gravel, clay, and silt are readily available, their use for proposed Unit 4 represents an irretrievable commitment because they cannot be reused.
- o Some construction materials such as finished steel, aluminum, copper, zinc, and lead could be retrieved and reused at least in part, if Unit 4 were dismantled.
- o Forest and crop land have been acquired by MP&L for the proposed action. Clearing of this land represents an irretrievable commitment of resources.
- o Water removed from the Mississippi River for the operation of the proposed Unit 4 will remain in the earth's hydrologic cycle. Therefore, its use is not an irretrievable and irreversible impact, except as it relates to the Clay Boswell Station vicinity.
- o About 1,200 construction workers will be required to build the proposed Unit 4. These workers will expend 30,740 person-months of labor, or 2,562 person-years of labor, over the 46 month construction period. MP&L will employ 170 operational employees at the proposed Unit 4. These people will expend 5,950 person-years of labor during the life of the Unit 4. This labor is an irretrievable commitment of human resources.

IMPACTS ON STATE GOVERNMENT OF ANY FEDERAL CONTROLS AND MULTI-STATE RESPONSIBILITIES

Minnesota and Federal laws and regulations relating to MP&L's proposed Unit 4 interact in many areas. MP&L will apply to the MPCA for necessary water quality permits for proposed Unit 4. EPA will review these permit applications, and has the authority to deny these permits if necessary. In addition, MP&L must obtain Prevention of Significant Deterioration (PSD) approval from the EPA. The denial of this approval would supercede any State approval. There do not appear to be any significant areas of conflict between the 2 sets of laws and regulations.

Because the Clay Boswell Station lies well within Minnesota borders, there are no formal multi-state responsibilities associated with the proposed action. There are, however, multi-state implications related to air emissions, water consumption, and other natural resources.

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CHAPTER I

INTRODUCTION

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INTRODUCTION

Minnesota Power & Light Company (MP&L) has proposed to expand the Clay Boswell Steam Electric Station by construction of a 504 megawatt (MW) coal-fired electric generating unit. This new unit will be designated Clay Boswell Unit 4. The Clay Boswell Station presently consists of 3 coal-fired electric generating units with a combined capacity of approximately 500 MW. The Clay Boswell Station is located in Bass Brook Township, Itasca County, Minnesota. It is approximately 5 miles west of Grand Rapids and 80 miles west of Duluth.

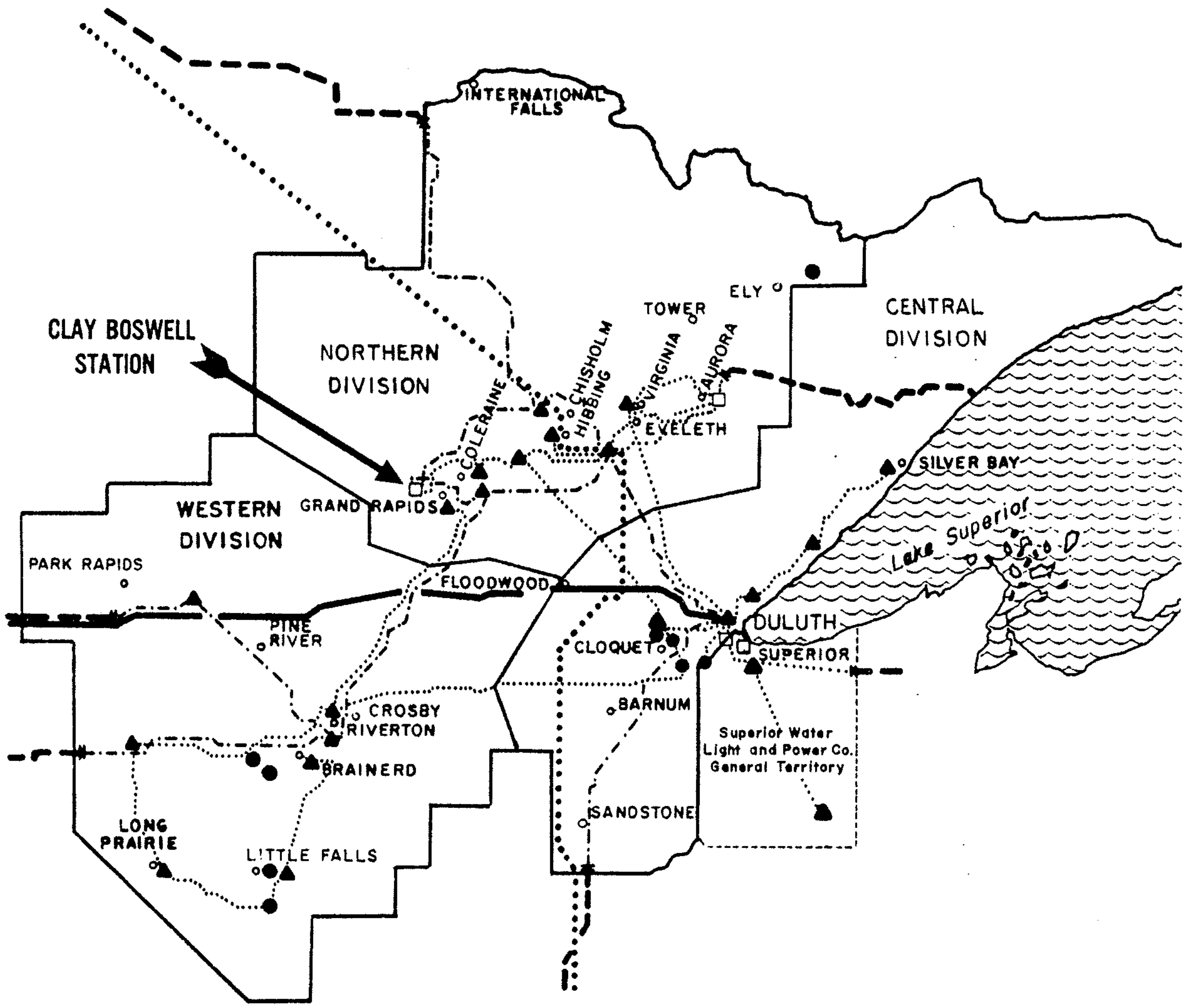
Chapter I deals with the history of MP&L and describes and explains the sequence of events related to the proposed construction of Unit 4. In recent years, the expanding taconite mining industry in northern Minnesota has increased its demands for electric power. MP&L, the main electric power company serving the area, has responded to these increased demands by proposing construction of new facilities.

MP&L has received a Certificate of Need from the Minnesota Energy Agency (MEA) and a Certificate of Site Compatibility from the Minnesota Environmental Quality Board (MEQB) for the proposed Unit 4. The MEQB was formerly the Minnesota Environmental Quality Council (MEQC), and was renamed the MEQB in January 1976. This document is the Draft Environmental Impact Statement (EIS) prepared by the Minnesota Pollution Control Agency (MPCA). The MPCA was designated by the MEQB as the Responsible Agency for preparation of the EIS for MP&L's proposed action of constructing and operating Unit 4 at the Clay Boswell Station. Preparatory work on Unit 4 commenced after the Minnesota Pollution Control Agency granted MP&L an Interim Permit in June 1976.

The following sections of Chapter I present a brief history of MP&L, its inter-action with other electric power networks, and its plans for the proposed construction of Unit 4 at the Clay Boswell Steam Electric Station; and a description of Minnesota's need, siting, and EIS permitting process including the Limited Work Authorization and preparation of the EIS. Mention will be made of some of the problems arising from the operation of Units 1, 2, and 3 which were built in 1958, 1960, and 1973, respectively. Some of the recommendations made by various State agencies during the site selection process to rectify these problems will be described.

MINNESOTA POWER & LIGHT COMPANY

Minnesota Power & Light Company with corporate headquarters in Duluth, Minnesota, is an investor-owned utility. Originally incorporated as the Duluth Edison Electric Company in 1906, it was reorganized as MP&L in 1923 under articles of incorporation specifying a public franchise service of electric power to 15 counties of northeastern Minnesota, and 2 counties of northwestern Wisconsin. The MP&L system is shown in Figure I-1. Of the electric energy supplied, 92% goes to Minnesota customers. With its subsidiary, the Superior Water Light & Power Company (SWL&P), MP&L provides electricity for approximately 98,000 homes, businesses, and factories in 144 communities.



LEGEND

- STEAM ELECTRIC STATION
- HYDRO ELECTRIC STATION
- SUBSTATION
- 250 KV DIRECT CURRENT TRANSMISSION LINE
- 230 KV TRANSMISSION LINES
- 115 KV TRANSMISSION LINES
- PROPOSED 500 KV TRANSMISSION LINE
- OTHER OWNERSHIP
- INTERCONNECTION

MP & L SERVICE AREA AND TRANSMISSION LINES

(ADAPTED FROM "MINNESOTA POWER AND LIGHT COMPANY REPORT TO SHAREHOLDERS", 1975, MINNESOTA POWER AND LIGHT COMPANY, DULUTH, MINNESOTA)

FIGURE I-1

MP&L provides service for the rapidly expanding mining industry in northern Minnesota. Since 1955, the developing taconite mining industry has demanded an increasingly large share of MP&L's generated electric power. In 1975, of revenues totalling $112 million, $30 million came from mining operations (1). In 1973, anticipating future power demands, MP&L renegotiated an electric power purchase and interconnection agreement with the Manitoba Hydro-Electric Board and agreed to seek electric power supplies from other regional sources (2).

Projected future electric power demands until 1980 mainly will come from the rapidly expanding Minnesota taconite mining industry, resulting in increased capacity requirements of approximately 400 MW (3). MP&L already has signed electric service agreements to provide electric power for U.S. Steel's expansion of its Minntac plant near Mountain Iron; Inland Steel's Minorca plant near Virginia; National Steel's expansion of operations at Keewatin; Hibbing Taconite's operations at Hibbing; and Eveleth Taconite's expansion at the Fairlane plant. The Minntac expansion is to be completed in late 1977 (4), and the Minorca plant is scheduled to begin operations in April 1977 (5). National Steel's plant (operated by Hanna Mining Company) at Keewatin was essentially complete in early 1977 (6). The Hibbing Taconite Company started operation of its first phase in mid-1976; the completed addition will not be in operation until 1979 (7). Eveleth Expansion Co.'s addition to the Thunderbird Mine went into operation in May 1976, and the expanded Fairlane processing plant was in full operation by November 1976 (8). The result of new expansions in the mining industry has caused a substantial increase in the production capacity of taconite mining companies on the Masabi Range. By 1979, 65,000,000 gross tons (58,967,008 mt) of iron ore pellets will be produced annually. This is an increase of nearly 60% from the current capacity of 41,000,000 tons (37,194,574 mt) (9).

Expansion of the taconite mining industry and anticipated expansion of paper and pulp industries will result in increased commercial and residential electrical energy needs in northern Minnesota. These increases will add to the electrical power demands which must be supplied by MP&L.

Until 1980, a portion of MP&L's electric power will be supplied by interconnection with the Manitoba Hydro-Electric System and with members of the Mid-Continent Area Power Pool (MAPP), and planning assistance will be provided through the Mid-Continent Area Reliability Coordination Agreement (MARCA).

Mid-Continent Area Power Pool

The Mid-Continent Area Power Pool (MAPP) which began operations in November 1972 includes 12 investor-owned utilities, 7 generation cooperatives, 2 public power districts, 11 municipalities, and a Federal hydro-electric system. The members of MAPP, interconnected by an extensive network of high voltage transmission facilities, provide service in a 9 state area.

The main objectives of the members of MAPP are to provide reliable service and economic service through coordination of installation and operation of generation and transmission facilities. The various committees of MAPP determine and plan for future needs and deal with critical problems. Increased time for installation of generation and transmission facilities to meet governmental requirements for construction and operation is a major factor in planning for the future. In 1975, MAPP's plans were updated to reflect the changing availability of fuel and the increase in fuel costs.

Mid-Continent Area Reliability Coordination Agreement (MARCA)

The region covered by MARCA includes Minnesota, Iowa, North Dakota, most of South Dakota and Nebraska, and portions of Wisconsin, Illinois, Michigan, and Montana (Figure I-2).

The main function of the MARCA organization is to plan for reliable electrical service in the region. Organized in 1968, it presently has 22 members including 11 investor-owned utilities, 8 generation and transmission cooperatives, 2 public power districts, and a Federal agency. The Manitoba Hydro-Electric Board is an associate member of MARCA. Of the 22 MARCA utilities, 21 (along with 12 smaller utilities) are also members of MAPP.

Regional planning consists of each system reporting on load forecasts and planned new facilities. Periodic testing of the overall projected system is in accordance with criteria set forth in MARCA Design Standards. These criteria contain sets of contingencies to minimize interruptions in service. Coordination between MARCA and the Mid-American Interpool Network (MAIN) is effected through an Inter-Region Reliability Coordination agreement which establishes an Inter-Region Review Committee responsible for bulk power supply reliability in planning and operating. Further cooperation has been developed between MARCA and the Southwest Power Pool (SWPP), and the Western Systems Coordinating Council (WSCC), and an understanding has been reached that the operations relating to East-West ties will be performed by the East-West Work Group of the WSCC Operations Committee (10).

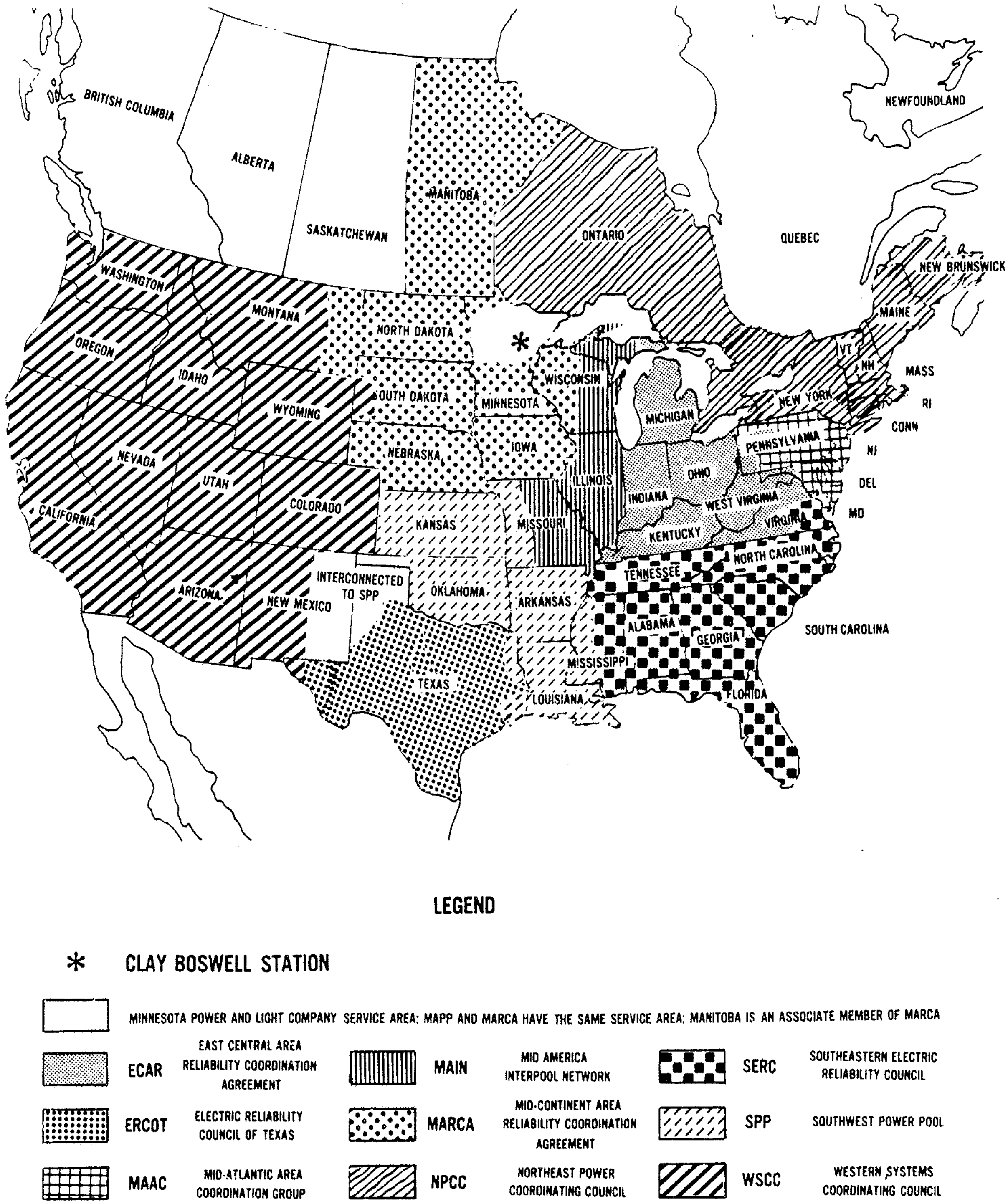
Clay Boswell Steam Electric Station Units 1, 2, and 3

The Clay Boswell Steam Electric Station is situated approximately 1½ miles west of what was formerly the Village of Cohasset and is now a part of Bass Brook Township, Minnesota. Units 1, 2, and 3 are coal-fired steam generating units using pulverized western sub-bituminous coal. Units 1 and 2, which went into operation in 1958 and 1960, respectively, have a gross generating capacity of 75 MW each. Unit 3, which went into operation in 1973, has a gross generating capacity of 369 MW.

Proposed Unit 4 will have a gross generating capacity almost equal to the capacity of the other 3 units. To satisfy the projected demands of the expanding taconite mining industry, MP&L needs Unit 4 to be in operation by May 1980.

MINNESOTA'S NEED, SITING, EIS, AND PERMITTING PROCESS

Before MP&L or any electric power utility can construct a Large Electric Power Generating Plant (LEPGP) in Minnesota, certain procedures must be followed which include a four step review process by the appropriate State agencies.



NATIONAL RELIABILITY COUNCIL

(ADAPTED FROM A REPORT BY MARCA TO THE FEDERAL POWER COMMISSION, APRIL 1, 1975, MIDWEST AREA RELIABILITY COORDINATION AGREEMENT, pp. A-5.)

FIGURE I-2

First, in accordance with Minn. Stat. § 116H.13 (1974), a utility company must apply to the Minnesota Energy Agency (MEA) for a Certificate of Need. The MEA only assesses the need for a proposed facility, and on that basis grants or denies a Certificate of Need.

Second, according to Minn. Stat. § 116C.51 (1974), the company must file a Certificate of Site Compatibility with the Minnesota Environmental Quality Board (MEQB). The purpose of a site compatibility review is to determine the best site for the location of the LEPGP.

Third, a Draft Environmental Impact Statement (Draft EIS) must be prepared providing a "basic document for review and comment on the environmental effects" of the proposed facility [Minn. Reg. MEQC 22(3) (1974)]. After the Draft EIS is complete, public meetings or hearings will be held. When the time has elapsed for review by the appropriate State agencies and the general public, the Final EIS will be prepared and submitted to the MEQB for final approval.

Fourth, once the EIS has been approved by the MEQB, the company then must apply to the appropriate State agencies for permits for construction of the planned facility. The Final EIS precedes final decisions on the proposed action and accompanies the proposed action through the permitting process and any other administrative review processes [Minn. Reg. MEQC 26(j)(4) (1974)].

Certificate of Need

MP&L filed an application for a Certificate of Need with the MEA on December 12, 1975. This application was for a 500 MW electrical generating facility scheduled for commercial operation by May 1980. Two days of hearings were held at the St. Louis County Courthouse in Duluth, Minnesota, on February 13 and 14, 1976, and the Director of the MEA subsequently granted a Certificate of Need on April 6, 1976.

The MEA Director's decision (11) was based on whether the application for Certificate of Need met with the requirements set out in [Minn. Reg. EA 611(a)(b) (1974)]. An application for a Certificate of Need shall be granted if:

(a)

it is determined that the probable result of denial of the application will be an unacceptable level of reliability of electric service to ultimate consumers in Minnesota or in neighboring states.

or

(b)

a determination is made that the socially beneficial uses of the output of the proposed facility, including its uses to protect or enhance environmental quality, are deemed significant enough to justify the need for the facility.

Some of the most important reasons listed below established that construction of the proposed facility would be "socially beneficial", and that if permission to construct the facility were to be denied that the "level of reliability" would be unacceptable.

1. The taconite mining industry will need electric power by 1980.

2. There is no reason to believe that the taconite mining industry would install its own electric power generating facilities.

3. There may be an increase in electrical use as a result of fuel substitutions in the area.

4. There may be fuel price increases.

5. Projected conservation measures will not have a noticeable effect on future electrical power requirements.

6. Only short term supplies of energy are available from outside the immediate area.

7. The reserve margin of MP&L would be eliminated, thus affecting the reliability and integrity of the entire MAPP system.

8. An excess 550 MW of electrical power does not exist in the MAPP.

After the Director of the MEA evaluated the findings of fact, he concluded in the Certificate of Need that:

1. The probable result of denial of this application will be an unacceptable level of reliability of electric service to ultimate consumers within the Applicant's service area in the near future;

2. The socially beneficial uses of output of the proposed facility justify its need; and

3. The proposed facility is needed without delay, i.e. by May 1, 1980, as asserted by the Applicant (9).

The Certificate of Need was granted and became effective on April 6, 1976.

Certificate of Site Compatibility

On March 11, 1975, MP&L, in accordance with Minn. Stat. § 116C.51 et seq. (1974) and Minn. Reg. MEQC 71-25 (1976), filed with the MEQC an application for a Certificate of Site Compatibility for Large Electric Power Generating Plants (LEPGP). In its application, MP&L submitted several alternative sites for a proposed 500 MW unit.

On August 26, 1975, a Hearing Officer was appointed by the MEQB to conduct public hearings and make recommendations to the MEQB with respect to MP&L's application. In August 1975, a 21 member Site Evaluation Committee was appointed to provide citizen participation in the site selection process and was charged with reviewing the Clay Boswell and 7 undeveloped sites.

Public hearings commenced on September 3, 1975 and were continued in the study area for a period of months; testimony and exhibits presented at these hearings were used to assist the Hearing Officer in making his recommendations, as were the findings and recommendations of the Site Evaluation Committee.

In making its recommendation to the Hearing Officer, the Site Evaluation Committee was guided by Minn. Reg. MEQC 74(c)(3) (1974) regarding population displacement and disruption to local communities and institutions, removal of valuable land and water from other productive uses, use of existing operating sites and transportation systems, and use of sites for larger rather than smaller generating capacity. An analysis of the direct and indirect economic impact of proposed large electric generating plants [Minn. Reg. MEQC 74(j)(5) (1974)] also was considered. The Clay Boswell site was selected for the following reasons (12).

- It was decided that Grand Rapids could best support the needs of the increased work force during plant construction.
- At the Clay Boswell site, no increase in water appropriation from the Mississippi River would be necessary, as the new unit would withdraw its water from the discharge canal of the existing once-through cooling system for Units 1, 2, and 3.
- An addition to the existing plant would more fully utilize the existing coal handling facilities.
- The proposed addition would bring the Clay Boswell site near its ultimate capacity for sludge and ash disposal and transmission line corridors.
- Selecting a site other than Clay Boswell would cause a 2 to 3 year time delay which would increase costs to both company and consumers.

The Site Evaluation Committee recommended that a Certificate of Site Compatibility should be granted to MP&L for construction of Unit 4 at the Clay Boswell site. However, it strongly urged the MEQB to recommend that MP&L should solve the stack mist problem in the existing units. On January 29, 1976, the Hearing Officer recommended that the Clay Boswell site was a suitable site for the 504 MW facility, but that the Certificate of Site Compatibility should be granted contingent upon compliance by MP&L with particulate standards for Units 1 and 2, and elimination of stack mist from Unit 3 (13). The MEQB subsequently granted the Certificate of Site Compatibility within the allotted year, on February 11, 1976. It was granted on condition that prior to the start of operation of Unit 4, MP&L should enter into a binding agreement with the MPCA to modify existing Units 1, 2, and 3 to be in compliance with all applicable particulate standards and to modify Unit 3 to eliminate the stack mist problem (14).

It is important to mention here that the initial Stipulation Agreement between the MPCA and MP&L concerning particulate emissions initially was signed in 1970. The agreement was amended in 1973. MP&L then made modifications to Units 1, 2, and 3 in an attempt to lower the impact of emissions on air and water quality. On March 23, 1976, an installation permit for substantial emission control improvements to the existing units was approved by the MPCA. A new

Stipulation Agreement was approved by the MPCA on April 6, 1976. These 2 agreements required that full compliance be achieved by Units 1, 2, and 3 no later than December 31, 1978.

Limited Work Authorization Permits

Once the MEA had determined that construction of Unit 4 was urgently needed (April 6, 1976), the application for a Limited Work Authorization was considered by the MEQB. MP&L already has filed a preliminary request for a Limited Work Authorization with the MEQB on January 29, 1976. This preliminary request was to do limited preparatory work on the proposed site of Unit 4 in advance of completion and acceptance of the EIS. MP&L proposed to start immediate construction of access roads, railroad spurs, equipment storage areas, parking lots, plant foundations, underground piping and utilities, pile driving and excavation, and a waste disposal area. The estimated schedule for construction would be approximately 9 months and would cost an estimated 5% of the total plant cost ($19,000,000 of the total $390,000,000). The application did not include requests to construct air and water pollution control systems required to meet MPCA regulations. On April 13, 1976, the MEQB determined that the requested preliminary site preparation work could be allowed to begin subject to obtaining appropriate permits from State regulatory agencies and to a continuing review by the MEQB chairman of the extent and effect of the work. It should be noted that questions were raised regarding the legality of granting a Limited Work Authorization before completion of the EIS. Minn. Stat. § 116(d)4 (1974) states: "The final, detailed Environmental Impact Statement and the comments received thereon shall precede final decisions in the proposed action and shall accompany the proposal through an administrative review process".

MP&L then made application to the MPCA for a Limited Work Authorization. After due consideration, the MPCA decided the following.

1. Preparatory construction work did not constitute a final decision as the requested authorization is not the last approval which must be obtained from the agency (permits still were needed for installation of major air emissions and water pollution control facilities).

2. Approval of the part of the project allowed under the Limited Work Authorization would not likely present the agency with an irreversible situation.

Subsequently, the MPCA Board approved commencement of preliminary site preparation on June 22, 1976, by authorizing an interim permit for an Air Pollutant Emission Facility I.P. No. 73B-76-IW-1, to expire on June 1, 1977, and a Water Quality Stipulation Agreement (15). A second Limited Work Authorization was granted by the MEQB which granted MP&L permission to work on the boiler turbine, coal handling system, loop track, administration and material processing area, and the west parking lot. This work was approved by the MPCA on May 24, 1977.

Environmental Impact Statement

Because MP&L's proposal to construct a 500 MW generating facility at the Clay Boswell Steam Electric Station constituted a "major action with the potential for significant environmental effects" [Minn. Reg. MEQC 25(c)(1) (1974)], the MEQB determined that an EIS should be prepared. An EIS is principally an informational document containing all relevant and reasonably available environmental information to be considered in the development of an action. An EIS is not a decision-making document. However, it is designed to provide decision-makers with information on the proposed action, various alternatives, existing conditions, environmental impacts, and possible mitigating measures. An EIS, according to the regulations, shall inform public and private decision-makers and the public of the environmental effects of actions that have been proposed. An EIS is not intended as an instrument to justify an action, nor shall indications of adverse environmental effects necessarily require that an action be disapproved [Minn. Reg. MEQC 22(b)(c) (1974)].

At present, the MEQB has the authority to site transmission line corridors [Minn. Reg. MEQC 7(a) (1974)]. No regulations state that the impact of transmission limes must be examined in an EIS for a proposed LEPGP. However, the impact of high voltage transmission lines has become an issue as citizens are demanding more studies and regulation of transmission line routing.

For MP&L's proposed additional Unit 4 at the Clay Boswell Station, the MPCA was designated by the MEQB on February 10, 1976, as the Responsible Agency for preparation of the EIS. The MPCA then selected Ronald M. Hays and Associates to assist in preparation of the EIS.

Preparation of the Draft EIS

Work commenced on preparation of the Draft EIS on December 2, 1976. Initially, information was gathered and a documents library was established. In the areas of terrestrial vegetation and terrestrial wildlife, it was determined that additional field studies would have to be conducted during the summer of 1977. The results of these field studies will be presented during the EIS public meetings or hearings.

Work papers were compiled by the technical experts to examine the following areas for the Draft EIS.

1. Proposed action - These Work Papers included detailed descriptions of all aspects of Clay Boswell Unit 4 and its interrelationship with existing Units 1, 2, and 3.

2. Environmental setting - Work Papers describing the existing environment were prepared. These focussed on the regional, local, and site-specific characteristics of the area around the Clay Boswell Station and their relationships to the proposed action and reasonable alternatives.

3. Alternatives - In these Work Papers, the consideration of alternatives to the proposed action was based on the premise that

alternatives are not simple modifications to the proposed action, or simple measures for mitigating adverse environmental impacts, but rather are major changes in construction and equipment or operating procedures. Reasonable alternatives would not include alternative sites, or not constructing the plant, as both the Certificate of Site Compatibility and the Certificate of Need have been issued.

4. Probable impacts of the proposed action - In these Work Papers, probable impacts of the proposed action and each alternative were identified, analyzed, and quantified. These included impacts relating to the disciplinary areas of geography, energy, geology, glacial geology, ground and surface hydrology, water quality, aquatic biota, meteorology and climatology, air quality, noise, socio-economics, land use, recreation, aesthetics, terrestrial vegetation, and terrestrial wildlife.

5. Mitigation of adverse impacts - These Work Papers identified, analyzed, and explored mitigating measures which could be incorporated into the proposed action and each reasonable alternative to reduce or minimize significant adverse environmental impacts.

Once these Work Papers had been reviewed by the MPCA, they were reorganized and edited to provide the basic information in the technical portions of the Draft EIS.

Final EIS

After the Draft EIS has been submitted to the MEQB, meetings and/or hearings will be held for citizens to voice their concerns about and comments on the Draft EIS. The record must remain open for a period of not less than 45 days nor more than 90 days after completion of the Draft EIS. Comments or concern about environmental issues must be incorporated into the Final EIS within 30 days after the closing for comments on the Draft EIS. Once the Final EIS has been submitted to the MEQB and has been determined to be adequate, the EIS review process is complete. The Final EIS then accompanies the proposed action through the permitting and any other administrative review processes which precede final decisions on the proposed action.

Permitting Process - Environmental Regulations and Their Administration

A principal purpose of the EIS process is to provide information to governmental decision-makers to aid them in determining whether and how a new pollution emitting source should be constructed in the light of its impacts upon the physical, biological, and human environments. The most critical parameters of environmental quality have been encoded into various State and Federal statutes and regulations, and the broad phrasing of the Minnesota Environmental Policy Act Minn. Stat. Ch. 116 (1973) further allows the permitting authorities to consider environmental problems, such as long-term or long-range impacts, which are not addressed by specific statutes or regulations. For a potential new pollution point-source, these statutes and regulations are enforced through the permitting process. During the permitting process, the appropriate agencies scrutinize the proposed action, solicit public comment, and determine whether the proposed action is feasible and prudent and will comply with applicable environmental statutes and regulations. The feasibility and prudence of the proposed action and alternatives are of special importance. State permits cannot be granted for a proposed action significantly affecting the quality of the environment where the proposed action is likely to cause pollution, impairment, or destruction of the air, water, land, or other natural resources within the State, so long as there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare, and the State's paramount concern for the protection of its natural resources, Minn. Stat. Ch. 116D. If the agencies determine that the proposed action is feasible and prudent and that the regulations will not be violated, the proposer then is granted permits. If it is determined that there is a more feasible and prudent alternative than the proposed action or that the statutes and regulations will be violated, permits are denied and the developer either must redesign or abandon the proposed facility.

The Federal and Minnesota environmental statutes and regulations which apply to MP&L's proposed Unit 4 at the Clay Boswell Steam Electric Station are discussed briefly below, under the broad categories of Air Quality, Water Quality, and Noise. Each of the applicable major regulations creates a requirement of an installation and/or an operating permit for MP&L's proposed Unit 4.

Air Quality Regulations and Their Administration

The original Clean Air Act was passed by Congress in 1963. It was amended in 1965 and 1967, but it was not until the Clean Air Act Amendments of 1970 (16) that regulatory agencies were mandated substantial authority to control and reduce air pollution. The U.S. Environmental Protection Agency (EPA) now administers most aspects of the 1970 Amendments and regulations promulgated thereunder. The 1970 Amendments place the primary burden for controlling air pollution upon the states, but the Federal government retains near total supervisory and approval authority. The 1970 Amendments also allowed the EPA to define air pollution and, for the first time, provided for extensive research to determine acceptable nationwide air pollution standards. The granting of broad discretionary power to the EPA Administrator to use the combination of emission limitations, transportation controls, land use controls, and civil and criminal penalties probably is unparalleled in Federal regulatory schemes (17).

All air pollutants which the EPA determines may adversely affect human health and welfare are potentially subject to the comprehensive regulatory program. Presently, 2 types of standards apply to large stationary sources of air pollution. These are the New Source Performance Standards (NSPS), which restrict emission rates from new stationary sources in terms of pounds per day, (kilograms per day), pounds per Btu (kilograms per kilogram-calorie) input, etc., and Ambient Air Quality Standards (AAQS), which limit the concentration of pollutants in the air. The ambient standards are generally expressed in parts per million (ppm) on a volume basis, or in micrograms per cubic meter (ugm per cm) on a weight per volume basis. In addition to the NSPS and AAQS regulations, Prevention of Significant Deterioration (PSD) regulations and National Emission Standards for Hazardous Air Pollutant Sources (NESHAPS) also have some application to large stationary sources of air pollution.

The states have the primary responsibility for controlling air pollution. In Minnesota, this is a function of the Minnesota Pollution Control Agency (MPCA). Under the 1970 Clean Air Act Amendments, each state was required to submit to the EPA, by 1972, plans to implement the new Federal regulations. These implementation plans must include inventories of major emitting facilities, compliance schedules for these major sources, and other information for each "Air Quality Control Region" in the state. In addition, each state is permitted to adopt its own New Source Performance Standards and Ambient Air Quality Standards which can be more restrictive than the EPA standards.

New Source Performance Standards. Under the authority of the Clean Air Act Amendments of 1970, the EPA thus far has promulgated standards of performance for 19 categories of new stationary sources of air pollution. One of these categories covers fossil-fuel steam electric plants of more than 250 million Btu per hr (63.1 million kg-cal per hr) heat input (18). The MPCA has adopted 7 of the EPA NSPS without change and has proposed adoption of 5 more. Under its inventory program, the MPCA has identified 650 major sources in the State. Major sources are those which emit 25 tons (22.7 metric tons) (mt) or more of pollutants each year (19). In addition, the MPCA has on file about 600 smaller emission sources (19). The Minnesota NSPS which limits sulfur dioxide, nitrogen oxides, and particulate emissions from large fossil-fueled power plants is APC 4 (Table I-1). APC 4 and its Federal counterpart place the

TABLE I-1
MINNESOTA AIR QUALITY REGULATIONS POSSIBLY APPLICABLE TO
CLAY BOSWELL STEAM ELECTRIC STATION

Regulation	Title	Date of Promulgation or Most Recent Amendment
APC 1	Ambient Air Quality Standards	April 13, 1972
APC 2	Definitions, Abbreviations, Applicability of Standards, Access to Premises, Variances, Circumvention, Severability	May 7, 1976
APC 3	Permits	June 4, 1976
APC 4	Emission Limitations from Fuel-Burning Equipment Used for Indirect Heating	November 4, 1976
APC 5	Standards for Motor Vehicles and Stationary Internal Combustion Engines	June 4, 1976
APC 6	Preventing Particulate Matter from Becoming Air-borne	July 7, 1969
APC 9	Control of Odors in the Ambient Air	September 14, 1971
APC 12	Standards of Performance for Industrial Process Equipment	July 7, 1969
APC 14	Emissions of Certain Settleable Acids and Alkaline Substances	July 7, 1969
APC 21	Emission Source Monitoring, Performance Tests, Reports, Shutdowns and Breakdowns	May 7, 1976

following upper limits on emission rates from new fossil-fueled power plants having a capacity of 250 million Btu per hr (63 million kg-cal per hr) or more:

sulfur dioxide	-	1.2 lb per million Btu (2.2 kg per million kg-cal) heat input
nitrogen oxides	-	0.70 lb per million Btu (1.26 kg per million kg-cal) heat input expressed as NO_2
particulate matter	-	0.10 lb per million Btu (0.18 kg per million kg-cal) heat input.

These standards reflect the emission levels attainable by the application of the best control technologies currently available and will apply to MP&L's proposed Unit 4, though not to existing Units 1, 2, and 3 at the Clay Boswell Station.

In addition to sulfur dioxide, nitrogen oxides, and particulate standards, there are opacity standards which apply to new fossil-fueled power plants. APC 4 (Table I-1) and 40 C.F.R. pt. 60 (18) limit the stack plume to 20% opacity during normal operations, i.e., incident sunlight can be reduced by no more than 20% in intensity during transmission through the plume. Allowances are made in the opacity regulations for periodic short-term emissions during boiler start-up and maintenance periods and for condensed water vapor in the plume.

Ambient Air Quality Standards. The 1970 Clean Air Act Amendments required the EPA to, within 90 days of enactment, identify the major ambient pollutants and establish human health and welfare standards for them. The EPA drafted criteria documents for these major pollutants and promulgated the final AAQS in April of 1971. The criteria documents were based on reviews of literature existing in 1971. Because of subsequent gains in knowledge of pollutant effects, some of the original AAQS have been deleted (e.g. annual and 24 hr secondary SO_2 standards) and others are currently being subjected to critical review (e.g. primary and secondary oxidant standards). The AAQS currently in effect are shown in Table I-2. As with New Source Performance Standards, each state retains the power to establish AAQS more strict than the EPA's and to establish AAQS for pollutants not covered by Federal ambient regulations. The MPCA has set stricter standards for sulfur oxides, photochemical oxidants, and carbon monoxide, and has established its own standard for hydrogen sulfide.

Controlling ambient pollutant levels involves "primary" and "secondary" AAQS. The higher, primary standards were to be met in all regions of the Country by 1975 and are based on levels thought to be safe for human health. The lower, secondary standards were to be met by 1977 and are meant to protect human welfare, i.e. to prevent damage to vegetation, animals, materials, aesthetics, etc. Of the 247 Air Quality Control Regions (AQCR) nation-wide, only about half are on schedule in meeting the ambient standards (20). In Minnesota, as of January 1975, 6 out of 7 of the AQCR did not comply with the particulate ambient standards. One of the seven regions did not comply with SO_2 standards. Two were not in compliance for carbon monoxide and the reamining five were not monitored for carbon monoxide. Three regions complied with the oxidant standards where four were not monitored. Three of these regions monitored for nitrogen dioxide

TABLE I-2
AMBIENT AIR STANDARDS AND PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENTS PROMULGATED BY
THE U.S. ENVIRONMENTAL PROTECTION AGENCY AND MINNESOTA POLLUTION CONTROL AGENCY
UNDER THE CLEAN AIR ACT

	Prevention of Significant Deterioration				Ambient Air Quality Standards and Class III PSD Designation[b]							
	Class I[a] Increment		Class II[a] Increment		Secondary AAQS				Primary AAQS			
					Federal (c)		Minnesota (d)		Federal (c)		Minnesota (d)	
Pollutant	µg per cu m[e]	ppm[e]	µg per cu m	ppm	µg per cu m	ppm	µg per cu m	ppm	µg per cu m	ppm	µg per cu m	ppm
Sulfur dioxide												
annual average	2	0.00076	15	0.0057	60[f]	0.02[f]	60	0.02	80	0.03	60	0.02
24 hr maximum	5	0.0019	100	0.038	260[f]	0.1[f]	260	0.1	365	0.14	260	0.1
3 hr maximum	25	0.0095	700	0.27	1,300	0.5	655	0.25	1,300	0.5	655	0.5
Particulates												
annual geometric mean	5		10		60		60		75		75	
24 hr maximum	10		30		150		150		260		260	
Carbon monoxide												
8 hr maximum	no standard		no standard		10	9	10	9	10	9	10	9
24 hr maximum	no standard		no standard		40	35	35	30	40	35	35	30
Photochemical oxidants												
1 hr maximum	no standard		no standard		160	0.08	130	0.07	160	0.08	130	0.07
Hydrocarbons (less methane)												
3 hr maximum (6 a.m. to 9 a.m.)	no standard		no standard		160	0.024	160	0.024	160	0.024	160	0.3
Nitrogen dioxide												
annual average	no standard		no standard		100	0.05	100	0.05	100	0.05	100	0.05
Hydrogen sulfide												
½ hr average	no standard		no standard		no standard		42	0.03	no standard		70	0.05

[a] Allowable incremental increase in pollution over the 1974 baseline concentration (24).
[b] Class III designation allows pollution up to the Federal Ambient Air Quality Standards (24).
[c] 40C.F.R. pt. 60 (19) - not to be exceeded more than once a year.
[d] Minnesota Regulation APC 1 - not be be exceeded more than once a year.
[e] µg per cu m (micrograms per cubic meter) is a weight per volume ratio; ppm (parts per million) is a volume per volume ratio.
[f] These standards have been voided by Federal courts.

were in compliance (21). More specifically, the Duluth-Superior AQCR, which consists of Itasca, Koochiching, Aitkin, St. Louis, Carlton, Lake, and Cook counties, was in compliance with the State AAQS for sulfur oxides and nitrogen oxides, but St. Louis County did not comply with the particulate standards. The Duluth-Superior AQCR was not monitored for carbon monoxide or oxidants (21).

Prevention of Significant Deterioration of Air Quality. An additional tier of ambient air quality regulations recently has been added as the result of a Federal court case entitled Sierra Club v. Ruckelshaus (22). In this suit, the Sierra Club challenged those State implementation plans which were not designed to prevent air quality deterioration in regions where the ambient pollutant levels already were below the standards set in the AAQS. The Sierra Club claimed, and the courts agreed, that the Clean Air Act Amendments of 1970 required that clean air be kept clean. Consequently, the EPA promulgated its final Prevention of Significant Air Quality Deterioration (PSD) Standards on December 5, 1974 (23). These standards currently are being reviewed and likely will be changed by Congress and are again being challenged in court by environmentalists and industry (24).

The PSD regulations define 3 classes of areas. In Class III regions, pollution is allowed up to the secondary AAQS presented in Table I-2. This classification may encompass most large urban areas and major industrial regions. The Class II designation, into which the entire country has been placed initially, allows a certain incremental increase in ambient air pollution concentrations above the 1974 baseline concentration. These increments are presented in Table I-2. It should be noted that the PSD regulations currently apply only to sulfur oxides and particulates. Regardless of the 1974 baseline and the allowable increment, Class II areas will not be allowed to exceed the secondary AAQS and presumably will remain much cleaner than Class III areas. The Class II increments were set to allow, for example, one 1,000 MW electric generating facility every 20 to 30 miles (32 to 48 km), depending on the terrain (25).

Class I designated areas are those where virtually no degredation will be tolerated (Table I-2). The Class I increments over the 1974 baseline were set low enough to essentially preclude any major source of pollution (25). Those areas most likely to be designated Class I are National Parks, National Wilderness Areas, and National Monuments.

As mentioned above, the entire country currently has a Class II designation (areas experiencing ambient levels near AAQS probably have a de facto Class III designation). The PSD regulations provide procedures by which Federal land managers, State and local governments, Indian reservation leaders, private citizen groups, and others can petition the EPA for redesignation of their area to Class III or to Class I (26). Reclassification to Class I is, of course, a major land-use decision and usually considers aspects much broader than ambient air quality. The PSD regulations are a unique tool which the EPA has provided to prevent misuse of land and water, deleterious impacts on visual aesthetics, and other impacts which Federal, State, local, and private decision-makers view as socially unacceptable (25). As of April 5, 1977, no areas in the country had been redesignated from Class II, and most state environmental agencies have been reluctant to make use of the PSD procedures (20).

Besides the area designation provisions, the PSD regulations also require a closer scrutiny of major point sources built or modified after June 1, 1975 (24). Thus, for 18 major stationary source categories, including one for fossil-fueled steam electric plants of more than 1,000 million Btu per hr (252 kg-cal per hr) heat input, construction cannot begin until the EPA has determined: (27)

1. That the effect on air quality of the new source, in conjunction with the effects of growth or reductions after January 1, 1975 of other sources in the area, will not violate the applicable air quality increments; and

2. That the new source will meet an emission limit (NSPS) which represents that level of emission reduction achievable by the application of the best available technology for the control of particulates and sulfur oxides.

This permitting process requires that the company submit to the EPA site information, engineering details, and information on the air emissions of the new facility and other sources in the area. The entire process requires several months for the review of material submitted by the company, public comment, etc. MP&L's proposed Unit 4 at the Clay Boswell Station will have a heat input of approximately 3,600 million Btu per hr (908.5 million kg-cal per hr). Consequently, MP&L has made application to the EPA for the PSD permit, and a final decision is expected in June 1977.

Hazardous Air Pollutant Control. The Clean Air Act contains several special control schemes for the reduction of emissions of certain "hazardous" compounds, such as cadmium, beryllium, mercury, asbestos, arsenic, and others (28). Federal and state agencies are limiting emission rates of new and existing sources, rather than establishing nationwide or state ambient standards for hazardous compounds. To date, the EPA has established standards for emissions of beryllium and mercury (29). The MPCA has adopted the EPA standards for beryllium and mercury essentially verbatim (30).

Coal-fired electric generating facilities may emit significant amounts of beryllium and mercury (as well as other hazardous compounds), but neither the EPA nor the MPCA regulations apply to electric generating facilities. These regulations are rather narrowly focussed on beryllium and mercury mining operations, extraction plants, processing facilities, incinerators, and other sources traditionally thought to be of primary concern.

Water Quality Regulations and Their Administration

The history of water pollution control dates back much farther than other areas of environmental regulation because the spread of water borne diseases creates more acute and easily identified public health impacts than the spread of contaminants transported by other modes. The first U.S. Federal Water Pollution Control Act (FWPCA) was passed by Congress in 1948 (31), but it did not assume its present form until the comprehensive FWPCA Amendments were passed in 1972 (32). In Minnesota, there is legislation dating back to 1885 to control pollution of the State's rivers and other sources of potable water (19). In

1945, the Minnesota Water Pollution Control Act, Minn. Stat. Ch 115, was passed, giving the State the first substantial control over municipal and industrial effluents. In 1967, the power to administer this act was given to the then newly created MPCA, Minn. Stat. Ch. 116.

The FWPCA basically accomplishes 3 tasks: 1) regulates pollutants from point sources such as electricity generating plants or municipal sewage treatment plants; 2) regulates spills of oil and hazardous substances; and 3) provides financial assistance for municipal sewage treatment plant construction. The focus of the FWPCA is "navigable waters", a term which includes the upper Mississippi River in the vicinity of the Clay Boswell Station (33).

The FWPCA has separate regulatory schemes for 2 types of point-source dischargers: those discharging directly into navigable waters, and those discharging into publicly owned sewage treatment networks. The Clay Boswell Station falls into the former classification. Direct dischargers are subject to a dual set of regulations, similar in approach to the air quality regulations: effluent standards, and water quality standards. The basic enforcement mechanism for both sets of standards is a permit system. The discharger cannot begin operation until the permitting authorities are satisfied that the source will comply with whichever is stricter of the effluent standards and the water quality standards (34), and until the appropriate permits are issued.

The permit system provided for by the FWPCA is the National Pollutant Discharge Elimination System (NPDES). The FWPCA allowed the administration of the NPDES to be delegated to the individual states upon the approval of the state's permit program by the EPA (35). This has been done in Minnesota, so that now the NPDES permits are issued by the MPCA, with the EPA retaining veto authority over each permit. The FWPCA also allows each state to set standards and goals which are more restrictive than the Federal regulations. Each NPDES permit is essentially a statement of law as it applies to that individual permittee. The Minnesota water quality regulations with which MP&L's proposed Unit 4 will have to comply before MP&L is issued NPDES permits are listed in Table I-3.

Effluent Standards. The FWPCA establishes 3 national water quality goals (36):

1. That the discharge of pollutants into navigable waters be eliminated by 1985;

2. That, wherever attainable, an interim goal of water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water be achieved by July 1, 1983; and

3. That the discharge of toxic pollutants in toxic amounts be prohibited.

To achieve these goals, the FWPCA further provides that existing point sources must adopt the "best practicable control technology currently available" by July 1, 1977, and the "best available technology economically achievable" by July 1, 1983 (37). For new sources, the FWPCA requires the EPA

TABLE I-3
MINNESOTA WATER QUALITY REGULATIONS POSSIBLY APPLICABLE TO
CLAY BOSWELL STEAM ELECTRIC STATION

Regulation	Title	Date of Promulgation or Most Recent Amendment
WPC 4	Regulation Relating to Storage of Keeping of Oil and Other Liquid Substances Capable of Polluting Waters of the State	June 26, 1964
WPC 15	Criteria for the Classification of the Interstate Waters of the State and the Establishment of Standards of Quality and Purity	October 4, 1973
WPC 22	Classification of Underground Waters of the State and Standards for Waste Disposal	August 14, 1973
WPC 25	Classification of Interstate Waters of Minnesota	September 7, 1973
WPC 28	Effluent Standards for Disposal Systems Discharging to the St. Louis River from its Source to and Including St. Louis Bay and Superior Bay; the Mississippi River from its Source to the Blandin Dam in Grand Rapids including Lakes Andrusia, Bemidji, Cass, Itasca, Pokegama, and Winnibigoshish; and the Little Minnesota River and Big Stone Lake, and Albert Lea Lake	February 4, 1971
WPC 36	Regulation for Administration of the National Pollutant Discharge Elimination System (NPDES) and State Disposal System Permit Programs	April 10, 1974

to establish standards of performance for the control of pollutant discharge "which reflect the grestest degree of effluent reduction which the (EPA) Administrator determines to be achievable through application of the best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants." (38). The FWPCA lists an initial 27 industries, including steam electric generating stations, for which the EPA was to promulgate performance standards by October 18, 1973. The effluent performance standards for steam electric generating stations were published October 8, 1974 and are presented in Table I-4 (39).

In Minnesota, the MPCA established effluent standards in 1971 for any source discharging into the upper Mississippi River. This regulation, WPC 28 (Table I-3), predates the EPA performance standards and at least is as restrictive as the Federal performance standards. Therefore, under the delegation of authority permitted by the FWPCA, WPC 28 is controlling with respect to effluents from the Clay Boswell Station. WPC 15 and WPC 28 establish the following limiting permissible concentrations in facility discharges:

TABLE I-4
CHEMICAL EFFLUENT CONCENTRATION LIMITATIONS IN WATER DISCHARGES FROM CLAY BOSWELL STEAM ELECTRIC STATION, UNITS 1, 2, 3, AND 4

Effluent Source and Characteristic	Clay Boswell NPDES[a] Permit Limitations 7/1/77 to 7/31/79	Federal Effluent Standards for Steam Electric Generating Stations[b] Existing Stations met by 7/1/77	Existing Stations met by 7/1/83	New Stations met upon completion
Once-through cooling water				
Chlorine, mg per liter[c]				
daily maximum	0.2	0.5	0.5	0.5
monthly average	no standard	0.2	0.2	0.2
Oil and grease, mg per liter	no visible film	no standard	no standard	no standard
Floating solids or visible foam	trace amounts	no standard	no standard	no standard
Cooling system blowdown				
Chlorine, mg per liter[c]				
daily maximum	0.2	0.5	0.5	0.5
monthly average	no standard	0.2	0.2	0.2
Oil and grease, mg per liter	no visible film	no standard	no standard	no standard
Floating solids or visible foam	trace amounts	no standard	no standard	no standard
Total suspended solids (TSS) mg per liter				
daily maximum	30	no standard	no standard	no standard
Turbidity, JTU[d]				
daily maximum	25	no standard	no standard	no standard
pH	6.5 to 8.5	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Zinc, mg per liter				
daily maximum	no standard	no standard	1.0	no detectable amount
monthly average	no standard	no standard	1.0	no detectable amount
Chromium, mg per liter				
daily maximum	no standard	no standard	0.2	no detectable amount
monthly average	no standard	no standard	0.2	no detectable amount
Phosphorus, mg per liter				
daily maximum	no standard	no standard	5.0	no detectable amount
monthly average	no standard	no standard	5.0	no detectable amount
Other corrosion inhibiting materials	no standard	no standard	limit established on case by case basis	no detectable amount
Cooling tower basin drainage				
Chlorine, mg per liter[c]				
daily maximum	0.2 not to exceed 2 hr per day	no standard	no standard	no standard
Oil and grease, mg per liter				
daily maximum	no visible film	20	20	20
monthly average	no visible film	15	15	15
Floating solids or visible foam	trace amounts	no standard	no stnadard	no standard
Total suspended solids (TSS) mg per liter				
daily maximum	30	100	100	100
monthly average	no standard	30	30	30
Turbidity, JTU				
daily maximum	25	no standard	no standard	no standard
pH	6.5 to 8.5	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0

TABLE I-4 (continued)
CHEMICAL EFFLUENT CONCENTRATION LIMITATIONS IN WATER DISCHARGES FROM CLAY BOSWELL STEAM ELECTRIC STATION, UNITS 1, 2, 3, AND 4

Effluent Source and Characteristic	Clay Boswell NPDES[a] Permit Limitations 7/1/77 to 7/31/79	Federal Effluent Standards for Steam Electric Generating Stations[b] Existing Stations met by 7/1/77	Existing Stations met by 7/1/83	New Stations met upon completion
Cooling tower roof and floor drainage				
Oil and grease, mg per liter				
daily maximum	15	20	20	20
monthly average	10	15	15	15
Floating solids or visible foam	trace amounts	no standard	no standard	no standard
Total suspended solids (TSS) mg per liter				
daily maximum	30	100	100	100
monthly average	no standard	30	30	30
Turbidity, JTU				
daily maximum	25	no standard	no standard	no standard
pH	6.5 to 8.5	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Ash pond effluent				
Oil and grease, mg per liter				
daily maximum	no visible film	20	20[e]	20[f]
monthly average	no visible film	15	15[e]	15[f]
Floating solids or visible foam	trace amounts	no standard	no standard	no standard
Total suspended solids (TSS) mg per liter				
daily maximum	30	100	100[e]	100[f]
monthly average	no standard	30	30[e]	30[f]
Turbidity, JTU				
daily maximum	25	no standard	no standard	no standard
pH	6.5 to 8.5	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Ash sluice head tank overflow				
Chlorine, mg per liter[c]				
daily maximum	0.2 not to exceed 2 hr per day	no standard	no standard	no standard
Oil and grease, mg per liter				
daily maximum	no visible film	20	20	20
monthly average	no visible film	15	15	15
Floating solids or visible foam	trace amounts	no standard	no standard	no standard
Metal cleaning wastes and boiler blowdown[g]				
Oil and grease, mg per liter				
daily maximum	h	20	20	20
monthly average	h	15	15	15
Total suspended solids (TSS) mg per liter				
daily maximum	h	100	100	100
monthly average	h	30	30	30

TABLE I-4 (continued)
CHEMICAL EFFLUENT CONCENTRATION LIMITATIONS IN WATER DISCHARGES FROM CLAY BOSWELL STEAM ELECTRIC STATION, UNITS 1, 2, 3, AND 4

Effluent Source and Characteristic	Clay Boswell NPDES[a] Permit Limitations 7/1/77 to 7/31/79	Federal Effluent Standards for Steam Electric Generating Stations[b] Existing Stations met by 7/1/77	Existing Stations met by 7/1/83	New Stations met upon completion
Metal cleaning wastes and boiler blowdown[g] (continued)				
pH	h	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Total copper, mg per liter				
daily maximum	h	1.0	1.0	1.0
monthly average	h	1.0	1.0	1.0
Total iron, mg per liter				
daily maximum	h	1.0	1.0	1.0
monthly average	h	1.0	1.0	1.0
Low volume waste sources taken collectively[i]				
Oil and grease, mg per liter				
daily maximum	h	20	20	20
monthly average	h	15	15	15
Total suspended solids (TSS), mg per liter				
daily maximum	h	100	100	100
monthly average	h	30	30	30
pH	h	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0

a MPCA Permit No. MN 0001007. In addition to the limitations listed, the plant discharges shall not raise the sulfate concentration of the receiving water, measured at the Cohasset Bridge, above 40 mg per liter during the period of April 15 (or ice out in Blackwater Lake, whichever is later) to June 15 (or emergence of wild rice in the aerial leaf stage, whichever is earlier), or above 60 mg per liter at other times (75 mg per liter when Units 1 and 2 scrubbers are put on line).

b The daily quantity of pollutants discharged shall not exceed the quantity determined by multiplying the daily average flow times the concentration listed. Where limitations are not specified, they are currently unregulated by Federal standards. In the event that waste streams from various sources are combined for treatment or discharge, the total quantity (mass/time) of each pollutant allowed to be discharged from the treatment system or the combined sources shall not exceed the sum of the quantities of pollutant (mass/time) allowed to be discharged from each separate source. There shall be no discharge of polychlorinated biphenol compounds. (40 C.F.R. pt. 423)

c Chlorination is limited to a total of 2 hr per day and neither free available chlorine nor total residual chlorine may be discharged from the station for more than two hours in any one day. NPDES is for total residual chlorine; Federal standards are for free available chlorine.

d JTU means Jackson Turbidity Unit, which is a measure of light transmitted through a water sample.

e These Federal standards distinguish bottom ash transport water from fly ash transport water. The NPDES permit considers the two combined as the ash pond effluent. The daily quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the daily average flow of bottom ash transport water times the concentration listed in the table and dividing the product by 12.5. The fly ash transport water standards are the same as those presented.

f These Federal standards distinguish bottom ash transport water from fly ash transport water. The NPDES permit considers the two combined as the ash pond effluent. The daily quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the daily average flow of bottom ash transport water times the concentrations listed in the above table and dividing the product by 20. For fly ash transport water there shall be no discharge of total suspended solids or oil and grease.

g "Metal cleaning wastes" means any cleaning compounds, rinse waters, or any other waterborne residues derived from cleaning any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

h The NPDES permit contains no separate standards for these effluent sources. If these sources are present at the Clay Boswell Station, they are combined with the other effluent sources listed in the table.

i Including wet scrubber air pollution control system, ion exchange water treatment system, water treatment evaporator blowdown, laboratory sampling streams, floor drainage, and recirculating house water system blowdown, taken collectively as though one source.

Substance or Characteristic	Limiting Concentration
5 day biochemical oxygen demand	25 milligrams per liter (mg per liter)
Total suspended solids	30 mg per liter
Fecal coliform group organisms	200 most probable number per 100 milliliters (ml)
Total coliform group organisms	1,000 most probable number per 100 ml
Pathogenic organisms	None
Oil	Essentially free of visible oil
Turbidity value	25 Jackson Turbidity Units (JTU)
pH	6.5 to 8.5
Phosphorus	1 mg per liter
Unspecified toxic or corrosive substances	None at levels acutely toxic to humans or other animals or plant life, or directly damaging to real property.

On November 18, 1975, the MPCA issued a NPDES permit to MP&L for the operation of the effluent treatment and discharge facilities of Clay Boswell Units 1, 2, and 3 (40). This permit makes a specific application of the provisions of WPC 28, WPC 15, and the best practicable control requirements of the FWPCA to the Clay Boswell Station and will expire in 1979. Upon its renewal, the same maximum effluent concentration limitations probably will apply to Units 1, 2, 3, and 4. Table I-4 lists the effluent concentration limitation provisions of the Clay Boswell Station's NPDES permit.

Water Quality Standards. Prior to the 1972 Amendments, water quality standards were the only type of standards provided for by the FWPCA (33). The 1972 Amendments reinforced the old water quality provisions by establishing procedures for EPA review and approval of State plans for the implementation of the overall FWPCA goals of swimmable and fishable waters by 1983 and zero discharge by 1985 (41). FWPCA § 303 further requires the states to implement long-term planning schemes for each water basin and to set total maximum daily loading rates for watersheds which forseeably will not meet the overall goals through the use of the ordinary effluent limitations (Table I-4).

Minnesota began its water classification program in 1963 (19). This program attempts to classify all of the State's water according to the best use and to set standards of quality and purity for each of those uses (42). The MPCA has defined 6 use classes and grouped each of the State's waters into one or more of these classes. These classes are: Class 1) domestic consumption; Class 2) fisheries and recreation; Class 3) industrial consumption; Class 4) agriculture and wildlife; Class 5) navigation and waste disposal; and Class 6) other beneficial uses (42), as presented in WPC 15 (Table I-3). Some of these classes are subdivided into sub-classes A, B, C, and D, indicating a decreasing level of purity. The 2B classification is considered by the MPCA to be equivalent to the 1983 national goal of swimmable and fishable water (42).

The upper Mississippi River from Lake Itasca to Fort Ripley has a use classification of 2B, 3B, 4A, 4B, 5, and 6 (WPC 25). Table I-5 presents the limiting concentrations or ranges of substances or characteristics which apply to the Mississippi River in the vicinity of the Clay Boswell Station. In addition to the WPC 25 criteria, the NPDES effluent permit for the Clay Boswell Station imposes a water quality standard for sulfates. This standard is included in Table I-4 .

FWPCA § 301(b)(2)(c) prohibits pollution sources from violating whichever is stricter of the effluent limitations or the water quality standards. Thus, the Clay Boswell Station cannot cause the Mississippi River to exceed the criteria listed in Table I-5, regardless of whether the Station's effluents are within the NPDES permit limitations listed in Table I-4. The water quality standards listed in Table I-5 are to be maintained at all times, except when the stream flow rate drops below the lowest weekly flow with a once in 10 year recurrence interval (43). In addition, WPC 15(c)(5) places the following restrictions on the mixing zone (area of Blackwater Lake near the Clay Boswell Station discharge point where the effluents are mixed with Mississippi River water):

1. Mixing zones in rivers shall permit an acceptable passageway for the movement of fish;

2. The total mixing zone or zones at any transect of the stream should contain no more than 25% of the cross sectional area and/or volume of the stream; and should not extend over more than 50% of the width;

3. Mixing zone characteristics shall not be lethal to aquatic organisms;

4. For contaminants other than heat, the 96 hr median tolerance limit for indigenous fish and food organisms should not be exceeded at any point in the mixing zone;

5. Mixing zones should be as small as possible, and not intersect spawning or nursery areas, migratory routes, water intakes, nor mouths or rivers; and

6. Overlapping of mixing zones should be minimized and measures taken to prevent adverse synergistic effects.

WPC 15 further provides that waters which are of a quality better than the applicable use classification standards be maintained at that high quality unless the MPCA determines that a detrimental change is justifiable as a result of necessary economic or social development, and then only if the change will not preclude appropriate beneficial present and future use of the water (44).

TABLE I-5
WATER QUALITY STANDARDS
MISSISSIPPI RIVER NEAR CLAY BOSWELL STEAM ELECTRIC STATION[a]

Substance or Characteristic	Limit or Range
Dissolved oxygen	Not less than 6 mg per liter from April 1 through May 31 Not less than 5 mg per liter at other times
Temperature	5°F (2.78°C) above natural in streams and 3°F (1.67°C) above natural in lakes, based on monthly average of maximum daily temperature, except in no case shall it exceed daily average temperature of 86°F (30.0°C)
Ammonia (N)	1 mg per liter
Chromium (Cr+6)	0.05 mg per liter
Copper (Cu)	0.01 mg per liter or not greater than 1/10 the 96 hr TLM[b] value
Cyanides (CN)	0.02 mg per liter
Oil	0.5 mg per liter
pH	6.5 to 8.5
Phenols	0.01 mg per liter and none that could impart odor or taste to fish flesh or other fresh-water edible products such as crayfish, clams, prawns, and like creatures. Where it seems probable that a discharge may result in tainting of edible aquatic products, bioassays and taste panels will be required to determine whether tainting is likely or present.
Turbidity value	25 JTU[c]
Fecal coliform organisms	200 most probable number per 100 ml as a monthly geometric mean based on not less than 5 samples per month, nor equal or exceed 2000 most probable number per 100 ml in more than 10% of all samples during any month.
Radioactive materials	Not to exceed the lowest concentration permitted to be discharged to an uncontrolled environment as prescribed by the appropriate authority having control over their use.
Chlorides (Cl)	100 mg per liter
Hardness	250 mg per liter
Bicarbonates (HCO_3)	5 meq per liter
Boron (B)	0.5 mg per liter
Specified conductance	1,000 μmhos per cm
Total dissolved salts	700 mg per liter
Total salinity	1,000 mg per liter
Sodium (Na)	60% of total cations as meq per liter
Arsenic (As)	0.05 mg per liter
Barium (Ba)	1 mg per liter
Cadmium (Cd)	0.01 mg per liter
Fluoride (F)	1.5 mg per liter
Lead (Pb)	0.05 mg per liter
Selenium (Se)	0.01 mg per liter
Silver (Ag)	0.05 mg per liter
Unspecified toxic substances	None at levels harmful either directly or indirectly, or not greater than 1/10 the 96 hr TLM[b] value
Sulfates (SO_4)	10 mg per liter, applicable to water used for production of wild rice during periods when the rice may be susceptible to damage by high sulfate levels.
Hydrogen sulfide	0.02 mg per liter

[a] Sources: Minn. Reg. WPC 15 Use Class 2B, 3B, 4A, 4B, 5, and 6.

[b] TLM means Median Tolerance Limit.

[c] JTU means Jackson Turbidity Unit, which is a measure of light transmitted through a water sample.

The FWPCA supports this non-degradation approach (45). The upper Mississippi River above Grand Rapids is well within the standards listed in Table I-5 for dissolved oxygen, temperature, ammonia, copper, pH, turbidity, fecal coliform organisms, and total hardness (42). Refer to Chapter IV for discussions of these and other water quality parameters. The upper Mississippi River above Grand Rapids presently is of a quality considerably higher than the applicable use classification standards. The non-degradation provisions of WPC 15 stipulate that the proposed Clay Boswell Unit 4 shall not cause a deterioration of this water quality.

Thermal Discharges. FWPCA § 316(a) allows individual dischargers to attempt to show that any effluent limitation proposed for the thermal component of his discharge is "more stringent than necessary to assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water into which the discharge is to be made. . .". This showing is to be made to the MPCA under its permitting authority of WPC 36(u)(3). If the discharger makes the showing that the thermal effluent limitation is more stringent than necessary, taking into account the interaction of the heat component with other pollutants, the MPCA may modify or terminate the interim thermal effluent standards. Pursuant to WPC 36(u)(3) and the FWPCA, MP&L has undertaken a "316(a) Demonstration" study. Until this study is completed, WPC 15 (Table I-5) and the NPDES effluent permit for the Clay Boswell Station (43) place the following limitations on thermal effluents from the Clay Boswell Station:

> The heated effluents shall not raise the temperature of the receiving water at the edge of the mixing zone either by more than 5°F (2.8°C) above natural, based on the monthly average of the maximum daily temperatures, or above the following weekly average temperatures, whichever is less:

January 40°F (4.4°C)	July 83°F (28.3°C)
February 40°F (4.4°C)	August 83°F (28.3°C)
March 48°F (8.9°C)	September 78°F (25.6°C)
April 60°F (15.6°C)	October 68°F (20.0°C)
May 72°F (22.2°C)	November 50°F (10.0°C)
June 78°F (25.6°C)	December 40°F (4.4°C)

Toxic Compound Standards. Section 307 of the FWPCA contains special provisions for the control of effluents containing compounds which may be toxic, carcinogenic, mutagenic, teratogenic, or which may cause physiological or behavioral malfunctions. To date, the only standards promulgated by the EPA for the control of toxic compound effluents from steam electric generating stations apply to polychlorinated biphenols, which is limited to zero discharge (39). WPC 15 (Table I-5) contains additional limitations for ambient water concentrations of radioactive materials, chromium, cyanides, and other compounds of high toxicity.

Ground Water Quality Regulations. The FWPCA has very limited application to pollution of ground water (46). Minnesota has, however, adopted regulations of specific application to ground water (WPC 22). WPC 22 provides that all ground water of suitable natural quality is classified for use as sources of drinking, culinary, or food processing water. Thus, the standards for the MPCA's highest water use classification, Class 1, apply to most ground water in

Minnesota (47). WPC 22 also requires that, to the maximum practicable extent, ground water shall not be degraded below its natural quality. Specifically, WPC 22(d) provides that no pollutants shall be discharged to the saturated or unsaturated zone in such a manner that the effluent may actually or potentially preclude or limit the use of the ground water as a potable water supply. Additional MPCA sewage stabilization pond criteria will further limit the percolation rate of water from the Clay Boswell Station waste disposal pond to 500 gallons per day per acre (1892.7 liters per day per hectare) (48).

Noise Control Regulations and Their Administration

Noise is a physical phenomenon which can have significant acute or insidious effects upon the psychological and physiological well-being of humans, animals and, possibly, plants. The Federal government's role in controlling noise is limited to occupational health aspects under the Occupational Safety and Health Act of 1970 (49) and to noise from transportation sources and from products moved through interstate commerce under the Noise Control Act of 1972 (50). (Since this Draft EIS is not concerned with in-plant occupational hazards, the OSHA provisions will not be discussed.) The MPCA recently has become quite active in noise control (19). The State control programs will be discussed after the Federal programs.

The Federal Noise Control Act (FNCA) takes the approach of controlling noise emissions rather than establishing receiver standards. The FNCA focuses on 2 major categories of noise emitting activities and devices: transportation, including airplanes, automobiles, interstate carriers, and related facilities; and products traded through interstate commerce. By its general policy clauses, the FNCA also requires all Federal agencies to further noise abatement in any activities or programs directly or indirectly involving the Federal government (51).

Coal trains are the primary transportation type noise source associated with the Clay Boswell Station. The FNCA regulates noise from trains in 2 ways: first, by authorizing the promulgation of noise emission standards for transportation equipment (52), and second, by authorizing the control of noise emissions resulting from the operation of this equipment (53). This Draft EIS will not deal with coal trains en route to and from the Clay Boswell Station. Noise from trains in the station yards, while unloading, etc., will be treated as aggregated with other noise sources at the Clay Boswell Station.

FNCA §6 requires that the EPA establish noise emission standards for all products distributed in interstate commerce. The Act includes specific categories for electrical and electronic equipment and for any motors or engines. To date, noise emissions standards have not been promulgated for the type of stationary equipment which will be used in the Clay Boswell Station (54). Furthermore, though the FNCA contains the parenthetical language: "Any motor or engine (including any equipment of which an engine or motor is an integral part)" (emphasis added), there will be no Federal noise emission standard applicable to the Clay Boswell Station as a whole (55).

The MPCA was first given the authority to control environmental noise pollution in 1971, Minn. Stat. § 116.07. In 1974, the general noise pollution control regulations NPC 1 and NPC 2 were promulgated by the MPCA (56). These standards, unlike the FNCA, limit noise in terms of what the receiver hears. NPC 2 sets standards for 4 distinct land use categories. Noise Area Classification - 1 (NAC 1) includes household units; hotels; mobile home parks; educational services; health services facilities; cultural activities and nature exhibitions; and camping, picnicking, and resort areas. NAC 2 includes air, rail, and bus terminals; wholesale and retain trade; consumer services; and amusement and recreational areas and parks. NAC 3 includes industry and manufacturing; motor vehicle and aircraft transportation; agricultural, forestry, and fishing activities; and resource production and extraction. NAC 4 includes water areas, and undeveloped and unused land.

The standards which apply to these land use classifications are given in Table I-6. Note that the Minnesota noise regulations make no distinction between new and existing sources; i.e. the MPCA can force retrofitting of noise-mitigating measures to old sources as well as forcing the incorporation of these measures into new sources.

TABLE I-6
MINNESOTA NOISE REGULATIONS APPLICABLE TO CLAY BOSWELL STEAM ELECTRIC STATION[a]

Noise Area Classification[c]	Daytime Standards 7 a.m. to 10 p.m. dB(A)[b] L_{50}[d]	L_{10}[e]	Nighttime Standards 10 p.m. to 7 a.m. dB(A)[b] L_{50}[d]	L_{10}[e]
NAC-1	60	65	50	55
NAC-2	65	70	65	70
NAC-3	75	80	75	80
NAC-4	no standard		no standard	

[a] Minn. Reg. NPC 2 (1974)

[b] dB(A) as used here is a measure of human response to sound pressure on the A frequency weighted scale where a typical living room is 45 dB(A), an air conditioning unit at 50 ft is 75 dB(A) and a jet takeoff at 2,000 ft is 105 dB(A). Note that the standards do not apply to impulsive sound such as from a pile driver.

[c] NAC-1 includes residences, schools, hospitals, and camping and picnicking areas.

NAC-2 includes transportation terminals, commercial trade, and parks.

NAC-3 includes industry, agriculture, forestry, and mining.

NAC-4 includes water areas and unused land.

[d] L_{50} is the sound level, expressed in dB(A), which is exceeded 50% of the time during a one hour survey, as measured by approved test procedures.

[e] L_{10} is the sound level, expressed in dB(A), which is exceeded 10% of the time during a one hour survey, as measured by approved test procedures.

The Minnesota noise standards are enforced against large stationary sources in 2 ways. First, the MPCA can require issuance of a permit certifying that the facility will comply with NPC 2, Minn. Stat. § 116.07 subd. 4a. This permit can be either a distinct, separate permit, or, more likely, a subpart of the air quality permit. The MPCA is permitted by statute to issue noise permits (57). A noise permit program has not been initiated to date.

The second method of enforcement is by direct court action against violators. Thus, if the MPCA is unsuccessful in persuading a source to mitigate its noise emissions, the MPCA can sue in court to obtain an injunction or to force the source to apply noise abatement measures. As with other Minnesota environmental regulations, municipalities, counties, and other local governmental units also have the authority to enforce the State noise regulations, Minn. Stat §116.05 subd. 3. The local governments can enforce the noise regulations by adopting them as ordinances, by establishing permit or license requirements, or by other means. Neither Itasca County nor Bass Brook Township have adopted noise regulations. However, the MPCA encourages these programs and they can be set up at a relatively small expense (55).

The Minnesota noise standards establish limiting levels of sound dependent on the land use of the receiving area. Thus, the sound level in the vicinity of homes near the Clay Boswell Station cannot exceed the prescribed NAC 1 levels in Table I-6. The sound levels in the undeveloped forests and swamps surrounding the station (e.g. north and south of the MP&L property) are unregulated because there are no NAC 4 standards. However, if new homes are built in these areas subsequent to the completion of MP&L's proposed Unit 4, these homes may be entitled to the same NAC 1 protection as preexisting homes.

The Federal noise control programs interact in many areas with Minnesota's program. For example, where a piece of equipment such as an air compressor is meeting EPA's new-product noise emission standards but is causing Minnesota's receiver standards to be exceeded at a nearby home, there is an apparent conflict. However, the 2 sets of standards, though complementary to each other, are not directly comparable and, in this case, the more restrictive of the 2 (NPC 2) will control.

Another area of double coverage is in new housing. FNCA § 5(a)(2) required the EPA to "publish information on levels of environmental noise requisite to protect public health and welfare with an adequate margin of safety". This the EPA has done (58), (Table I-7), and these guidelines and others have been adopted by the Housing and Urban Development Authority (HUD) as receiver standards for new housing, nursing home facilities, low income apartments, etc. (59). The HUD receiver standards are presented in Table I-8. These standards must be complied with before HUD will grant housing loans, Federal Home Administration mortgage guarantees, or similar assistance. The HUD standards are similar in approach to MPCA's NPC 2 and, again, the more restrictive of the 2 standards will control.

TABLE I-7

YEARLY AVERAGE[a] EQUIVALENT SOUND LEVELS IDENTIFIED AS REQUISITE TO PROTECT PUBLIC HEALTH AND WELFARE (59)

		Indoor			Outdoor		
	Measure	Activity Interference dB(A)[d]	Hearing Loss Consideration[b] dB(A)[d]	To Protect Against Both Effects[c] dB(A)[d]	Activity Interference dB(A)[d]	Hearing Loss Consideration[b] dB(A)[d]	To Protect Against Both Effects[c] dB(A)[d]
Residential with outside space and farm residences	L_{dn}[e]	45		45	55		55
	$L_{eq(24)}$[f]		70			70	
Residential with no outside space	L_{dn}	45		45			
	$L_{eq(24)}$		70				
Commercial	$L_{eq(24)}$	g	70	70[h]	g	70	70[h]
Inside transportation	$L_{eq(24)}$	g	70	g			
Industrial	$L_{eq(24)}$[i]	g	70	70[h]	g	70	70[h]
Hospitals	L_{dn}	45		45	55		55
	$L_{eq(24)}$		70			70	
Educational	$L_{eq(24)}$	45		45	55		55
	$L_{eq(24)}$[i]		70			70	
Recreational areas	$L_{eq(24)}$	g	70	70[h]	g	70	70[h]
Farm land and general unpopulated land	$L_{eq(24)}$				g	70	70[h]

a Refers to energy rather than arithmetic averages.

b Explanation of identified level for hearing loss: The exposure period which results in hearing loss at the identified level is a period of 40 years.

c Based on lowest level.

d dB(A) as used here is a measure of human response to sound pressure on the A frequency weighted scale.

e L_{dn} is the day-night average sound level; i.e., the 24-hr A-weighted equivalent sound level with 10 decibel penalty applied to nighttime levels.

f $L_{eq(24)}$ is the equivalent A-weighted sound level over a 24-hr period.

g Since different types of activities appear to be associated with different levels, identification of a maximum level for activity interference may be difficult except in those circumstances where speech communication is a critical activity.

h Based on hearing loss.

i An $L_{eq(8)}$ of 75 dB may be identified in these situations so long as the exposure over the remaining 16 hours per day is low enough to result in a negligible contribution to the 24-hr average, i.e., no greater than an L_{eq} of 60 dB.

TABLE I-8

HOUSING AND URBAN DEVELOPMENT AUTHORITY RECEIVER STANDARDS (60)

Unacceptable

1. Exceeds 80 dB(A)[a] for 60 min or more per 24 hr.
2. Exceeds 75 dB(A)[a] for 8 hr or more per 24 hr.

Discretionary - Normally Unacceptable

1. Exceeds 65 dB(A)[a] for 8 hr or more per 24 hr.
2. Loud repetitive sounds on site.

Discretionary - Normally acceptable

1. Does not exceed 65 dB(A)[a] for 8 hr or more per 24 hr.

Acceptable

1. Does not exceed 45 dB(A)[a] for 30 min or more per 24 hr.

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[a] dB(A) as used here is a measured human response to sound pressure on the A frequency weighted scale.

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CHAPTER II

DESCRIPTION OF PROPOSED ACTION

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The existing Clay Boswell Steam Electric Station, located near Grand Rapids, consists of 3 coal-fired steam electric generating units. Unit 1 with a gross generating capacity of 75 MW began commercial operation in 1958. Unit 2 is a replica of the first unit and began commercial operation in 1960. Unit 3 went into operation in 1973 and has a gross generating capacity of 369 MW. MP&L now has proposed to construct and operate at the Clay Boswell Station a Unit 4 with a gross generating capacity of 554 MW (1).

The following chapter presents a detailed technical description of Units 1, 2, and 3 and proposed Unit 4 at the Clay Boswell Steam Electric Station. The descriptions of Units 1, 2, and 3 have been included to point out the interdependence of proposed Unit 4 with the existing units. Although there are elements in the structure and operation of Unit 4 which will differ from the other 3 units, many facilities are shared.

EXISTING PLANT

The existing Clay Boswell Steam Electric Station consists of 3 coal-fired steam electric generating units. Unit 1 has a gross generating capacity of approximately 75 MW and generating Unit 2 is a duplicate of Unit 1. Unit 3 has a gross generating capacity of 369 MW.

Figure II-1 shows the general location and boundaries of the existing facility. Operation of these units varies over time depending on energy demands and operational problems. Table II-1 shows the capacity factors for Units 1, 2, and 3 for the last several years.

TABLE II-1
CAPACITY FACTORS - UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION
1972, 1973, 1974, 1975 (2)

Year	Unit 1 %	Unit 2 %	Unit 3 %
1972	68.7	75.2	-
1973	74.3	75.6	31.5
1974	72.1	71.1	64.8
1975	55.7	63.1	77.3

Capacity Factor =

$$\frac{\text{Total Gross Generation in Period (kwh)} \times 100}{\text{Nameplate Capacity (gross kwh)} \times \text{Hours in Period}}$$

MP&L anticipates that Units 1 and 2 will not operate after the year 1999, and Unit 3 will not operate after the year 2008 (2). However, future energy planning and policy may affect both the capacity factors and planned retirement dates.

Raw Materials

Coal Transportation

Approximately 2.3 million tons per year (tpy) (2.1 million metric tons per year) (mtpy) of western sub-bituminous coal from the Peabody Coal Company's (Peabody) Big Sky Mine near Colstrip, Montana is delivered to the Clay Boswell Station, via the Burlington Northern railroad. MP&L has existing agreements with Peabody and the Burlington Northern for shipment of this coal (3).

The coal is transported to the Clay Boswell Station in unit trains made up of approximately 100 rotary coupled gondola cars, each having a 100 ton (90.7 mt) capacity. Approximately 4 to 5 trains per week arrive at the Clay Boswell Station for off-loading (4).

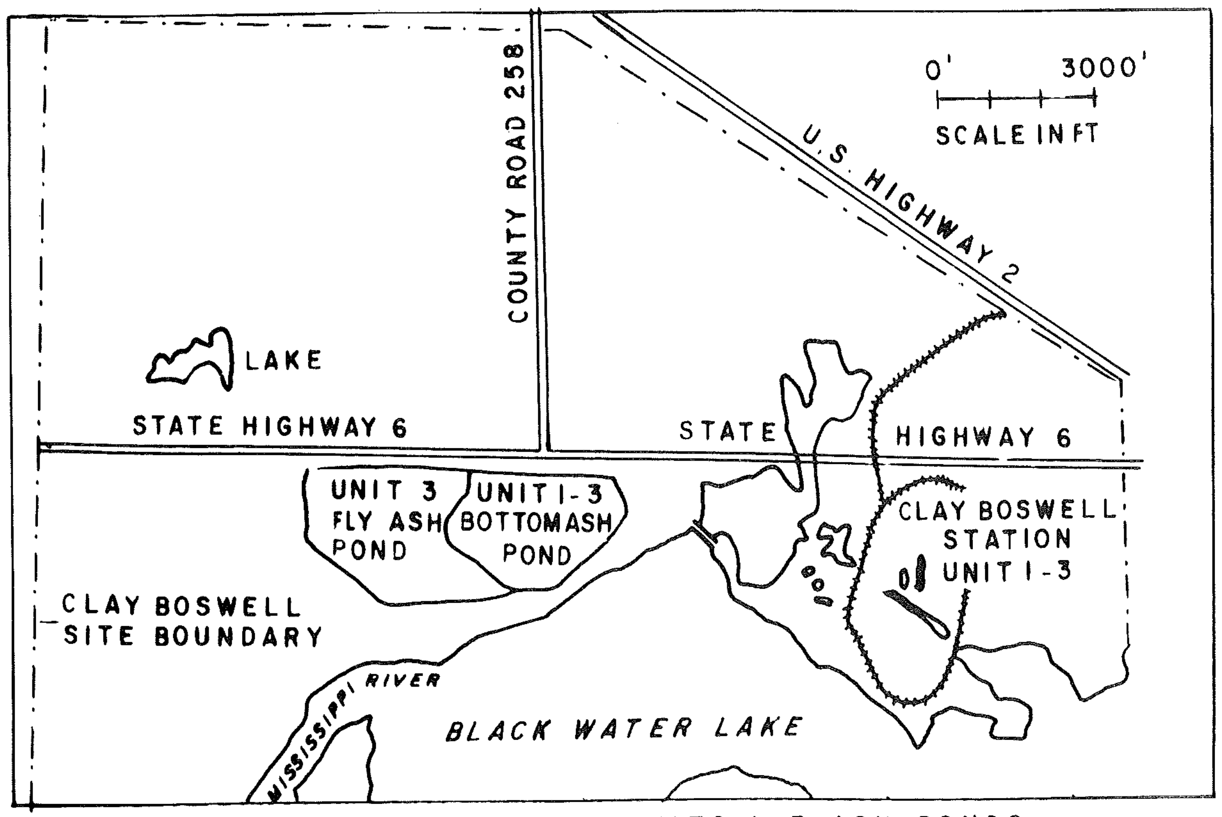
The large annual volume of coal delivered to MP&L makes the unit train the cheapest mode of transportation. Each unit train travels from the Big Sky Mine to the Clay Boswell Station and returns without breaking up the set of cars (4).

Of approximately 2.3 million tons (2.1 million mt) of coal delivered to the Clay Boswell Station, 300,000 to 400,000 tons (272,155 to 362,874 mt) annually is designated for MP&L's Syl Laskin Steam Electric Station (formerly the Aurora Station). The remaining 1.9 to 2.0 million tons (1.72 to 1.81 mt) annually are used for Units 1, 2, and 3 at the Clay Boswell Station. The coal for the Syl Laskin Station is unloaded at Clay Boswell Station and then reloaded by front end loader into random rail cars and shipped in lots of from 12 car minimum (generally during the winter months) to approximately 30 to 40 car units (during the summer months). Normally, these shipments are made 5 days per week, but cold weather, frozen coal, and an occasional shortage of cars will alter the schedule (4).

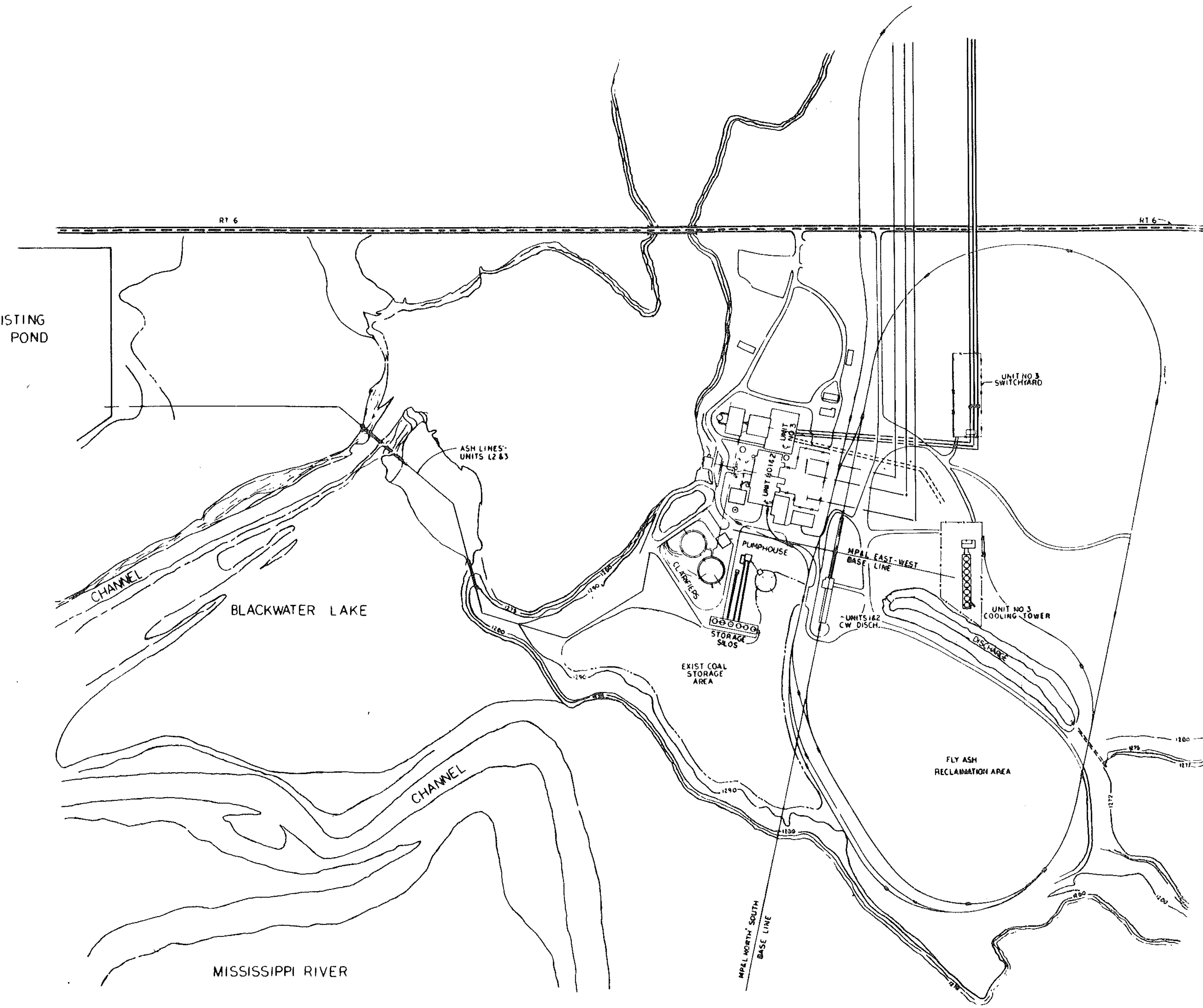
Present routing and schedules of unit trains for shipments between Colstrip, Montana and the Clay Boswell Station are determined by the Burlington Northern. As shown in Figure II-2, present routing from Colstrip involves trackage through Forsythe and Glendive, Montana; Bismarck, Fargo, and Grand Forks, North Dakota; and Crookston, Bemidji, and Cass Lake, Minnesota; and terminates at the Clay Boswell Station. Round trips under normal conditions of loading, traveling, and unloading require approximately 4 days (4).

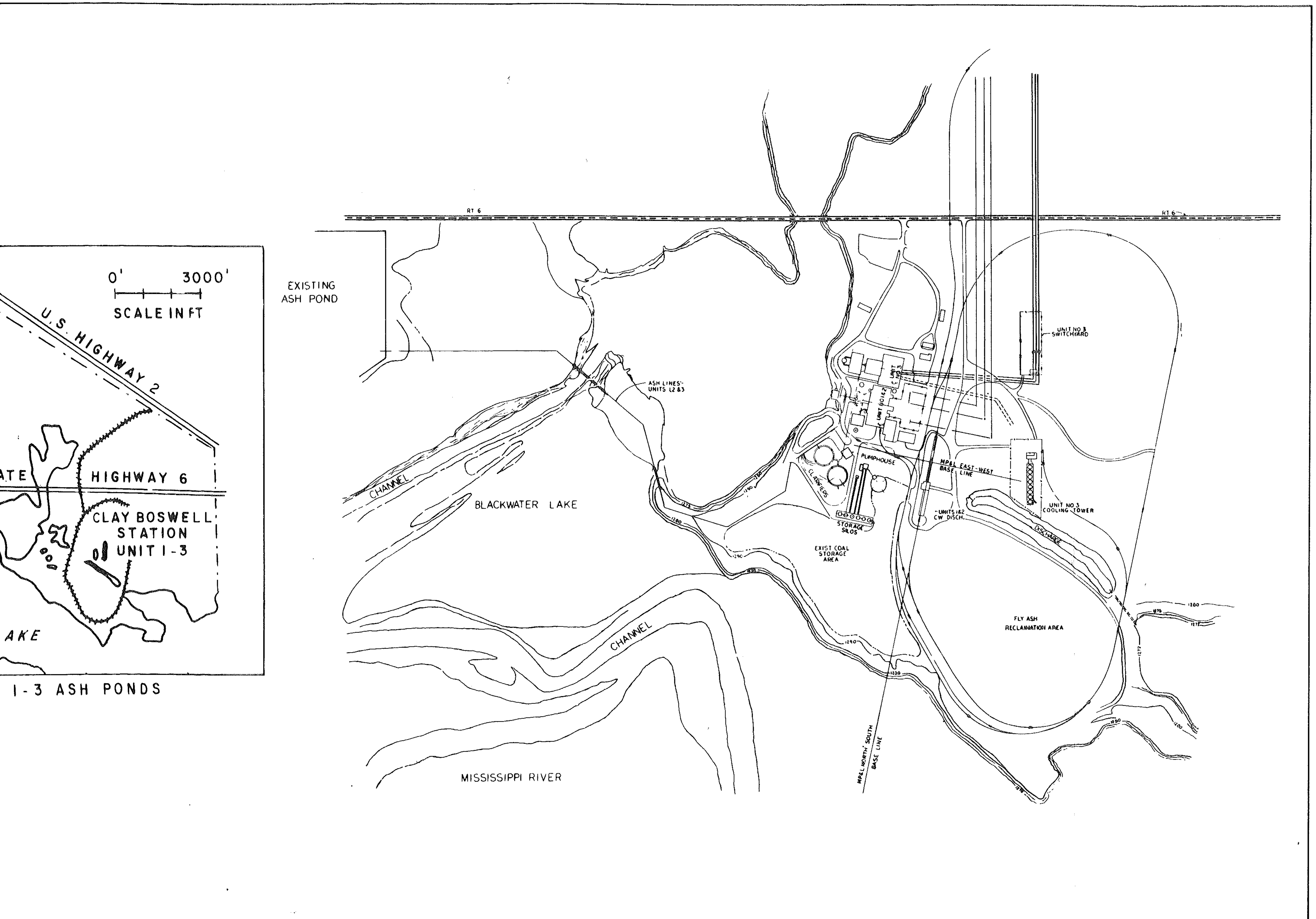
Speed restrictions on Burlington Northern's unit coal train movement between Grand Forks and the Clay Boswell Station include (5):

1. Unless otherwise restricted, loaded unit coal trains are limited to a maximum speed of 50 miles per hour (mph) (80.5 kilometers per hour) (kmph) and unloaded unit coal trains are limited to a maximum speed of 60 mph (96.6 kmph); and



INSET : LOCATION OF UNITS I-3 ASH PONDS

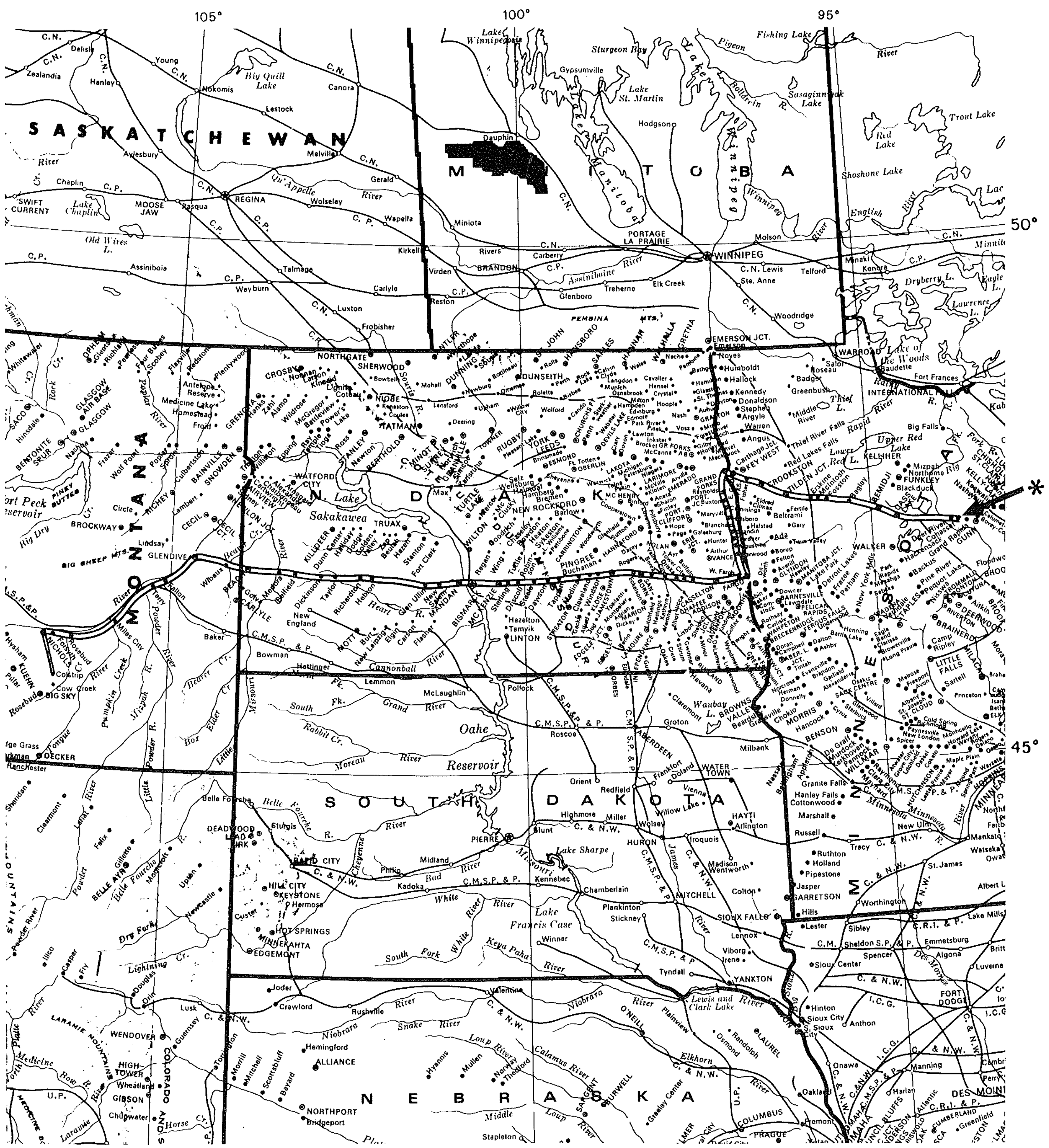




PLOT PLAN
UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", EXHIBIT II-A-1

FIGURE II-1

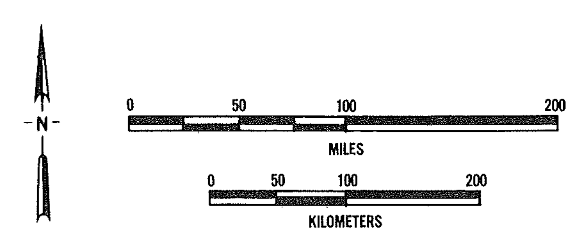


LEGEND

MAIN LINE

BRANCH LINE

* CLAY BOSWELL STATION



BURLINGTON NORTHERN RAIL ROUTE COLSTRIP, MONTANA TO CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: BURLINGTON NORTHERN

FIGURE II-2

2. Restricted rail segments include Erskine to Bemidji and Cass Lake to the Clay Boswell Station where loaded unit coal trains are limited to a maximum speed of 30 mph (48.3 kmph), and unloaded unit coal trains are limited to a maximum speed of 35 mph (56.3 kmph).

Between Grand Forks and the community of Cohasset, Burlington Northern estimates that the annual average total freight rail movement for 1977 will be 7.2 trains per day, consisting of an average of 1.2 unit coal trains and 6.0 other freight trains per day. Approximately one-half of these unit coal trains are for coal delivered to the Clay Boswell Steam Electric Station. The other unit coal trains are for coal delivered to Superior, Wisconsin for transshipment. Thus, 17% of the Burlington Northern train movements between Grand Forks and the community of Cohasset are unit coal trains, but only about half of these unit coal train movements are related to the existing Clay Boswell Station (5).

Coal Supply

All the coal used in Units 1, 2, and 3 is and will be supplied by Peabody's Big Sky Mine at Colstrip, Montana. MP&L is proposing that all the coal used in the proposed Unit 4 also will be supplied by Peabody's Big Sky Mine.

Coal Contract. MP&L and Peabody entered into a Coal Supply Agreement on July 29, 1968 (6). Peabody agreed to supply coal for the Clay Boswell Steam Electric Station at the rates of 1,000,000 to 2,500,000 tons (907,185 to 2,267,962 mt) annually from 1973 to 1993. Peabody also agreed to supply up to 300,000 tons and 250,000 tons (272,155 and 226,796 mt) of coal annually to MP&L's Syl Laskin and M.L. Hibbard Steam Electric Stations, respectively, from May 1, 1969 to 1993. Peabody would deliver the coal f.o.b. railroad cars at MP&L's steam electric stations. The agreement contained options which can be elected by MP&L to extend the agreement to the year 2008. Peabody agreed to maintain adequate coal reserves at the Big Sky Mine, near Colstrip, Montana, to comply with the agreement. However, Peabody could substitute other coals from the coal produced from Big Sky Mine, providing that the substitute coals met the coal specifications in the agreement. The specifications state that the coal shall be minus 2 in. (5.1 centimeters) (cm), free from excessive quantities of bone, slate, fire clay, and other impurities, and shall have approximately the average analysis given in Table II-2.

The agreement gives MP&L the right to refuse coal for which the analysis shows the coal to be outside certain limits or "rejection points." These "rejection points" were to be set by negotiations between Peabody and MP&L. To date no "rejection points" have been established.

On June 20, 1975, MP&L and Peabody amended the Coal Supply Agreement (7). Peabody represented that it owned, leased, or controlled 152 million tons (137.9 million mt) of uncommitted coal in the vicinity of Colstrip, Montana, and it had the capacity to produce a maximum of 4,500,000 tons (4,082,331 mt) of coal annually. Under this amended agreement, MP&L must purchase not less than 1,000,000 tons (907,185 mt) of coal annually, and Peabody can sell to a "third party" up to 2,000,000 tons (1,814,369 mt) of coal annually subject to the following:

1. MP&L's right to purchase coal was limited to Peabody's production capability;

2. MP&L must give Peabody at least three years advance written notice before the "increase date" if MP&L elects to increase annual coal purchases 1,000,000 or more tons (907,185 mt) in excess of the "base quantity" of 2,500,000 tons (2,267,962 mt);

3. If MP&L elects to purchase more than 4,500,000 tons (4,082,331 mt) of coal annually, Peabody's obligation is subject to Peabody's ability to obtain and install the necessary mining equipment;

4. After MP&L has elected to increase annual coal purchases 1,000,000 tons (907,185 mt) or more in excess of the "base quantity", MP&L annually must purchase, or pay for, on a take-or-pay basis, not less than the greater of 3,000,000 tons (2,721,554 mt) of coal or 75% of the "base quantity" plus the "excess quantity", and Peabody's annual coal sales to "third parties" are limited to 2,000,000 tons (1,814369 mt) minus the "excess quantity"; and

5. Peabody coal sales to "third parties" after the "increase date" will be deducted from the coal dedicated to MP&L.

TABLE II-2
COAL SPECIFICATIONS
COAL SUPPLY AGREEMENT BETWEEN MINNESOTA POWER & LIGHT COMPANY AND PEABODY COAL COMPANY (6)

Parameter	Coal Dry	Coal "As Received"
Heating value		
Btu per lb	11,375	8,700
kg-cal per kg	6,319	4,833
Moisture, %	-	23.50
Ash, %	13.40	10.25
Sulfur, %	1.70	1.30
Fusion temperature of ash		
Reducing H = W, °F	-	2,262
Reducing H = W, °C	-	1,239
Reducing H = ½W, °F	-	2,281
Reducing H = ½W, °C	-	1,249
Grindability (Hardgrove Index)	-	52.2

Peabody is responsible for payment for cost of coal transportation from the mine to the steam electric station or stations designated by MP&L. The coal can be utilized at any electric generating facility owned or leased by MP&L or at any electric generating facility from which MP&L purchases substantial quantities of electricity.

To date, MP&L has not provided Peabody with written notice stating that MP&L elects to increase annual coal purchases 1,000,000 tons (907,185 mt) or more in excess of the "base quantity" and to establish an "increase date". Unless Peabody waives this notice requirement, MP&L must provide Peabody with a written notice three years prior to operation of Clay Boswell Steam Electric Station's Unit 4. This written notice is necessary to insure adequate coal deliveries for operation of Unit 4.

Big Sky Mine. The Big Sky Mine, operated by Peabody, is located in southeastern Montana. The mine is in Rosebud County, approximately 5 miles (8.0 kilometers) (km) south of the small community of Colstrip. The coal reserves are located in 3 areas, as shown in Figure II-3 (7). Coal presently is being mined from Area A. The mine tipple, coal storage areas, and other support facilities are located adjacent and to the southeast of Area A (8). Peabody leases contiguous or nearly contiguous Federally owned coal areas under Federal Lease M-15969 (9). Peabody leases the adjacent privately owned coal areas from Burlington Northern Inc. (8). Figure II-3 depicts the Federal and Burlington Northern lease areas.

Central Rosebud County is located at the northern end of the Powder River Basin in southeastern Montana. Together with adjacent parts of eastern Montana, Wyoming, and the Dakotas, the area forms the Fort Union coal region.

The estimated coal reserves for Areas A, B, and C are presented in Table II-3. Summaries of the coal analyses of drill cores for Areas A, B, and C are

TABLE II-3
COAL RESERVES - BIG SKY MINE (7)

Area	Lease	Tons	Metric Tons
A	Federal	23,476,253	21,297,298
	Other	18,420,500	16,710,796
	None	2,018,200	1,830,880
	Total	43,914,953	39,838,974
B	Federal	31,396,400	28,482,334
	Other	44,122,800	40,027,530
	None	1,454,200	1,319,228
	Total	76,973,400	69,829,092
C	Federal	3,384,300	3,070,185
	Other	30,793,800	27,935,665
	None	893,200	810,297
	Total	35,071,300	31,816,147
	Grand Total	155,959,653	141,484,213

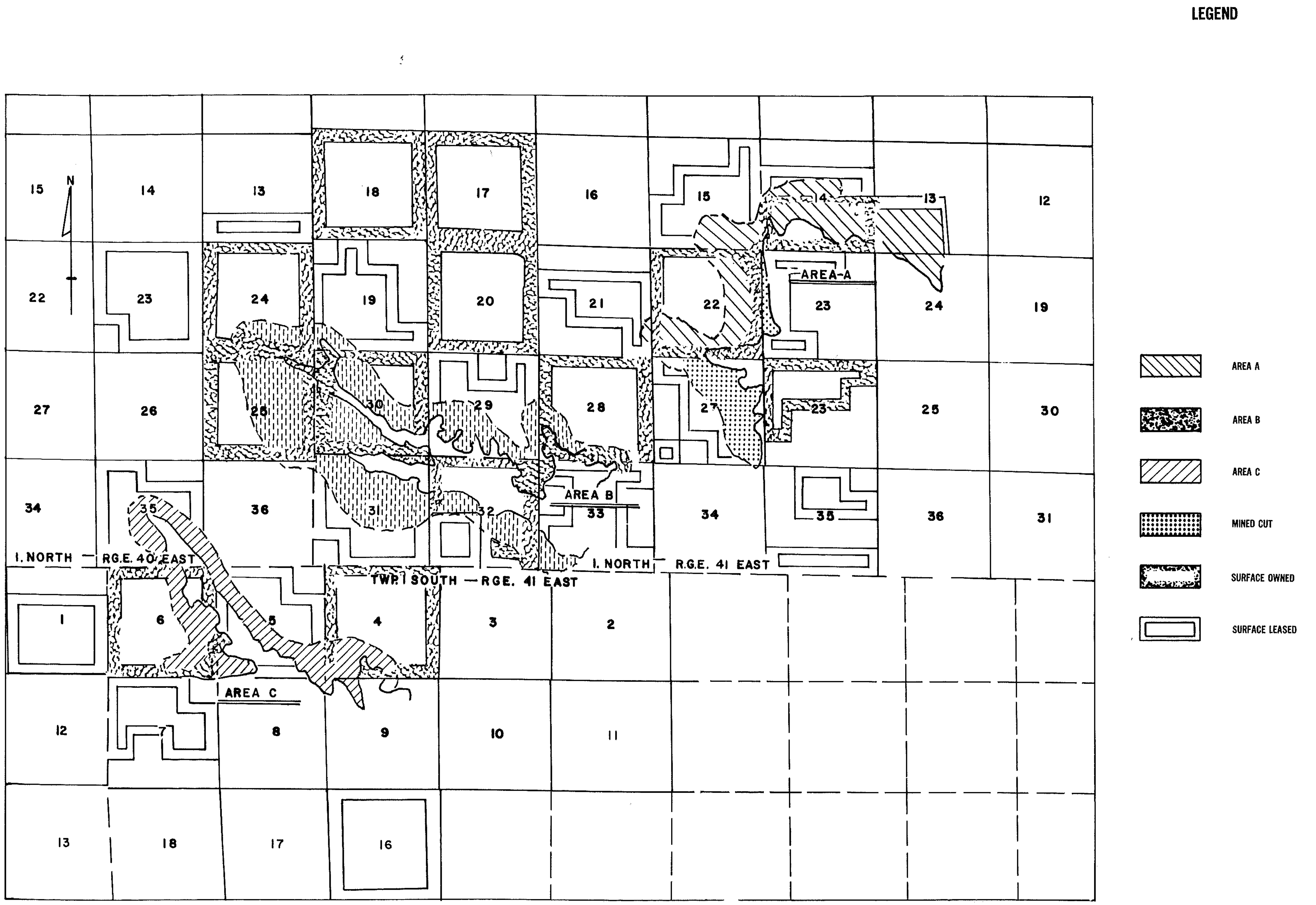
presented in Tables II-4, II-5, II-6, and II-7 for dry Btu per lb, percent moisture, dry percent ash, and dry percent sulfur, respectively. Drill core coal analyses have been correlated with analyses of coal "as received" at the Clay Boswell Steam Electric Station. These correlations indicate that the mean sulfur contents as determined from the drill core are higher than the sulfur contents of the coal "as received" at the Clay Boswell Station. These differences are 0.40% and 0.06% sulfur for the Rosebud and McKay seams, respectively (9). Table II-8 presents the estimated average dry and "as received" coal analyses for the drill core and coal delivered to the Clay Boswell Station for the total coal reserves at the Big Sky Mine. An extensive new drilling and analytical program is being conducted by Peabody to re-evaluate the coal reserves at the Big Sky Mine.

TABLE II-4
SUMMARY OF DRILL CORE RESULTS - DRY BTU PER LB AND KG-CAL PER KG
BIG SKY MINE (9)

Identification	No. of Cores	Dry Btu per Lb			Kg-Cal per Kg			Tonnage	
		Mean	Standard Deviation	Confidence Limits @ 95%	Mean	Standard Deviation	Confidence Limits @ 95%	% of Area	% of Mine
Area A McKay	72	11,647	223	11,595-11,700	6,471	124	6,441-6,500	26.1	7.4
Area A Rosebud	110	11,417	414	11,339-11,494	6,343	230	6,299-6-386	73.9	21.0
Area A Total		11,477	364		6,376	202		100.0	28.4
Area B McKay	45	11,674	186	11,618-11,730	6,486	103	6,454-6,517	24.9	12.3
Area B Rosebud	49	11,479	261	11,404-11,554	6,377	145	6,336-6,419	75.1	37.1
Area B Total		11,582	242		6,434	134		100.0	49.4
Area C McKay	6	11,434	209	11,214-11,653	6,352	116	6,230-6,474	25.1	5.6
Area C Rosebud	5	11,357	337	10,938-11,776	6,309	187	6,077-6,542	74.9	16.6
Area C Total		11,376	305		6,320	169		100.0	22.2
Grand Total		11,480			6,378				100.0

TABLE II-5
SUMMARY OF DRILL CORE RESULTS - PERCENT MOISTURE
BIG SKY MINE (9)

Identification	No. of Cores	Percent Moisture			Tonnage	
		Mean	Standard Deviation	Confidence Limits @ 95%	% of Area	% of Mine
Area A McKay	64	24.81	1.16	24.52-25.10	26.1	7.4
Area A Rosebud	50	23.80	1.33	23.43-24.18	73.9	21.0
Area A Total		24.06	1.29		100.0	28.4
Area B McKay	36	23.56	1.05	23.20-23.91	24.9	12.3
Area B Rosebud	37	22.66	1.01	22.32-23.00	75.1	37.1
Area B Total		22.88	1.02		100.0	49.4
Area C McKay	0	-	-	-	25.1	5.6
Area C Rosebud	0	-	-	-	74.9	16.6
Area C Total		-	-	-	100.0	22.2
Grand Total		23.31				77.8



BIG SKY MINE
PEABODY COAL COMPANY
ROSEBUD COUNTY, MONTANA

SOURCE: PEABODY COAL COMPANY, JUNE 1977

FIGURE II-3

TABLE II-6
SUMMARY OF DRILL CORE RESULTS - DRY PERCENT ASH
BIG SKY MINE (9)

Identification	No. of Cores	Dry Percent Ash Mean	Standard Deviation	Confidence Limits @ 95%	Tonnage % of Area	% of Mine
Area A McKay	72	10.94	1.25	10.65-11.24	26.1	7.4
Area A Rosebud	110	12.36	1.88	12.01-12.71	73.9	21.0
Area A Total		11.99	1.72		100.0	28.4
Area B McKay	45	11.21	1.16	10.86-11.56	24.9	12.3
Area B Rosebud	49	13.17	1.59	12.72-13.63	75.1	37.1
Area B Total		12.68	1.48		100.0	49.4
Area C McKay	6	10.39	1.14	9.19-11.59	25.1	5.6
Area C Rosebud	5	13.32	2.08	10.73-15.90	74.9	16.6
Area C Total		12.59	1.84		100.0	22.2
Grand Total		12.46				100.0

TABLE II-7
SUMMARY OF DRILL CORE RESULTS - DRY PERCENT SULFUR
BIG SKY MINE (9)

Identification	No. of Cores	Dry Percent Sulfur Mean	Standard Deviation	Confidence Limits @ 95%	Tonnage % of Area	% of Mine
Area A McKay	72	2.14	0.71	1.98-2.31	26.1	7.4
Area A Rosebud	110	1.50	0.41	1.43-1.58	73.9	21.0
Area A Total		1.67	0.49		100.0	28.4
Area B McKay	45	2.03	0.65	1.84-2.23	24.9	12.3
Area B Rosebud	49	1.50	0.42	1.38-1.62	75.1	37.1
Area B Total		1.63	0.47		100.0	49.4
Area C McKay	6	2.21	1.17	0.98-3.43	25.1	5.6
Area C Rosebud	5	1.70	0.28	1.35-2.04	74.9	16.6
Area C Total		1.83	0.50		100.0	22.2
Grand Total		1.69				100.0

TABLE II-8
ESTIMATED AVERAGE COAL ANALYSES - COAL RESERVES
BIG SKY MINE

Parameter	Big Sky Mine Dry	Big Sky Mine "As Received"	Clay Boswell Station Dry	Clay Boswell Station "As Received"
Heating value				
Btu per lb	11,480	8,804	11,480	8,804
kg-cal per kg	6,378	4,891	6,378	4,891
Moisture, %		23.31		23.31
Ash, %	12.46	9.55	12.46	9.55
Sulfur, %	1.69	1.30	1.37	1.05

The Rosebud and McKay coal seams were sampled and analyzed for trace elements and major oxides in the NW¼ NE¼ sec. 27, T1N,R41E at the Big Sky Mine. Channel samples of the Rosebud seam were taken from a face freshly exposed for mining. A channel sample of the upper part of the McKay seam was from an older mine cut which was being filled when the sample was taken. A tipple sample was taken for comparison with the channel samples. Descriptions of the samples and the analytical results are presented in Tables II-9, II-10, and II-11. The samples were taken and analyzed in 1973 during preparation of the Environmental Impact Statement for the Big Sky Mine and are assumed to be representative of coal in sec. 22. These analyses reveal no unusual concentrations of trace elements in the coal when these trace elements analyses are compared with analyses for coal seams in other parts of the Powder River Basin (8). It is anticipated that analyses of trace elements for samples from other portions of the Big Sky Mine could vary substantially when compared with these analyses.

Because the Rosebud and McKay seams are mined separately for substantial periods of time with little blending, the coal received at the Clay Boswell Steam Electric Station, will be essentially coal from either the Rosebud or McKay seam. Thus, the analyses of coal "as received" will vary considerably from the average coal analysis in Table II-8. The possible variation in analyses of coals "as received" at the Clay Boswell Station are presented in Table II-12, with coal shipments within the lower and upper limits specified. The actual variation in Btu per lb, percent ash, and percent sulfur probably will be less than indicated in Table II-12 since these limits are based on Area C where there are only 6 and 5 drill cores for the McKay and Rosebud seams, respectively. It is anticipated that additional drilling in Area C would provide a better estimate of the mean values for Btu, ash, and sulfur content. Although the actual limits for Btu, ash, and sulfur content of the coal "as received" at the Clay Boswell Station are expected to be nearer the average values, these limits cannot be better defined until additional drill core analyses are available. It also is expected that the actual upper limits for moisture could be 1.0 to 1.5% higher than indicated on Table II-12 because of moisture picked up during rail transport, coal handling, and stockpiling. Table II-12 also presents the "as received" design performance coal analysis used to evaluate the performance of steam generators or boilers at the Clay Boswell Station.

TABLE II-9

QUANTITATIVE VALUES FOR 12 TRACE ELEMENTS - ROSEBUD AND McKAY COAL SEAM SAMPLES - BIG SKY MINE (8)

Coal Seam	Sample Description	Sample Interval	Ppm												
			As	Cd	Cu	F	Hg	Li	Pb	Sb	Se	Th	U	Zn	% Ash
Rosebud	Coal	0-6.8 ft (2.07 m) from top of coal	1	<0.1	7.6	105	0.04	12.0	6.0	0.3	0.7	<1.5	0.4	1.9	9.17
	Coal	6.8-12.5 ft (2.07-3.81 m) from top of coal	1	<0.1	6.2	<20	0.03	18.0	5.9	0.3	0.2	1.9	0.6	2.4	9.84
	Coal	12.5-17.5 ft (3.81-5.33 m) from top of coal	1	<0.1	6.5	<20	0.06	13.0	5.0	0.2	0.2	<1.5	0.4	2.6	8.28
	Coal	17.5-22.5 ft (5.33-6.86 m) from top of coal	1	<0.1	8.7	40	0.08	10.0	5.6	0.3	0.8	<1.5	0.5	3.0	10.20
	Coal	22.5-24.6 ft (6.86-7.50 m) from top of coal	1	<0.1	3.6	<20	0.06	3.7	3.0	0.4	0.8	<1.5	0.5	2.0	5.01
	Claystone and coal	24.6-25.1 ft (7.50-7.65 m) from top of coal	2	<0.1	43.0	100	0.05	122.0	36.0	0.5	2.4	4.0	1.5	23.0	51.70
	Coal	25.1-27.6 ft (7.65-8.41 m) from top of coal	2	0.1	7.0	20	0.14	8.9	6.4	0.5	0.8	<1.5	0.8	3.1	9.11
	Coal	Tipple sample of coal shipped	2	<0.1	7.7	60	0.07	14.0	7.5	0.5	0.5	1.5	0.7	5.4	11.50
McKay	Coal	Upper 5.4 ft (1.65 m), slightly weathered	1	<0.1	4.6	70	0.05	6.6	5.4	2.7	0.4	<1.5	0.8	2.5	7.18

NOTE: Values listed for Cd, Cu, Li, Pb, and Zn in coal samples have been recalculated from analyses on ash of coal.

TABLE II-10

SEMI-QUANTITATIVE SPECTROGRAPHIC ANALYSES - ROSEBUD AND McKAY COAL SEAM SAMPLES - BIG SKY MINE (8)

Coal Seam	Sample Description	Sample Interval	Ppm																	
			B	Ba	Be	Co	Cr	Ga	La	Mn	Mo	Nb	Ni	Sc	Sr	Ti	V	Y	Yb	Zr
Rosebud	Coal	0-6.8 ft (2.07 m) from top of coal	70	700	0.70	<0.5	5.0	3	7	50	10.0	<1.0	1.5	1.5	300	300	7	3	0.30	30
	Coal	6.8-12.5 ft (2.07-3.81 m) from top of coal	70	150	<0.15	<0.5	5.0	3	7	70	2.0	2.0	1.5	1.5	200	300	7	3	0.30	20
	Coal	12.5-17.5 ft (3.81-5.33 m) from top of coal	50	150	<0.15	<0.5	5.0	2	5	20	1.5	<1.0	1.0	1.0	70	200	5	2	0.20	15
	Coal	17.5-22.5 ft (5.33-6.86 m) from top of coal	50	150	<0.15	<0.5	3.0	3	<5	30	3.0	<1.0	1.0	1.5	100	300	7	3	0.30	30
	Coal	22.5-24.6 ft (6.86-7.50 m) from top of coal	70	100	0.15	0.5	1.5	3	5	50	5.0	<1.0	1.5	1.0	70	150	5	3	0.15	10
	Claystone and coal	24.6-25.1 ft (7.50-7.65 m) from top of coal	30	70	<0.15	<0.5	15.0	15	<5	70	5.0	<1.0	<3.0	3.0	70	3,000	30	10	1.00	150
	Coal	25.1-27.6 ft (7.65-8.41 m) from top of coal	70	100	0.70	<0.5	2.0	5	7	70	3.0	5.0	1.5	2.0	100	300	7	5	0.30	20
	Coal	Tipple sample of coal shipped	50	500	0.50	1.0	3.0	3	<5	30	7.0	1.5	3.0	1.5	150	300	7	2	0.30	20
McKay	Coal[a]	Upper 5.4 ft (1.65 m), slightly weathered	70	200	1.00	0.5	2.0	2	5	15	0.7	1.0	2.0	1.0	200	150	5	3	0.30	10

[a] Sample also contains 2 ppm Ge.

NOTE: All values listed for coal samples have been recalculated from analyses on ash of coal.

TABLE II-11

MAJOR OXIDE COMPOSITION OF ASH - ROSEBUD AND McKAY COAL SEAM SAMPLES - BIG SKY MINE (8)

Coal Seam	Description	Sample Interval	Percent									
			Ash	SiO_2	Al_2O_3	Na_2O	K_2O	CaO	MgO	P_2O_5	Fe_2O_3	SO_3
Rosebud	Coal	0-6.8 ft (2.07 m) from top of coal	9.17	48	16	0.33	<0.1	9.3	4.60	0.10	1.8	13.0
	Coal	6.8-12.5 ft (2.07-3.81 m) from top of coal	9.84	49	16	0.34	0.5	8.8	3.90	0.18	2.5	12.0
	Coal	12.5-17.5 ft (3.81-5.33 m) from top of coal	8.28	39	15	0.21	0.1	9.7	4.20	0.27	5.0	17.0
	Coal	17.5-22.5 ft (5.33-6.86 m) from top of coal	10.20	45	12	0.21	<0.1	8.3	3.40	0.67	7.7	15.0
	Coal	22.5-24.6 ft (6.86-7.50 m) from top of coal	5.01	22	15	0.42	0.1	13.5	6.00	0.22	5.3	23.0
	Claystone and coal	24.6-25.1 ft (7.50-7.65 m) from top of coal	51.70	37	13	0.10	<0.1	0.5	0.55	<0.05	0.2	0.5
	Coal	25.1-27.6 ft (7.65-8.41 m) from top of coal	9.11	31	21	0.22	0.1	7.5	3.50	<0.05	10.0	15.0
	Coal	Tipple sample of coal shipped	11.50	53	15	0.37	0.8	7.6	3.70	0.26	5.4	12.0
McKay	Coal	Upper 5.4 ft (1.65 m), slightly weathered	7.18	32	18	0.38	<0.1	12.0	5.30	<0.05	6.7	17.0

were in compliance (21). More specifically, the Duluth-Superior AQCR, which consists of Itasca, Koochiching, Aitkin, St. Louis, Carlton, Lake, and Cook counties, was in compliance with the State AAQS for sulfur oxides and nitrogen oxides, but St. Louis County did not comply with the particulate standards. The Duluth-Superior AQCR was not monitored for carbon monoxide or oxidants (21).

Prevention of Significant Deterioration of Air Quality. An additional tier of ambient air quality regulations recently has been added as the result of a Federal court case entitled Sierra Club v. Ruckelshaus (22). In this suit, the Sierra Club challenged those State implementation plans which were not designed to prevent air quality deterioration in regions where the ambient pollutant levels already were below the standards set in the AAQS. The Sierra Club claimed, and the courts agreed, that the Clean Air Act Amendments of 1970 required that clean air be kept clean. Consequently, the EPA promulgated its final Prevention of Significant Air Quality Deterioration (PSD) Standards on December 5, 1974 (23). These standards currently are being reviewed and likely will be changed by Congress and are again being challenged in court by environmentalists and industry (24).

The PSD regulations define 3 classes of areas. In Class III regions, pollution is allowed up to the secondary AAQS presented in Table I-2. This classification may encompass most large urban areas and major industrial regions. The Class II designation, into which the entire country has been placed initially, allows a certain incremental increase in ambient air pollution concentrations above the 1974 baseline concentration. These increments are presented in Table I-2. It should be noted that the PSD regulations currently apply only to sulfur oxides and particulates. Regardless of the 1974 baseline and the allowable increment, Class II areas will not be allowed to exceed the secondary AAQS and presumably will remain much cleaner than Class III areas. The Class II increments were set to allow, for example, one 1,000 MW electric generating facility every 20 to 30 miles (32 to 48 km), depending on the terrain (25).

Class I designated areas are those where virtually no degredation will be tolerated (Table I-2). The Class I increments over the 1974 baseline were set low enough to essentially preclude any major source of pollution (25). Those areas most likely to be designated Class I are National Parks, National Wilderness Areas, and National Monuments.

As mentioned above, the entire country currently has a Class II designation (areas experiencing ambient levels near AAQS probably have a de facto Class III designation). The PSD regulations provide procedures by which Federal land managers, State and local governments, Indian reservation leaders, private citizen groups, and others can petition the EPA for redesignation of their area to Class III or to Class I (26). Reclassification to Class I is, of course, a major land-use decision and usually considers aspects much broader than ambient air quality. The PSD regulations are a unique tool which the EPA has provided to prevent misuse of land and water, deleterious impacts on visual aesthetics, and other impacts which Federal, State, local, and private decision-makers view as socially unacceptable (25). As of April 5, 1977, no areas in the country had been redesignated from Class II, and most state environmental agencies have been reluctant to make use of the PSD procedures (20).

"rejection points" have not been established, this poor quality coal presently is consumed at the Clay Boswell Station.

The present practice is for the coal to be sampled when unloaded at the Clay Boswell Station. The coal usually is burned before being analyzed because it is more efficient to dump the contents of the unit train cars directly into the storage silos for the boilers, rather than placing the coal in the stockpile. MP&L believes that the cost of analyzing the coal at the mine before shipping, and the cost of double handling and disposing of poor quality coal is not justified.

Raw Materials Handling

The Raw Materials Handling section includes descriptions of coal consumption, coal handling, coal transfer, and a brief description of the handling of petroleum fuels and other miscellaneous materials needed for plant operation.

Coal Consumption. Estimated coal consumption in Units 1, 2, and 3 at the Clay Boswell Station is based on the coal having an "as received" heating value of 8,610 Btu per lb (4,783 kg-cal per kg) as presented in Table II-12 and net unit ratings and the estimated plant operating parameters listed in Table II-14. Coal consumption rates using the values in Table II-14 are presented in Table II-15.

Coal Handling. Coal is delivered to the Clay Boswell Station via a rail spur from the Burlington Northern main rail line to the coal unloading track loop. After the front cars have been positioned in the rotary dumper, the engines are detached and moved ahead. The rotary dumper then inverts each car to dump its contents, moving the train along automatically until all the cars have been emptied. Since the rotary dumper unloads the train at the rate of 35 cars (100 tons each) (90.7 mt) per hr, unloading takes about 3 hrs for a 100-car train (12). The train cars remain coupled during this operation. To prevent the coal from freezing in the cars during winter, an electric thawing shed has been installed to heat the car sides and bottoms just prior to unloading.

A schematic diagram of the coal handling system is shown in Figure II-4. The coal is unloaded into 3 under-track hoppers, each of which supplies coal to a 1,400 ton per hour (tph) (1,270 mtph) (12) vibrating feeder which feeds the coal for weighing and subsequent delivery to a transfer point (TP-1). At the transfer point, the coal can be unloaded onto either the conveyor to the active storage silos, or to the stocking-out conveyor. If it cannot be delivered to the active storage silos, it is conveyed to the stocking-out point and dumped on the ground. From here it may be moved later by mobile ground equipment (bulldozer or highloader) to either the active storage pile or the inactive storage pile.

The active storage pile is used to accommodate minor variations between coal consumption and delivery rates. The inactive storage pile is carefully placed and compacted to permit long-term storage to supply the Clay Boswell Station with fuel should a major interruption occur in the coal supply. This storage supply is adequate to fuel Units 1, 2, and 3 during a 90-day interruption.

TABLE II-14
ESTIMATED OPERATING PARAMETERS - UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

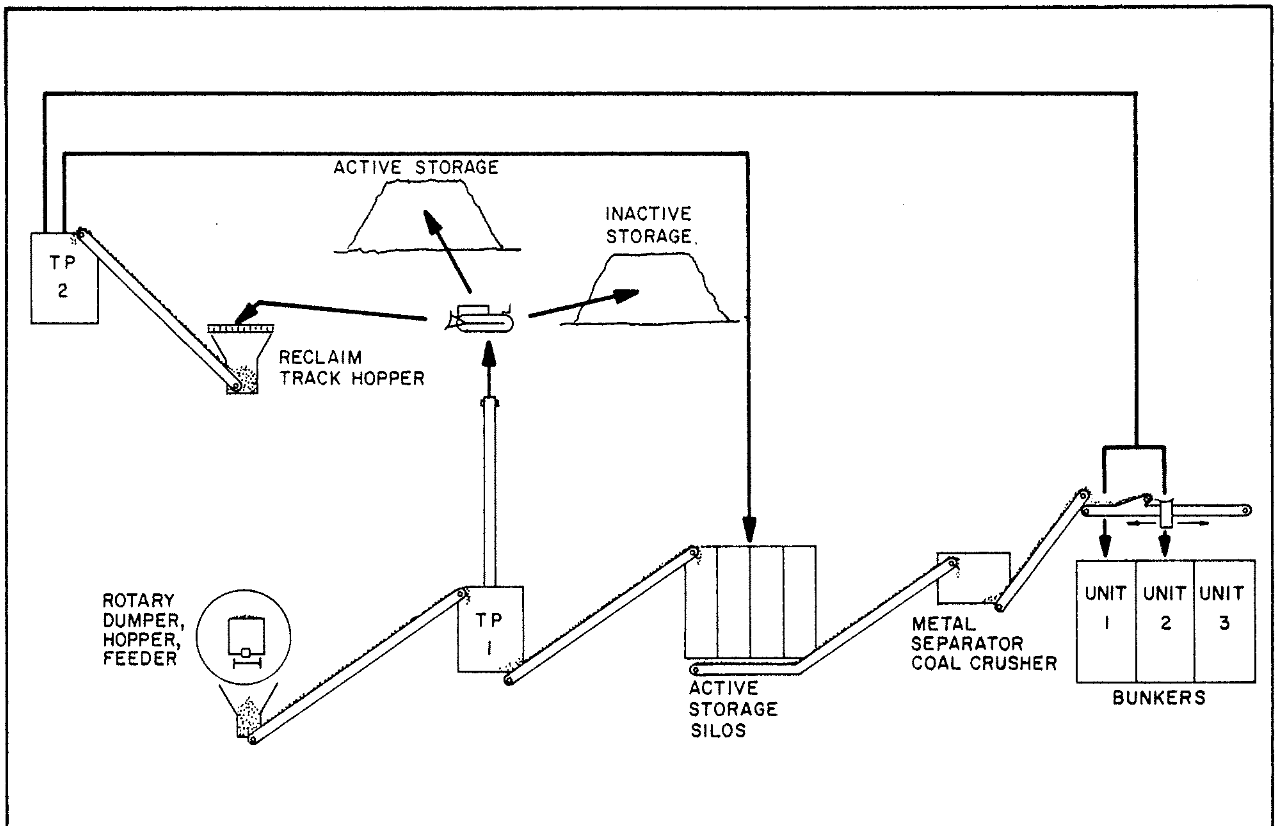
Parameter	Unit 1	Unit 2	Unit 3
Net generating capacity rating, kw	69,000	69,000	350,000
Net heat rate			
Btu per kw	10,250	10,250	10,200
kg-cal per kw	2,587	2,587	2,574
Estimated capacity factor			
percent until 1980	65.0	60.0	77.3
percent over remaining life	41.3	33.3	77.3
Retirement date			
year	1999	1999	2008

TABLE II-15
ESTIMATED COAL CONSUMPTION RATES - UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

Estimated Coal Consumption	Unit 1	Unit 2	Unit 3	Total
Average hourly				
tons	26.7	24.6	160.3	211.6
metric tons	24.2	22.4	145.4	192.0
Maximum hourly				
tons	41.1	41.1	207.3	289.5
metric tons	37.3	37.3	188.0	262.6
Average annual				
tons	233,857	215,869	1,403,843	1,853,569
metric tons	212,152	195,833	1,273,545	1,681,530
Maximum annual[a]				
tons	359,782	359,782	1,816,097	2,535,661
metric tons	326,389	326,389	1,647,535	2,300,313
Total[b]				
tons	3,907,232	3.259,625	44,922,976	52,089,833
metric tons	3,544,581	2,957,082	40,753,438	47,255,101

a Based on 100% capacity factor.

b For total coal consumption, capacity factors used for Units 1, 2, and 3 are in accordance with estimated capacity factors in Table II-14.



COAL HANDLING FACILITIES

CLAY BOSWELL STEAM ELECTRIC STATION

FIGURE II-4

Coal can be moved from either storage pile to a railroad track hopper by mobile ground equipment. This track hopper is the initial feed point for the 800 tph (726 mtph) reclaim system (12). This reclaim system can deliver the coal either to the active storage silos or to the bunkers for Units 1, 2, and 3 as shown in Figure II-4.

From the active storage silos the coal is delivered by conveyor to the processing building, where tramp iron is removed magnetically. The coal is crushed, sampled, and then moved by inclined belt conveyor to the coal storage bunker conveyor, which distributes it to the individual bunkers.

From the individual bunkers, coal is withdrawn by feeders and dumped into pulverizers. The pulverizers grind the coal fine enough for it to be carried in suspension in the primary combustion air supplied to the furnace of the steam generator or boiler.

Coal Reloading for Transfer to Other Stations. As mentioned previously, coal is delivered by unit train to the Clay Boswell Station and then a portion of the delivered coal is transferred to MP&L's Laskin Station. This transfer is completed by dumping the coal from the stocking-out conveyor onto the active storage pile, where it is then picked up by a front-end loader and loaded into waiting railroad cars for transfer to the Laskin Station.

Chemicals and Supplies. Chemicals are used for various purposes in the Clay Boswell Station's water systems. Acid is added to the Unit 3 circulating water system for pH control; an oxygen scavenger such as hydrazine is added to the boiler feedwater system for corrosion control; sulfites and phosphates are added to the boiler feed water system for scale control; and chlorine is added to circulating systems to prevent biological fouling.

Chemicals normally are delivered to the Station in trucks. Acid is delivered by bulk tank truck and stored in an above-ground tank. Compressed chlorine gas is delivered in bottles and the dry chemicals are delivered in bags.

Supplies such as maintenance parts, lubricants, compressed gases (hydrogen for generator cooling, carbon dioxide for generator purging, acetylene and oxygen for maintenance work), personnel supplies, tools, etc., normally are delivered by truck, although large items may arrive by train.

Petroleum Fuels. At the Clay Boswell Station, fuel oil is required for coal ignition in each of the steam generators. A single 200,000 gallon (757,061 liter) (13) tank provides storage for No. 2 fuel oil used for Units 1, 2, and 3. In addition, a single 20,300 gallon (76,842 liter) (13) tank provides storage for diesel fuel used for coal handling equipment, and a single 25,000 gallon (94,633 liter) (13) buried tank provides storage for heating oil used for coal silos. Diesel fuel is required to power the emergency generating units and large mobile ground equipment. Gasoline is required for maintenance and personnel vehicles. These fuels are brought to the Clay Boswell Station by bulk tank truck and stored in tanks.

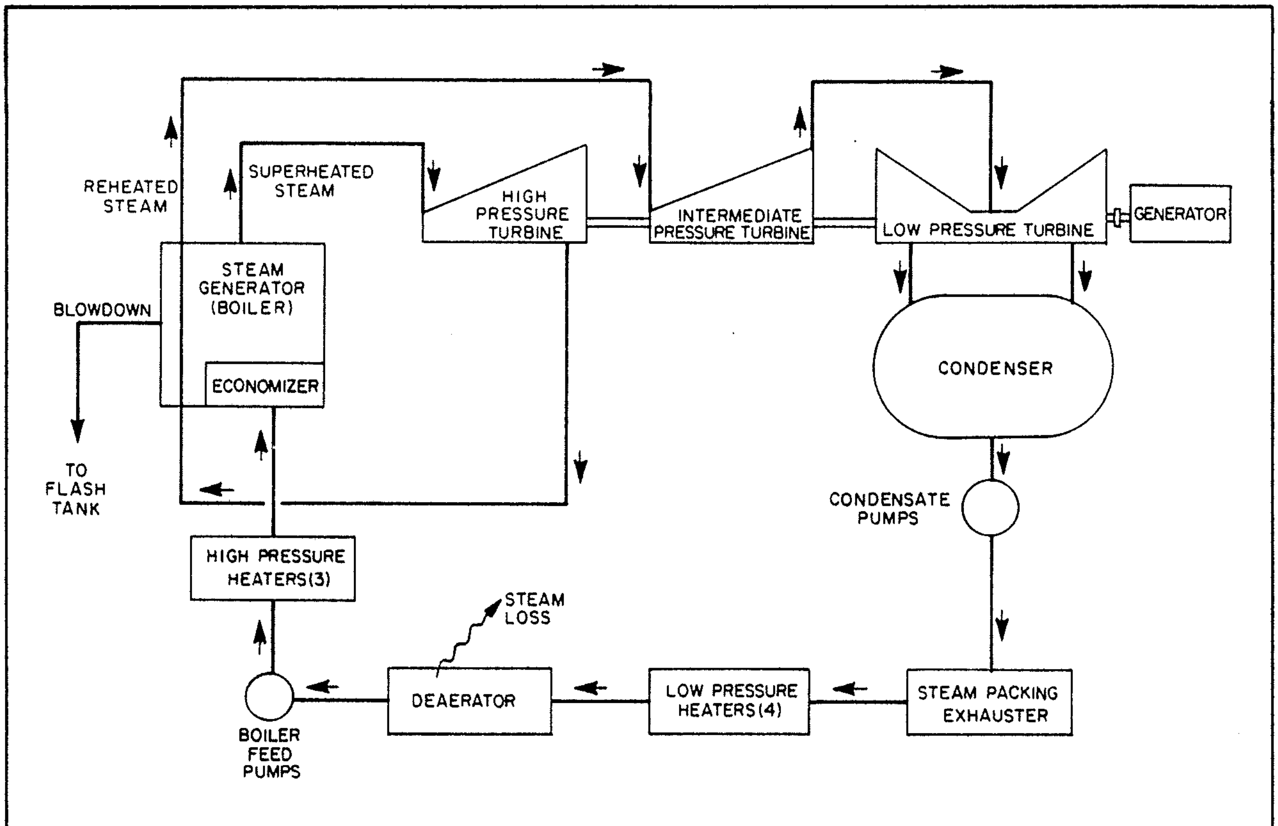
Facilities Operation

The major components of the Clay Boswell Steam Electric Station's Units 1, 2, and 3 are described in this section. Figure II-5 schematically illustrates the thermodynamic cycle and major components of a typical modern coal-fired steam electric power facility.

Power Generation Cycle

Steam Generators. The steam generators or boilers for Units 1 and 2 are outdoor, water-cooled furnace, single-drum units of the dry bottom type utilizing pulverized coal-firing. These boilers are designed to produce 500,000 pounds (13) (226,796 kilograms) (kg) of steam per hour at 1,465 pounds per square inch gage (psig) (101 bars) (b) and a superheater outlet temperature of 1,005°F (541°C), and to reheat the steam to 1,005°F (541°C) when it is returned to the steam generator after partial expansion through the turbine (14).

The steam generator or boiler for Unit 3 is an indoor, water-cooled furnace, single-drum unit. It uses pulverized coal-firing and is a dry bottom unit. This generator is designed to produce 2,472,000 pounds (1,121,280 kg) of



TYPICAL STEAM CYCLE
COAL-FIRED STEAM ELECTRIC GENERATING STATION

SOURCE: ADAPTED FROM MP&L "ENVIRONMENTAL REPORT", EXHIBIT II-A-9

FIGURE II-5

steam per hour at 2,520 psig (174 b) and 1,005°F (541°C) superheat/1,005°F (541°C) reheat temperature (14).

Steam Turbine-Generators. The steam turbine-generators for Units 1 and 2 are outdoors. The turbines are tandem compound with two exhaust sections having a maximum gross output of 75,000 kw (15). Each unit's turbine is designed to only receive steam from their respective steam generating units.

The Unit 3 steam turbine-generator is indoors. The turbine is a tandem compound, two-flow unit having a gross capacity of 369,000 kw and is designed to utilize only the steam generated by the Unit 3 steam generator (15).

Condenser and Circulating Water Systems. The steam surface condensers for Units 1 and 2 are single-shell, single-pass units in which the circulating water flows through the condenser only one time (once-through cooling water system). The condensers are sized at 30,000 sq ft (2,787 sq m) of surface area to maintain 1.5 in. (38.1 mm) mercury (Hg) absolute (abs) when receiving 335 x 10^6 Btu (84.5 x 10^6 kg-cal) per hr (16). The design circulating water flow rate is 54,000 gallons per minute (gpm) (204,407 liters per minute) (lpm) with a temperature rise of 12.5°F (6.9°C) in traversing the condenser.

The Unit 3 steam surface condenser is a single-shell, two-pass condenser in which the circulating water traverses the condenser once and then is returned from the opposite end through a different section of tubes. This condenser has a surface area of 147,000 sq ft (13,657 sq m) and is designed to maintain 3.5 in. (88.9 mm) Hg abs turbine exhaust pressure when receiving 1,596 x 10^6 Btu (403 x 10^6 kg-cal) per hr (16). The condenser is designed to maintain this pressure by utilizing a circulating water flow of 110,000 gpm (416,384 lpm) with a circulating water temperature rise of 29.0°F (16°C).

Unit 3 uses a recirculating cooling water system which employs a mechanical-draft cooling tower to cool the recirculating cooling water before it is pumped back to the condenser. The circulating water then passes through the condenser and returns to the cooling tower. Cooling in the tower results from evaporation and convection as air is moved through the tower by motor-driven fans. After cooling, the water again is pumped back to the condenser. The principal design conditions for the Unit 3 cooling tower are presented in Table II-16.

TABLE II-16
PRINCIPAL DESIGN CONDITIONS - UNIT 3 COOLING TOWER
CLAY BOSWELL STEAM ELECTRIC STATION (17)

Design Parameter	Design Condition
Water flow rate	
gpm	110,000
lpm	416,384
Heat rejection rate	
Btu per hr	1.7 x 10^9
kg-cal per hr	0.43 x 10^9
Dry bulb temperature	
°F	82.0
°C	27.8
Wet bulb temperature	
°F	71.0
°C	21.7
Approach to wet bulb temperature	
°F	14.0
°C	7.7
Range (warm water temperature less cold water temperature)	
°F	29.0
°C	16.1

Water Systems

Intake System. A common water intake structure for all 3 existing units is located on Blackwater Lake. Originally, this intake structure was designed for the once-through circulating water system for Units 1 and 2. When Unit 3 was constructed, the intake house was modified to accommodate the additional pumps for the Unit 3 service water system and for the makeup water requirements of the Unit 3 recirculating cooling water system. Figure II-6 illustrates the existing intake system.

The intake structure is of conventional design with its invert set at an elevation of 1235.5 ft (377 meters) (m) mean sea level (MSL). The structure contains 2 bays with a combination of pumps for the 3 units. Each bay contains stop log guides, an inclined trash rack, and a traveling screen. The breakdown of pumps for each bay is as follows (18):

Bay 1

o Unit 1 circulating water	- 2 pumps @ 27,000 gpm (102,203 lpm)
o Units 1 and 2 ash sluice	- 1 pump @ 2,000 gpm (7,571 lpm)
o Units 1 and 2 ash sluice	- 1 pump @ 1,600 gpm (6,056 lpm)
o Units 1, 2, and 3 fire pump	- 1 pump @ 1,700 gpm (6,435 lpm)

Bay 2

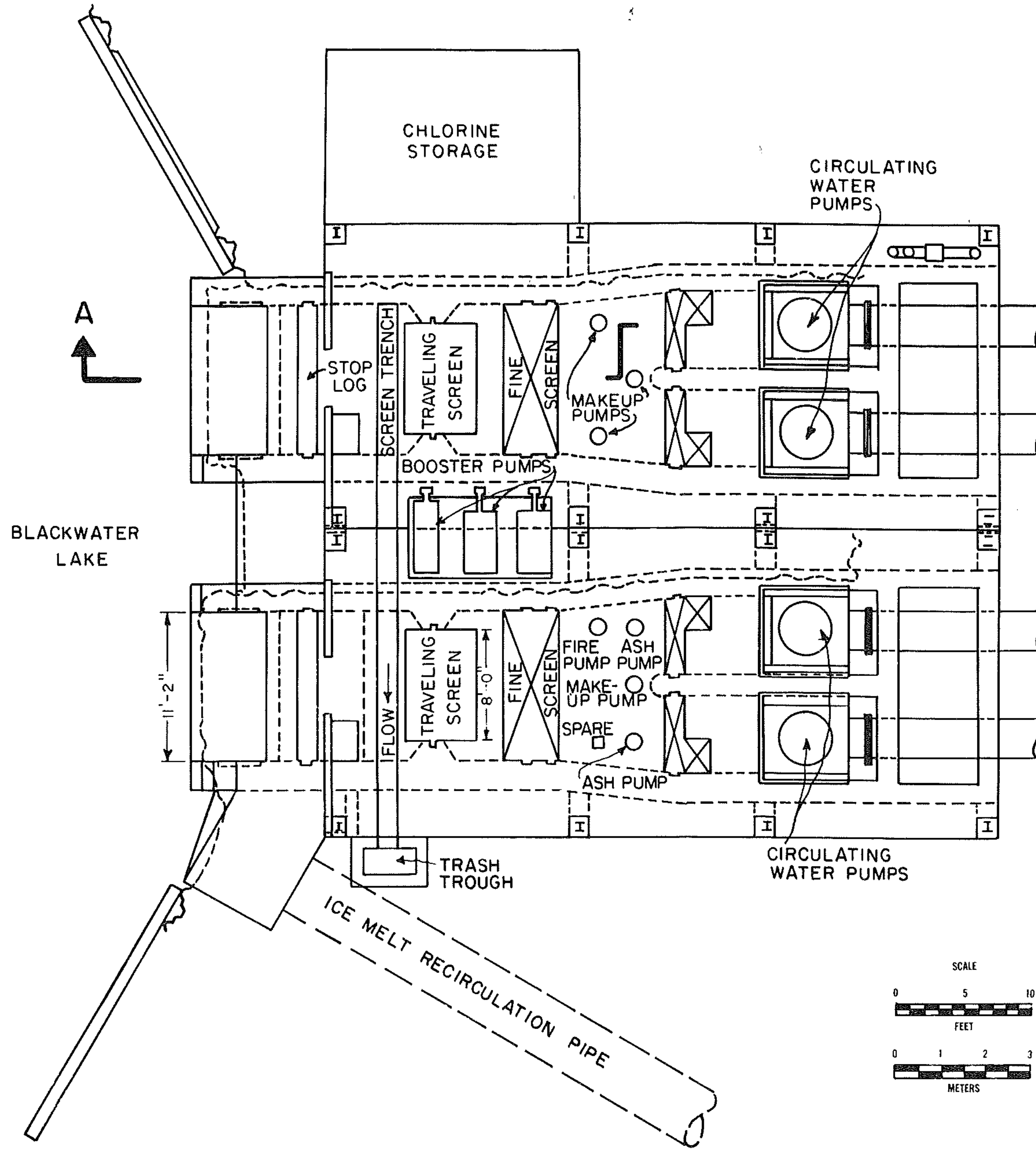
o Unit 2 circulating water	- 2 pumps @ 27,000 gpm (102,203 lpm)
o Unit 3 service & makeup water	- 4 pumps @ 3,800 gpm (14,384 lpm)

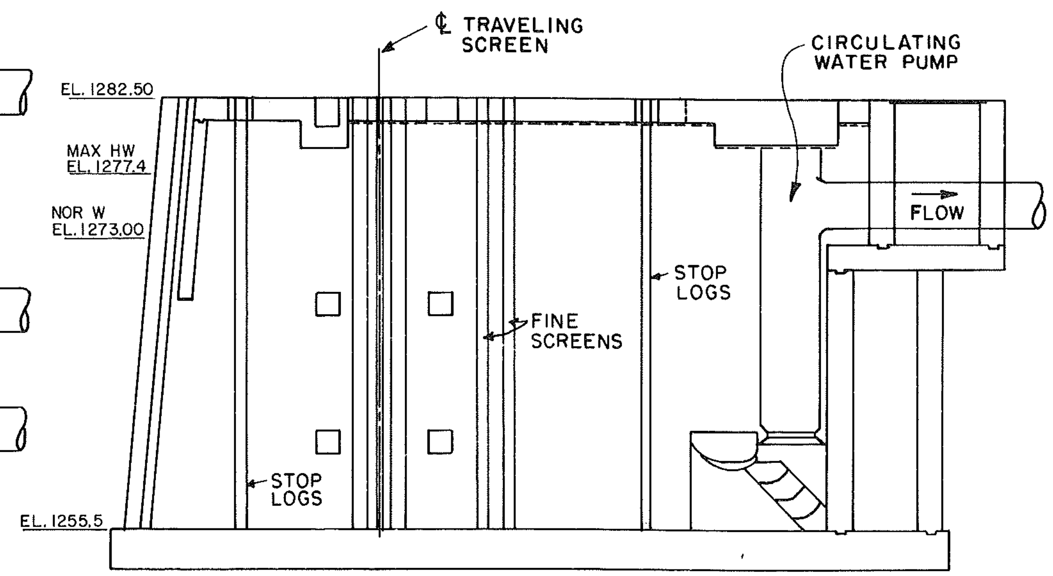
Three booster pumps are included in the intake structure: two for makeup water for Unit 3 and one for the fire pumps. Water for the booster pumps is taken from both bays.

To avoid icing in the winter, warmer condenser cooling water from Units 1 and 2 is recirculated to the area in front of the intake structure. Based on observation of the Units 1 and 2 condenser cooling water temperature at the condenser inlet, this recirculation is adjusted to achieve an approximate intake temperature of 40 to 45°F (4.44 to 7.22°C) (19).

Traveling screens are backwashed periodically to remove accumulated debris including fish which have been impinged on the screens. Material washed from the screens is collected in a trash basket and dumped into a "dumpster" for removal by a licensed scavenger service to the county landfill (19).

Condenser Cooling Water Systems. The steam condensers for Units 1 and 2 as previously described, utilize once-through cooling water which is withdrawn from Blackwater Lake and discharged into an embayment flowing into the Mississippi River. Normal maximum operation requires withdrawal of approximately 115,000 gpm (435,310 lpm) of water from Blackwater Lake, of which 108,000 gpm (408,813 lpm) is required for condenser cooling. The condenser cooling water is included in the water balance for Units 1, 2, and 3 presented in Figure II-7.

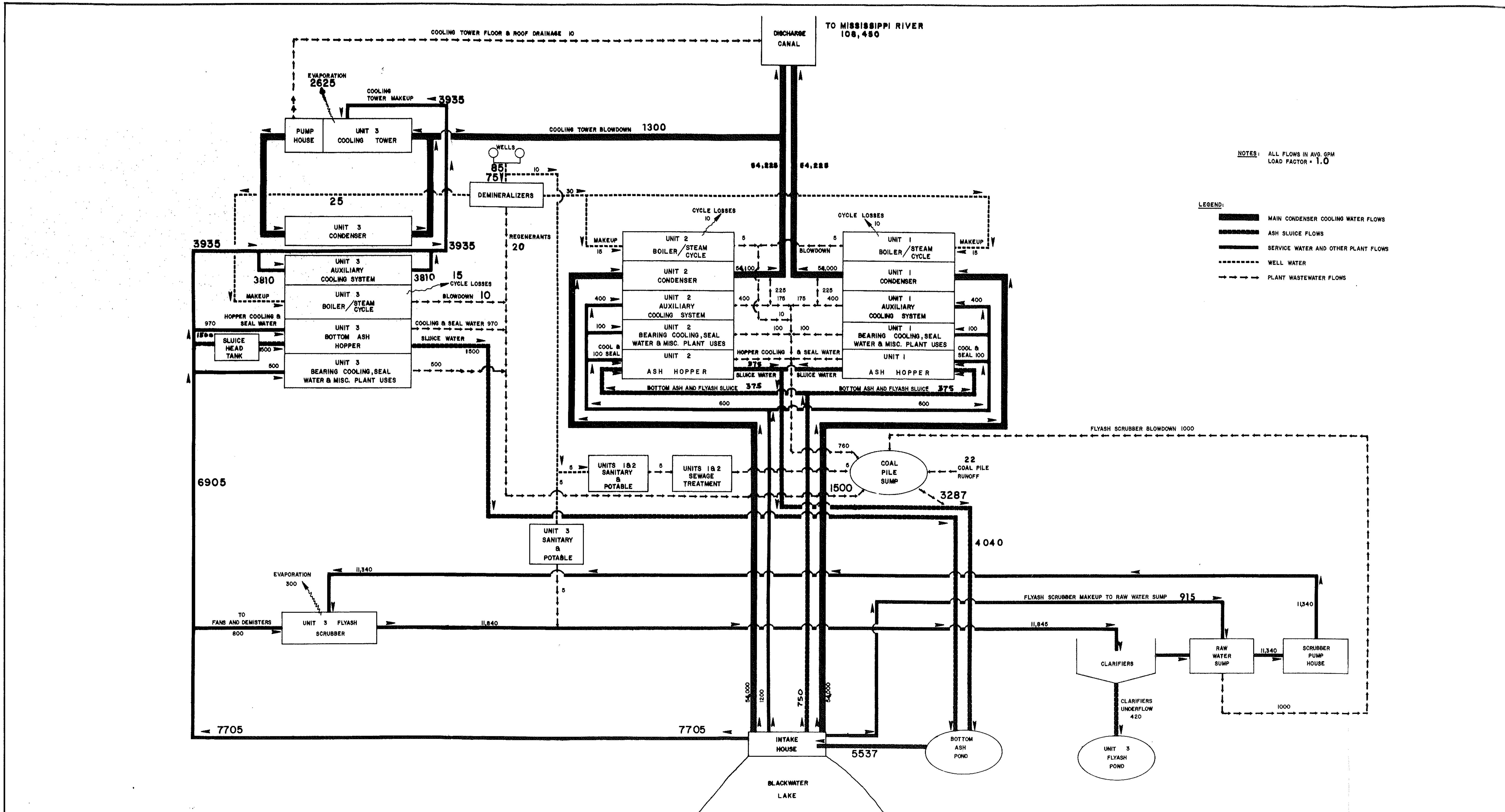


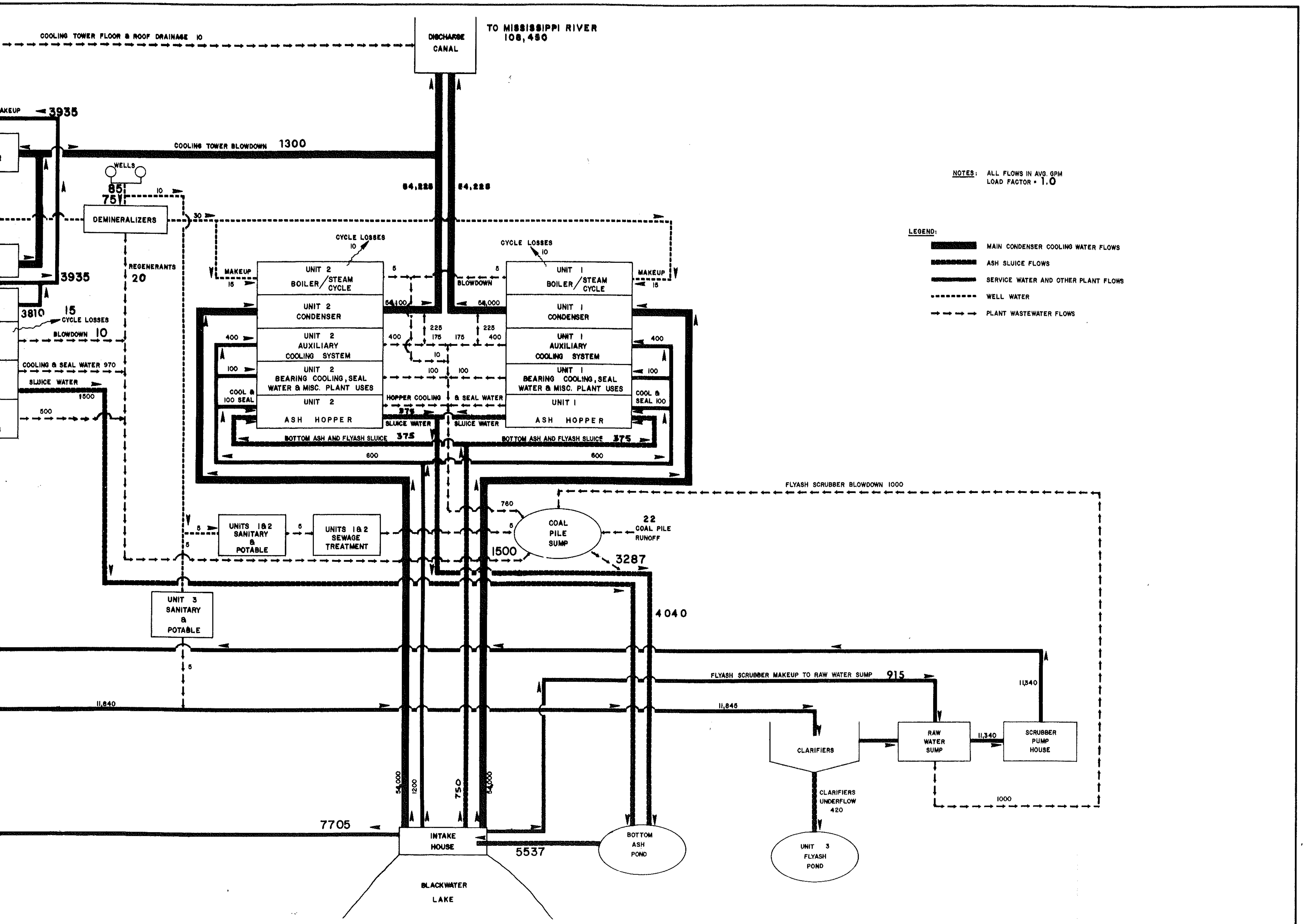


SECTION A-A

INTAKE STRUCTURES
UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

FIGURE II-6


COOLING TOWER FLOOR & ROOF DRAINAGE 10
DISCHARGE CANAL
TO MISSISSIPPI RIVER 108,480
EVAPORATION 2625
COOLING TOWER MAKEUP 3935
PUMP HOUSE
UNIT 3 COOLING TOWER
COOLING TOWER BLOWDOWN 1300
WELLS
DEMINERALIZERS
REGENERANTS 20
UNIT 3 CONDENSER
UNIT 3 AUXILIARY COOLING SYSTEM
UNIT 3 BOILER/STEAM CYCLE
CYCLE LOSSES
BLOWDOWN 10
HOPPER COOLING & SEAL WATER
COOLING & SEAL WATER 970
UNIT 3 BOTTOM ASH HOPPER
SLUICE WATER
SLUICE HEAD TANK
UNIT 3 BEARING COOLING, SEAL WATER & MISC. PLANT USES
MAKEUP
UNIT 2 BOILER/STEAM CYCLE
UNIT 2 CONDENSER
UNIT 2 AUXILIARY COOLING SYSTEM
UNIT 2 BEARING COOLING, SEAL WATER & MISC. PLANT USES
UNIT 2 ASH HOPPER
UNIT 1 BOILER/STEAM CYCLE
UNIT 1 CONDENSER
UNIT 1 AUXILIARY COOLING SYSTEM
UNIT 1 BEARING COOLING, SEAL WATER & MISC. PLANT USES
UNIT 1 ASH HOPPER
HOPPER COOLING & SEAL WATER
SLUICE WATER
BOTTOM ASH AND FLYASH SLUICE 375
FLYASH SCRUBBER BLOWDOWN 1000
UNITS 1&2 SANITARY & POTABLE
UNITS 1&2 SEWAGE TREATMENT
COAL PILE SUMP
22 COAL PILE RUNOFF
6905
3287
4040
UNIT 3 SANITARY & POTABLE
EVAPORATION 300
TO FANS AND DEMISTERS 800
UNIT 3 FLYASH SCRUBBER
FLYASH SCRUBBER MAKEUP TO RAW WATER SUMP 915
CLARIFIERS
RAW WATER SUMP
SCRUBBER PUMP HOUSE
CLARIFIERS UNDERFLOW 420
UNIT 3 FLYASH POND
BOTTOM ASH POND
7705
INTAKE HOUSE
5537
BLACKWATER LAKE
NOTES: ALL FLOWS IN AVG. GPM
LOAD FACTOR = 1.0
LEGEND:
MAIN CONDENSER COOLING WATER FLOWS
ASH SLUICE FLOWS
SERVICE WATER AND OTHER PLANT FLOWS
WELL WATER
PLANT WASTEWATER FLOWS



WATER BALANCE
UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L "ENVIRONMENTAL REPORT", EXHIBIT II-A-11

FIGURE II-7

Normal warm-weather operation (April to November) requires the use of 2 circulating water pumps per unit (54,000 gpm per unit) (204,407 lpm per unit). During cold weather (December through March), only one circulating water pump per unit (27,000 gpm per unit) (102,203 lpm per unit) is used. Assuming operation at maximum capacity, the resulting temperature rises are 12.5°F (6.9°C) during the warm months, and 25°F (14°C) during the cold months.

Chlorine is added to the circulating water to prevent biological fouling of the condenser tubes. During summer operation, with all circulating water pumps operating, chlorine is added at an average rate of abour 75 lb (34 kg) per hr for a duration of about 20 min per unit per shift. Currently, in winter, the circulating water flow is halved, and the addition of chlorine is reduced to an average rate of 8.3 lb (3.8 kg) per hr for a duration of 30 min per unit per day. This results in a total usage for Units 1 and 2 of 150 lb (68 kg) per day during the summer and 8.3 lb (3.8 kg) per day during the winter. A recently completed chlorine optimization study indicates that winter operation under the above-described conditions will be in compliance with the 0.2 mg per liter total residual chlorine limitation in the National Pollutant Discharge Elimination System (NPDES) permit (20). For summer operation, optimization is yet to be completed. Data are not available for summer chlorine concentrations.

Unit 3 utilizes a recirculating cooling water system. Cooling water circulates from the Unit 3 steam condenser to the Unit 3 cooling tower. The heat added by the steam condenser is vented to the atmosphere through evaporation and heat transfer to the air in the cooling tower. Makeup water, required to replenish water lost by evaporation, drift, blowdown, or leakage, is added to the system at the cooling towers. This water is supplied from the Unit 3 auxiliary cooling system and service water system. Blowdown is the intermittent or continuous wasting of a small amount of water from a closed loop water system to prevent an increase in concentration of solids in the water due to evaporation. Blowdown leaves the system from the hot side (side nearest the condenser) of the cooling tower at the return water box and is combined with Unit 2 condenser cooling water prior to being discharged into the discharge canal for Units 1, 2, and 3 as shown in Figure II-7. Normal condenser cooling water flow rate is approximately 110,000 gpm (416,384 lpm) with a 29°F (16°C) temperature rise in the condenser, assuming operation at maximum capacity.

A mechanical-draft cross-flow cooling tower is provided for Unit 3. The tower includes a concrete basin and circulating water pump chamber (both below ground level), piping to and from the condenser, tower superstructure with fans and stacks, and water treatment section. Also, fine screens and provisions for stop logs are provided at the pump chamber, which is connected to the north side of the cooling tower basin. Two horizontal circulating water pumps are utilized and a monorail is provided for maintenance. The tower is located approximately 1,200 ft (366 m) east of the main power generating facilities. Its longitudinal axis lies in the north-south direction.

Average annual evaporation rate from the cooling tower with operation at maximum capacity is 2,625 gpm (9,936 lpm), and the maximum daily evaporation rate is about 3,600 gpm (13,627 lpm). Table II-17 details monthly average evaporation and blowdown quantities.

TABLE II-17
MONTHLY AVERAGE EVAPORATION AND BLOWDOWN QUANTITIES
UNIT 3 COOLING TOWER - CLAY BOSWELL STEAM ELECTRIC STATION (21)

Month	Evaporation		Blowdown	
	gpm	lpm	gpm	lpm
January	1,715	6,492	430	1,628
February	1,587	6,007	397	1,503
March	1,914	7,245	480	1,817
April	2,087	7,900	522	1,976
May	2,387	9,036	597	2,260
June	2,566	9,713	642	2,430
July	2,848	10,659	712	2,695
August	2,816	10,659	704	2,665
September	2,464	9,327	616	2,332
October	2,323	8,793	581	2,199
November	1,946	7,366	486	1,840
December	1,773	6,711	443	1,677

Makeup water supply is controlled by a mechanism which is triggered when the water in the cooling tower basin reaches a certain level. Measuring the conductivity of water at the Unit 3 condenser discharge determines the quantity of blowdown needed in the system. Currently, the tower is operating at approximately 2 to 3 cycles of concentrations, although the tower design allows for 5 cycles (22). Average annual and maximum makeup and blowdown rates at full load with 3 cycles of concentration are presented in Table II-18.

TABLE II-18
AVERAGE ANNUAL AND MAXIMUM MAKEUP AND BLOWDOWN RATES
UNIT 3 COOLING TOWER
CLAY BOSWELL STEAM ELECTRIC STATION (23)

	Makeup		Blowdown	
	gpm	lpm	gpm	lpm
Average	3,900	14,800	1,300	4,900
Maximum	5,400	20,400	1,800	6,800

Chlorine is added to the Unit 3 main condenser cooling system to prevent biological fouling. Hydrochloric acid is added for pH (and, therefore, scale) control. Hydrochloric acid is used instead of the commonly used sulfuric acid to minimize the discharge of sulfate from the plant. Both chemicals are fed at the suction side of the circulating water pumps in the cooling tower pump house. Chlorination takes place once each shift for 20 min at the approximate rate of 170 lb (77 kg) per hour, resulting in utilization of approximately 170 lb (77 kg) per day of chlorine. The blowdown is discharged to the Unit 2 seal well and mixes with the Units 1 and 2 circulating water discharge to the Mississippi River. This discharge is in compliance with the State and Federal chlorine limitations. After chlorine feeding, the concentration in the tower basin slowly decreases over time due to loss of chlorine in the blowdown, volatilization of chloramines, photo decay, and reaction with chlorine-demanding substances in the circulating water system. To insure that no scaling takes place, hydrochloric acid is fed into the system on demand to maintain a makeup water pH of about 7.7. Approximately 7,000 to 8,000 lb (3,175 to 3,629 kg) per day of 22° Baumé (Be) hydrochloric acid is utilized for this purpose. The average Unit 3 recirculating water quality, and, therefore, blowdown quality are presented in Table II-19. These values are based upon more than 200 observations between April 8, 1974 and June 10, 1975.

TABLE II-19
AVERAGE RECIRCULATION WATER AND BLOWDOWN QUALITY
UNIT 3 CONDENSER COOLING SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION (24)

Parameter	
pH	7.85
Conductivity, microhms	756.0
Total alkalinity, mg per liter $CaCO_3$	90
Calcium hardness, mg per liter $CaCO_3$	210
Carbon dioxide, mg per liter	1.9
Langelier Saturation Index (LSI)[a]	+ 0.34

[a] The LSI is a mathematical computation of the pH at which water is saturated with calcium carbonate. Positive LSI values result in a tendency toward carbonate scaling. Negative LSI values result in a tendency towards corrosion. An LSI value of zero indicates the saturation point at which the chemistry is in equilibrium and which, in practice, is impossible to maintain.

About twice each year, during a unit outage, the cooling system is drained and the tower basin cleaned. Cleaning consists of mechanically collecting and removing the sediment, which is disposed of in the fly ash reclamation area west of the electric generating facilities (25).

Boiler Water Systems. Groundwater from 194 ft (59 m) wells is demineralized for boiler makeup for units 1, 2, and 3. Water is withdrawn from these wells at an average rate of 75 gpm (284 lpm) when all generating units are operating at maximum capacity. The existing wells are capable of supplying the maximum continuous capacity - 270 gpm (1,022 lpm) - of the demineralizer system and the plant potable water system. The demineralized water is stored in any of 3 condensate storage tanks, from which it is withdrawn for boiler makeup and as rinse and dilution water for the demineralizers.

The demineralizer system consists of 2 trains or 2 parallel sets of 3 tanks each with separate tanks for cation, anion, and mixed resin beds. There is no pre-demineralizer filtration system. The maximum continuous production capacity of the demineralizer system is 270 gpm (1,022 lpm). On the average, with all 3 units operating at full capacity, the requirement for demineralized water is about 65 gpm (246 lpm), with 45 gpm (170 lpm) being used as boiler makeup and 20 gpm (76 lpm) being used for dilution rinse water in the demineralizer regeneration process. Approximately 135,000 gallons (511,016 liters) of demineralized water are produced between regenerative cycles. Forty thousand gallons (151,412 liters) of this demineralized water are used in each regeneration. The cation and anion resin beds are regenerated with hydrochloric acid and sodium hydroxide, respectively. The mixed resin bed is regenerated following a resin separation based on relative buoyancy. Regenerative wastewater is discharged at the equivalent of an approximate 20 gpm (76 lpm) continuous discharge. Approximate daily discharge loading quantities for various constituents in the regeneration wastewater are presented in Table II-20.

TABLE II-20
APPROXIMATE DAILY DISCHARGE LOADING QUANTITIES FOR
VARIOUS CONSTITUENTS - UNITS 1, 2, AND 3
REGENERATIVE WASTEWATER - CLAY BOSWELL STEAM ELECTRIC STATION (26)

Parameter	Discharge Loading lb per day	kg per day
Calcium ($CaCO_3$)	250.0	113.0
Magnesium ($CaCO_3$)	130.0	59.0
Sodium + Potassium	998.0	453.0
Chloride	421.0	645.0
Sulfate	19.0	8.6
Iron	0.3	0.1

The large concentration of chloride, with respect to calcium, results from particulate (organic and iron) fouling of the cation beds. This results in relatively large hydrochloric acid requirements for the cation beds when compared to the sodium hydroxide requirements for the anion beds. Demineralizer regeneration wastes flow via the coal pile sump to the bottom ash pond.

Once demineralized water is introduced into the boiler-water/steam/condensate system of one of the three boilers, it may leave the system as vented steam (from the deaerator or other small miscellaneous losses) or as boiler blowdown. Contaminants tend to build up in the boiler water due to the concentrating effects of steam losses and the continuous, unavoidable attrition of metal surfaces within the boiler-water/steam/condensate cycle. Sodium phosphates are added to the boiler water for pH control and scale inhibition. Ammonia and hydrazine are added to the feedwater and/or condensate for pH control and dissolved oxygen scavenging, respectively. Hydrazine decomposes to ammonia as it reaches the boiler.

Continuous blowdown of boiler water is necessary to prevent buildup of contaminants. Of special concern is silica, which above certain concentrations is steam-soluble and forms deposits on turbine blades. This blowdown, which includes steam losses, removes approximately 55 gpm (170 lpm) from all 3 boilers. Chemical characteristics of the boiler water for Units 1, 2, and 3 are presented in Table II-21.

TABLE II-21
CHEMICAL CHARACTERISTICS
UNITS 1, 2, AND 3 BOILER WATER
CLAY BOSWELL STEAM ELECTRIC STATION (27)

Parameter		
pH	Units 1 and 2	8.8 - 10.5
	Unit 3	8.7 - 9.2
Ammonia (NH_3), mg per liter		0.1
Phosphorus (P), mg per liter		7.0[a]
Silica, mg per liter		0.1
Sodium		Trace

[a] Phosphates used only in Units 1 and 2.

Liquid boiler blowdown also should have the composition presented in Table II-21, except that as boiler water is released to the atmosphere, approximately one-half of it immediately flashes to steam. Thus, the concentrations of the last 4 parameters are roughly doubled in the liquid boiler blowdown. Boiler blowdown is routed to the bottom ash pond via the coal pile sump.

Bottom Ash Handling Systems. Approximately 15 to 20% of the total coal ash resulting from combustion in the existing units is bottom ash. Water is used to sluice this ash from the bottom of the boilers to the bottom ash pond. Quantities of bottom ash produced and characteristics of pond effluent are discussed in the section on solid waste disposal systems. Information on characteristics of bottom ash sluice water entering the ash pond is not available.

Fly Ash Handling System. The remaining 80 to 85% of the ash produced is fly ash, of which the majority is collected by air emission control equipment. The fly ash handling method depends upon the type of emission control equipment employed. In the past, both Units 1 and 2, used mechanical cyclone-type collectors to remove fly ash. Now these 2 units are being converted to baghouse (fabric filter) collectors. In either type of system, particulates removed from the stack gases fall into a hopper from which they are removed by a dry vacuum system. The fly ash then is sluiced to the Unit 3 bottom ash pond.

Auxiliary Cooling Water System. Various equipment components in the electric generating facility require cooling water to maintain proper operating temperatures. Typical cooling water uses are for turbine lubrication oil coolers, hydrogen coolers, boiler feed pump lubrication oil coolers, and coal pulverizer coolers. Chlorine is the only chemical introduced into the auxiliary cooling water system. It is added at the intake structure on an intermittent basis during chlorination of the main condenser cooling water for Units 1 and 2. Since Units 1, 2, and 3 auxiliary cooling water systems are supplied by the same intake structure, chlorination occurs simultaneously for all units (28). It should be noted that any erosion and corrosion of the auxiliary cooling water system will introduce trace quantities of materials to the water system.

Units 1 and 2 auxiliary cooling water requirements are approximately 800 gpm (3,028 lpm). Approximately 350 gpm (1,325 lpm) are discharged to the coal pile sump after use. The remaining 450 gpm (1,703 lpm), which are used for boiler feed pump cooling, flow to the discharge canal. Unit 3 auxiliary cooling water uses 3,000 to 3,500 gpm (11,356 to 13,249 lpm), and flows to the Unit 3 cooling tower basin as makeup water after use.

Service Water Systems. Service water systems supply all miscellaneous water needs for operation of the electric generating facility. These requirements include the auxiliary cooling water system which has been described previously, bottom ash hopper cooling water and seal water, floor washes, and any other minor plant needs.

Service water requirements for Units 1 and 2 are 1,200 gpm (4,542 lpm), of which 800 gpm (3,028 lpm) flow to the auxiliary cooling systems previously described. The remaining 400 gpm (1,514 lpm) are used for miscellaneous needs and drained to the coal pile sump from which they are pumped along with other inflows to the bottom ash pond (29).

Service water requirements for Unit 3 are 1,470 gpm (5,564 lpm). This consists of 970 gpm (3,672 lpm) for ash hopper cooling and seal water and 500 gpm (1,893 lpm) for bearing cooling, seal water, and miscellaneous needs. Total service water flows to the coal pile sump (30).

Cooling waters most likely contain little contamination except for chlorine added for biological control. Miscellaneous washes contain suspended material such as coal and ash dust. These wastes are pumped to the ash ponds.

Potable Water and Sanitary Systems. Existing wells located on the Clay Boswell Station's site provide potable water. For domestic use, Units 1 and 2 require a total of about 5 gpm (19 lpm), and Unit 3 requires another 5 gpm (19 lpm). This water is chlorinated prior to use. Wastes from the potable water system for Units 1 and 2 flow to a septic tank which overflows to the coal pile sump. Wastes from the Unit 3 potable water system flow to a holding tank, from which they are pumped to the Unit 3 fly ash scrubber flume which flows to the clarifier (31).

Contaminated Rainfall Runoff. Rainfall runoff from the coal storage area is drained by an above-ground system and flows to the coal pile sump where it is pumped to the bottom ash pond. Based on a once-in-10-year, 24-hr rainfall event [approximately 4 in (10 cm)], and a runoff coefficient of 0.7, the flow to the coal pile sump from the 24 acre (9.7 hectare) coal pile would be 1.8 million gallons (6.8 million liters) (32). In addition, runoff from the coal handling area also is routed to the coal pile sump. Information on characteristics of coal pile runoff and contaminated yard drainage is not available.

Equipment Cleaning Wastes. Air preheaters, boiler firesides, and economizer sections are washed periodically to remove fly ash, sulfur contaminants, and other contaminants that may cause plugging or corrosion. However, to date, Units 1 and 2 have never required such washes. Unit 3 preheaters have been washed only once, but are not expected to require any future washing (33).

Boiler chemical cleaning wastes, which are the result of acid cleaning the insides of the boiler tubes to remove scale build-up, are generated about once every 5 years. In the future, it is anticipated that these wastes will be handled by providing a basin for the total quantity of waste and then having a licensed contractor dispose of the waste in an acceptable regulatory manner (33).

Coal Pile Sump. Table II-22 identifies the inflows to the coal pile sump and indicates both average and maximum flows for Units 1, 2, and 3. Based on this inventory, the maximum inflow to the sump is approximately 5,800 gpm

TABLE II-22
COAL PILE SUMP INVENTORY - UNITS 1, 2, AND 3 - CLAY BOSWELL STEAM ELECTRIC STATION

		Inflow[a]				
		Average		Maximum		
Unit	Source	gpm	lpm	gpm	lpm	Type of Flow
1 and 2	Auxiliary Cooling	350	1,325	350	1,325	Continuous
1 and 2	Boiler Blowdown	10	38	10	38	Continuous
1 and 2	Bearing Cooling, Seals, Miscellaneous	200	757	200	757	Continuous
1 and 2	Ash Hopper Cooling	200	757	200	757	Continuous
1 and 2	Sewage Treatment	5	19	10[b]	38	Continuous[c]
1, 2, and 3	Demineralizer Wastes	20	76	200[b]	757	Periodic
3	Fly Ash Scrubber Blowdown	1,000	3,785	1,000	3,785	Continuous
1, 2, and 3	Coal Pile Runoff	22[d]	83	1,250[e]	4,732	Periodic
3	Boiler Blowdown	10	38	10	38	Continuous
3	Ash Hopper Cooling	970	3,672	970	3,672	Continuous
3	Bearing Cooling, Seals, Miscellaneous	500	1,893	500	1,893	Continuous
	Total	3,287	12,443	4,700	17,792	

[a] Based on flows shown in Figure II-7.
[b] Estimate.
[c] Average.
[d] Based on average annual rainfall.
[e] Based on the once in 10 yr 24-hr rainfall event.

(21,955 lpm) under conditions of full operation and a once-in-10-year, 24-hr rainfall. Pumping of the sump outflow to the bottom ash pond is by two 5,000 gpm (18,927 lpm) pumps in series designed for a total capacity of 5,000 gpm (18,927 lpm). Under extreme rainfall conditions, inflows to the pond may exceed the outflow pump capacity (33).

Discharge System. Once-through condenser cooling water and auxiliary cooling water constitute approximately 99%, during summer, and 98%, during winter, of the Clay Boswell Station's total discharge to the Mississippi River. The remaining percentages consist of Unit 3 cooling tower blowdown and bottom ash pond effluent. The bottom ash pond effluent is recycled by pumping to the water intake (Figure II-6). Normal maximum plant discharge to the Mississippi River is approximately 112,000 gpm (423,954 lpm). During winter operation, this value decreases to approximately 58,000 gpm (219,548 lpm) due to decreasing by one half the circulating water for Units 1 and 2. This value actually will be less than 58,000 gpm (219,548 lpm) due to recirculation of Unit 1 and 2 condenser cooling water for ice melt. The total discharge flows to the Mississippi River via the present discharge canal (Figure II-1).

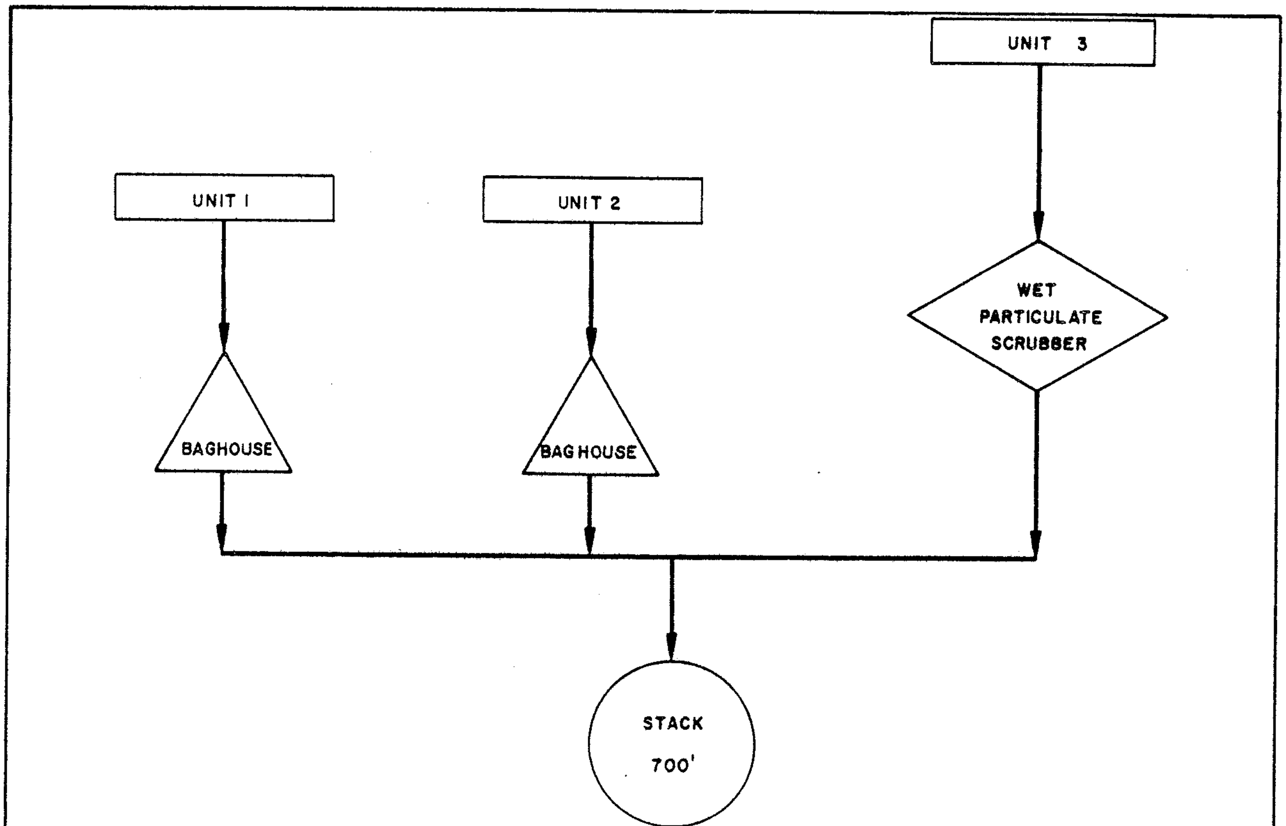
Air Quantity Control Systems (AQCS)

For stack gas emissions to comply with regulatory limits, Units 1, 2, and 3 have been equipped with air emission control systems. Emissions from Units 1, 2, and 3 are discussed under Emissions, Effluents, and Waste Production.

Steam Generator AQCS for Units 1 and 2. The steam generators or boilers for Units 1 and 2 were equipped with mechanical particulate collectors. These collectors were multiple cyclone units which utilize centrifugal force, combined with gravitational force, to separate the dense particulate from the stack gases. The average collection efficiency was about 60% by weight (34).

Since this removal efficiency was inadequate to meet Minnesota regulations, baghouse filters (filtration system using fabric filters) are being installed in lieu of the mechanical collectors. The baghouse system for both Units 1 and 2 has an estimated approximate collection efficiency of 99.4% (35). Units 1 and 2 combustion gases exited through a single 250 ft (76 m) stack with a top inside diameter of 9.5 ft (2.9 m). The combustion gases from Units 1, 2, and 3 now will exit normally through a new 700 ft (213 m) stack. The top inside diameter of the new stack is 29 ft (8.8 m). The combination of effluents provides reheat for humidity reduction for the Unit 3 combustion gas. When Unit 3 is out of service, combustion gases from Units 1 and 2 may be redirected to the 250 ft (76 m) stack to allow for maintenance or inspection of the 700 ft (213 m) stack. Figure II-8 is a flow diagram for the stack gas effluent for the existing units, using the baghouse system for Units 1 and 2 and the new 700 ft (213 m) stack for all 3 existing units (36).

Steam Generator AQCS for Unit 3. The steam generator or boiler for Unit 3 is equipped with a Krebs-Elbair wet particulate scrubber (37). The flue gas enters the wet scrubber at 250°F (121°C) and is quenched by 138 peripheral and 546 main prequench sprays. The flue gas then flows through chevron mist eliminators to remove the majority of the entrained water. Finally, before the gas leaves the scrubber, it passes through post-humidification sprays. This scrubber has performance criteria of 96.6% and 15.0% (by weight) particulate and sulfur dioxide collection efficiency, respectively. Figure II-8 shows the flow of stack gases from the existing units to the new 700 ft (213 m) stack.



AIR QUALITY CONTROL SYSTEM CONFIGURATION
UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-A-3

FIGURE II-8

EMISSIONS, EFFLUENTS, AND WASTE PRODUCTION

The electrical energy output of a generating facility varies over time in accordance with energy demand, maintenance requirements, and operational problems. Consequently, an electric generating unit may operate at full capacity for parts of the year and only intermittently at other times. Furthermore, use of a unit may decrease over time as newer, more efficient units are added. In calculating effluents, emissions, and solid waste production rates, the capacity factors and plant retirement dates used were 41.3% and 1999 for Unit 1, 33.3% and 1999 for Unit 2, and 77.3% and 2008 for Unit 3.

Air Emissions

Air emissions associated with Units 1, 2, and 3 come from combustion of the primary fuel, operation of the cooling towers, coal handling, venting processes, and miscellaneous operations.

Units 1 and 2 Stack Emissions. MPCA regulations limit particulate emissions from Units 1 and 2 to 0.6 lb per million Btu (1.08 kg per million kg-cal) input (38). These same regulations limit opacity to 20% for these units, except for periods of start-up, soot blowing, and malfunction during which up to 60% opacity is allowed for 4 min in any 30 min period. Because regulations did not limit NO_x emissions when Units 1 and 2 were constructed, the steam generators were not designed for control of these emissions.

MPCA regulations limit SO_2 emissions for Units 1 and 2 to 4.0 lb per million Btu (7.2 kg per million kg-cal) input (38). The present method of meeting this regulation is to attempt to limit the sulfur content of the fuel to a maximum of 1.7% (38). However, MP&L reports that coal usually is consumed before coal samples have been analyzed (38). So the viability of this method of assuring compliance with SO_2 emission limitations is questionable.

Estimated particulate, NO_x, and SO_2 stack emissions from Units 1 and 2 are presented in Tables II-23, II-24, and II-25. Trace elements and sulfates air emissions presently are not regulated. Emission estimates for these are presented in Table II-26. The trace elements air emissions estimates are based on the analyses in Tables II-9 and II-10. Actual maximum trace elements air emissions could vary substantially from the emissions estimates in Table II-26.

Unit 3 Stack Emissions. MPCA regulations limit particulate emissions for Unit 3 to 0.6 lb per million Btu (1.08 kg per million kg-cal) input (38). The opacity limits stated above for Units 1 and 2 also apply to Unit 3. Because MPCA regulations did not limit NO_x emissions when Unit 3 was constructed, the steam generator was not designed for control of these emissions.

MPCA regulations limit SO_2 emissions for the unit to 4.0 lb per million Btu (7.2 kg per million kg-cal) input (38). The present method of meeting this regulation is an attempt to limit the sulfur content of the fuel (38). The same problem exists for Unit 3 with respect to sampling as for Units 1 and 2. Some SO_2 removal occurs in the wet particulate scrubber, thereby allowing the use of coal with a slightly higher sulfur content. The SO_2 removal efficiency of the particulate scrubber is estimated to be 15%, which allows the use of coal with a maximum sulfur content of 2.0% (38). Unit 3 stack gases exit through the new 700 ft (213 m) stack.

Estimated particulate, NO_x, and SO_2 stack emissions from Unit 3 are presented in Tables II-23, II-24, and II-25. Sulfate and heavy metals emissions presently are not regulated. However, estimated emissions for these materials are presented in Table II-26.

Cooling Tower Emissions. There are no existing MPCA regulations limiting emissions from the cooling towers. In addition to heat, cooling towers contribute to the atmosphere 3 principal emissions which are water vapor, drift (mist), and salts. Estimated evaporation rates for the Unit 3 cooling tower are presented in Table II-17. For the Unit 3 cooling tower, the estimated drift is 5,500 lb per hour (2,495 kg per hour) or 0.01% of the circulating water flow, and estimated salt emission is 7.7 lb per hr (3.5 kg per hr) at 1,400 mg per liter for the estimated drift.

TABLE II-23
ESTIMATED AIR EMISSIONS - UNITS 1, 2, AND 3 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 1	Unit 2	Unit 3	Units 1, 2, and 3
Full load/electrical output				
Gross MW/net MW	75/69	75/69	369/350	519/488
Heat input rate				
Btu x 10^6 per hr	707	707	3,570	4,984
kg-cal x 10^6 per hr	178	178	901	1,258
Fuel consumption[a]				
Average				
lb per hr	82,114	82,114	414,634	578,862
kg per hr	37,246	37,246	188,075	262,567
Maximum				
lb per hr	94,153	94,153	475,429	663,735
kg per hr	42,707	42,707	215,651	301,065
Products of combustion				
Average				
Mass flow rate, lb per hr	796,506[b]	796,506[b]	4,643,923[c]	6,236,935
Mass flow rate, kg per hr	361,289[b]	361,289[b]	2,106,448	2,829,026
Volume flow rate, actual cfm	271,718	271,718	1,155,205	1,698,641
Volume flow rate, actual cu m per min	7,694	7,694	32,712	48,100
Temperature, °F	360	360	136	193[d]
Temperature, °C	182	182	58	89[d]

Parameter	Unit 1	Unit 2	Unit 3	Units 1, 2, and 3
Emissions at full load[e]				
Average				
Particulate, lb per hr	39	39	2,142	2,220
Particulate, kg per hr	18	18	972	1,008
NO_x, lb per hr	756	756	3,820	5,332
NO_x, kg per hr	343	343	1,733	2,419
SO_2 at 38(%S),[f] lb per hr	1,607	1,607	6,897	10,111
SO_2 at 38(%S),[f] kg per hr	729	729	3,128	4,586
SO_2 at 34(%S),[f] lb per hr	1,438	1,438	6,171	9,047
SO_2 at 34(%S),[f] kg per hr	652	652	2,799	4,103
Worst Case				
Particulate, lb per hr	77	77	2,197	2,351
Particulate, kg per hr	35	35	997	1,066
NO_x, lb per hr	756	756	3,820	5,332
NO_x, kg per hr	343	343	1,733	2,419
SO_2 at 38(%S),[f] lb per hr	8,140	8,140	34,936	51,216
SO_2 at 38(%S),[f] kg per hr	3,692	3,692	15,847	23,322
SO_2 at 34(%S),[f] lb per hr	7,283	7,283	31,259	45,825
SO_2 at 34(%S),[f] kg per hr	3,304	3,304	14,179	20,786

[a] Fuel consumption rate based on 8,610 Btu per lb (4,783 kg-cal per kg) higher heating value.

[b] Assumed products of combustion per pound of fuel ratio is 9.7 (approximately 25% excess air).

[c] Assumed products of combustion per pound of fuel ratio is 11.2 (approximately 50% excess air). This is very high and is required as a result of slagging problem in Unit 3 steam generator.

[d] Includes temperature loss resulting from evaporation of carryover and stack heat loss.

[e] See Tables II-24 and II-25 for emission criteria.

[f] SO_2 emissions at 38(%S) and 34(%S) assumes that 5% and 15%, respectively, of the SO_2 will be retained in the boiler and emissions control solid waste (bottom and fly ash) and, therefore, will not be emitted to the atmosphere. The AP-42 emission factor for pulverized bituminous coal-fired units is 38(%S).

TABLE II-24
ASSUMED AVERAGE AIR EMISSION CRITERIA - UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 1	Unit 2	Unit 3
Coal			
Heating value			
Btu per lb	8,610	8,610	8,610
kg-cal per kg	4,783	4,783	4,783
Ash content			
%	9.35	9.35	9.35
Sulfur content			
%	1.03	1.03	1.03
Emission control equipment			
Particulate removal efficiency[a]			
%	99.4	99.4	96.6
SO_2 removal efficiency			
%	0	0	15.0
Emissions			
Particulate[b]			
lb per million Btu input	0.055[c]	0.055[c]	0.600
kg per million kg-cal input	0.100[c]	0.100[c]	1.080
NO_x			
lb per million Btu input	1.07	1.07	1.07
kg per million kg-cal input	1.93	1.93	1.93
SO_2 at 38(%S)[d e]			
lb per million Btu input	2.27	2.27	1.93
kg per million kg-cal input	4.09	4.09	3.47
SO_2 at 34(%S)[d e]			
lb per million Btu input	2.03	2.03	1.73
kg per million kg-cal input	3.65	3.65	3.11

[a] Source: Prevention of Significant Air Deterioration Approval Application (revised 11/76).

[b] Assumes bottom ash to fly ash ratio of 15% to 85%.

[c] Assumes baghouse particulate removal efficiency is independent of inlet grain loading.

[d] SO_2 emissions at 38(%S) and 34(%S) assumes that 5% and 15%, respectively, of the SO_2 will be retained in the boiler and emissions control solid waste (bottom and fly ash) and, therefore, will not be emitted to the atmosphere.

[e] MPCA regulations limit SO_2 emissions to 4.0 lb per million BTU (7.20 kg per million kg-cal) input.

TABLE II-25
ASSUMED WORST CASE AIR EMISSION CRITERIA - UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 1	Unit 2	Unit 3
Coal			
Heating value			
Btu per lb	7,509	7,509	7,509
kg-cal per kg	4,172	4,172	4,172
Ash content			
%	15.99	15.99	15.99
Sulfur content			
%	4.55	4.55	4.55
Emission control equipment			
Particulate removal efficiency[a]			
%	99.4	99.4	96.6
SO_2 removal efficiency			
%	0	0	15
Emissions			
Particulate[b]			
lb per million Btu input	0.11[c]	0.11[c]	0.62[d]
kg per million kg-cal input	0.20[c]	0.20[c]	1.12[d]
NO_x			
lb per million Btu input	1.07	1.07	1.07
kg per million kg-cal input	1.93	1.93	1.93
SO_2 at 38(%S)[e f]			
lb per million Btu input	11.51	11.51	9.79
kg per million kg-cal input	20.72	20.72	17.62
SO_2 at 34(%S)[e f]			
lb per million Btu input	10.30	10.30	8.76
kg per million kg-cal input	18.54	18.54	15.77

[a] Source: Prevention of Significant Air Deterioration Approval Application (revised 11/76).

[b] Assumes bottom ash to fly ash ratio of 15% to 85%.

[c] Assumes baghouse particulate removal efficiency is independent of inlet grain loading.

[d] To comply with MPCA regulations limiting particulate emissions to 0.6 lbs per million Btu (1.08 kg per million kg-cal) input, a particulate removal efficiency of 97.4% is necessary with 15% bottom ash.

[e] SO_2 emissions at 38(%S) and 34(%S) assumes that 5% and 15%, respectively, of the SO_2 will be retained in the boiler and emission control solid waste (bottom and fly ash) and, therefore, will not be emitted to the atmosphere. The AP-42 emission factor for the pulverized bituminous coal fired units is 38(%S).

[f] MPCA regulations limit SO_2 emissions to 4.0 lb per million Btu (7.20 kg per million kg-cal) input.

TABLE II-26
MAXIMUM TRACE ELEMENT AND SULFATE AIR EMISSIONS
UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION

	lb per hr	kg per hr
Arsenic	0.39	0.18
Barium	24.21	10.98
Beryllium	0.04	0.02
Cadmium	0.04	0.02
Chromium	0.55	0.25
Cobalt	0.04	0.02
Copper	0.79	0.36
Fluorine	34.08	15.46
Gallium	1.25	0.57
Lead	3.19	1.45
Mercury	0.05	0.02
Manganese	2.99	1.36
Molybdenum	1.23	0.56
Nickel	0.31	0.14
Strontium	9.28	4.21
Sulfates	257.00	116.57
Titanium	44.93	20.38
Uranium	0.04	0.02
Vanadium	1.50	0.68
Zinc	2.11	0.96
Total	383.39	173.92

Note: Units 1, 2, and 3 will discharge stack gas via a single 700 ft. (213 m) stack. The baghouse filters used to control particulate emissions from Units 1 and 2 have estimated removal efficiencies of 95% for metals, 90% for mists, and 10% for gaseous trace elements. The wet scrubber used to control particulate emissions from Unit 3 have estimated removal efficiencies of 90% for metals and mists and 10% for gaseous trace elements. The maximum air emissions are based on coal with a heating value of 7,509 Btu per lb (4,172 kg-cal per kg).

The once-through cooling systems for Units 1 and 2 do not emit drift and salt, however, they do result in some evaporation of water from the discharge canal and the Mississippi River. This evaporation is less than that for a comparable cooling tower system.

Other Emission Sources. The main source of fugitive dust at the Clay Boswell Station is the coal handling facilities, primarily the stocking-out conveyor and front-end loaders. The problem is compounded because coal for all other MP&L coal-fired plant(s) is received and reloaded at the Clay Boswell Station. Fugitive dust can be generated from a number of other sources, including traffic on unpaved roads, land areas without vegetative cover, and coal storage.

MPCA regulations require that material be handled in a manner which will prevent all but a minimum amount of particulate matter from becoming airborne (39). An estimate of fugitive dust emissions has not been made for the existing

Clay Boswell Station. Typically, regulations for fugitive dust do not provide emission limitations, but rather require adequate handling equipment and dust-suppression systems.

Certain systems within the power plant require continuous venting. For example, the deaerator system has vents which emit steam to the atmosphere in very small quantities. These quantities are not considered to be significant in comparison to other emissions from the Clay Boswell Station. Distillate oil is stored in a vented tank for use in starting up the boilers. The vapor pressure of the oil is such that estimated hydrocarbon emissions are insignificant relative to other emissions from the station.

Wastewater Effluents

Wastewater discharges to the Mississippi River from Units 1, 2, and 3 consist of streams identified in Table II-27 (Figure II-7).

TABLE II-27
WASTEWATER DISCHARGES - UNITS 1, 2, AND 3
CLAY BOSWELL STEAM ELECTRIC STATION (40)

Unit		Normal Operating Flow gpm	lpm
1 and 2	Condenser Cooling Water	108,000	408,813
3	Cooling Tower Blowdown	1,300	4,921
1 and 2	Auxiliary Cooling Water (Boiler feed pump cooling)	450	1,703
1, 2, and 3	Bottom Ash Pond	5,535[a]	20,952
	Total Average Discharge Flow	109,750	415,437

[a] Recycled to Intake Structure; therefore, part of Units 1 and 2 Condenser Cooling Water.

Except for chlorine content and temperature, the discharged once-through cooling water and auxiliary cooling water for Units 1 and 2 are basically the same as the Blackwater Lake intake water (not accounting for the approximately 5% flow addition of bottom ash pond water at the intake). The quality of this discharge water should thus be consistent with the average water quality of the Mississippi River as presented in Table II-28.

The cooling tower blowdown concentrations for Unit 3 as presented in Table II-29 and bottom ash pond concentrations as presented in Table II-30 were used in conjunction with Mississippi River concentrations (intake) to evaluate the present effluent concentrations. Table II-31 summarizes individual discharge wastewater concentrations, final calculated effluent concentrations, and measured effluent concentrations.

TABLE II-28
AVERAGE WATER QUALITY MISSISSIPPI RIVER - COMMUNITY OF COHASSET, MINNESOTA (41)

	Station 1186				Station 1182				MP&L Circulating Water Intake				Summary Grand Mean
	Number	Mean	Maximum	Minimum	Number	Mean	Maximum	Minimum	Number	Mean	Maximum	Minimum	
Temperature, °F	79	49	78	30									49
Temperature, °C	79	9.4	25.6	1.1									9.4
Turbidity, JTU	79	3.1	15	0.2									3.1
Color, units	42	27	130	0.0									27
Conductivity, micromho	72	288	4,600	100	38	279	362	190					285
Dissolved oxygen, mg per liter	64	8.5	13.1	4.2									8.5
BOD,[a] mg per liter	79	2.0	4.8	0.5					30	2.2	4.3	.3	2.1
COD,[b] mg per liter	6	35	50	21					39	30.6	58.8	10	31
pH	80	7.7	8.4	6.8	38	7.6	8.2	6.8					7.7
Total alkalinity, mg per liter	79	142	180	72	35	139	106	95	40	134	214	68	139
Total residue, mg per liter	61	183	350	81	35	172	216	122	36	194	304	146	183
Suspended solids, mg per liter	79	6.5	32	0.5					36	5	13	0.5	6
Organic nitrogen, mg per liter N	61	0.75	1.5	0.14									0.75
Ammonia, mg per liter N	79	0.12	0.52	0.04					40	0.01	0.16	0.0	0.08
Nitrite, mg per liter N	61	0.02	0.04	0.01									0.02
Nitrate, mg per liter N									40	0.1	0.4	0.0	0.1
Kjeldahl nitrogen, mg per liter N									40	0.51	1.07	0.0	0.51
Phosphorus, mg per liter P	79	0.07	0.64	0.01					40	0.07	0.46	0.0	0.07
Total hardness, mg per liter $CaCO_3$	79	142	210	72									142
Calcium, mg per liter $CaCO_3$	40	87	150	40	35	83	108	60					85
Sodium, mg per liter	37	5.5	9.4	2.0	35	5.7	7.3	3.0					5.6
Potassium, mg per liter	38	2.5	9.5	1.0	38	2.9	3.1	0.4					2.7
Chloride, mg per liter	79	3.7	58	1.0	35	5.0	7.3	3.0					4.1
Sulfate, mg per liter	22	7.0	12	3.6	35	7.9	12	4.2					7.6
Fluoride, mg per liter	39	0.11	0.2	0.1	35	0.16	0.3	0.1					0.13
Silica, mg per liter	3	9.7	10	9.2	35	7.4	11	1.4					7.6
Arsenic, mg per liter	46	0.009	0.01	0.001									0.009
Cadmium, mg per liter	75	0.011	0.073	0.010									0.011
Copper, mg per liter	75	0.011	0.045	0.010									0.011
Iron, mg per liter	70	0.17	0.65	0.01	37	0.13	0.9	0.00					0.16
Lead, mg per liter	72	0.036	0.45	0.01									0.036
Manganese, mg per liter	70	0.070	0.83	0.02	34	0.04	0.9	0.0					0.06
Nickel, mg per liter	75	0.018	0.16	0.01									0.018
Zinc, mg per liter	78	0.068	0.39	0.01									0.068
Selenium, mg per liter	43	0.006	0.010	0.001									0.006
Total coli, number per 100 ml	80	508	11,000	20									508
Fecal coli, number per 100 ml	80	77	2,400	20									77
PCB's,[c] μg per liter	23	0.4	6.5	0.05									0.4
Mercury, μg per liter	46	0.25	1.4	0.03									0.25
Aluminum, mg per liter					31	0.31	0.8	0.0					0.31

[a] Biochemical oxygen demand.
[b] Chemical oxygen demand.
[c] Polychlorinated biphenol.

TABLE II-29
BLOWDOWN QUALITY - UNIT 3 COOLING TOWER
CLAY BOSWELL STEAM ELECTRIC STATION (42)

Parameter	Average[a] Conc	Maximum[b] Conc
pH	7.8	7.7
Cl^-, mg per liter	500.0	800.0
$SO_4^=$, mg per liter	38.0	60.0
Na^+, mg per liter	28.0	47.0
K^+, mg per liter	14.0	48.0
Ca^{++} (as Ca^{++}), mg per liter	170.0	300.0
Mg^{++} (as Mg^{++}), mg per liter	69.0	108.0
Silica (as SiO_2), mg per liter	38.0	55.0
HCO_3^- (as HCO_3^-), mg per liter	44.0	28.0
Total dissolved solids (TDS), mg per liter	900.0	1,450.0

[a] Based on average Mississippi River water quality, cooling tower operation at 5 cycles of concentration, and addition of 98 mg per liter HCl to makeup water for pH control.

[b] Based on worst Mississippi River water quality, cooling tower operation at 5 cycles of concentration, and addition of 154 mg per liter HCl to makeup water for pH control.

NOTE: These concentrations are higher than present measured concentrations due to the towers operating at 2 to 3 cycles of concentration.

TABLE II-30
MONITORING RESULTS
UNITS 1, 2, AND 3 BOTTOM ASH POND EFFLUENT
CLAY BOSWELL STEAM ELECTRIC STATION (43)

Parameter	Average Concentration mg per liter
Total alkalinity (as $CaCO_3$)	74.0
Biochemical oxygen demand (BOD_5)	2.0
Chemical oxygen demand (COD)	22.0
NO_3 (as nitrogen)	0.12
NH_3 (as nitrogen)	0.09
Total Kjeldahl nitrogen	0.67
Total phosphorus	0.63
Total dissolved solids (TDS)	855.0
Total suspended solids (TSS)	9.0
$SO_2^=$	398.0

Temperature of the total discharge to the Mississippi River with Units 1 and 2 operating at maximum capacity is 12.5 °F (6.9°C) above the Blackwater Lake intake temperature for summer and 25°F (14°C) above the intake temperature for winter. Assuming recirculation for ice melt in winter with a 40 to 45°F, (4.4 to 7.2 ° C) intake temperature, the effluent temperature during winter is approximately 65 to 70°F (18.3 to 21.2°C) (44).

Effluent chlorine concentrations must comply with the conditions of the present Clay Boswell Station's NPDES permit. Total residual chlorine is limited to 0.2 mg per liter. Based on measurements and observations to date, problems are not expected in complying with this limit (45).

Solid Waste Production

The primary source of solid waste from the existing Clay Boswell Station is ash contained in the coal. The existing pulverized coal boilers are designed as "dry-bottom" units which remove 15 to 20% of the total ash in the furnace as bottom ash (46). Most of the remainder is collected as fly ash in the particulate control system.

All ash is collected and hydraulically sluiced to the disposal site. The following indicates ash sources and present disposal sites for the 3 existing units:

Ash Source	Disposal Site
Units 1 and 2 Bottom Ash	Unit 3 Bottom Ash Pond
Units 1 and 2 Fly Ash	Unit 3 Bottom Ash Pond
Unit 3 Bottom Ash	Unit 3 Bottom Ash Pond
Unit 3 Fly Ash	Unit 3 Fly Ash Pond

Based on the "as received" design performance coal analysis and the estimated coal consumption presented in Tables II-12 and II-15, respectively, the estimated future solid waste or ash production for Units 1, 2, and 3 is presented in Table II-32. The bottom ash solids in the bottom ash pond have an average dry bulk in place density of approximately 91 lb per cu ft (1.45 g per cc) and the fly ash solids in the fly ash pond have an average dry bulk in place density of approximately 63 lb per cu ft (1.01 g per cc).

Bottom Ash Handling and Disposal Systems. Bottom ash, about 15 to 20% of the total ash, is stored in the hopper section of the boiler units and then sluiced to the disposal area as a 3 to 5% solids slurry of bottom ash and water. Units 1 and 2 bottom ash handling system (Figure II-9) consists of two 2,000 gpm (7,571 lpm) sluice pumps (operated one at a time) located in the Units 1 and 2 water intake house. During normal full load operation, sluicing occurs once each shift for a duration of about ½ hr per unit. With these frequencies and durations, the average sluice flow is about 250 gpm (946 lpm) for both units (47). The Unit 3 bottom ash handling system uses two 4,000 gpm (15,141 lpm) sluice pumps and a separate pipeline. Normal sluicing occurs once per shift for about 3 hrs. This average daily sluice flow at full load is about 1,500 gpm (5,678 lpm) (47).

TABLE II-31

COMPARISON OF DISCHARGE CONCENTRATIONS - UNITS 1, 2, AND 3 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Mississippi River(a)		MP&L Clay Boswell Intake(b)	Bottom Ash Pond Effluent(c)	Unit 3 Cooling Tower Blowdown(d)		Calculated Effluent Concentration(e)		Measured Effluent Concentration(f)
	Average	Maximum	Mean	Mean	Average	Maximum	Average	Maximum	Average
Biochemical oxygen demand (BOD), mg per liter	2.0	4.8	2.2	2	-	-	2	4.4	1.6
Chemical oxygen demand (COD), mg per liter	35	50	30.6	22	-	-	34	45.8	36
pH	7.7	8.4	-	-	7.8	7.7	7.7	7.7	-
Total alkalinity, mg per liter	142	180	134	74	-	-	138	164	113
Suspended solids, mg per liter	6.5	32	5	9	-	-	6.6	28.5	4
Nitrate N, mg per liter	-	-	0.1	0.12	-	-	0.1	0.1	.09
Phosphorus P, mg per liter	0.07	.64	0.07	0.63	-	-	0.1	0.64	.042
Total hardness, mg per liter $CaCO_3$	142	210	-	-	-	-	142	210	-
Calcium, mg per liter	34.8	60	-	-	68	300	35.6	65.7	-
Sodium, mg per liter	5.5	9.4	-	-	28	47	5.8	10.3	-
Chloride, mg per liter	3.7	58 [g]	-	-	500	800	9.9	-	-
Sulfate, mg per liter	7.0	12	-	398	38	60	27.4	73.4	18.5
Total dissolved solids (TDS), mg per liter	142	350	194	855	900	1,450	189.0	498	208

[a] MP&L Environmental Report, Table III-C-1, Station 1186, mean value.

[b] MP&L Environmental Report, Table III-C-1, MP&L Intake, mean value.

[c] MP&L Environmental Report, Revised Chapter II, p. II-19.

[d] MP&L Environmental Report, Revised Chapter IV, Table IV-B-11.

[e] Calculated Concentrations from the combination of intake water (using Mississippi River concentrations except for nitrate) with bottom ash pond effluent and cooling tower blowdown. Average values were calculated with normal operating flows. Maximum values were calculated with Unit 3 and either Unit 1 or 2 operating with half pumps operating (winter). Where a value is missing for cooling tower blowdown or bottom ash pond effluent, calculated effluent does not include any contribution from that stream.

[f] MP&L Environmental Report, Revised Chapter II, p. II-20.

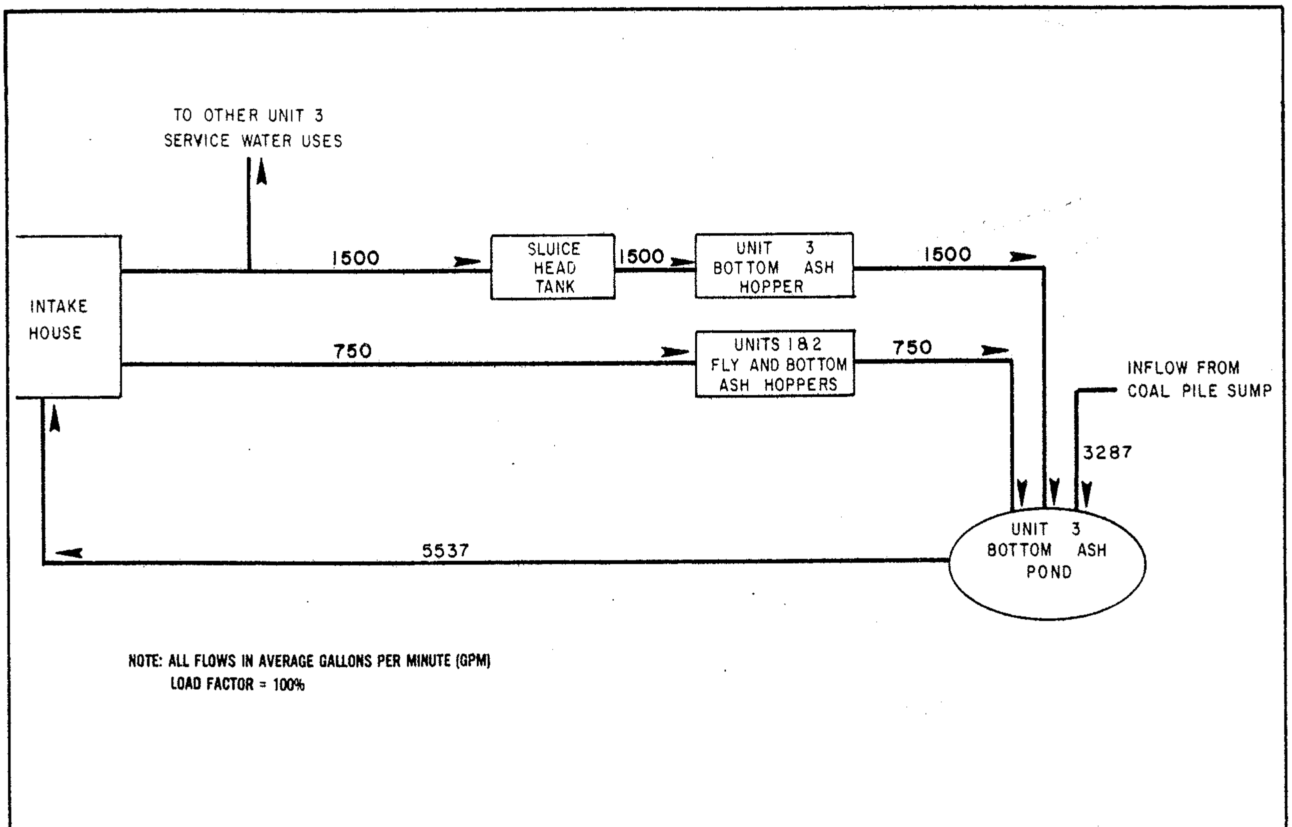
[g] Value is believed to be in error, therefore, maximum effluent has not been calculated.

TABLE II-32

ESTIMATED FUTURE SOLID WASTE OR ASH PRODUCTION - UNITS 1, 2, AND 3 - CLAY BOSWELL STEAM ELECTRIC STATION

Solid Waste	Unit 1	Unit 2	Unit 3	Total
Bottom Ash				
Average daily[a]				
tons	9.0	8.3	53.9	71.2
metric tons	8.2	7.5	48.9	64.6
Maximum daily[b]				
tons	31.5	31.5	159.1	222.1
metric tons	28.6	28.6	144.4	201.6
Average annual[a]				
tons	3,280	3,028	19.689	25,997
metric tons	2,976	2,747	17,862	23,585
Maximum annual[c]				
tons	6,728	6,728	33,961	47,417
metric tons	6,104	6,104	30,809	43,017
Average total[a]				
tons	54,799	45,716	630,045	730,560
metric tons	49,713	41,473	571,567	662,753
Maximum total[c]				
tons	73,065	60,955	840,060	974,080
metric tons	66,283	55,297	762,090	883,670
Fly Ash				
Average daily[a]				
tons	50.6	46.7	295.3	392.6
metric tons	45.9	42.4	267.9	356.2
Fly Ash (continued)				
Maximum daily[d]				
tons	133.2	133.2	653.3	919.7
metric tons	120.8	120.8	592.6	834.2
Average annual[a]				
tons	18,474	17,053	107,777	143,304
metric tons	16,759	15,470	97,774	130,003
Maximum annual[a]				
tons	28,422	28,422	139,427	196,271
metric tons	25,784	25,784	126,486	178,054
Average total[a]				
tons	308,664	257,504	3,448,865	4,015,033
metric tons	280,015	233,604	3,128,758	3,642,377
Maximum total[a]				
tons	308,664	257,504	3,448,865	4,015,033
metric tons	280,015	233,604	3,128,758	3,642,377
Solid Waste				
Average annual[a]				
tons	21,754	20,081	127,466	169,301
metric tons	19,735	18,217	115,636	153,588
Average total[a]				
tons	363,463	303,220	4,078,910	4,745,593
metric tons	329,728	275,077	3,700,325	4,305,130

[a] Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 15% to 85%.
[b] Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 20% to 80%.
[c] Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 20% to 80%.
[d] Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 15% to 85%.



FLY AND BOTTOM ASH SLUICING SYSTEM - UNITS 1 AND 2
BOTTOM ASH SLUICING SYSTEM - UNIT 3 CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-A-6

FIGURE II-9

Bottom ash from Units 1, 2, and 3 together with fly ash from Units 1 and 2 is sluiced to a disposal pond west of the plant as shown on Figure II-1. The bottom ash pond covers an area of 83 acres (33.6 hectares) and has an average depth of 25 ft (7.6 m). Total capacity is about 2,075 acre-ft (2,559,475 cu m) (48).

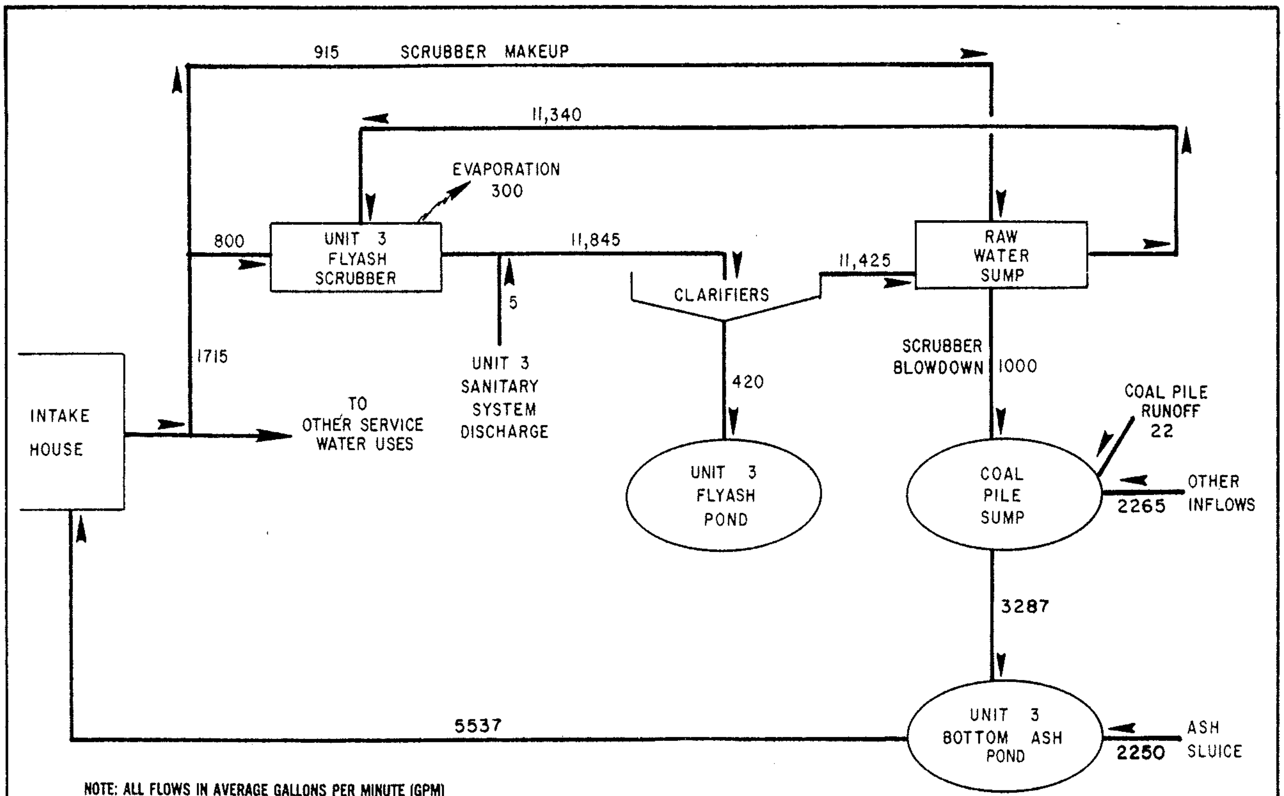
Fly Ash Handling and Disposal Systems. The fly ash is entrained in the flue gas and collected by the air quality control system. The dry fly ash stored in hoppers and the wet fly ash settled out in the clarifier is transported hydraulically to the disposal ponds.

Fly ash in Units 1 and 2 previously was collected by dry mechanical cyclone-type collectors which had a collection efficiency of 60% by weight. Fly ash in Units 1 and 2 will be collected by fabric filters with an estimated collection efficiency of 99.4%. The fly ash is sluiced using the same pumps as the bottom ash system (Figure II-9). The sluice rate is 2,000 gpm (7,571 lpm) for one hr per shift per unit. This average daily flow rate is 500 gpm (1,893 lpm) for both units. Information is available on characteristics of fly ash pond water. The analyses of ash pond water indicate that the water has a pH of

9.2 and contains 2,300 mg per liter total dissolved solids, 2,100 mg per liter total hardness of $CaCO_3$, 1,400 mg per liter sulfate, 9.9 mg per liter fluoride, 1,900 mg per liter calcium as $CaCO_3$, and 29 mg per liter bicarbonate alkalinity as $CaCO_3$(49).

Fly ash from Unit 3, shown in Figure II-10, is collected by a Krebs-Elbair wet particulate scrubber which has an efficiency of 96.6%. About 15% of the SO_2 also is removed by the scrubber. The fly ash from Unit 3 is settled in two 150 ft (46 m) diameter clarifiers. The thickener underflow is a concentrated fly ash slurry that is pumped at the rate of about 420 gpm (1,590 lpm) to a separate fly ash disposal pond adjacent to the bottom ash pond as shown in Figure II-1 (48). The fly ash pond is 109 acres (44.1 hectares) with an average depth of 14 ft (4.3 m), resulting in a total capacity of 1,526 acre-ft (1,882,293 cu m) (50).

The scrubber circulating water flow is approximately 11,340 gpm (42,774 lpm). About 915 gpm (3,464 lpm) of makeup water is added to the system at the raw water sump. About 1,000 gpm (3,785 lpm) of blowdown is bled off the raw water sump to the coal pile sump. The scrubber pumps located near the



FLY ASH HANDLING SYSTEM - UNIT 3
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-A-7

FIGURE II-10

clarifiers return water to the scrubber. Another 800 gpm (3,028 lpm) makeup water is added from the service water loop. Losses through the stacks amount to about 300 gpm (1,136 lpm) and losses through the clarifier underflow amount to about 420 gpm (1,590 lpm) (51).

Noise

Units 1, 2, and 3 at the Clay Boswell Station generate noise from a number of sources. In addition, noise is generated by facilities and equipment which serve the Station, but are not actually a part of the Station, such as coal trains and delivery trucks. A noise survey has been conducted for the area which measures the aggregate effect of all noise sources, including those within the plant. However, no identification of specific noise sources or levels within the plant has been attempted.

Existing Environmental Problems

A number of environmental problems have been identified for the existing Clay Boswell Steam Electric Station, including air emissions which presently violate MPCA regulations.

Air Quality

An Air Quality Stipulation Agreement between MP&L and the MPCA provided for the correction of certain past problems encountered at MP&L's Clay Boswell Steam Electric Station. In 1976, it was determined that the Clay Boswell Station did not comply with MPCA air pollution control regulations (52). Units 1 and 2 were found to be in violation of MPCA regulations which limit particulate emissions (APC 4) and opacity (APC 11) (53). Although both units were equipped with mechanical particulate collectors, it was determined that when using coal from the present source, these collectors lacked sufficient removal efficiency to meet the regulations. MP&L originally proposed to solve the problem by installing wet particulate scrubbers similar to the Krebs-Elbair scrubbers for Unit 3. However, when installation of the wet scrubbers was about 75% complete, the program was abandoned due to severe operating problems with the Unit 3 scrubber. These problems included internal plugging and moisture carryover. The plugging increased maintenance requirements, while the moisture carryover violated MPCA regulations concerning settleable acids (APC 14) (54).

MP&L initially proposed to install electrostatic precipitators on Units 1 and 2 as described in the Stipulation Agreement. MP&L later decided to install baghouse systems (55). Typical removal efficiencies for baghouses are equivalent to those for electrostatic precipitators (approximately 99.4%) and are more than adequate to meet APC 4.

A testing program was developed by MP&L to address the plugging and moisture carryover problems of Unit 3. This test program showed that, while some moisture was carried over from the scrubber, the primary moisture source was the spray system used to control particulate buildup on the induced-draft fans. The particulate apparently was being carried over with the moisture from the scrubber.

It was concluded that the problem might be solved by building a tall, low-velocity stack and using the gases from Units 1 and 2 to reheat the stack gases from Unit 3 (55). The low velocity in the stack is intended to allow water droplets to fall out in the stack. The tall stack also allows more time for the moisture droplets to evaporate before reaching ground level. Reheating the stack gases would also contribute to evaporation. However, the data submitted to date do not necessarily support the premise regarding the benefits of the low velocity design.

The reheat feature depends upon the continued operation of Units 1 and 2. A potential long-range problem exists in the likelihood that these units will be retired earlier than Unit 3. However, it is possible that when Units 1 and 2 are retired, the baghouses for Units 1 and 2 could be converted for use for a portion of the flue gas from Unit 3. A problem may result in the near future if Units 1 and 2 are used only during periods of peak demand.

The schedule included in the Air Quality Stipulation Agreement calls for all corrections to be completed on or before December 31, 1978 (56). Since this date precedes the startup date for Unit 4 by more than one year, it has been assumed that Units 1, 2, and 3 will be in compliance with all applicable MPCA air pollution control regulations by the time Unit 4 is placed in operation.

Other Environmental Problems

Other environmental problems have been identified for the existing plant as follows:

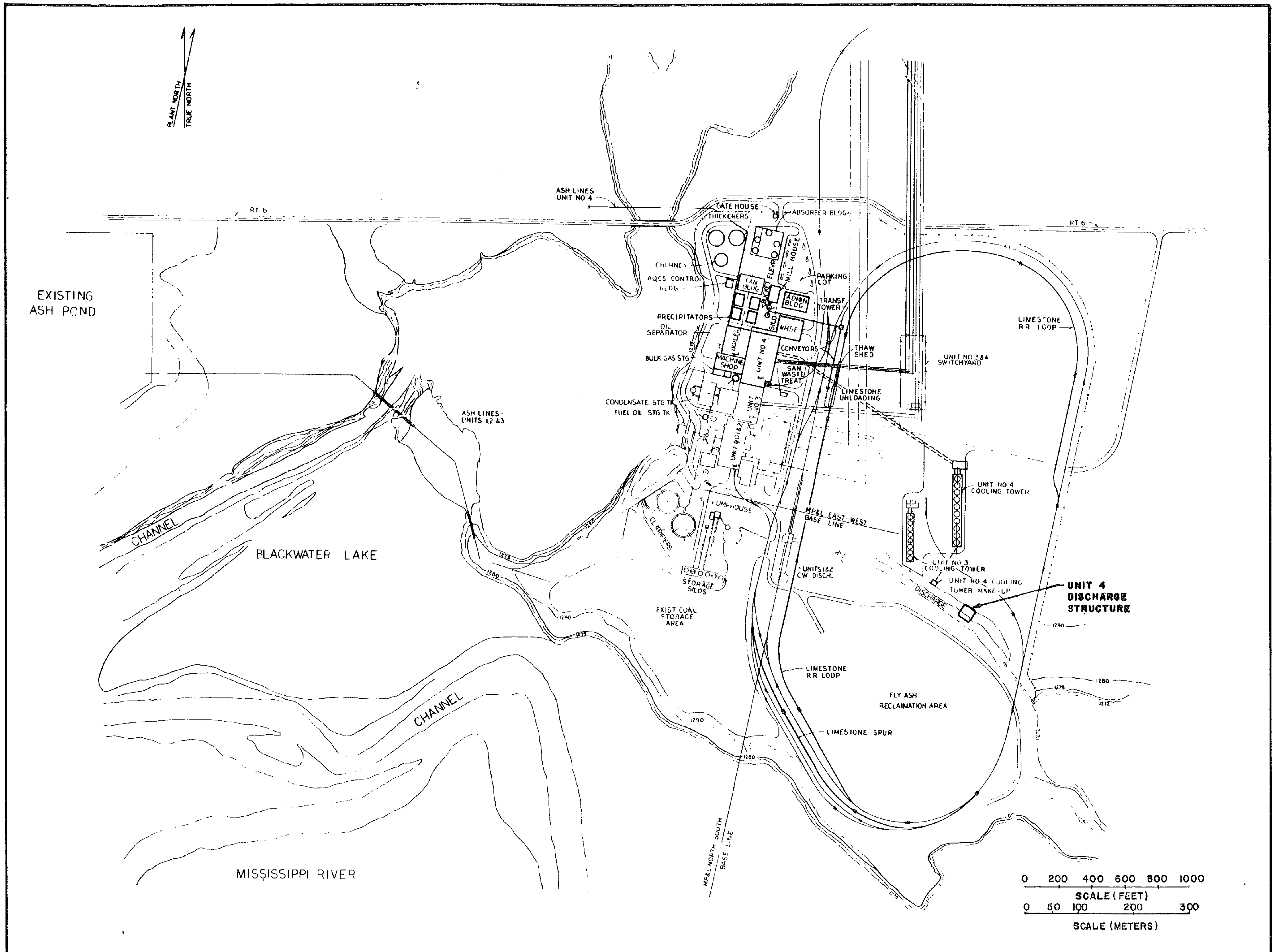
1. Several accidental overflows of the coal pile sump into Blackwater Lake have occurred due to insufficient pumping capacity, pump breakdown, and standby pump failure. Corrective measures have not yet been totally successful.

2. In 1976, there were numerous violations of discharge limitations established in the NPDES permit issued on November 18, 1975. There were 11 violations for pH limitations for effluent from the ash pond. Control of pH began in January 1977 and compliance with pH limitations was attained in April 1977. There were 3 violations for TSS limitations for the Unit 3 cooling tower blowdown. These violations resulted from shutdown and startup of Unit 3. Remedial measures have been implemented by changes in internal operating procedures. There were 6 violations for TSS limitations and 7 violations for turbidity limitations for the Unit 3 cooling tower roof and floor drainage. MP&L is correcting these problems.

3. Ash pond water has leaked into surface water and probably has leaked into ground water.

PROPOSED UNIT 4

The proposed Unit 4 addition to the Clay Boswell Steam Electric Station will be located immediately north of the existing Unit 3 (Figures II-11 and II-



PLOT PLAN
UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L "ENVIRONMENTAL REPORT", EXHIBIT II-B-1

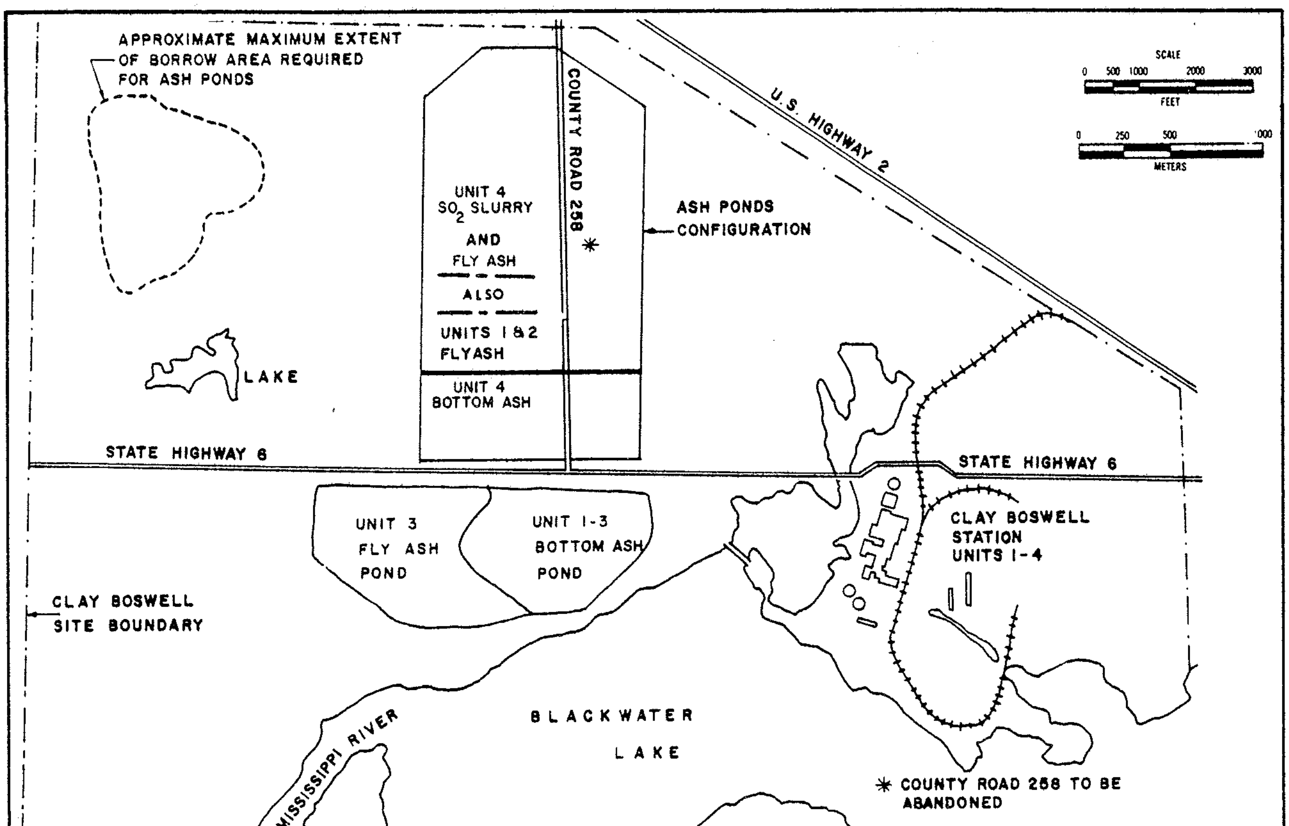
FIGURE II-11

12). Commercial operation for Unit 4 is planned for May 1980, with testing and startup scheduled for earlier in the year (57). In order to accommodate this schedule, a limited amount of work was authorized and started in 1976 (58).

The current Clay Boswell Station covers approximately 720 acres (291 hectares). Approximately 2,880 acres (1,165 hectares) will be acquired for the addition of Unit 4, resulting in a total Station acreage of approximately 3,600 acres (1,457 hectares) (59).

Unit 4 will have a gross generating capacity of 554,000 kw (60) (at 5% overpressure with throttle valves wide open). The net Unit 4 output will be 504,000 kw at the 5% overpressure maximum expected generator output, assuming a 10% unit auxiliary electrical requirement. Auxiliary requirements include such items as forced draft and induced-draft fans, pumps, conveyors, wet scrubber system, and coal pulverizers. At the maximum guaranteed generator output, the net Unit 4 output will approximate 456,000 kw.

The heat balance diagram for Unit 4 in Figure II-13 shows flows and generator output at the maximum gross guaranteed load rating (506,703 kw) (61).



PLOT PLAN ASH PONDS - PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-B-2

FIGURE II-12

Flow conditions at the maximum anticipated generator output at 5% overpressure with valves wide open (554,000 kw) will be approximately 10% higher (62).

The unit will be operated to satisfy MP&L's electrical energy demand. MP&L has indicated that the capacity factor averaged over the life of the plant for Unit 4 is projected to be approximately 71.4% over its 35 year life (63). (It should be noted that both the anticipated capacity factor and Unit 4's life may vary according to future circumstances with regard to energy planning and policy).

Raw Materials

Coal Transportation

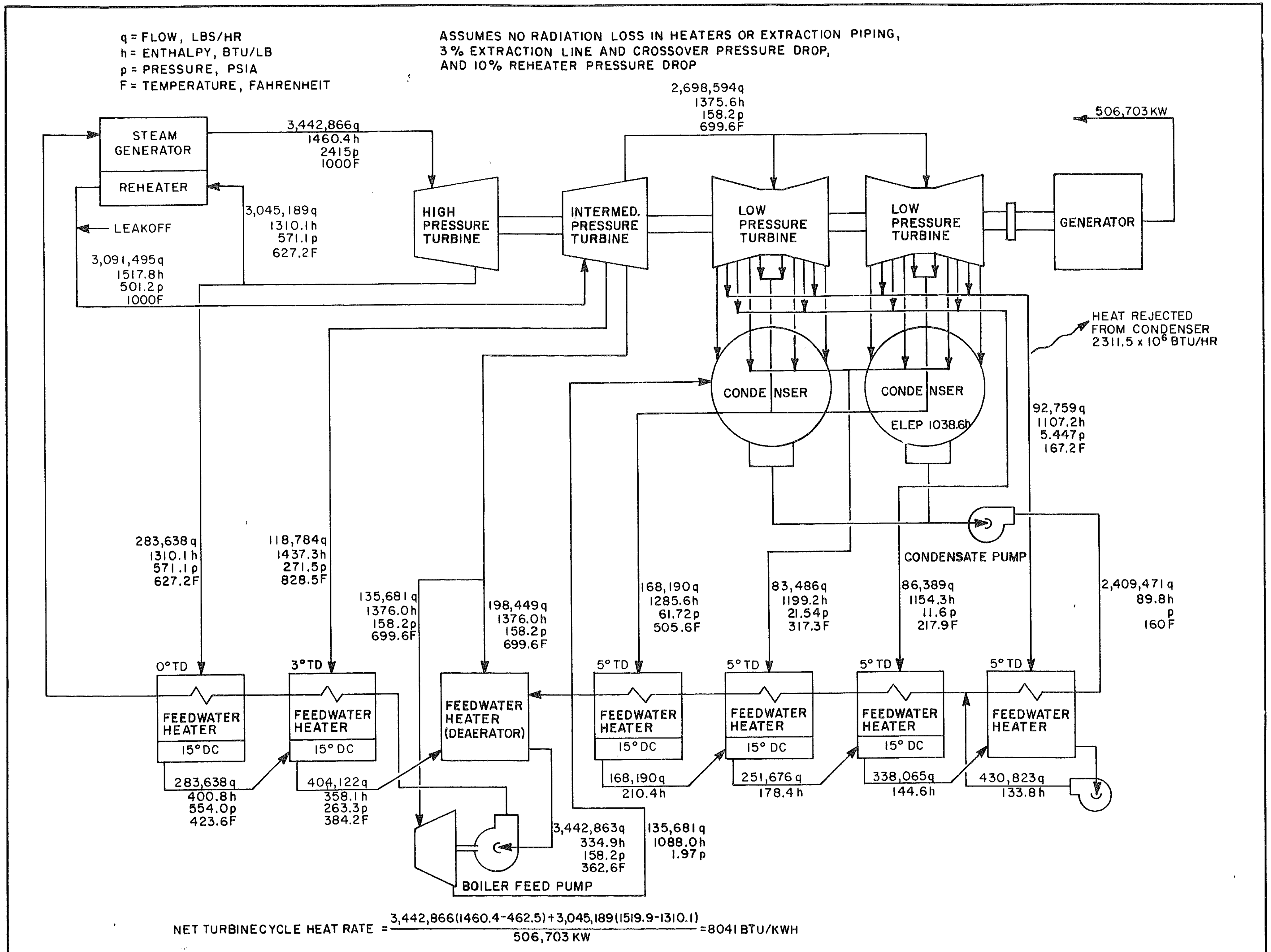
The proposed Unit 4 will require the delivery of an additional estimated 2.2 million tpy (2.0 million mtpy) of western sub-bituminous coal from Peabody's Big Sky Mine near Colstrip, Montana. This will increase coal deliveries to the Clay Boswell Steam Electric Station to approximately 4.5 million tpy (4.1 million mtpy) when the Unit 4 becomes operational in 1980. The coal will be transported by the Birlington Northern along the same railroad route as the coal for the existing 3 units. Providing coal for Unit 4 will require about 4 unit trains per week, increasing unit train arrivals at the Clay Boswell Station for off-loading to 8 to 9 unit trains per week. These trains will be similar to those already in service to transport coal between the Big Sky Mine and the Clay Boswell Station. By 1981, Burlington Northern estimates the annual average total freight rail movements between Grand Forks and the community of Cohasset to be 9.0 trains per day, consisting of an average of 2.1 unit coal trains and 6.9 other freight trains per day. No variation is expected in the monthly averages for unit coal train movements. Thus, of the Burlington Northern trains between Grand Forks and the community of Cohasset, 23% are expected to be unit coal trains, with about 60% of these unit coal train movements related to the Clay Boswell Station.

Present plans are to continue reloading coal at the Clay Boswell Station for use at the Syl Laskin Station.

Coal Supply

All the coal used in Unit 4 will be supplied by Peabody's Big Sky Mine as is the coal used in the existing 3 units. Coal will be delivered under the existing Coal Supply Agreement (7) and amendments between MP&L and Peabody. Table II-12 presents the "as received" coal average analyses, variations in coal analyses, and design performance coal analyses for coal delivered at the Clay Boswell Station from the Big Sky Mine.

MP&L's proposed air quality control system for Unit 4 at the Clay Boswell Station is designed for coal with an upper limit of 2.8% sulfur (64). To insure that the "as received" coal does not exceed this upper limit, sampling and analyses will be necessary before the coal is unloaded and burned. It also may be desirable to blend the coal to decrease the variation in sulfur content of the coal "as received". MP&L and Peabody probably will have to negotiate "rejection points" as provided for in the Coal Supply Agreement (6) so that coal containing more than 2.8% sulfur can be rejected by MP&L.



HEAT BALANCE - PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

FIGURE II-13

Raw Materials Handling

Many of the raw materials handling facilities for Unit 4 are shared with the existing 3 units. Coal for Unit 4 is supplied by the Big Sky Mine in Colstrip, Montana. Lime supply and handling for Unit 4 are described later in this section.

Coal Consumption. The Unit 4 steam generator or boiler at the Clay Boswell Station will burn western sub-bituminous coal from the Big Sky Mine as do the other 3 units. Estimated coal consumption in Unit 4 is based on coal having an "as received" heating value of 8,610 Btu per lb (4,783 kg-cal per kg) as presented in Table II-12, and the net unit rating and estimated operating parameters listed in Table II-33. Table II-34 presents the estimated quantities of coal to be consumed at Unit 4. The maximum coal consumption rate for Unit 4 of 298.5 tph (270.8 mtph), when added to the maximum coal consumption for the existing 3 units of 289.7 tph (262.6 mtph), will result in a maximum coal consumption of approximately 600 tph (544 mtph).

Coal Handling. The existing coal reclaim system is designed to handle 800 tph (726 mtph) and, therefore, is capable of providing coal for all 4 units when reclaiming from inactive or active storage piles (65). However, only 6 hr per day would be available for maintenance when there are no unit train deliveries. Thus, MP&L plans to install a new reclaim system to service Unit 4.

Planned modifications to the existing coal handling facilities to accommodate Unit 4 have not been fully defined. Tentative plans are for this new reclaim system to consist of a fully enclosed conveying system to service Units 3 and 4 only, with an enclosed gallery linking the new conveyor with Units 1 and 2. The existing conveyor system for Units 1 and 2 will then be committed to standby service. Capabilities of this new system to supply the required coal to each units' bunkers are presented in Table II-35.

Lime. The proposed air quality control system for Unit 4 will use a lime absorber system for flue gas desulfurization (67). The present proposal is to use lime with the possible injection of fly ash into the lime slurry. Future consideration may be given to the possible use of limestone as a substitute for lime (67).

Lime consumption rate in the absorber system will be 4.5 tph (4.1 mtph) for average design conditions or 32,000 tons per year (tph) (29,030 metric tons per year) (mtpy) when burning 1.03% sulfur coal. When burning high-sulfur coal (2.8%), the design consumption rate will be 13 tph (12 mtph) or 91,000 tpy (82,554 mtpy).

A new lime handling facility will be installed with provision for 7,700 tons (6,985 mt) of closed-silo storage capacity. From storage the lime will be reclaimed and delivered to the lime preparation facility using two 15 tph (13.6 mtph) pneumatic systems.

Lime can be delivered to the facility by pneumatic unloading trucks, pneumatic unloading rail cars, closed rail hopper cars, or 24 ton (21.7 mt) dump trucks. Lime will be unloaded in a shed using a pneumatic system rated at

TABLE II-33
ESTIMATED OPERATING PARAMETERS - UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 4
Net generator capacity rating	
kw	504,000
Net heat rate	
Btu per kw	10,200
kg-cal per kw	2,574
Estimated capacity factor	
%	71.4
Retirement date	
year	2015

TABLE II-34
ESTIMATED COAL CONSUMPTION RATES - UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

Estimated Coal Consumption	Unit 4
Average hourly	
tons	213.2
metric tons	193.4
Maximum hourly	
tons	298.5
metric tons	270.8
Average annual	
tons	1,867,239
metric tons	1,693,931
Maximum annual	
tons	2,615,180
metric tons	2,372,451
Total	
tons	65,353,365
metric tons	59,287,566

TABLE II-35
COAL RECLAIM SYSTEM CAPACITY - UNITS 1, 2, 3, AND 4
CLAY BOSWELL STEAM ELECTRIC STATION (68)

Unit	Feed Capacity tph	Feed Capacity mtph	Bunker Fill Time hr
1 and 2	500[a]	454[a]	4.3
3	800	726	5.8
4	1,000	907	7.4
Total			17.5

[a] Reduced capacities due to tripper limitations

approximately 60 tph (54.4 mtph). The pneumatic system will be completely automatic with provision for manual override. A dust control system will be included to minimize fugitive dust potential, with buildings maintained under slight negative pressure to provide "in-flow" of dust.

MP&L has not entered into contracts or purchase arrangements for lime delivery. However, it is anticipated that the lime can be purchased from Minnesota vendors with delivery by either rail or truck.

Chemicals and Supplies. Chemicals and supplies for Unit 4 will be handled in the same way as for Units 1, 2, and 3.

Petroleum Fuels. Petroleum fuels for Unit 4 will be delivered and stored in the same way as for Units 1, 2, and 3.

Facilities Operation

The major components of the Clay Boswell Steam Electric Station's Unit 4 are described in this section. Many of the elements in the Unit 4 electric generating facility are typical of modern coal-fired steam electric power facilities, as are the major components of Units 1, 2, and 3 (Figure II-5).

Power Generation Cycle

Steam Generator. The Unit 4 steam generator or boiler will be an indoor-boiler, water-cooled furnace, single-drum unit. It will be a pulverized coal-fired unit of the dry-bottom type (68).

This unit will have the capacity to continuously produce 3,807,000 lb (1,726,826 kg) per hr of superheater outlet steam at 2,660 psig (183 b) and 1,005°F (541°C) while simultaneously reheating 3,357,000 lb (1,522,710 kg) per hr of steam from conditions of 628 psig (43.3 b) and 634°F (334°C) to 1,005°F (541° C). These conditions are based on a feedwater temperature of 487.9°F (253.3°C) and an inlet air temperature of 80°F (27°C). This output matches the steam flow and pressure conditions at the 5% overpressure with valves wide open rating (69).

The steam generator will have a balanced-draft design, utilizing forced-draft fans and primary-air fans to introduce air into the furnace. Gases will be removed from the steam generator by induced-draft fans. The fans will be controlled to maintain a slightly lower-than-atmospheric pressure in the furnace.

Coal will be pulverized and then conveyed into the boiler furnace by the primary air.

Steam Turbine-Generator. The steam turbine-generator will be rated at 554,000 kw gross capacity at 5% overpressure with valves wide open. It will be a tandem compound machine with 4 exhaust flows having 25 in. (64 cm) last-stage buckets. The steam turbine-generator will be rated at 506,703 kw (maximum guaranteed capacity) with steam conditions of 2,400 psig (165 b) and 1,000 °F (538°C) (70).

Condenser and Circulating Water System. The condenser for Unit 4 will utilize 2 condenser shells with a single-pass arrangement for each shell. The cold circulating water will be introduced into the inlet of the low-pressure shell, passing through the condenser tubes, picking up the heat from steam condensation in that shell, and then discharging through the outlet. This warmed circulating water will be introduced into the inlet of the high-pressure shell, picking up the heat from steam condensation in that shell, and then being returned to the cooling tower (71). The condenser for Unit 4 will have the design characteristics presented in Table II-36.

TABLE II-36
PRINCIPAL DESIGN CONDITIONS - UNIT 4 CONDENSER
CLAY BOSWELL STEAM ELECTRIC STATION (72)

Design Parameter	Design Condition
Effective surface	
sq ft	260,000
sq m	24,154
Circulating water flow	
gpm	135,900
lpm	514,423
Cold water temperature	
°F	87.5
°C	30.9
Temperature rise	
°F	34.0
°C	18.9
Average exhaust pressure	
Hg absolute, in.	3.66
Hg absolute, mm	93
Heat absorbed	
Btu per hr	2.311×10^6
kg-cal per hr	583×10^6

The heated circulating water returned to the cooling tower will be cooled by evaporation and convection as air is moved through the tower by motor-driven fans. When the water reaches the cold water basin, it will be pumped back to the condenser. Design parameters for the Unit 4 cooling tower are presented in Table II-37.

TABLE II-37
PRINCIPAL DESIGN CONDITIONS - UNIT 4 COOLING TOWER
CLAY BOSWELL STEAM ELECTRIC STATION (68)

Design Parameter	Design Condition
Water flow rate	
gpm	146,200
lpm	553,412
Heat rejection rate	
Btu per hr	2.5×10^9
kg-cal per hr	0.63×10^9
Dry bulb temperature	
°F	82
°C	27.8
Wet bulb temperature	
°F	71
°C	21.7
Approach to wet bulb temperature	
°F	16
°C	8.9
Range (warm water temperature less cold water temperature)	
°F	34
°C	18.9

Water Systems

The water systems for the proposed Unit 4 are related to the water systems for existing Units 1, 2, and 3. The water balance for the entire plant including Unit 4 is presented in Figure II-14.

Intake System. The existing water intake structure for Units 1, 2, and 3 will be expanded to meet the water requirements of Unit 4. Expansion of the existing intake structure will entail upgrading the main floor and superstructure to accommodate larger pumps and larger maintenance areas. The 2 intake bays on the lower level of the intake structure will remain basically unchanged.

Makeup water requirements for Unit 4 will be provided by replacing three 3,800 gpm (14,384 lpm) service and makeup pumps for Units 1, 2, and 3 with three 6,800 gpm (25,740 lpm) pumps with higher discharge heads. These 3 new pumps, together with a fourth 3,800 gpm (14,384 lpm) pump, will provide the service and makeup water requirements for the entire Clay Boswell Station.

Along with modifications to the intake structure for Unit 4, the impellers on the four 27,000 gpm (102,203 lpm) pumps for Units 1 and 2 condenser cooling water will be trimmed to reduce the water requirements for these units. It is estimated that the water intake requirements for Units 1 and 2 will be reduced by 9,000 gpm (34,068 lpm) when they are operating at maximum capacity. The reduction in flow to Units 1 and 2 condenser cooling water is designed to balance the additional water requirements of Unit 4, so that total water withdrawal at the intake structure for the Clay Boswell Station will not increase significantly (73).

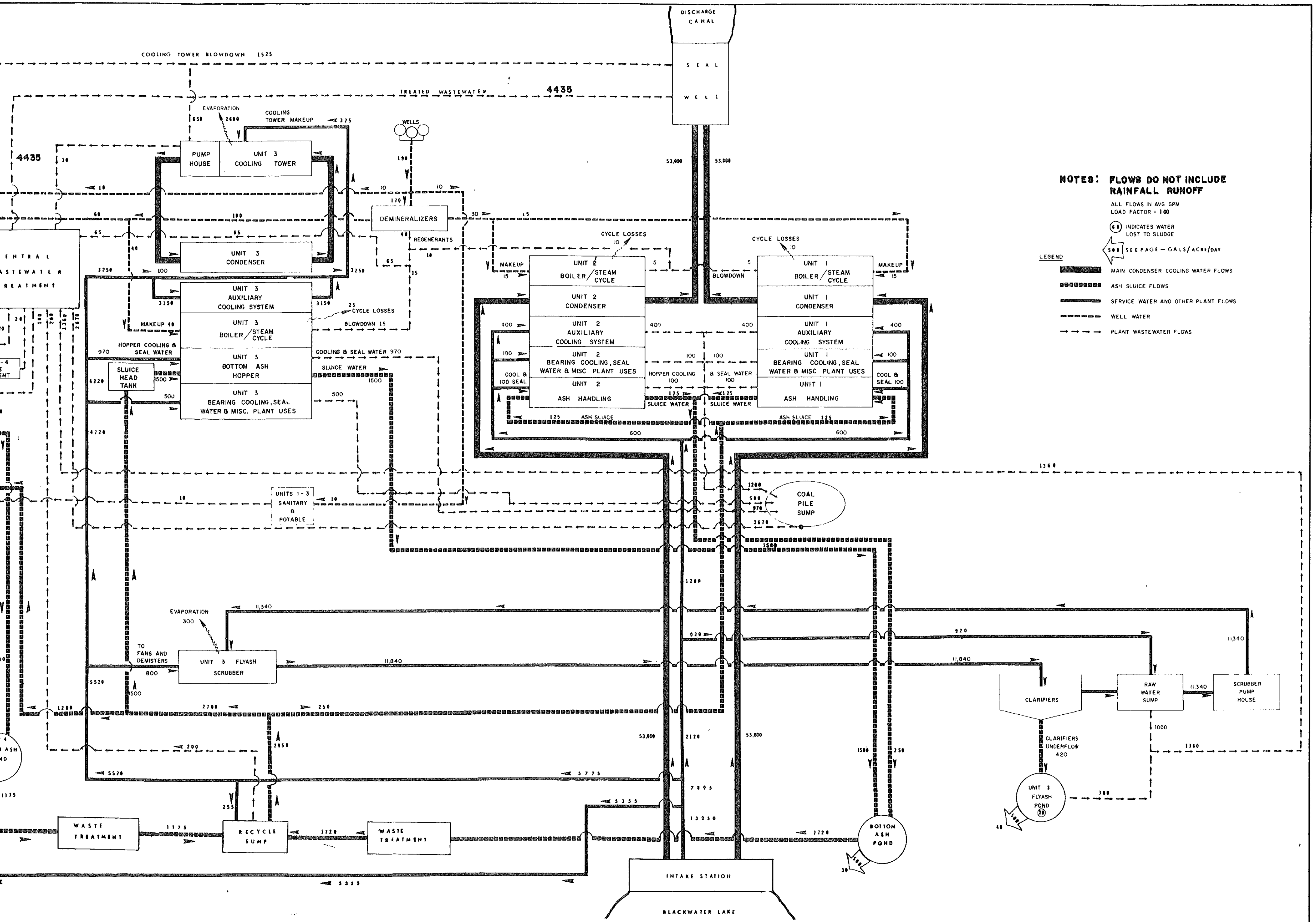
In addition, the existing 1,700 gpm (6,435 lpm) fire pump will be replaced with one of the 3,800 gpm (14,384 lpm) makeup pumps removed from service. This pump will meet the fire protection requirements of Units 1, 2, 3, and 4.

Condenser Cooling Water System (74). An evaporative mechanical-draft cooling tower will be used to dissipate waste heat from the main condenser cooling water system. The recirculating flow in this system will be approximately 135,900 gpm (514,423 lpm). Waste heat from the boiler steam cycle will be transferred in the condenser to this recirculating flow, raising the temperature of the water 34°F (18.9°C) under design conditions.

For operation of the evaporative cooling tower, condenser cooling water flows over a matrix of small passages in the towers where moving air contacts the water. As the water falls through the tower and is cooled a portion of the water evaporates to the atmosphere. The remaining water will be collected in a basin beneath the tower and returned to the condensers. In addition, a small amount of the cooling water will be entrained in the air and released to the atmosphere in liquid form. This phenomenon, termed "drift", will be minimized effectively by the use of mist eliminators on the cooling tower exhaust.

The rate of evaporation in the cooling tower will depend directly upon instantaneous meteorological conditions and unit load. Of particular importance are the wet-bulb temperature and relative humidity. The annual average rate of water loss in the proposed Unit 4 cooling tower due to evaporation and drift will be approximately 3,500 gpm (13,249 lpm) at 100% load factor, based on average meteorological conditions. Under extreme meteorological conditions, this water loss will amount to approximately 4,500 gpm (17,034 lpm) when the unit operates at maximum capacity. A monthly tabulation of the estimated rate of water loss based on average monthly meteorological conditions is presented in Table II-38.

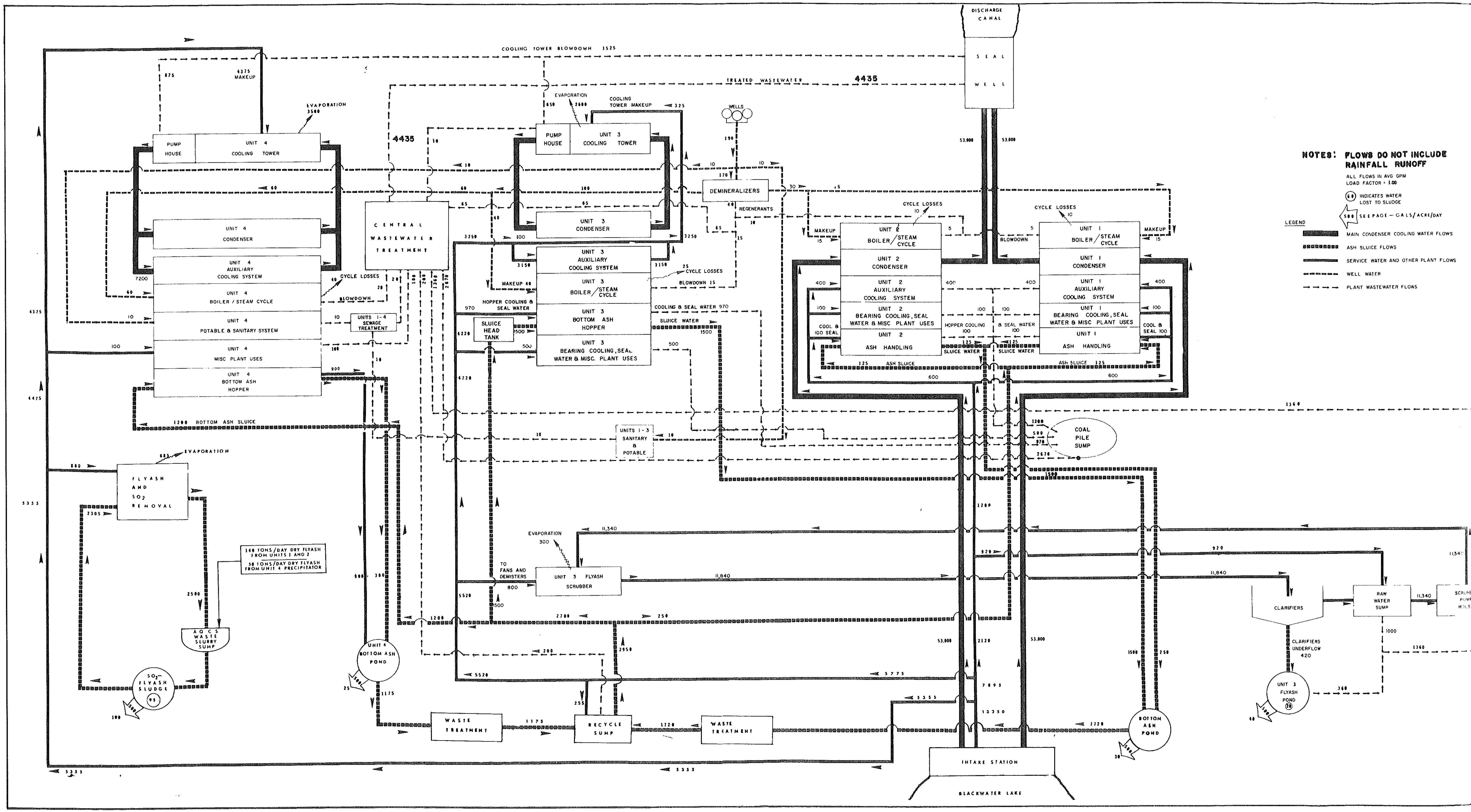
The loss of water in the cooling tower will result in a continuous concentrating effect on the dissolved constituents of the recirculating water. Consequently, blowdown from the recirculating water system will be necessary to maintain the condenser cooling water in usable condition. The Unit 4 cooling tower will be designed to operate at 5 cycles of concentration. The quantity of blowdown will depend on the quantity of water lost to drift and evaporation and, therefore, directly depends on meteorological conditions. Cooling tower blowdown is estimated to average 875 gpm (3,312 lpm) annually at maximum capacity with a maximum of 1,125 gpm (4,258 lpm) under extreme meteorological



WATER BALANCE
UNITS 1, 2, 3, AND PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L, "ENVIRONMENTAL REPORT", EXHIBIT II-B-13

FIGURE II-14


NOTES: FLOWS DO NOT INCLUDE RAINFALL RUNOFF
ALL FLOWS IN AVG GPM
LOAD FACTOR = 1.00
INDICATES WATER LOST TO SLUDGE
SEEPAGE - GALS/ACRE/DAY
LEGEND
MAIN CONDENSER COOLING WATER FLOWS
ASH SLUICE FLOWS
SERVICE WATER AND OTHER PLANT FLOWS
WELL WATER
PLANT WASTEWATER FLOWS
DISCHARGE CANAL
SEAL WELL
COOLING TOWER BLOWDOWN 1525
TREATED WASTEWATER 4435
EVAPORATION 3500
PUMP HOUSE
UNIT 4 COOLING TOWER
UNIT 4 CONDENSER
UNIT 4 AUXILIARY COOLING SYSTEM
UNIT 4 BOILER / STEAM CYCLE
UNIT 4 POTABLE & SANITARY SYSTEM
UNIT 4 MISC PLANT USES
UNIT 4 BOTTOM ASH HOPPER
1200 BOTTOM ASH SLUICE
CYCLE LOSSES
BLOWDOWN
UNITS 1-4 SEWAGE TREATMENT
CENTRAL WASTEWATER TREATMENT
EVAPORATION 2600
COOLING TOWER MAKEUP
UNIT 3 COOLING TOWER
UNIT 3 CONDENSER
UNIT 3 AUXILIARY COOLING SYSTEM
UNIT 3 BOILER/STEAM CYCLE
UNIT 3 BOTTOM ASH HOPPER
UNIT 3 BEARING COOLING, SEAL WATER & MISC. PLANT USES
MAKEUP 40
HOPPER COOLING & SEAL WATER
SLUICE HEAD TANK
COOLING & SEAL WATER 970
SLUICE WATER
WELLS
DEMINERALIZERS
REGENERANTS
UNIT 2 BOILER/STEAM CYCLE
UNIT 2 CONDENSER
UNIT 2 AUXILIARY COOLING SYSTEM
UNIT 2 BEARING COOLING, SEAL WATER & MISC PLANT USES
UNIT 2 ASH HANDLING
UNIT 1 BOILER/STEAM CYCLE
UNIT 1 CONDENSER
UNIT 1 AUXILIARY COOLING SYSTEM
UNIT 1 BEARING COOLING, SEAL WATER & MISC PLANT USES
UNIT 1 ASH HANDLING
ASH SLUICE
COOL & 100 SEAL
UNITS 1-3 SANITARY & POTABLE
COAL PILE SUMP
FLYASH AND SO_2 REMOVAL
EVAPORATION
140 TONS/DAY DRY FLYASH FROM UNITS 1 AND 2
50 TONS/DAY DRY FLYASH FROM UNIT 4 PRECIPITATOR
AQCS WASTE SLURRY SUMP
SO_2-FLYASH SLUDGE
UNIT 4 BOTTOM ASH POND
TO FANS AND DEMISTERS
UNIT 3 FLYASH SCRUBBER
EVAPORATION 300
WASTE TREATMENT
RECYCLE SUMP
WASTE TREATMENT
INTAKE STATION
BLACKWATER LAKE
BOTTOM ASH POND
CLARIFIERS
CLARIFIERS UNDERFLOW 420
UNIT 3 FLYASH POND
RAW WATER SUMP

conditions. Table II-38 shows the amount of blowdown required on a monthly basis under average meteorological conditions. Blowdown will be from the cold side of the cooling tower basin into the Units 1 and 2 condenser seal well. The

TABLE II-38
ESTIMATED MONTHLY AVERAGE EVAPORATION AND DRIFT, BLOWDOWN, AND MAKEUP QUANTITIES
UNIT 4 COOLING TOWER - CLAY BOSWELL STEAM ELECTRIC STATION (75)

Month	Evaporation and Drift		Blowdown		Makeup	
	gpm	lpm	gpm	lpm	gpm	lpm
January	2,680	10,145	670	2,536	3,350	12,681
February	2,480	9,388	620	2,347	3,100	11,734
March	2,990	11,318	750	2,839	3,740	14,157
April	3,260	12,340	815	3,085	4,075	15,425
May	3,730	14,119	935	3,539	4,665	17,658
June	4,010	15,179	1,005	3,804	5,015	18,983
July	4,450	16,845	1,115	4,221	5,565	21,065
August	4,400	16,655	1,100	4,164	5,500	20,819
September	3,850	14,573	965	3,653	4,815	18,226
October	3,630	13,741	910	3,445	4,540	17,185
November	3,040	11,507	760	2,877	3,800	14,384
December	2,770	10,485	695	2,631	3,465	13,116

estimated condenser recirculation water quality, and therefore, the cooling tower blowdown quality, are presented in Table II-39.

Makeup to the recirculating water system will be necessary to replenish water lost by drift, evaporation, and blowdown. The actual rate of makeup will be controlled by the water level in the cooling tower basin. The makeup rate is estimated at an annual average of 4,375 gpm (16,561 lpm) at maximum capacity and at a maximum of 5,625 gpm (21,252 lpm) under extreme meteorological conditions. Table II-38 presents the average monthly makeup water required for the recirculating water system.

Water chemistry in the cooling tower will be regulated by the addition of hydrochloric acid for pH and scale control. The level of pH will be maintained at approximately 7.5 units, resulting in a slightly positive Langelier Saturation Index (LSI). This eliminates the need for utilization of zinc, chromium, phosphorus, or other corrosion-inhibiting chemicals.

Control of biological fouling is an important function in cooling water chemistry. The existence of slime and algal growth on cooling tower surfaces retards heat transfer and reduces efficiency. In addition, serious pitting of metal surfaces can result from the differential oxygen concentrations created by biological growth. An intermittent chlorination system has been selected to control biological fouling in the Unit 4 cooling tower. Chlorination will take

TABLE II-39
ESTIMATED AVERAGE RECIRCULATION WATER AND BLOWDOWN QUALITY[a]
UNIT 4 CONDENSER COOLING SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION (76)

Parameter	
pH	7.8
Total dissolved solids (TDS), mg per liter	900
Chloride,[b] mg per liter	516
Sulphate, mg per liter	35
Bicarbonate, mg per liter	12
Sodium, mg per liter	28
Calcium, mg per liter	180
Magnesium, mg per liter	67
Carbon dioxide, mg per liter	1
Nitrate nitrogen, mg per liter	0.7
Ammonia nitrogen, mg per liter	0.6
Silica (as SiO_2), mg per liter	46

[a] Based on 5 cycles of concentration and makeup water quality equivalent to river water quality as shown in Table II-28.

[b] Assumes HCl will be used for circulating water pH control (102 mg per liter dosage).

place once per shift for a duration of ½ hr. When chlorine is added to water, it forms hypochlorous acid, hypochlorite ions, and chloramines. Hypochlorous acid and hypochlorite are very effective biocides, while chloramines are significantly less effective.

A residual chlorine monitor will be provided at the cooling tower basin in order to control chlorine residual levels in the circulating water system. The total residual chlorine concentration discharged in the blowdown from the cooling tower basin is limited to a concentration not to exceed 0.2 mg per liter for more than 2 hours per day. For a continuous blowdown, the residual chlorine level discharged is limited to the lowest detectable limit of an approved analytical method or 0.03 mg per liter 30 day average and 0.05 mg per liter maximum.

Boiler Water System (77). Boiler makeup water for the proposed Unit 4 will be withdrawn from the existing supply system presently serving the Units 1, 2, and 3 boiler makeup and potable water systems. A third well will be added to this system to meet the increased requirements. It is expected that the existing 2 train demineralizer system will operate at its design specifications of 270 gpm (1,022 lpm) providing for the additional demand for demineralized water. This demineralizer system will be adequate to supply a continuous 65 gpm (246 lpm) for Units 1, 2, and 3 and an additional continuous 100 gpm (379 lpm) for Unit 4. Of this 100 gpm, approximately 20 gpm (76 lpm) will replace system steam losses and 40 gpm (151 lpm) will replace blowdown (including the steam produced in the flash tank as blowdown). The remainder will be required for regeneration.

The regeneration cycle, which can be expected to occur once every 3 days for each train for a period of several hours, consists of a backwash, regeneration, and rinse cycle for both the cation and anion exchangers. Approximately 60,000 gallons (227,118 liters) of regenerant waste will be produced when the system is regenerated. It has been estimated that an additional average of 20 gpm (76 lpm) of demineralized water will be required for demineralizer regeneration with the addition of Unit 4. This quantity is based on current operating procedures. Normally, however, 5 to 10% of the water is wasted in the regeneration cycle (78). This indicates that a large amount of demineralized water presently is being lost during regeneration.

If present operating procedures are continued, regeneration wastes will have approximately the same average composition as the present wastes. If regenerant water volume is reduced, the wastes will become more concentrated. Table II-40 presents the estimated discharge loadings.

TABLE II-40
ESTIMATED DAILY DISCHARGE LOADING QUANTITIES FOR
VARIOUS CONSTITUENTS - UNIT 4 REGENERATIVE WASTEWATERS
CLAY BOSWELL STEAM ELECTRIC STATION (79)

	Discharge Loading	
Parameter	lb per day	kg per day
Calcium (as $CaCO_3$)	500	227
Magnesium (as $CaCO_3$)	260	118
Sodium + Potassium	1,996	905
Chloride	2,842	1,289
Sulfate	38	17
Iron	0.6	0.3

The demineralizer wastes may be expected to have extremes of pH and total dissolved solids as well as some suspended solids. Total dissolved solids values in the range of 7,500 mg per liter are typical. However, it is expected that the wastes from Unit 4 will be considerably more diluted if current practices are continued.

Since the demineralizers are regenerated in stages, the constituents of the waste discharge vary widely. Demineralizer regeneration wastes for the entire demineralizer system will be routed to a holding basin for equalization and self-neutralization. This basin will be sized to handle 2 regenerations of the system. The wastes will then flow to neutralization tanks equipped with automatic acid and caustic feed. Sensors for pH at the influent and effluent of these tanks will provide automatic feedback control of neutralization. The flow of these wastes then will be discharged to the central waste treatment facility.

A full flow condensate polishing demineralizer will be installed for Unit 4 startup. High-purity condensate normally will place very little load on this system, except during startup and during incidents of condenser leakage. The condensate polishing demineralizer will normally require regeneration approximately once every 2 months. It also will contribute waste discharge loadings substantially smaller than the makeup demineralizer system. Regeneration wastes for this system will flow to the central waste treatment facility.

Boiler blowdown is required to limit chemical concentrating effects inside the boiler caused by steam losses, unavoidable attrition of metal surfaces, and chemical additions. Blowdown (including the steam lost in the flash tank) removes approximately 40 gpm (151 lpm) of water from the boiler. It is anticipated that hydrazine and ammonia will be added to the boiler as for Unit 3. Chemical characteristics of Unit 4 boiler water are expected to be similar to those of Unit 3. The boiler water is expected to have a pH of 8.7 to 9.2 and to contain 0.1 mg per liter of ammonia as NH_3 and 0.1 mg per liter of silica. When boiler water is released to the atmosphere, approximately one-half immediately flashes to steam, roughly doubling the ammonia and silica concentrations of the remaining blowdown water. Boiler blowdown will be routed to the central waste treatment facility.

Bottom Ash Handling System (80). Bottom ash resulting from the combustion of coal falls to the bottom ash hopper located directly beneath the boiler, where it will be stored for intermittent removal by water sluicing to the Unit 4 bottom ash disposal pond (Figure II-11).

The bottom ash handling system cycles water from the bottom ash hopper, to the bottom ash pond, and then returns the water to the bottom ash hopper. Overflow from the bottom ash pond is estimated to be 1,175 gpm (4,448 lpm). This water may require treatment to control its mineral content and scaling potential. After treatment, it will flow to the bottom ash recycle sump, where it will combine with the 1,720 gpm (6,511 lpm) of treated overflow from the Units 1, 2, and 3 bottom ash pond. From the recycle sump, the sluice water will be returned to the respective bottom ash hoppers for each unit. A blowdown for the entire plant of 200 gpm (757 lpm) from the bottom ash recycle sump will be conveyed to the central treatment facility for appropriate treatment before discharge. Federal effluent limitations restrict the quantity of discharge from the bottom ash handling system to 5% of the recirculating flow for new sources and 8% for existing sources.

Studies have been conducted at the Clay Boswell Station to determine water quality changes when water is in contact with ash. Table II-41 presents the water quality in terms of average increase in concentration over influent river water and also in terms of discharge loading in the blowdown, assuming average river water. In addition, the bottom ash pond and, therefore, the blowdown can be expected to have a total suspended solids (TSS) concentration in the range of 10 to 30 mg per liter if properly designed and operated.

Fly Ash and SO_2 Absorber System (81). A wet scrubber/absorber system will be used to remove particulates and sulfur dioxide (SO_2) from the Unit 4 steam

TABLE II-41
ESTIMATED BLOWDOWN QUALITY AND AVERAGE INCREASE IN CONCENTRATIONS OVER INFLUENT MISSISSIPPI RIVER WATER
UNIT 4 BOTTOM ASH HANDLING SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION (80)

Parameter	Change in Concentration	Blowdown Concentration
Calcium (as $CaCO_3$)		
mg per liter	200	285
Magnesium (as $CaCO_3$)		
mg per liter	-80	0
Sulfates		
mg per liter	100	108
Chloride		
mg per liter	0	4
Total dissolved solids (TDS)		
mg per liter	250	427

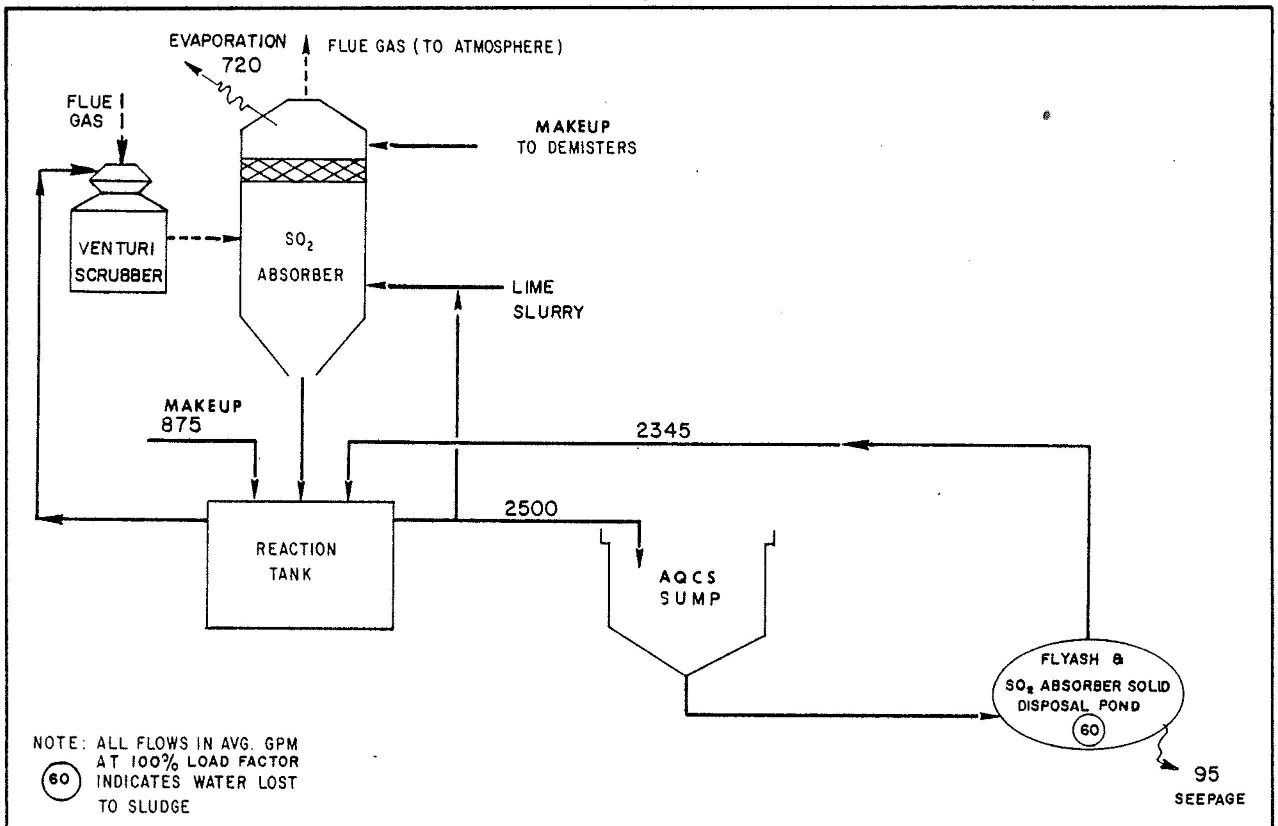
generator or boiler exhaust gases. A schematic diagram of this system is shown in Figure II-15. The flue gas first passes through the wet scrubber and then through the SO_2 absorber. In the SO_2 absorber, the gas is contacted with a lime/water slurry for removal of particulate matter and SO_2. The resulting lime/water slurry then flows to a reaction tank where the chemical reactions associated with absorption are completed. From the reaction tank, the slurry flows to a clarifier from which the clarified supernatant is recycled to the system. The concentrated sludge from the clarifier is sluiced to the fly ash scrubber sludge disposal pond. The supernatant from this pond is recycled to the system.

The absorber system will use a closed-loop water system, requiring no blowdown and resulting in no direct discharge. Water losses from this system result from evaporation in the scrubber (approximately 720 gpm) (2,725 lpm), entrainment in sludge to the disposal pond (60 gpm) (227 lpm), and seepage from the disposal pond (95 gpm) (360 lpm). Operation in the closed-cycle mode is possible because dissolved-solids concentrations resulting from evaporation are offset by sludge entrainment and disposal pond seepage, which in effect act as blowdown.

Makeup to the system occurs at the reaction tank and at the SO_2 absorber demisters, which must be washed down to avoid solids buildup. The quantity of makeup required is estimated at 880 gpm (3,331 lpm).

Auxiliary Cooling System (82). The auxiliary cooling water system is designed to cool the auxiliary equipment, which includes the following:

1. Main turbine lubrication oil coolers;
2. Boiler feed pump turbine lubrication oil coolers;
3. Condenser vacuum pump coolers;



FLY ASH AND SO_2 REMOVAL SYSTEM – PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-B-11

FIGURE II-15

4. Duplex alternator air coolers;
5. Soot blower air compressor inter and after coolers; and
6. Hydrogen coolers.

This equipment is cooled by a closed-loop water system which transfers excess heat to the circulating water through heat exchangers and dissipates it to the atmosphere in the Unit 4 cooling tower, raising the auxiliary cooling water temperature by approximately 10°F (5.6°C). This system will be designed to have a hot side temperature of 95°F (35°C) and a cold side temperature of 85°F (29 °C), and will require about 10,300 gpm (38,989 lpm) (83). Since the system uses the same circulating water as the main condenser cooling water system, the chemical water quality will be the same.

<u>Service Water System (84)</u>. An estimated 100 gpm (379 lpm) of service water for Unit 4 will be required for bearing cooling, pump seals, cleaning of equipment and floors, and other miscellaneous uses for the electric generating facility. This water will be supplied from the water intake structure by the makeup and service water pumps for Units 1, 2, 3, and 4.

Most of the service water used in the electric generating facility will be discharged to the floor drainage system, which is separate from the outdoor yard drainage system and the sanitary sewer. The floor drainage system runs directly to the central waste treatment system. Floor and equipment drains located throughout the electric generating facility will collect leaks from various pieces of equipment and washings from equipment and floors. During startup operations and at certain times during maintenance periods, a significant short-term flow may be expected in the floor drainage system. This flow will consist of wastes from cleaning of boiler firesides, air preheaters, and other miscellaneous equipment.

Normally, the wastewater in the floor drains may be expected to contain dirt, oil and grease, and cleaning solutions. In addition, coal dust, ash, fuel oil, lubricating oil, chemicals, and other materials may find their way to the floor drains. Generally, these materials are treated as wastewater before discharge. Large spills of such wastes must be handled specially to insure that they are not discharged to navigable waters.

Unit 4 floor drainage will flow to a gravity oil separation basin to remove free oil and grease. This unit will be designed for peak flow of 100 gpm (379 lpm). The effluent from the oil separator will be pumped to the central waste treatment facility. Accumulated oil and grease will be periodically conveyed from the basin to an oil concentrator for dewatering. The oil and grease then will be transferred to a storage tank for eventual removal from the Clay Boswell Station.

Potable Water and Sanitary System (85). Potable water for domestic purposes will be supplied from wells on the Station's site. Two such wells serve the domestic requirements for personnel at Units 1, 2, and 3. Another well will be added to the system to provide for the increased requirements resulting from the addition of Unit 4. Water for domestic purposes will be chlorinated. The additional demand for Unit 4 is estimated to be 10 gpm (38 lpm).

The sanitary sewage system will be separated from other waste collection systems. A prefabricated sewage treatment facility will be installed to handle sewage from the entire Station. The existing septic tanks serving Units 1 and 2 and the holding tank serving Unit 3 will be abandoned. The packaged sewage treatment plant is planned to consist of biological treatment (aeration), followed by clarification and chlorination. The effluent will be discharged to the discharge seal well for eventual release to the river. This effluent is expected to amount to 20 gpm (76 lpm) on a daily average basis for all 4 units. Sludge generated at the sewage treatment facility will be trucked off-site for appropriate disposal by a licensed contractor.

Approximately 1,200 construction workers will be present at the Station during the peak construction period. An appropriate number of portable chemical sanitary facilities will be provided on-site to accommodate all construction personnel. Wastes generated will be disposed of off-site in a regulatory approved manner by a licensed contractor, and no on-site discharge of sanitary wastes is expected.

Contaminated Rainfall Runoff. Rainfall runoff from the coal storage pile and outdoor coal handling facilities may contain significant amounts of suspended solids and may be acidic. This runoff must be collected and treated before discharge (86). The existing coal pile will be diked and the perimeter of the dike will be channelized and graded to collect the runoff as shown in Figure II-16. The channels will be designed to prevent premature deposition of solids, infiltration and erosion of the channel. Runoff will flow in the unsealed channels to a wet well and, subsequently, to a settling pond. An overflow weir at the wet well will prevent flooding of the settling pond in the event that its design capacity is exceeded.

The coal pile dike drainage channels, wet well overflow weir, and settling pond are designed to handle the 10-year, 24-hr rainfall event, which is 3.75 in. (9.53 cm) at the Clay Boswell Station (87). Based on a coal pile area of 24 acres (9.7 hectares), a coal pile transfer and surrounding area of 6 acres (2.4 hectares), and a runoff coefficient of 0.7, the runoff is calculated to be 2.1×10^6 gallons (7.9×10^6 liters). In addition, provision will be made in the settling pond for storage of settled solids until the pond bottom can be cleaned. It is estimated that this amount is 300,000 gallons (1,135,592 liters) per year.

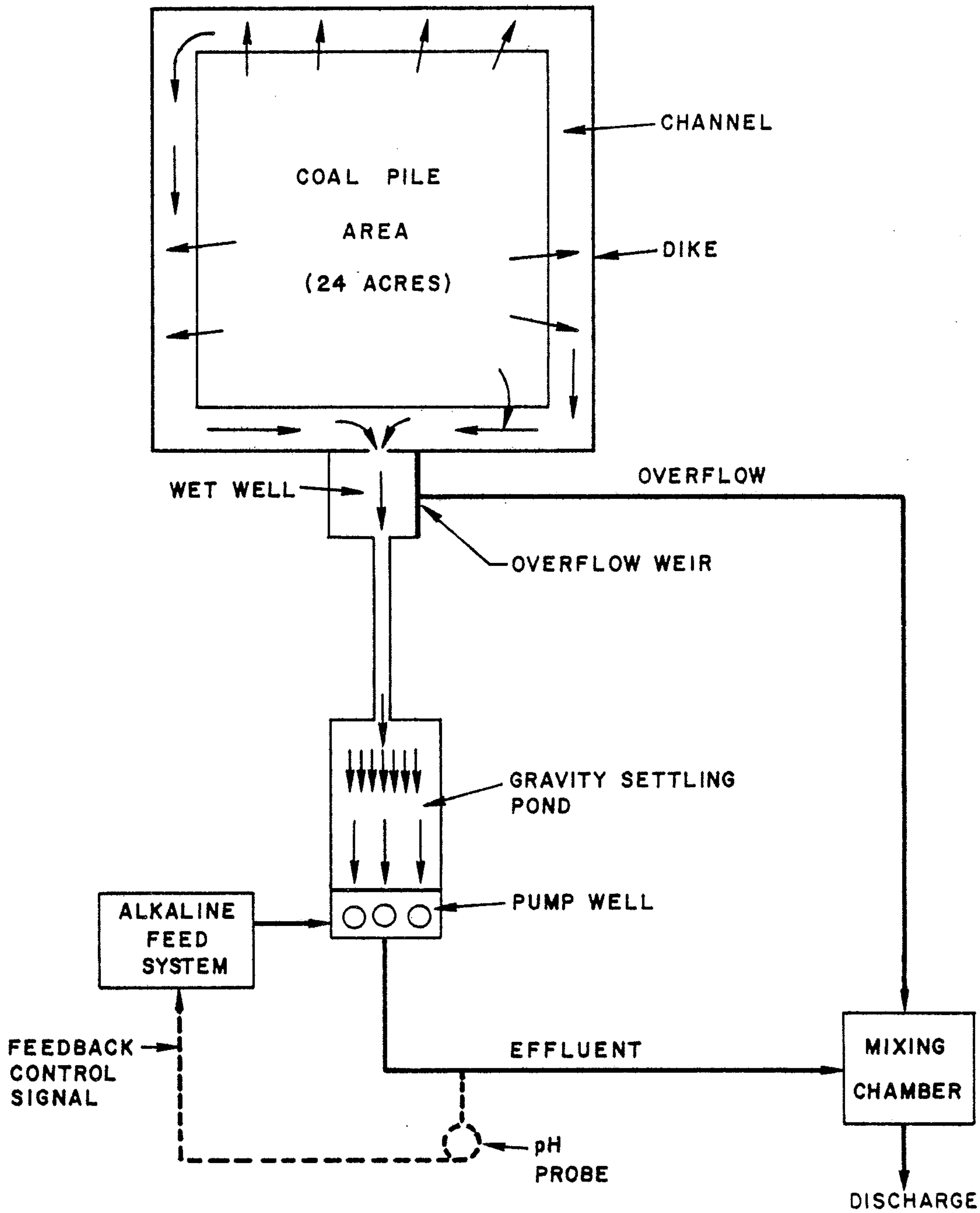
After settling has occurred, the effluent will flow to a pump well in the central waste treatment facility for neutralization. A pH sensor in the pump discharge pile will provide feedback control to an automatic chemical feed for pH adjustment. Pump operation should provide sufficient mixing to insure homogeneity of the effluent. The effluent will be pumped to a mixing chamber with subsequent discharge to the discharge seal well and the river. In addition, overflow that may occur from the wet well overflow weir will flow to this mixing chamber for subsequent discharge.

Solids which will be periodically cleaned from the bottom of the settling pond will be disposed of in the fly ash reclamation area.

<u>Equipment Cleaning Wastes</u>. Air preheaters are heat exchangers which transfer heat from the hot steam generator exhaust gases to the incoming combustion air. During operation, soot and fly ash collect on the heat exchanger surfaces, retarding efficient operation and creating a potential for plugging due to particulates and corrosion due to sulfur contaminants. These same materials collect on the surfaces of the boiler fireside and the economizers, hindering boiler performance. Often, it is necessary to clean the <u>air preheaters</u>, <u>boiler firesides</u> and <u>economizers</u> by washing to remove the objectionable materials and to prevent harmful corrosion. In the existing units, these washes have not been required, and if low sulfur coal is burned at the Clay Boswell Station's Unit 4, it is not unreasonable to expect that this type of wash will be very infrequent. However, should they be required, the wastes generated will be sluiced to the Units 1, 2, 3, and 4 bottom ash pond (88).

The waste volume generated per cleaning cycle depends largely upon the cleaning frequency. Larger waste volumes are generated when the cleaning cycles occur less often. Waste volumes generated during boiler fireside cleaning range from 20,000 to 700,000 gallons (75,706 to 2,649,714 liters). For air preheater cleaning, the volumes are typically 40,000 to 360,000 gallons (151,412 to 1,362,710 liters) for electric generating facilities of the same general size as Unit 4 (89).

The air preheater and boiler fireside cleaning wastes may be expected to have very high quantities of suspended and dissolved solids, as well as rust and dissolved metallic ions leached from the soot. The concentrations of these



COAL PILE RUNOFF TREATMENT FACILITY — PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT VI-9

FIGURE II-16

constituents, like the waste volume, depend upon the cleaning frequency. Low pH values are typical, with pH being most dependent upon the sulfur content of the fuel, and whether or not alkaline cleaning solutions are used.

Periodic internal cleaning of boiler tubes sometimes is necessary to remove boiler scale and maintain efficient performance. Boiler scale consists of salts precipitated from the boiler water and corrosion products. Despite preventive measures taken in boiler feedwater chemistry, precipitation occurs in the local area of the boiler tubes due to supersaturation of the salts at the heated tube surface. These salts may include calcium carbonate and sulfate, calcium and magnesium silicates, phosphates, and magnesium hydroxide. Corrosion products will contain iron and copper oxides, as well as possible trace amounts of aluminum, nickel and zinc (90).

Boiler tubes will be cleaned during scheduled maintenance shutdowns using chemicals specially chosen after analysis of the boiler scale. Cleaning frequency will depend upon boiler water chemistry and may well range from twice a year to once every eight years. A preoperational cleaning will be necessary to remove mill scale from the surfaces as well as dirt, oil, and grease left during construction.

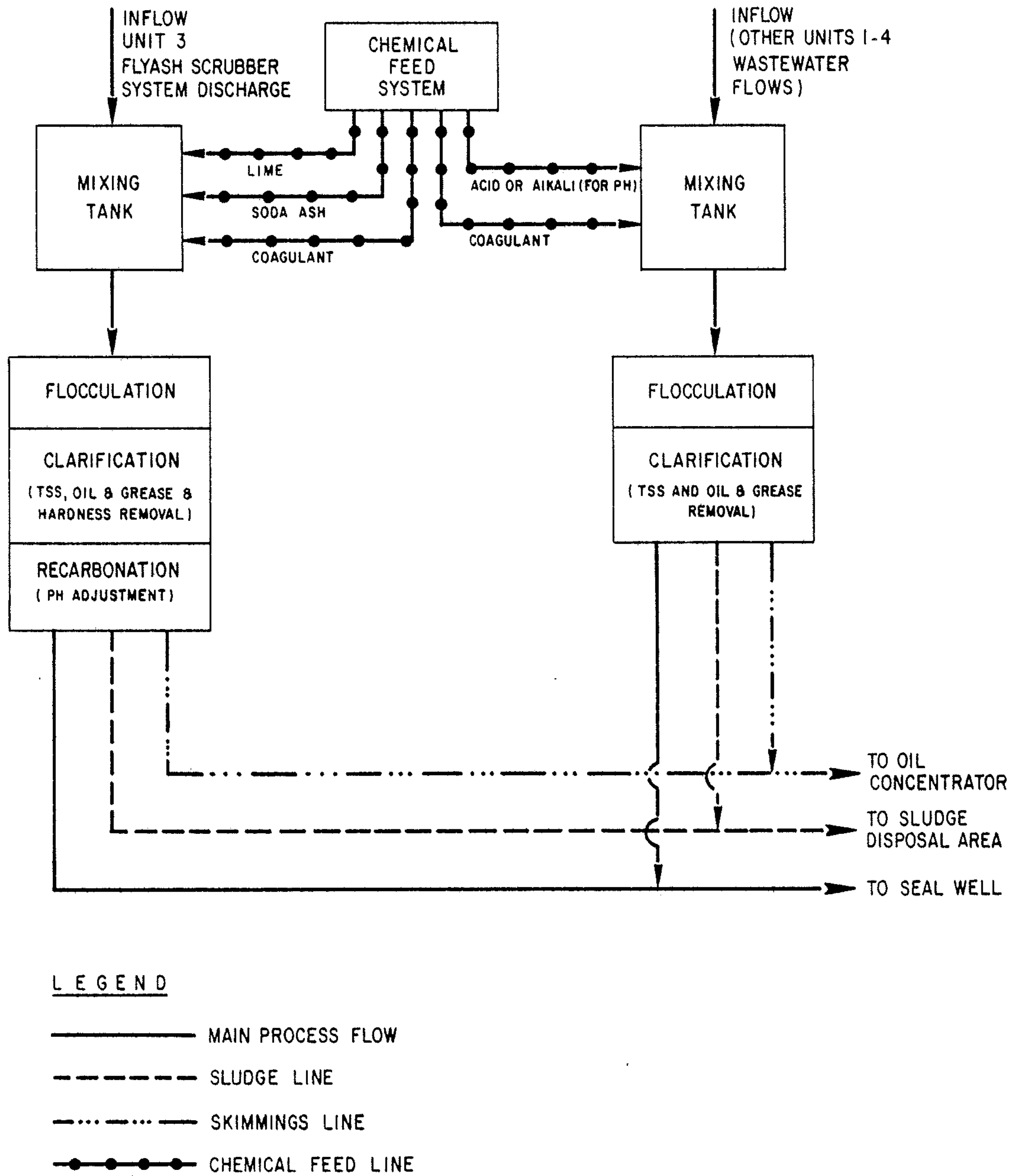
Boiler tube cleaning wastes will be routed to a holding pond where they will be stored until they are collected and hauled off-site by a private contractor who will be responsible for their proper disposal. The proposed site for the holding pond is in the fly ash reclamation area. The largest volume of wastes expected in this pond will be from preoperational cleaning. While the waste volume will depend on the type and length of cleaning, this volume has been conservatively estimated to be 1.25 million gallons (4.73×10^6 liters). The holding pond will be sized for this volume.

Periodic cleaning of the cooling tower basin will be necessary to remove particulate material which settles out of the recirculating water. A water wash is used for this purpose and the wastewater will be routed to the central waste treatment facility. The primary pollutant in the wastewater will be suspended solids. The heavy suspended solids will be physically removed from the bottom of the basin and transferred to a sludge disposal area located on the old ash pond to the east of the electric generating facility.

Condensate, hydrogen, and air compressor coolers may be cleaned periodically to maintain efficient operation. Hydrochloric acid, detergents, and wetting agents may be used for cleaning. The cleaning wastes are small in volume and flow via the floor drainage system to the central waste treatment facility.

Central Waste Treatment System (91). All of the wastewater generated at the Clay Boswell Station, with the exception of cooling tower blowdown, once-through cooling water, and sanitary wastes, generally will be treated for pH adjustment, suspended solids, and oil and grease removal before discharge. In addition, Unit 3 fly ash scrubber blowdown and Unit 3 fly ash pond overflow will be treated before discharge. These treatments will occur at the new central waste treatment facility.

A flow diagram of the proposed treatment process is presented in Figure II-17. Table II-42 summarizes the characteristics of the influent wastes and the final treated effluent wastes. The Unit 1, 2, 3, and 4 wastewaters entering the central waste treatment facility will first flow to a mixing/neutralization tank where acid or caustic will be added as required for pH adjustment and coagulants



CENTRAL TREATMENT FACILITY — PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT VI-8

FIGURE II-17

TABLE II-42
INFLUENT AND TREATED EFFLUENT WASTE - UNITS 1, 2, 3, AND 4 CENTRAL WASTE TREATMENT FACILITY
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Units 1, 2, 3, and 4 Boiler Blowdown	Demineralizer Wastes	Bottom Ash Recirculation System Blowdown	Floor Drains	Coal Pile Sump Effluent	Untreated Composite Waste	Treated Composite Waste
Flow							
gpm	45	40	200	100	2,670	3,055	3,055
lpm	170	151	757	379	10,107	11,564	11,564
pH	8.7 to 9.2	6.5 to 8.5	4.0 to 7.0	7.0	7.0	4.0 to 9.2	6.0 to 9.0
Total dissolved solids (TDS)							
mg per liter	200	7,500	427	180	180	293	293
Total suspended solids (TSS)							
mg per liter	2	10	30	100	6	12	4
Oil and grease, mg per liter	-	-	-	20	-	1	<1
Sulfates, mg per liter	-	79	108	8	8	15	15
Chlorides, mg per liter	-	2,955	4	4	4	42	42
Calcium (as $CaCO_3$)							
mg per liter	-	520	285	85	85	103	103
Magnesium (as $CaCO_3$)							
mg per liter	-	270	0	57	57	56	56
Iron, mg per liter	-	214	-	-	-	3	3

will be added to assist in removing difficult-to-settle suspended and colloidal materials. Coagulants added to the waste form complexes with these materials, enmeshing them in rapidly settling aggregates called "flocs". Flash mixing for 4 to 6 min under design average flow will occur in the mixing/neutralization tank to insure homogeneity in the wastewater. The wastewater then will flow to a flocculator-clarifier where the waste will be flocculated and settled. The flocculator-clarifier will have an inner well for flocculation and an outer clarification chamber. Flocculation consists of gentle mixing of the waste to form the floc. The waste then flows out the bottom of the inner well to the clarification zone where the floc settles out. In addition, free oil and grease in the waste will float to the surface in the clarification zone. The clarifier effluent will flow over an effluent weir and be directed to the discharge seal well. Floating oil and grease will be prevented from flowing out the overflow weir by a surface baffle around the perimeter of the clarifier. The floating oil and grease will be removed by a surface skimmer and will flow to a collection box, from which it will be conveyed to an oil concentrator. Sludge which collects in the bottom of the clarifier will accumulate in a sludge well for removal to a sludge disposal area located in the fly ash reclamation area.

The Unit 3 fly ash scrubber flowdown and pond overflow will be segregated to provide effective hardness removal from this waste. Unit 3 fly ash scrubber blowdown quality is presented in Table II-43. Treatment of the Unit 3 fly ash scrubber system discharge will use the same equipment as used for treatment of Units 1, 2, 3, and 4 wastewater, with the addition of a recarbonation tank (Figure II-17). At the mixing tank, lime, soda ash, and coagulant aids (if required) will be added to affect the precipitation of calcium and magnesium for hardness removal. Material will settle in the flocculator-clarifier. The effluent will flow to the recarbonation tank, where carbon dioxide will be added

TABLE II-43
FLY ASH SYSTEM BLOWDOWN QUALITY
UNIT 3 AIR QUALITY CONTROL SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION (91)

Parameter	Before Treatment	Estimated After Treatment[a]
pH	3.4 to 6.3	6.0 to 9.0
Calcium Hardness (as $CaCO_3$), mg per liter	1,530	900
Magnesium Hardness (as $CaCO_3$) mg per liter	490	300
Sulfates, mg per liter	2,178	1,740

[a] Treatment required to meet hardness standard.

to eliminate calcium carbonate supersaturation and to provide pH adjustment. The clarifier will be equipped with an oil skimmer and collected oil and grease will be conveyed to the oil concentrator. Accumulated sludge from the clarifier will be conveyed to a disposal area located on the old fly ash pond to the east of the electric generating facility.

The oil concentrator, which also will be located at the central waste treatment facility, will receive waste oil and grease from the floor drainage oil separator and the flocculator-clarifiers. This concentrator will be heated electrically or by steam. The units will be designed for a retention time of 4 to 7 days under normal operation. The concentrated oil will be directed to a holding tank for eventual removal from the Station. The oil-free wastewater effluent will be transferred back to the control waste treatment facility.

Discharge System (92). The discharge from all wastewater systems will flow to the discharge seal well. These effluents will include the following:

1. Unit 4 cooling tower blowdown of 875 gpm (3,312 lpm) and Unit 3 cooling tower blowdown of 650 gpm (2,460 lpm);

2. Treated discharge from central wastewater treatment facility of 4,416 gpm (16,716 lpm);

3. Once-through condenser cooling water for Units 1 and 2 of 99,000 gpm (374,745 lpm) maximum during summer operation;

4. Sanitary wastes from the entire plant of 20 gpm (76 lpm); and

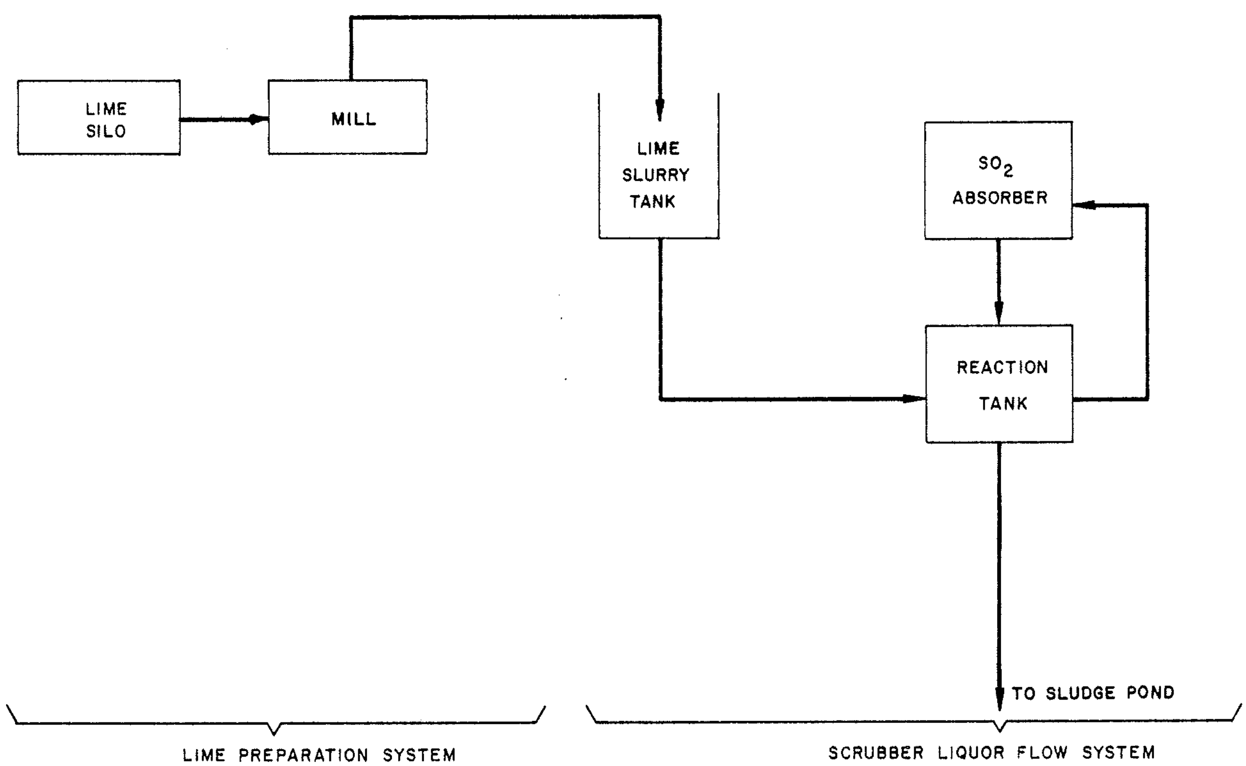
5. Coal pile runoff averaging 16.3 million gallons per year (6.17 million liters per year).

The outlet elevation of the discharge seal well is 1,280 ft (390 m). The seal well flows to a discharge canal which in turn flows to a backwater of the

Mississippi River. The discharge canal is approximately 1,450 ft (442 m) long and 50 ft (15.2 m) wide, having an invert elevation near the discharge of 1,265 ft (386 m). Normal river stage is 1,273 ft (388 m), with a low water elevation of 1,271 ft (387 m) and maximum water elevation of 1,279 ft (390 m).

Air Quality Control System (AQCS) (93)

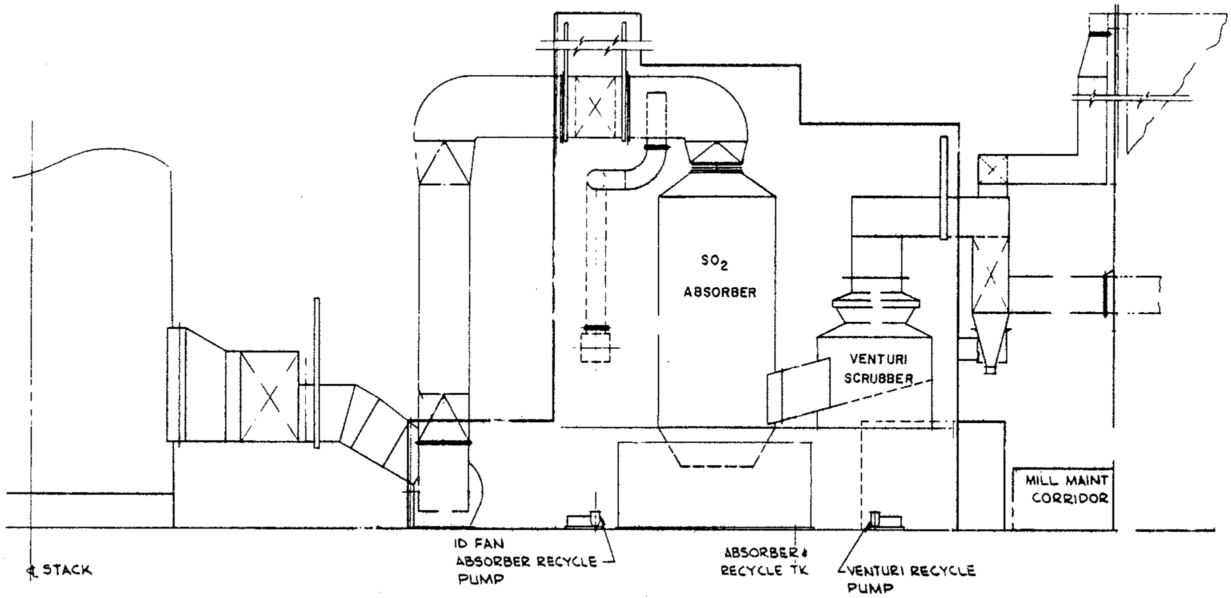
Unit 4 will be equipped with an air quality control system (AQCS) to reduce stack gas emissions to within regulatory limits. The steam generator or boiler for Unit 4 will be eqipped with a wet scrubber as the primary collection device for particulate matter and spray tower absorbers for SO_2 removal. Four 33% capacity scrubber-absorber modules will be installed. This allows approximately 20% extra capacity for abnormally high sulfur coal, for malfunctions, and for normal maintenance on one module on a regular basis. The alkali reagent for SO_2 removal will be lime with provisions for future use of limestone. A flow diagram for the wet scrubbing system is shown in Figure II-18. Figure II-19 is a cross-sectional view of one of the scrubber-absorber modules. Design basis of the system is shown in Table II-44.



AIR QUALITY CONTROL AND WET LIME ABSORBER SYSTEMS - PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-8-6

FIGURE II-18



VENTURI SCRUBBER - SO_2 ABSORBER SYSTEM – PROPOSED UNIT 4

CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-B-7

FIGURE II-19

Five percent of the stack gases will bypass the wet scrubber and flow to an electrostatic precipitator. The electrostatic precipitator will remove particulate matter from the bypass stream. The bypass stream then will be mixed with the treated combustion products from the wet scrubber, providing some reheat (129 to 154 °F) (54 to 68°C) for the scrubbed combustion products. Design basis for the electrostatic precipitator is shown in Table II-45.

MPCA regulations applicable to Unit 4 limit particulate emissions to 0.1 lb per million Btu (0.18 kg per million kg-cal) input and SO_2 emissions to 1.2 lb per million Btu (2.2 kg per million kg-cal) input (96). These regulations are identical to the new source performance standards promulgated by the U.S. Environmental Protection Agency (96).

The steam generator for Unit 4 will be designed so that NO_x emissions will not exceed 0.7 lb per million Btu (1.3 kg per million kg-cal) input, the maximum amount allowed by applicable MPCA regulations. Since NO_x formation is caused primarily by high flame temperatures and excess air in the burner area, the Unit 4 boiler will be designed for the stated emission rate.

TABLE II-44
DESIGN BASIS FOR WET SCRUBBER/SO_2 ABSORBER
UNIT 4 AIR QUALITY CONTROL SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION (94)

Parameter	
Gas rate to absorber system	
lb per hr (wet)	6,860,000
kg per hr (wet)	3,111,644
Gas temperature to absorber system	
°F	300
°C	149
Inlet SO_2 concentration, ppm (dry)	2,900
Inlet gas moisture	
lb H_2O per lb gas (dry)	0.072
kg H_2O per kg gas (dry)	0.072
Removal of SO_2 by absorber, %	85
Fly ash loading	
grains per standard cu ft (dry)	11.00
grains per standard cu m (dry)	25.17
Removal efficiency for fly ash, %	99.73
Moles of lime to moles of SO_2 absorbed ratio	1.10
Moles of $CaSO_4$ produced to moles of SO_2 absorbed ratio	0.30
Recycle slurry, % solids	15
Scrubber liquid to gas ratio	20
Absorber liquid to gas ratio	50
Lime CaCO content, %	95.15
Lime inert content, %	4.85
Lime slurry, % solids	20
Supernatant chloride content, ppm	2,700 (maximum)
Absorber recycle slurry, pH	5 to 9

TABLE II-45
DESIGN BASIS FOR ELECTROSTATIC PRECIPITATOR
UNIT 4 AIR QUALITY CONTROL SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION (95)

Parameter	
Gas temperature at inlet	
°F (range)	635 to 865
°C (range	334 to 463
°F (mean)	815
°C (mean)	435
Total gas flow, maximum	
actual cubic feet per minute	200,000
actual cubic meter per minute	5,663
Dust loading at inlet, maximum	
grains per standard cubic feet (dry)	11.00
grains per standard cubic meter (dry)	25.17
Dust loading at outlet, required maximum	
grains per standard cubic feet (dry)	0.03
grains per standard cubic meter (dry)	0.07
Collection efficiency overall, %	99.75
Specific collection area, minimum[a]	
sq ft per 1,000 actual cu ft	390
Gas velocity at inlet, maximum	
feet per second	5.5
Location relative to air heaters	Ahead of
Flue gas pressure, operating range	
in. of water gage	0 to -40
cm of water gage	0 to -102
Combustibles in particulate matter	
%	0 to 6

[a] Minimum operating specific collection area with 10% of electrical bus sections out of service.

The combustion products from Unit 4 will be discharged to the atmosphere from a 600 ft (183 m) stack with a top inside diameter of 37 ft (11.3 m).

Emissions, Effluents, and Waste Production

The level at which an electric generating facility operates varies over time in accordance with energy requirements, maintenance requirements, and operational problems. Consequently, a unit may operate at full capacity for parts of the year and only intermittently at other times. Furthermore, use of a unit may decrease over time as newer, more efficient units are added.

In calculating effluents, emissions, and solid waste production rates, an average capacity factor of 71.4% was assumed for the estimated 35 year lift of Unit 4.

Air Emissions

Sources of air emission from Unit 4 include combustion, operation of cooling towers, transfer of coal, and venting processes.

Unit 4 Stack Emissions. Particulate emissions from Unit 4 will be limited by MPCA regulations to 0.1 lb per million Btu (0.18 kg per million kg-cal) input, NO_x emissions to 0.7 lb per million Btu (1.3 kg per million kg-cal) input, and SO_2 emissions to 1.2 lb per million Btu (2.2 kg per million kg-cal) input. State emission limitations for particulates, NO_x, and SO_2 are identical to the new source performance standards promulgated by the U.S. Environmental Protection Agency. Also, the federal regulations mentioned above limit opacity to 20% for new sources, except for periods of startup, soot blowing, and malfunctions, during which 40% opacity is allowed for 2 min during any 60 min period.

Estimated particulate, NO_x , and SO_2 stack emissions from Unit 4 are presented in Tables II-46, II-47, and II-48. Trace elements and sulfates air emissions presently are not regulated. However, emission estimates for these items are presented in Table II-49. The trace elements emissions estimates are based on the analyses in Table II-9 and II-10. Actual maximum trace elements air emissions could vary substantially from the emission estimates in Table II-49.

Cooling Tower Emissions. There are no existing MPCA regulations limiting emissions from the cooling tower. However, the cooling tower contributes three principal emissions (in addition to heat) to the atmosphere: water vapor, drift (mist), and salts. Estimated annual evaporation and blowdown rates for the Unit 4 cooling tower are presented in Table II-38. Estimated drift and salt emissions are presented in Table II-50.

Other Emissions. The potential for fugitive dust emissions at the Clay Boswell Station will increase as a result of the addition of Unit 4. This is due to the increased number of personnel and handling of additional raw materials. In addition, actual construction of Unit 4 could cause an increase in fugitive dust emissions.

MPCA air pollution control regulations (APC 6) require that materials be

TABLE II-46
ESTIMATED AIR EMISSIONS - UNITS 1, 2, AND 3 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Units 1, 2, and 3	Unit 4	Total
Full load/electrical output			
Gross MW/net MW	519/488	554/504	1,073/992
Heat input rate			
Btu x 10^6 per hr	4,984	5,141	10,125
kg-cal x 10^6 per hr	1,258	1,297	2,555
Fuel consumption[a]			
Average			
lb per hr	578,862	597,096	1,175,958
kg per hr	262,567	270,838	533,405
Maximum			
lb per hr	663,735	684,645	1,348,380
kg per hr	301,065	310,550	611,615
Products of combustion			
Average			
Mass flow rate, lb per hr	6,236,935	5,732,122[b]	11,969,057
Mass flow rate, kg per hr	2,236,935	2,600,047[b]	5,429,073
Volume flow rate, actual cfm	1,698,641	1,531,199	3,229,840
Volume flow rate, actual cu m per min	48,100	43,359	91,459
Temperature, °F	193[c]	155[c]	-
Temperature, °C	89[c]	68[c]	-

Parameter	Units 1, 2, and 3	Unit 4	Total
Emissions at full load[d]			
Average			
Particulate, lb per hr	2,220	514	2,734
Particulate, kg per hr	1,008	233	1,241
NO_x, lb per hr	5,332	3,598	8,930
NO_x, kg per hr	2,419	1,632	4,051
SO_2 at 38(%S),[e] lb per hr	10,111	6,169	16,280
SO_2 at 38(%S),[e] kg per hr	4,586	2,798	7,384
SO_2 at 34(%S),[e] lb per hr	9,047	6,169	15,216
SO_2 at 34(%S),[e] kg per hr	4,103	2,798	6,901
Worst case			
Particulate, lb per hr	2,351	514	2,865
Particulate, kg per hr	1,066	233	1,299
NO_x, lb per hr	5,332	3,598	8,930
NO_x, kg per hr	2,419	1,632	4,051
SO_2 at 38(%S)[e], lb per hr	51,216	8,878	60,094
SO_2 at 38(%S)[e], kg per hr	23,231	4,027	27,258
SO_2 at 34(%S)[e], lb per hr	45,825	7,969	53,794
SO_2 at 34(%S)[e], kg per hr	20,786	3,615	24,401

[a] Fuel consumption rate based on 8,610 Btu per lb (4,783 kg-cal per kg) higher heating value.

[b] Assumed products of combustion per pound of fuel ratio is 9.6 (approximately 25% excess air).

[c] Includes temperature loss resulting from evaporation of carryover and stack heat loss.

[d] See Tables II-47 and II-48 for emission criteria.

[e] SO_2 emissions at 38(%S) and 34(%S) assumes that 5% and 15%, respectively of the SO_2 will be retained in the boiler and particulate emissions control solid waste (bottom and fly ash). The AP-42 emission factor for pulverized bituminous coal-fired units is 38(%S).

TABLE II-47

ASSUMED AVERAGE AIR EMISSION CRITERIA - UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 4
Coal	
Heating value	
Btu per lb	8,610
kg-cal per kg	4,783
Ash content	
%	9.35
Sulfur content	
%	1.03
Emission Control Equipment	
Particulate removal efficiency[a] [b]	
%	99.7
SO_2 removal efficiency[c]	
%	85.0
Emissions	
Particulates[d]	
lb per million Btu input	0.100
kg per million kg-cal input	0.180
NO_x	
lb per million Btu input	0.70
kg per million kg-cal input	1.26
SO_2 at 38(%S)[e]	
lb per million Btu input	1.20[f]
kg per million kg-cal input	2.16[f]
SO_2 at 34(%S)	
lb per million Btu input	1.20[g]
kg per million kg-cal input	2.16[g]

[a] Source: Prevention of Significant Air Deterioration Approval Application (Revised 11/76).

[b] Particulate removal is for both the wet particulate scrubber and spray tower absorbers.

[c] SO_2 removal efficiency is for the entire air quality control system, including the wet particulate scrubber and spray tower absorbers and 5% stack gas bypass for reheat of scrubber combustion products.

[d] Assumes bottom ash to fly ash ratio of 15% to 85%.

[e] SO_2 emissions at 38(%S) and 34(%S) assumes that 5% and 15%, respectively, of the SO_2 will be retained in the boiler and particulate emission control solid waste (bottom and fly ash).

[f] Unit 4 needs only 47% SO_2 removal efficiency to comply with MPCA regulations.

[g] SO_2 emissions at 38(%S) and 34(%S) are equal because the SO_2 spray tower absorbers will be operated only to meet MPCA emission regulations.

TABLE II-48

ASSUMED WORST CASE AIR EMISSION CRITERIA - UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 4
Coal	
Heating value	
Btu per lb	7,509
kg-cal per kg	4,172
Ash content	
%	15.99
Sulfur content	
%	4.55
Emission Control Equipment	
Particulate removal efficiency[a b]	
%	99.7
SO_2 removal efficiency[c]	
%	85.0
Emissions	
Particulates[d]	
lb per million Btu input	0.100[e]
kg per million kg-cal input	0.180[e]
NO_x	
lb per million Btu input	0.70
kg per million kg-cal input	1.26
SO_2 at 38(%S)[f]	
lb per million Btu input	1.73[g h]
kg per million kg-cal input	3.11[g h]
SO_2 at 34(%S)[f]	
lb per million Btu input	1.55[g h]
kg per million kg-cal input	2.79[g h]

[a] Source: Prevention of Significant Air Deterioration Approval Application (Revised 11/76).

[b] Particulate removal is for both the wet particulate scrubber and spray tower absorbers.

[c] SO_2 removal efficiency is for the entire air quality control system, including the wet particulate scrubber, spray tower absorbers, and 5% stack gas bypass for reheat of scrubbed combustion products.

[d] Assumes bottom ash to fly ash ratio of 15% to 85%.

[e] Unit 4 needs 99.6% particulate removal efficiency to comply with MPCA regulations.

[f] SO_2 emissions at 38(%S) and 34(%S) assumes that 5% and 15%, respectively, of the SO_2 will be retained in the boiler and particulate emission control solid waste (bottom and fly ash).

[g] MPCA regulations limit SO_2 emissions to 1.2 lb per million Btu (2.2 kg per million kg-cal) input.

[h] Unit 4 needs 90% SO_2 removal efficiency to comply with MPCA regulations.

TABLE II-49
MAXIMUM TRACE ELEMENT AND SULFATE AIR EMISSIONS
UNITS 1, 2, 3, AND 4
CLAY BOSWELL STEAM ELECTRIC STATION

	Units 1, 2, and 3		Unit 4		Total	
	lb per hr	kg per hr	lb per hr	kg per hr	lb per hr	kg per hr
Arsenic	0.39	0.18	0.24	0.11	0.63	0.29
Barium	24.21	10.98	14.56	6.60	38.77	17.58
Beryllium	0.04	0.02	0.02	0.01	0.06	0.03
Cadmium	0.04	0.02	0.02	0.01	0.06	0.03
Chromium	0.55	0.25	0.33	0.15	0.88	0.40
Cobalt	0.04	0.02	0.03	0.01	0.07	0.03
Copper	0.79	0.36	0.47	0.21	1.26	0.57
Fluorine	34.08	15.46	20.84	9.45	54.92	24.91
Gallium	1.25	0.57	0.75	0.34	2.00	0.91
Lead	3.19	1.45	1.92	0.87	5.11	2.32
Mercury	0.05	0.02	0.04	0.02	0.09	0.04
Manganese	2.99	1.36	1.80	0.82	4.79	2.18
Molybdenum	1.23	0.56	0.75	0.34	1.98	0.90
Nickel	0.31	0.14	0.19	0.09	0.50	0.23
Strontium	9.28	4.21	5.58	2.53	14.86	6.74
Sulfates	257.00	116.57	49.40[a]	22.41[a]	306.40	138.98
Titanium	44.93	20.38	27.02	12.26	71.95	32.64
Uranium	0.04	0.02	0.02	0.01	0.06	0.03
Vanadium	1.50	0.68	0.89	0.40	2.39	1.08
Zinc	2.11	0.96	1.30	0.59	3.41	1.55
Total	383.39	173.92	125.79	57.06	509.18	230.98

[a] Sulfates emissions estimated to be 50% non-acid sulfates.

Note: The emission removal efficiencies for Units 1, 2, and 3 are presented in Table II-26. Unit 4 will have a wet particulate scrubber and spray tower absorbers. The estimated removal efficiencies are 95% for metals and mists and 10% for gaseous trace elements. The maximum air emissions are based on coal with a heating value of 7,509 Btu per lb (4,172 kg-cal per kg).

TABLE II-50
ESTIMATED DRIFT AND SALT EMISSIONS
UNIT 4 COOLING TOWER
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	
Drift at 0.008% circulating water flow	
lb per hr	5,846
kg per hr	2,652
Salt at 1,400 mg per liter and the above drift	
lb per hr	8.2
kg per hr	3.7

handled in a manner which will prevent all but a minimum amount of particulate matter from becoming airborne (97).

Fugitive dust emissions can be estimated using techniques developed by EPA (98). However, since these estimates can vary widely, depending on the situation and site, no specific estimates have been made. Typically, regulations for fugitive dust do not provide emission limitations, but rather require adequate handling equipment and dust suppression systems or controls.

In general, the entire plant is expected to comply with APC 6 of the MPCA air pollution control regulations.

Certain systems within the Clay Boswell Station require continuous venting. For example, the deaerator system has vents which will emit steam to the atmosphere in very small quantities. These quantities are not considered to be significant in comparison to other emissions.

Distillate oil will be stored in a tank for use by a new emergency diesel generator (99). However, the vapor pressure of the oil will be such that hydrocarbon emissions will be insignificant relative to other emissions.

Wastewater Effluents (100)

With the addition of Unit 4, wastewater effluents will consist of the following:

1. Cooling tower blowdown from Units 3 and 4 averaging 650 gpm (2,460 lpm) and 875 gpm (3,312 lpm), respectively;

2. Treated wastewater from Units 1, 2, 3, and 4 and from the central waste treatment facility of 3,055 gpm (11,564 lpm);

3. Sanitary wastes from Units 1, 2, 3, and 4 averaging 20 gpm (76 lpm); and

4. Unit 3 fly ash system blowdown and pond overflow of 1,360 gpm (5,148 lpm).

Composition of these wastes is presented in Table II-51 together with a composite of wastes from all systems. The waste is presented as the "worst case", assuming Units 1 and 2 cooling water are not diluting waste concentrations.

TABLE II-51
WASTEWATER EFFLUENTS[a] - UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Central Waste Treatment Effluent	Units 3 and 4 Cooling Tower Blowdown	Treated Unit 3 Fly Ash Blowdown	Sanitary Wastes	Total Wastewater Effluent
Flow					
gpm	3,055	1,525	1,360	20	5,960
lpm	11,564	5,773	5,148	76	22,560
pH	6 to 9	7.8	6 to 9	7	6 to 9
Total dissolved solids (TDS)					
mg per liter	293	900	2,400	200	927
Total suspended solids (TSS)					
mg per liter	4	30	-	30	10
Oil and grease, mg per liter	<1	nil	nil	nil	nil
Sulfates, mg per liter	15	35	2,000	-	537
Chlorides, mg per liter	42	516	-	-	155
Calcium (as $CaCO_3$), mg per liter	103	180	50	-	112
Magnesium (as $CaCO_3$)					
mg per liter	56	67	10	-	48
Iron, mg per liter	3	nil	-	-	1.5

[a] Without Units 1 and 2 cooling water.

Solid Waste Production and Disposal

Unit 4 solid wastes will be comprised primarily of SO_2 scrubber wastes and bottom and fly ash from burning of the coal. The steam generator or boiler will be designed as a dry bottom unit which will result in collection of 15 to 20% of the total ash as bottom ash (101). The remainder of the ash will be collected in the wet scrubber and the electrostatic precipitator (on the scrubber bypass).

The estimated quantities of solid waste produced by Unit 4 is based on the "as received" design performance coal analysis in Table II-12; the estimated coal consumption in Table II-34; and ash removal efficiency of 99.6% for both the scrubber/absorber and electrostatic precipitator, a sulfur removal efficiency of 85% for the SO_2 absorber; and a stoichiometric ratio of 1.1 for the SO_2 absorber. Based on these criteria, the estimated solid waste production for Unit 4 is presented in Table II-52. The bottom ash solids in the bottom ash pond are estimated to have an average dry bulk in place density of 91 lb per cu ft (1.45 g per cc) and the fly ash solids in the fly ash pond are estimated to have an average dry bulk in place density of 63 lb per cu ft (1.01 g per cc). The estimated composition of the dry SO_2 scrubber waste is presented in Table II-53.

The SO_2 scrubber waste solids in the SO_2 scrubber solids pond are estimated to have an average dry bulk in place density of 47 lb per cu ft (0.75 g per cc).

Bottom Ash Handling System. Unit 4 bottom ash produced and stored in the hopper located directly beneath the boiler will be sluiced to a new disposal pond to be constructed approximately one mile (1.6 km) northwest of the existing electric generating facilities. The bottom ash will be sluiced in a 10% slurry at a rate of 3,200 gpm (12,113 lpm) for a duration of about 1 and 1/2 hr per day. In addition, pyrites separated from the coal in the pulverizer will be sluiced to the Unit 4 bottom ash pond at a rate of 3,200 gpm (12,113 lpm) for one hour per day. The bottom ash hopper cooling and seal water also will be conveyed to the Unit 4 bottom ash pond at a rate of 900 gpm (3,407 lpm). The total quantity of water transported to the Unit 4 bottom ash pond is estimated to be 1.78 million gallons per day (6.74 million liters per day) which is equivalent to 1,233 gpm (4,667 lpm) (102).

The Unit 4 bottom ash sluicing system will recirculate water as shown in Figure II-20. System blowdown will be equal to or less than 5% of the recirculating daily average flow and will have an estimated suspended solids concentration of 30 mg per l (102). The total recirculating flow of the bottom ash pond will be about 3,450 gpm (13,059 lpm) (125). This total recirculating flow will be treated for prevention of scale formation before it is used for sluicing and ash hopper cooling and sealing.

Fly Ash and SO_2 Absorber Solids Handling System

The Unit 4 air quality control system shown in Figure II-21 will incorporate a series arrangement of Venturi scrubbers and SO_2 lime or limestone spray absorbers incorporating wet removal of fly ash and SO_2 from the flue gas.

Figure II-15 shows the Unit 4 fly ash and SO_2 removal system water flows. Recirculating scrubber slurry flows will be maintained at 15% solids content with excess solids disposed of in a new Unit 4 fly ash and SO_2 sludge disposal pond located adjacent to the Unit 4 bottom ash pond (Figure II-12). Pond effluent will be returned to the system. An estimated 60 gpm (227 lpm) will be lost in the voids in the fly ash and SO_2 scrubber waste. Seepage from the Unit 4 fly ash and SO_2 sludge disposal pond is estimated to be 95 gpm (360 lpm).

Proposed New Disposal Pond A new ash and SO_2 sludge pond is to be constructed northwest of the electric generating facility as shown on Figure II-12 and Figure II-22 (104). Construction of this new pond will require Itasca County to vacate County Road 258. The pond will be constructed with a single peripheral impermeable embankment. A dividing dike will subdivide this large pond into 2 compartments. The smaller compartment will be used for Unit 4 bottom ash and the larger compartment will be used for fly ash from Units 1, 2, and 4 and SO_2 absorber sludge from Unit 4. The quantities and dimensions associated with this new ash and SO_2 slurry pond are presented in Table II-54.

A subsurface investigation of the ash pond area shows the existence of a nearly continuous natural clay layer within 20 ft (6.1 m) of the ground surface. The pond has been located to utilize the clay as part of a low permeability seal forming an impervious boundary. This seal is shown in the embankment section Figure II-23. At the up-stream toe of the embankment, a trench will be

TABLE II-52

ESTIMATED FUTURE SOLID WASTE OR ASH AND SO_2 SCRUBBER WASTE PRODUCTION - UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Solid Waste	Unit 4
Bottom Ash	
Average daily[a]	
tons	71.7
metric tons	65.1
Maximum daily[b]	
tons	229.1
metric tons	207.9
Average annual[a]	
tons	26,188
metric tons	23,757
Maximum annual[c]	
tons	48,904
metric tons	44,365
Average total[a]	
tons	916,581
metric tons	831,508
Maximum total[c]	
tons	1,222,108
metric tons	1,108,678
Fly Ash and SO_2 Scrubber Waste	
Average daily[a]	
tons	554.0
metric tons	502.5
Fly Ash and SO_2 Scrubber Waste (continued)	
Maximum daily[d]	
tons	1,038.7
metric tons	942.3
Average annual[a]	
tons	202,196
metric tons	183,429
Maximum annual[a]	
tons	283,187
metric tons	256,903
Average total[a]	
tons	7,076,857
metric tons	6,420,017
Maximum total[a]	
tons	7,076,857
metric tons	6,420,017
Solid Waste	
Average annual[a]	
tons	228,384
metric tons	207,186
Average total[a]	
tons	7,993,438
metric tons	7,251,525

[a] Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 15% to 85%.

[b] Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 20% to 80%.

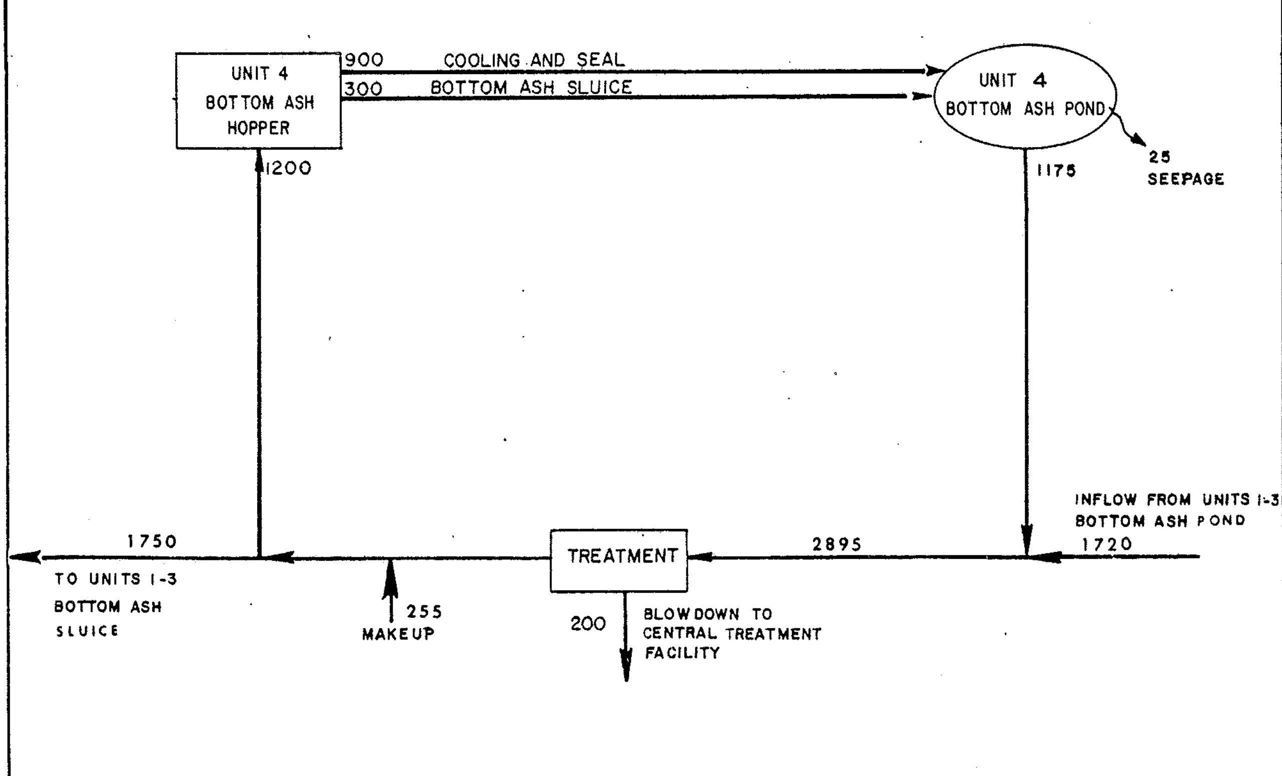
[c] Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 20% to 80%.

[d] Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 15% to 85%.

TABLE II-53
ESTIMATED COMPOSITION - SO_2 ABSORBER WASTE
UNIT 4 AIR QUALITY CONTROL SYSTEM
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	%	Tpd[a] (dry)	Mtpd[a] (dry)
$CaSO_3 \cdot \frac{1}{2}H_2O$	15.8	123	111
$CaSO_4 \cdot 2H_2O$	9.0	70	63
$CaCO_3$	1.8	14	13
Inerts	0.3	2	2
Fly ash	73.1	567	515
Total	100.0	776	704

[a] Based on maximum generating capacity and a coal with 1.03% sulfur and 8,610 BTU per lb (4,783 kg-cal per kg).



BOTTOM ASH HANDLING SYSTEM — PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

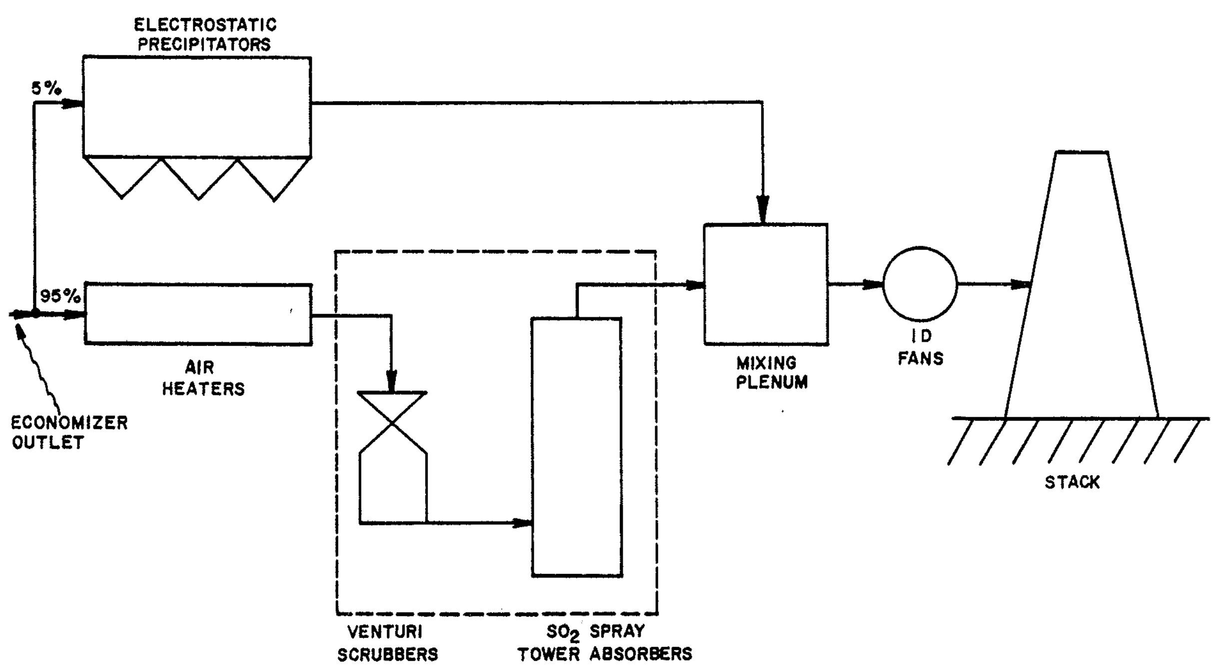
SOURCE: ADAPTED FROM MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-8-10

FIGURE II-20

excavated to the natural clay layer and filled with compacted clay. The clay fill will be extended up the up-stream face of the embankment forming the continuous clay seal (105).

Proposed Changes for Units 1, 2, and 3. To meet MPCA stipulation agreements (52), the air quality control systems on Units 1 and 2 are being changed from mechanical collectors to baghouse filters using fabric filters. Stack gases from Units 1 and 2 will combine with the combustion gas from Unit 3, finally exiting through a new common 700 ft (213 m) stack (Figure II-8).

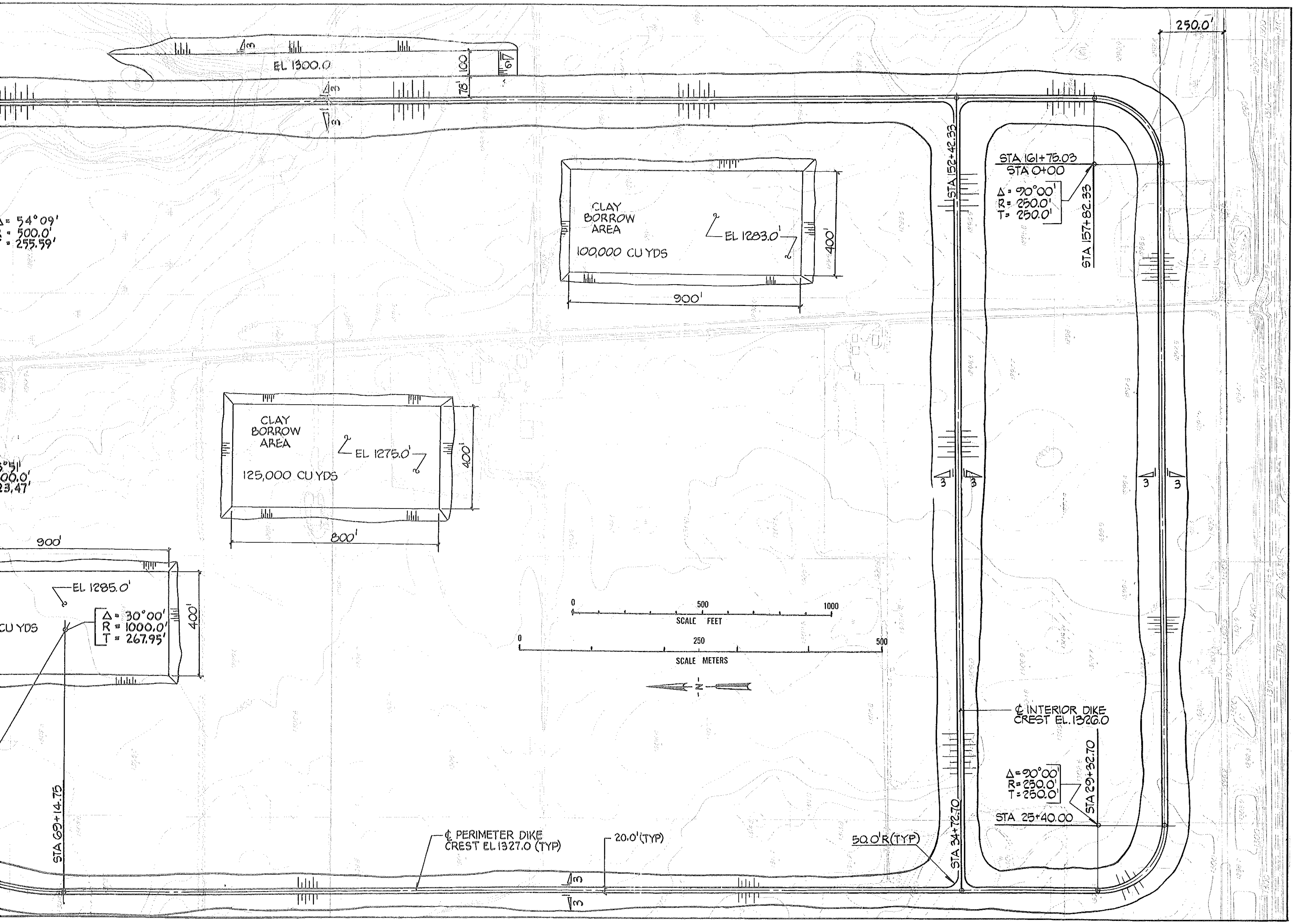
Evaluation of the existing ponds indicates that they will have sufficient capacity to receive all future waste to be produced during the life of Units 1, 2, and 3. Table II-55 presents data on the capacity of the existing bottom and fly ash ponds. The bottom ash to be generated from Units 1, 2, and 3 from mid-1980 until the units are retired is estimated to be about 614,846 tons (557,779 mt) or the equivalent of 310 acre-ft (382,648 cu m). The fly ash to be generated from Units 1 and 2 from mid-1980 until the unit is retired is estimated to be about 413,439 tons (375,066 mt) or the equivalent of 301 acre-ft (371,660 cu m). The existing bottom ash pond will have available about 1,873 acre-ft. (2,310,665 cu m). Therefore, more than adequate volume will be available in the existing



AIR QUALITY CONTROL SYSTEM WITH BYPASS REHEAT SYSTEM—PROPOSED UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: MP&L, "ENVIRONMENTAL REPORT", (REVISED), EXHIBIT II-B-4

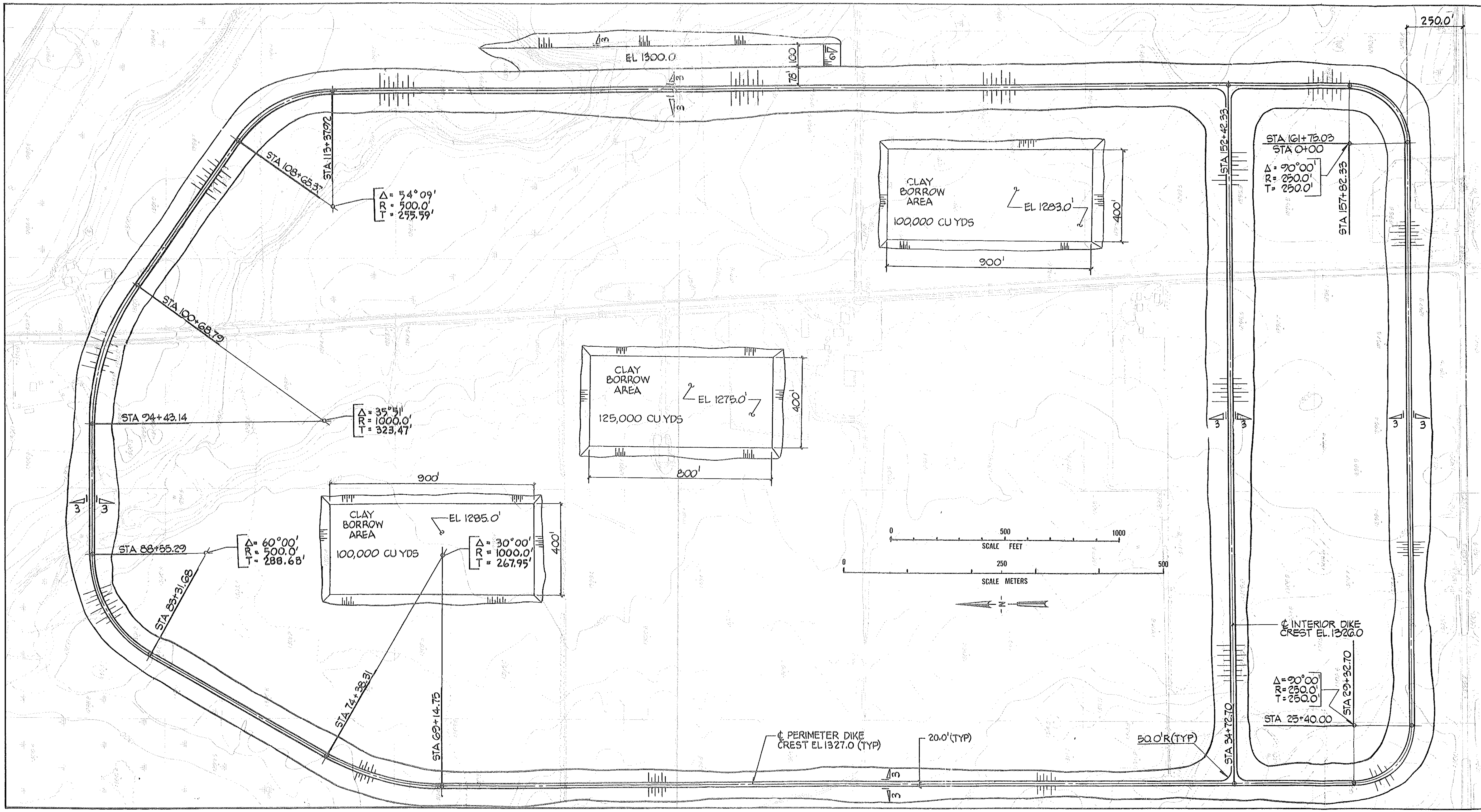
FIGURE II-21



ASH POND AREA
GENERAL PLAN
CLAY BOSWELL STEAM ELECTRIC STATION

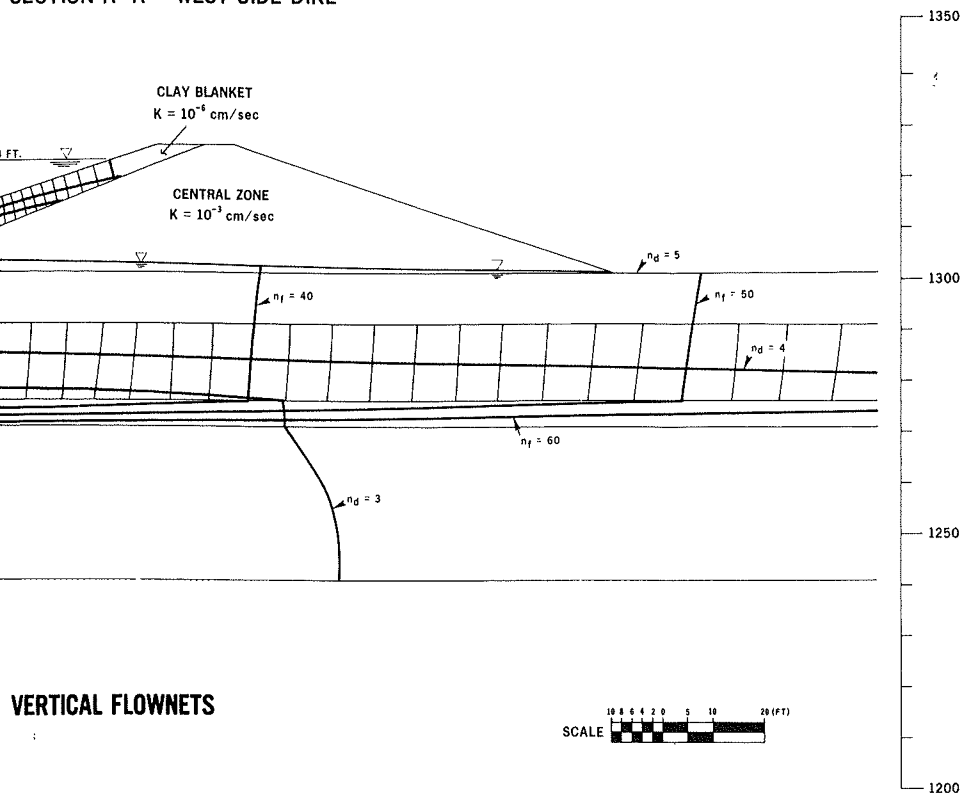
SOURCE: ADAPTED FROM, "MP&L CLAY BOSWELL STEAM ELECTRIC STATION, UNIT NO. 4, ASH DISPOSAL POND DIKE AND FOUNDATION STUDIES - ENGINEERING REPORT", APRIL 1977, FIGURE 15

FIGURE II-22



250.0'
EL 1300.0
100
617
75'
STA 113+37.92
STA 108+65.53
Δ = 54°09'
R = 500.0'
T = 255.59'
STA 100+68.79
STA 94+43.14
Δ = 35°51'
R = 1000.0'
T = 323.47'
STA 88+55.29
Δ = 60°00'
R = 500.0'
T = 288.68'
STA 83+31.68
STA 74+38.31
STA 69+14.75
900'
CLAY
BORROW
AREA
EL 1285.0'
100,000 CU YDS
Δ = 30°00'
R = 1000.0'
T = 267.95'
400'
CLAY
BORROW
AREA
EL 1275.0'
125,000 CU YDS
400'
800'
CLAY
BORROW
AREA
EL 1283.0'
100,000 CU YDS
400'
900'
STA 152+42.33
STA 161+75.03
STA 0+00
Δ = 90°00'
R = 250.0'
T = 250.0'
STA 157+82.33
0
500
1000
SCALE FEET
0
250
500
SCALE METERS
N
℄ INTERIOR DIKE
CREST EL. 1326.0
Δ = 90°00'
R = 250.0'
T = 250.0'
STA 29+32.70
STA 25+40.00
STA 34+72.70
50.0'R(TYP)
℄ PERIMETER DIKE
CREST EL 1327.0 (TYP)
20.0'(TYP)
3

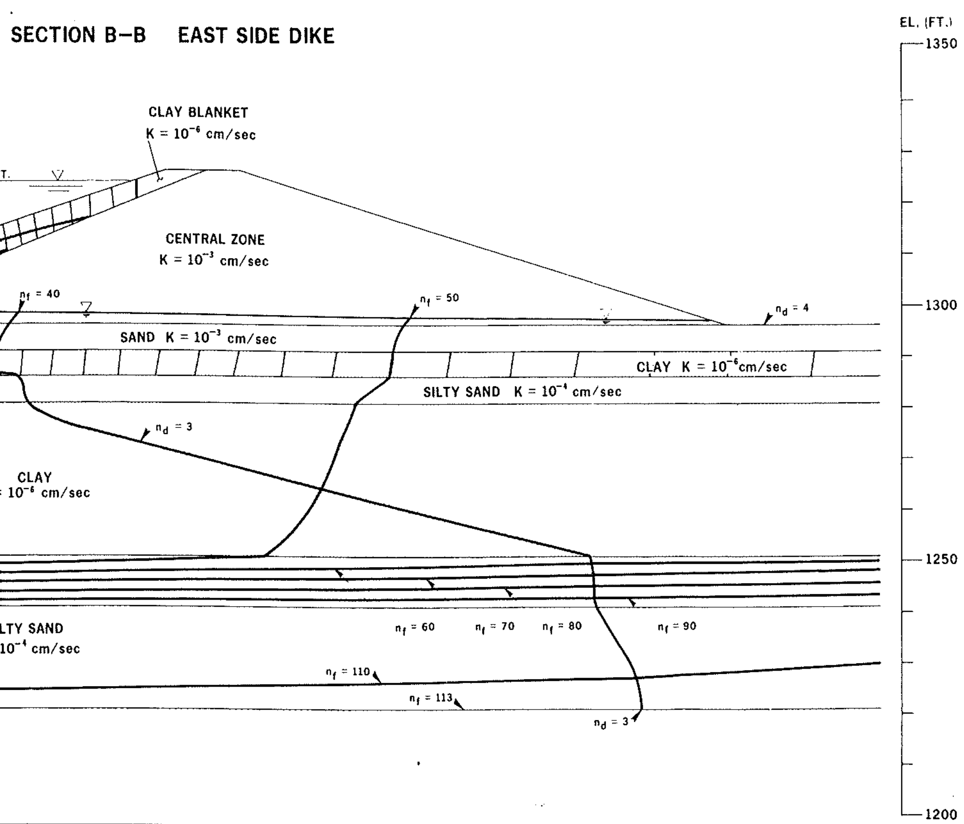
SECTION A–A WEST SIDE DIKE

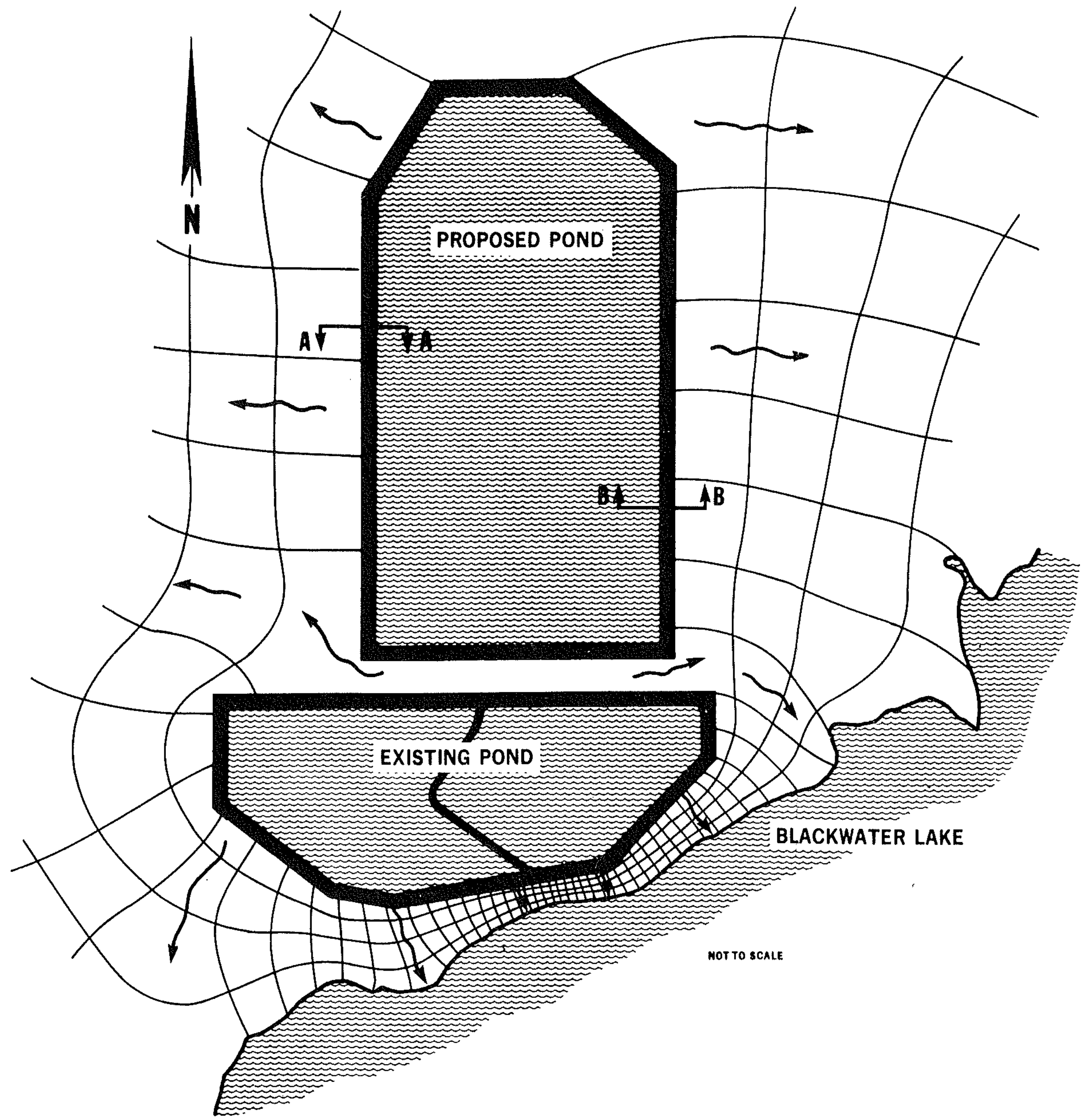


VERTICAL FLOWNETS

SCALE 10 8 6 4 2 0 5 10 20 (FT)

SECTION B–B EAST SIDE DIKE





HORIZONTAL FLOWNETS

TOTAL SEEPAGE FROM PROPOSED POND

Q = LENGTH OF WEST SIDE DIKE × WEST SIDE DIKE SEEPAGE + LENGTH OF EAST SIDE DIKE × EAST SIDE DIKE SEEPAGE

Q = (5600' FT. × .0042 GPM/LIN. FT.) + (5600' FT. × .01128 GPM/LIN. FT.)

Q = 23.52 GPM + 63.17 GPM = 87 GPM

$$Q = 87\ \frac{\text{GAL.}}{\text{1 MIN.}} \times \frac{\text{60 MIN.}}{\text{1 HR.}} \times \frac{\text{24 HR.}}{\text{1 DAY}} = 125{,}280\ \text{GAL./DAY}$$

POND AREA = 360 ACRES

$$Q\ \text{per ACRE} = \frac{125{,}280}{360} \sim 350\ \text{GAL./DAY/ACRE}$$

SEEPAGE ANALYSIS - HORIZONTAL AND VERTICAL SEEPAGE FLOW NETS - PROPOSED UNIT 4 CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM, "MP&L CLAY BOSWELL STEAM ELECTRIC STATION, UNIT NO. 4, ASH DISPOSAL POND DIKE AND FOUNDATION STUDIES - ENGINEERING REPORT", APRIL 1977, FIGURES 20, 21, AND 22

FIGURE II-23

$q = K \frac{n_f}{n_d} \Delta H$

WHERE

$K = 10^{-6}$ cm./sec. $= 1.97 \times 10^{-6}$ FT./MIN.

$n_f = 65$

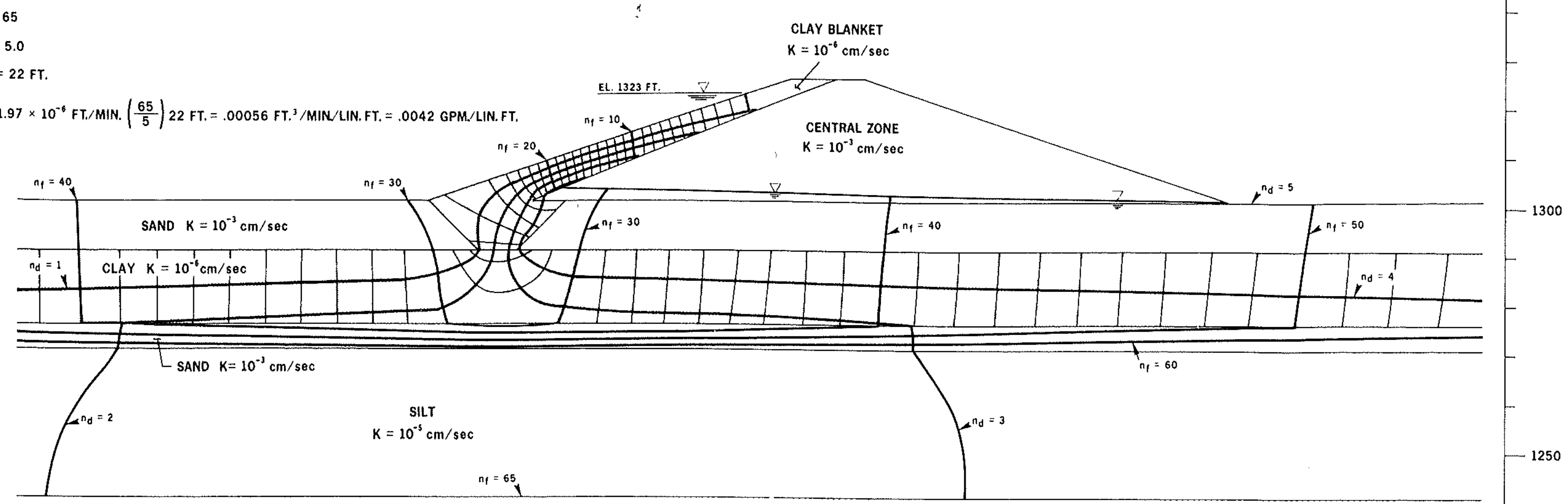
$n_d = 5.0$

$\Delta H = 22$ FT.

THEN

$q = 1.97 \times 10^{-6}$ FT./MIN. $\left(\frac{65}{5}\right)$ 22 FT. = .00056 FT.^{3}/MIN./LIN. FT. = .0042 GPM./LIN. FT.

SECTION A–A WEST SIDE DIKE



VERTICAL FLOWNETS

SCALE 10 8 6 4 2 0 5 10 20 (FT)

$q = K \frac{n_f}{n_d} \Delta H$

WHERE

$K = 10^{-6}$ cm/sec $= 1.97 \times 10^{-6}$ FT./MIN

$n_f = 113$

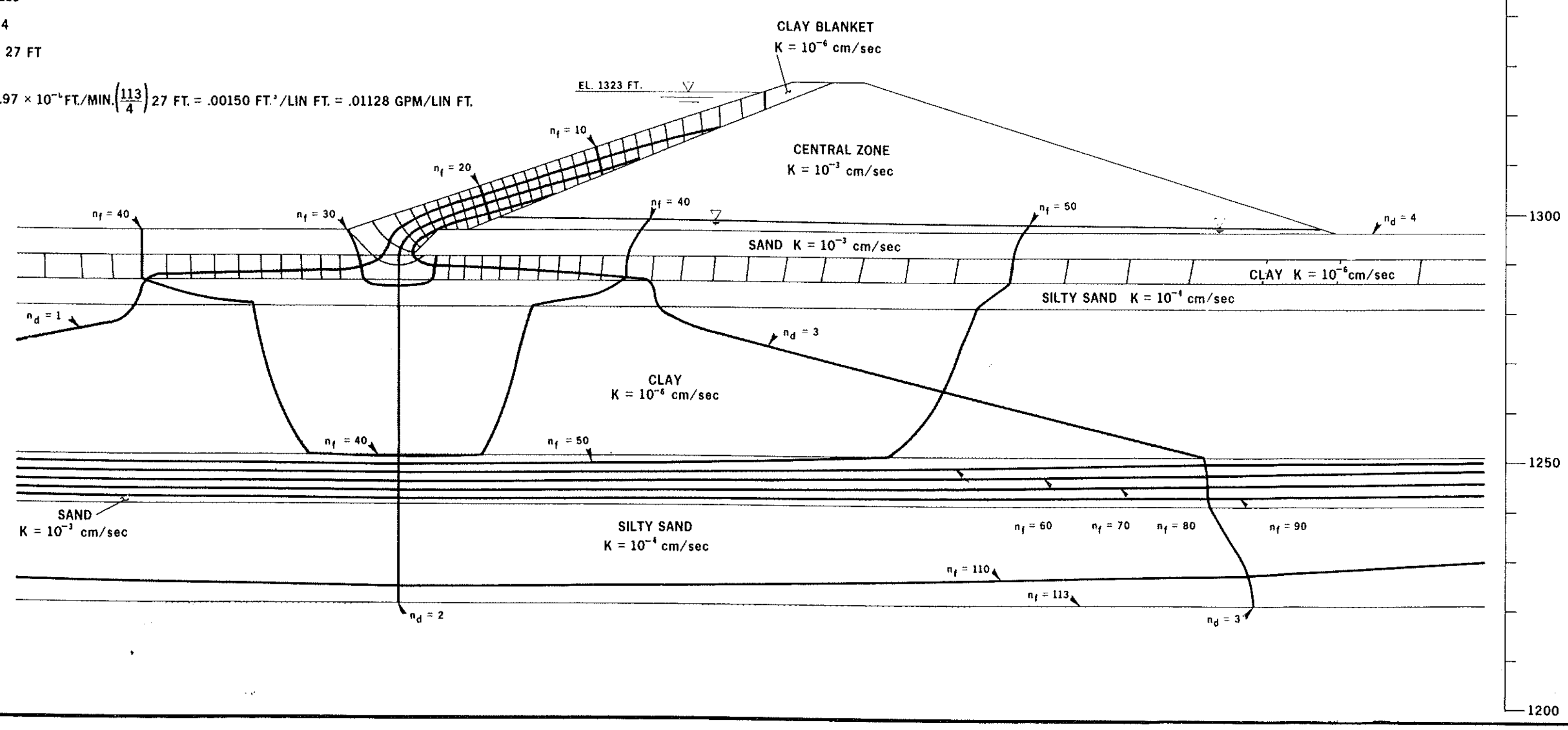
$n_d = 4$

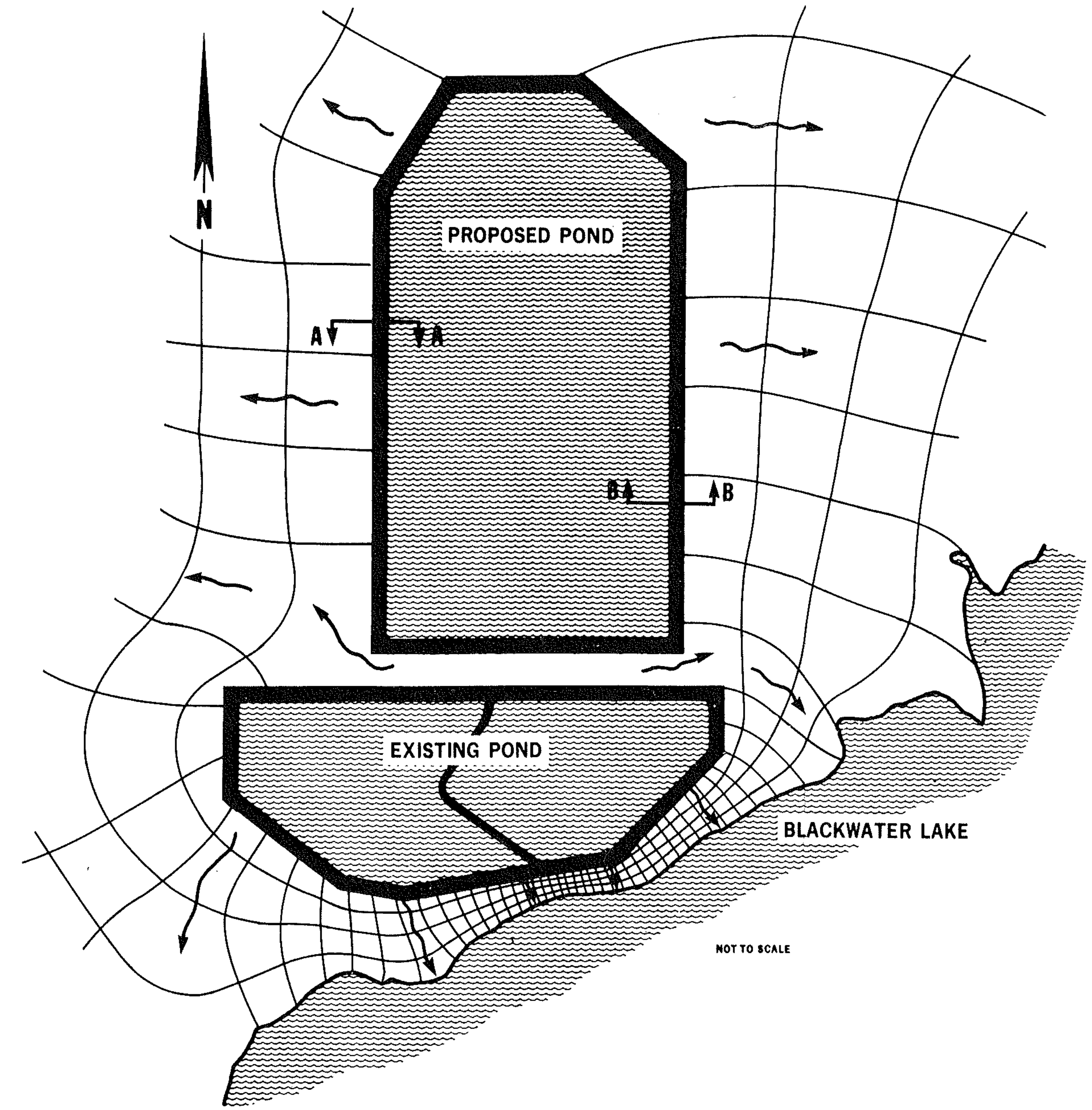
$\Delta H = 27$ FT

THEN

$q = 1.97 \times 10^{-6}$FT./MIN.$\left(\frac{113}{4}\right)$ 27 FT. = .00150 FT.^{3}/LIN FT. = .01128 GPM/LIN FT.

SECTION B–B EAST SIDE DIKE





HORIZONTAL FLOWNETS

TOTAL SEEPAGE FROM PROPOSED POND

Q = LENGTH OF WEST SIDE DIKE × WEST SIDE DIKE SEEPAGE + LENGTH OF EAST SIDE DIKE × EAST SIDE DIKE SEEPAGE

Q = (5600' FT. × .0042 GPM/LIN. FT.) + (5600' FT. × .01128 GPM/LIN. FT.)

Q = 23.52 GPM + 63.17 GPM = 87 GPM

$Q = 87 \ \frac{\text{GAL.}}{\text{1 MIN.}} \times \frac{\text{60 MIN.}}{\text{1 HR.}} \times \frac{\text{24 HR.}}{\text{1 DAY}} = 125{,}280$ GAL./DAY

POND AREA = 360 ACRES

Q per ACRE $= \frac{125{,}280}{360} \sim 350$ GAL./DAY/ACRE

TABLE II-54
DESIGN PARAMETERS - NEW SOLID WASTE DISPOSAL POND
UNITS 1 AND 2 FLY ASH AND UNIT 4 FLY ASH AND SO_2 ABSORBER SLUDGE
CLAY BOSWELL STEAM ELECTRIC STATION

Design Parameter	
Embankment crest width	
ft	20
m	6.1
Embankment side slopes	3 horizontal to 1 vertical
Embankment crest elevation	
ft	1,326
m	404.2
Pool elevation, maximum	
ft	1,324
m	403.6
Embankment height, maximum	
ft	48
m	14.6
Embankment height, average	
ft	26.5
m	8.1
Embankment linear length (excluding dividing dike)	
ft	15,860
m	4,834.1
Embankment fill volume (excluding dividing dike)	
cu yd	1.711×10^6
cu m	1.308×10^6
Storage capacity available, total	
acre-ft	9,945
cu m	12.267×10^6
Storage required for Unit 1 and 2 fly ash and Unit 4 fly ash and SO_2 absorber sludge	
acre-ft	5,932
cu m	7.317×10^6
Storage required for Unit 4 bottom ash	
acre-ft	462
cu m	0.570×10^6
Surface area available at elevation 1,324 ft (403.6 m)	
acres	360
hectares	146

bottom ash pond to accommodate both the bottom ash from Units 1, 2, and 3 and the fly ash from Units 1 and 2. MP&L proposes to dispose of Units 1, 2, and 3 bottom ash in the existing bottom ash pond until Units 1, 2, and 3 are retired. However, MP&L proposes that the Unit 1 and 2 fly ash produced between mid-1980 and when the units are retired be deposited in the new ash and SO_2 sludge pond located northwest of the electric generating facility.

The existing Unit 3 fly ash pond will have an available volume of 999 acre-ft (1,231,407 cu m) by mid-1980. However, the amount of fly ash generated from Unit 3 after mid-1980 is estimated to be 2,963,869 tons (2,688,777 mt) or the equivalent of 2,160 acre-ft (2,664,363 cu m). Therefore, about 1,161 acre-ft (1,432,072 cu m) additional capacity will be needed. It is estimated that the Unit 3 fly ash pond will be full by 1992, and additional fly ash disposal capacity must be provided at that time. There is sufficient capacity for the excess fly ash from Unit 3 to be placed in the existing bottom ash pond. However, consideration is being given to placing Unit 3 fly ash in the proposed new ash and SO_2 sludge pond or possibly another new pond to be constructed when necessary.

After Unit 4 comes on line, dry fly ash from Units 1 and 2 will not be sluiced to the Units 1, 2, and 3 bottom ash pond. Instead, Units 1 and 2 fly ash will be mixed with the fly ash and SO_2 sludge from the Unit 4 scrubber and sluiced with the scrubber solids to the new Unit 4 fly ash and SO_2 sludge pond.

Miscellaneous Solid Wastes (106). In addition to the production of ash and SO_2 absorber sludge, several miscellaneous wastes will be generated by the electric generating facility. Data are not available at this time concerning the rate of production of these miscellaneous solid wastes; however, their disposition has been determined. Pyrites from the coal pulverizers will be pumped to the bottom ash pond for disposal. Sludges from the central waste treatment facility, the cooling tower basins, and the sewage treatment plant will be trucked to the SO_2 sludge pond for disposal. Lime grits will be deposited in either the bottom ash or SO_2 sludge ponds. Engineering regarding disposal have not been completed for lime grits; therefore, it is not known what method will be used for transporting this material to the disposal point.

If it is determined that the sediment from the coal pile runoff basin is burnable, it will be spread on the coal pile and later burned as fuel. If not burnable, the coal pile runoff basin sediment will be conveyed to either the bottom ash or SO_2 sludge ponds for final disposal.

Construction debris will be placed in a designated disposal area on the Units 1 and 2 reclaimed ash pond. If this area becomes filled, the debris will be transported by truck to a local land fill.

Noise

The major sources of noise and expected sound levels for a typical electric generating facility are shown in Table II-56. For MP&L's proposed Unit 4, at the Clay Boswell Station, a number of these sources will be indoors and, therefore, will have a substantially reduced or, in some cases, negligible

TABLE II-55
CAPACITY OF EXISTING BOTTOM AND FLY ASH PONDS
UNITS 1, 2, AND 3 BOTTOM ASH POND AND UNIT 3 FLY ASH POND
CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Tons	Metric Tons	Acre-ft[a]	Cubic Meter[a]
Pond capacity, total				
Units 1, 2, and 3 bottom ash pond	-	-	2,075	2,559,475
Unit 3 fly ash pond	-	-	1,526	1,882,293
Solid waste disposal through December 1975				
Units 1 and 2 bottom ash	6,400	5,806	3	3,984
Unit 3 bottom ash	25,500	23,133	13	15,874
Units 1 and 2 fly ash	64,100	58,151	47	57,637
Units 1, 2, and 3 bottom ash pond	96,000	87,090	63	77,495
Unit 3 fly ash pond	239,800	216,817	174	214,900
Pond capacity remaining after December 1975				
Units 1, 2, and 3 bottom ash pond	-	-	2,012	2,481 980
Unit 3 fly ash pond	-	-	1,352	1,667,393
Estimated pond capacity after June 1985[b]				
Units 1, 2, and 3 bottom ash pond	-	-	1,873	2,310,665
Unit 3 fly ash pond	-	-	999	1,231,407
Solid waste disposal between June 1985 and end of unit's life				
Units 1 and 2 bottom ash	73,401	66,588	37	45,681
Unit 3 bottom ash	541,445	491,191	273	336,967
Units 1 and 2 fly ash	413,439	375,066	301	371,660
Units 1, 2, and 3 bottom ash pond	1,028,285	932,845	611	754,308
Unit 3 fly ash pond	2,963,869	2,688,777	2,160	2,664,363

[a] Based on average dry bulk in place densities of approximately 91 lb per cu ft (1.46 g per cc) and 63 lb per cu ft (1.01 g per cc) for bottom ash and fly ash, respectively.

[b] Assumes that Units 1, 2, and 3 bottom ash pond will be filled with bottom ash at a rate of 50,262 tons (45,597 mt) per year for 4.5 years and the Unit 3 fly ash pond will be filled with fly ash at a rate of 107,777 tons (97,774 mt) per year for 4.5 years.

impact on the sound level emitted to the surrounding environment. In other instances, acoustical treatment will be used to reduce sound levels.

The major sound sources associated with the proposed Unit 4 are listed below:

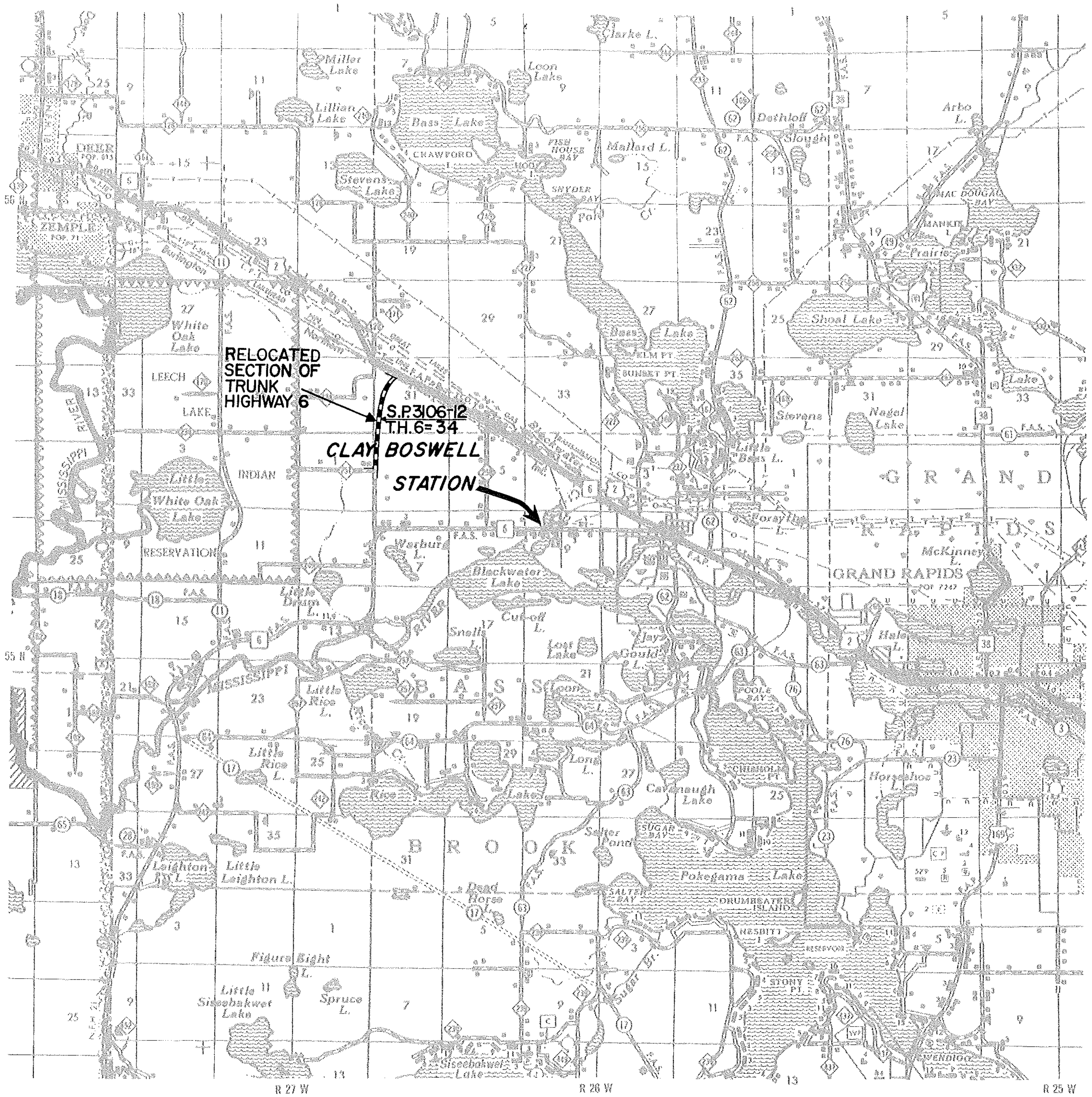
1. Two forced-draft fans;
2. Three induced-draft fans;
3. Power station building;
4. Two auxiliary transformers;
5. Two main transformers;
6. Two primary-air fans;
7. One cooling tower; and
8. Circulating-water station.

Intermittent sound sources, such as the power control valve and the emergency diesel generator, are expected to increase short-term sound levels. These are not expected to exceed MPCA regulations (107). Maintenance activities at the Clay Boswell plant, such as replacement of machinery parts, will generate a limited amount of noise without any significant impact on noise-sensitive land uses.

Minnesota noise standards, adopted September 17, 1974, limit levels of sound that may enter various noise-sensitive areas, according to land activity at the receiver. Noise area classification 1 (NAC-1), which includes household units, has daytime limits of 60 dB(A) (L_{50}) and 65 dB(A) (L_{10}) and nighttime limits of 50 dB(A) (L_{50}) and 55 dB(A) (L_{10}) (108). The total sound pressure level at the community of Cohasset is not expected to exceed a value of 50 dB(A) when considering the combined effects of the existing ambient (L_{50}) level and the maximum sound level produced by the proposed Unit 4 at the Clay Boswell Station.

Relocation of Minnesota Trunk Highway 6

MP&L has requested the Minnesota Department of Highways to relocate 2.2 miles (3.5 km) of Trunk Highway (T.H.) 6 and to vacate approximately 4.5 miles (7.2 km) of the present T.H. 6 as part of the proposed expansion of the Clay Boswell Steam Electric Station. The vacated present highway would not be a public right-of-way, but would provide access to the electric generating facilities. The present T.H. 6, which will be vacated, stretches east and west along the north side of the existing Clay Boswell Station. As shown in Figure II-24, the relocated segment of T.H. 6 will be along the western edge of the proposed Clay Boswell Station site, north from the present junction of T.H. 6 and County Road 251 to U.S. Highway 2. The relocated segment will have 2 paved moving traffic lanes constructed to Minnesota and Federal standards.



BASE MAP LEGEND

ROAD AND ROADWAY FEATURES

- PROJECTED ROAD
- GRADED AND DRAINED ROAD
- GRAVEL OR STONE ROAD
- BITUMINOUS ROAD
- PAVED ROAD

BOUNDARIES

- COUNTY
- CIVIL TOWNSHIP
- CONGRESSIONAL TOWNSHIP (U.S. LAND)
- SECTION LINE
- NATIONAL OR STATE PARK
- NATIONAL OR STATE FOREST
- NATIONAL INDIAN RESERVATION

DRAINAGE

- INTERMITTENT STREAM
- NARROW STREAM
- MARSH OR SWAMP LAND
- POND OR LAKE

PUBLIC SERVICE FACILITIES

- PIPE LINE, GAS
- PIPE LINE, OIL
- TRANSMISSION LINE (33 KV OR OVER)
- POWER PLANT

EDUCATIONAL AND CORRECTIONAL INSTITUTIONS

- SCHOOL HOUSE
- CONSOLIDATED OR LARGE SCHOOL

N

0 1 2 3
MILES

0 1 2 3
KILOMETERS

MINNESOTA TRUNK HIGHWAY 6 RELOCATION NEAR CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE: ADAPTED FROM "PROJECT DEVELOPMENT REPORT FOR T.H. 6", STATE OF MINNESOTA, DEPARTMENT OF HIGHWAYS

FIGURE II-24

The Minnesota Department of Highways presently plans to upgrade U.S. Highway 2 to a 4 lane expressway design between Deer River and Grand Rapids. Since both the relocated T.H. 6 and the present County Road 128 (north of U.S. Highway 2) will junction with the new expressway in the same vicinity, 2 crossovers will be required - one T-intersection for relocated T.H. 6 and a second T-intersection for County Road 128. The T.H. 6 and U.S. Highway 2 intersection will be placed far enough east to allow adequate sight distance and a safe crossing between the T.H. 6 and County Road 128 intersections.

The total land required for right-of-way to relocate T.H. 6 is 56 acres (22.7 hectares). This land includes 7 acres (2.8 hectares) of County Road 251 right-of-way, 27 acres (10.9 hectares) of land presently acquired or being acquired by MP&L, and 22 acres (8.9 hectares) of tax forfeited lands. The State of Minnesota is the fee holder for the tax forfeited lands which are located between U.S Highway 2 and the north line of township 55 North. The tax forfeited lands consist of 5 acres 2.0 hectares) of lowland conifer forest (bog), 7 acres (2.8 hectares) of mixed deciduous forest, 8 acres (3.2 hectares) of cut over forest, 1.5 acres 0.61 hectares) of Type II wetlands, and 0.5 acres (0.20 hectares) of Type VI wetlands.

TABLE II-56
MAJOR NOISE SOURCES - ELECTRIC GENERATING FACILITIES OPERATION
CLAY BOSWELL STEAM ELECTRIC STATION (107)

Equipment	Representative Sound Level decibel(A)	Distance from Equipment feet	Type of Operation[a]	Equipment Location
Turbine generator	92	3	C	Indoor
Pulverizer	90	3	C	Indoor
Induced draft fan	128	5 from open outlet	C	Indoor
Forced draft fan	106	5 from inlet	C	Indoor
Primary air fan	113	5 from inlet	C	Indoor
Boiler feed pump	105	3	C	Indoor
Boiler feed pump turbine	97	3	C	Indoor
Circulating water pump	82	3	C	Indoor
Main transformer	83	5	C	Outdoor
Auxiliary transformer	78	3	C	Outdoor
Emergency diesel generator	105	3	I	Indoor
Cooling tower	78	50	C	Outdoor
Power control vale discharge pipe	129	50	I	Outdoor
Public address system	122	4	I	Indoor/ Outdoor

[a] C means continuous; I means intermittent.

T.H. 6 must be vacated by the summer of 1977 to accommodate MP&L's schedule for the proposed expansion of the Clay Boswell Station. MP&L has agreed to pay for all the land required for the highway relocation and for construction of the relocated 2 lane highway. The estimated cost for relocation of Minnesota T.H. 6 is approximately $400,000 (109).

Unit 4 Construction

Schedule and Manpower

The total construction time for the Clay Boswell Station's Unit 4 is estimated by MP&L to be approximately 46 months. It involves about 30,740 person-months of labor. The peak construction period should occur between the 31st and 33rd months of construction during 1979, when there will be about 1,200 workers on the job.

Table II-57 lists the general occupations or skills that will be required, the percentage of total construction work force represented for each skill, the approximate number of workers in each skill at peak construction, and the total person-months required for all construction (110).

TABLE II -57
CONSTRUCTION WORK FORCE - UNIT 4
CLAY BOSWELL STEAM ELECTRIC STATION (111)

Occupation or Skill	% of Total Construction Work Force	Number of Workers at Peak Construction	Total Person-Months
Management	5.2	33	1,599
Laborers	9.0	122	2,763
Carpenters	5.5	17	1,698
Operating engineers	8.0	110	2,462
Cement finishers	1.2	16	373
Electricians	15.2	210	4,689
Ironworkers	12.6	82	3,877
Insulators	6.3	100	1,923
Millwrights	2.1	34	655
Boilermakers	16.1	225	4,945
Painters	1.3	21	410
Teamsters	1.1	12	333
Pipe fitters	12.6	195	3,863
Bricklayers	0.2	2	57
Sheet metal workers	2.1	29	644
Miscellaneous	1.5	21	449
Total	100.0	1,229	30,740

Construction Procedures

MP&L proposes to use the procedures outlined below during construction.

Site. Vegetation removal, excavation, and construction activities will physically disturb approximately 618 acres (250 hectares) or 17% of the total site area. On site geologic resources to be used in construction are sand and gravel from the northwest corner and lacustrine clay and silt from near the site's center.

Erosion and Sediment. Common erosion control methods as described by the EPA will be employed in accordance with the Construction Environmental Protection Plan and effluent limitations applicable to construction runoff. These limitations are as follows:

Total suspended solids (TSS) - 50 mg per liter
pH - 6 to 9 units

The MPCA regulations limit pH to 6.5 to 8.5 units. Areas experiencing heavy construction traffic will require stabilization and protection. Construction roads and parking areas will be covered with a coarse base material and compacted. Other areas disturbed by construction will be shielded and/or stabilized to reduce erosion.

Drainage ditches will vary in size depending on the water volume and the flow rate for each ditch. Ditches will be lined with rip-rap, or other suitable material to prevent erosion of the ditch sides. Diversion ditches will be located to minimize overland water flow with a retention pond located in the most advantageous area for minimizing interference with normal construction activities.

From the discharge structure, the water will flow toward the nearest stream and will be discharged in such a manner that the stream bed will not be disturbed. Energy dissipators will be used where necessary to eliminate turbulence or excessive velocity.

One area under consideration with respect to potential water quality problems is the railroad spur and construction laydown area, which will be located approximately 1,500 ft (457 m) from the shore of the Mississippi River embayment. The topography of the area is not steep and, therefore, not conducive to erosion caused by surface runoff. Additionally, every effort will be made to minimize disruption of the natural vegetation cover.

The sedimentation basin will have the capacity to contain all runoff from the maximum once-in-10-year, 24-hr rainfall, as stipulated by EPA effluent limitations and guidelines, and will be constructed with as large a surface area as possible to maximize settling of suspended solids. Additional depth will be provided to handle all settled solids over the construction period, thereby lessening and possibly eliminating the need for periodic cleaning of the basin bottom.

*This particular effluent limit currently is being reevaluated by EPA. A less stringent limitation is expected in the future.

Inflow structures to the basin will be provided to minimize any turbulent flow or churning action that may disrupt the settling process. These structures will be equipped with a filter system (e.g. sod filter, straw bales, etc.) to reduce maintenance.

In addition to the use of a retention basin and diversion ditches, appropriate methods will be employed where possible to shield or stabilize exposed soil. As each area reaches its final grade, the soil will be stabilized, covered, or seeded. The type of treatment used will depend upon the slope of the land, size of the area, and amount of construction activity.

Dewatering operations could result in high-turbidity water. This water will also be routed to the sedimentation basin before discharge to Blackwater Lake.

Ground water. A dewatering system, which will lower the ground water table sufficiently to permit excavation for deep foundations (such as those required for the generator pedestal), may be necessary in the electric generating facility area. This system will interfere with the ground water system only during construction and, once construction is complete, the dewatering will be discontinued. It currently is believed that a dewatering system will not be necessary in the new ash and SO_2 sludge pond area, because the excavation required will be shallow and the clay and silt found in that area contain only small quantities of ground water.

Dike cutoffs (excavations designed to restrict ash and SO_2 sludge pond seepage to the near surface) will be used to ensure that there will not be water contamination. The cutoffs consist of trenches excavated to suitable stratum of low permeability, such as clay or silt, then backfilled with an impervious material.

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CHAPTER III

ALTERNATIVES TO THE PROPOSED ACTION

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Minnesota Environmental Quality Board (MEQB), formerly Minnesota Environmental Quality Council (MEQC), regulations for the preparation of environmental impact statements require "an objective evaluation of all reasonable alternatives to the action, the environmental impact of each, and the reason for their rejection in favor of the ultimate choice...", Minn. Reg. MEQC 31(f).

The purpose of the environmental impact statement is to provide a basis for evaluating the benefits of a project in light of its environmental risk and to compare the environmental risk of the proposed action with reasonable alternatives. Sufficient information should be provided to allow decision-makers to make reasoned choices among available options when considering a project.

Alternatives are major changes to the proposed action which would require MP&L to make major changes in engineering, construction, equipment, or operating procedures. Because both the Certificate of Need and Certificate of Site Compatibility for MP&L's proposed Unit 4 at the Clay Boswell Steam Electric Station have been issued, alternatives not considered were alternate sites or the alternative of not constructing the plant. The following are the classifications of alternatives considered.

- Primary Fuel Source Alternatives
- Supplemental Fuel Alternatives
- Primary Fuel Processing System Alternatives
- Transportation of Primary Fuel Alternatives
- Cooling and Water Supply System Alternatives
- Air Quality Control System Alternatives
- Solid Waste Management System Alternatives

Criteria were developed for assessing each of the proposed alternatives and selecting reasonable alternatives. The criteria were based on anticipated major adverse environmental impacts; abatement effectiveness; safety; Federal, State, and local statutes, regulations and standards; technological and engineering feasibility, reliability, and flexibility; and economic feasibility and cost effectiveness.

The following are considered to be reasonable alternatives to the MP&L's proposed action.

- o The use of waste wood residue (hogged fuel) as a supplemental fuel.
- o Coal beneficiation as a primary fuel processing system alternative.
- o Dry cooling tower as cooling and water supply alternative.
- o Wet/dry cooling tower as cooling and water supply alternative.
- o Disposal of solid waste in an abandoned mine as a solid waste management system alternative.

ALTERNATIVES CONSIDERED AND ASSESSED

Primary Fuel Alternatives

Alternatives

The primary fuel sources considered as alternatives to MP&L's proposed use of coal from the Big Sky Mine at Colstrip, Montana include 1) eastern coal, 2) midwestern coal, 3) western coal, and 4) lignite.

Criteria

Criteria have been established for selecting reasonable alternatives to the MP&L proposed action. A reasonable alternative must be at least equally as acceptable as MP&L's proposed action of using sub-bituminous coal from the Big Sky Mine. These criteria are as follows.

- o The sulfur content of an alternative primary fuel must be the same or lower than the sulfur content of MP&L's proposed primary fuel.
- o The primary fuel from an alternative primary fuel source must be available by May 1, 1980.
- o The supply of an alternative primary fuel must be adequate for the life of the Clay Boswell Steam Electric Station.
- o An alternative primary fuel must have essentially the same or lower cost per Btu than MP&L's proposed primary fuel of Western sub-bituminous coal from the Big Sky Mine located in Colstrip, Montana.

Alternative Assessment

The assessment of the primary fuel alternatives using the established criteria is presented in Table III-1. A review of delivered cost per Btu for the various primary fuel alternatives indicates that both eastern and midwestern coal would have a delivered cost substantially higher than for MP&L's sub-bituminous coal from the Big Sky Mine. As an example, Northern States Power's cost for Midwestern (Illinois and Kentucky) coal delivered in the Twin Cities area ranges from $0.66 to $0.86 per million Btu (0.25 million kg-cal) (1) as compared with MP&L's 1975 delivered cost at the Clay Boswell Station of $0.50

per million Btu (0.25 million kg-cal) (2). The delivered cost for eastern coal would be even higher than for midwestern coal. Although no detailed studies have been made, the delivered cost of other western coals and lignite possibly could be competitive with sub-bituminous coal from the Big Sky Mine, located near Colstrip, Montana. Based on known coal reserves, MP&L would be able to obtain adequate western coal and lignite supplies with a sulfur content lower than the expected 1.03% sulfur "as received" in the coal from the Big Sky Mine (3) (4). MP&L probably would be able to obtain an adequate supply of midwestern coal, but difficulty would be expected in obtaining an adequate coal supply having a sulfur content lower than the sulfur content of the coal from the Big Sky Mine.

TABLE III-1
PRIMARY FUEL ALTERNATIVES

CRITERIA	Eastern Coal	Midwestern Coal	Western Coal	Lignite
Sulfur content the same or lower than MP&L's proposed coal.	?	?	yes	yes
Fuel available by May 1, 1980.	no	no	no	no
Supply adequate for life of facility.	?	yes	yes	yes
Cost per Btu essentially the same or lower than MP&L's proposed coal.	no	no	?	?

For eastern coal, MP&L probably could not obtain an adequate coal supply having a sulfur content lower than coal from the Big Sky Mine. The most important criterion in rejecting the various alternative primary fuel sources is the time necessary to place a new coal mine in operation. This normally would require 4 to 6 years. No new primary fuel source could be operational before scheduled commercial operation of Clay Boswell Station, Unit 4 on May 1, 1980. Thus, none of the alternative primary fuel sources considered are a reasonable alternative to MP&L's proposed use of coal from the Big Sky Mine.

Supplemental Fuel Alternatives

Alternatives

Supplemental fuels considered for Unit 4 include 1) oil, 2) natural gas, 3) peat or lignites, 4) solid waste, 5) waste wood residue (hogged fuel), and 6) coal from sources other than the Big Sky Mine. MP&L has not proposed a supplemental fuel for use in Units 1, 2, 3, and 4 at the Clay Boswell Steam Electric Station.

Criteria

Criteria have been established for selecting reasonable alternative supplemental fuels. A reasonable alternative supplemental fuel must be at least equally as acceptable as MP&L's proposed primary fuel, sub-bituminous coal from the Big Sky Mine in Montana. These criteria are as follows.

- o Transportation and storage of a supplemental fuel must not produce substantial adverse environmental impacts.
- o A supplemental fuel must be compatible with the primary fuel and generating facility equipment and operation.
- o A transportation system must be available to transport the supplemental fuel from its source to the Clay Boswell Steam Electric Station.
- o A supplemental fuel must have a lower sulfur content than the primary fuel.
- o A supplemental fuel must be available and obtainable by MP&L.
- o Use of a supplemental fuel must result in essentially the same or lower cost per Btu and/or per kw hr when replacing MP&L's proposed primary fuel of western sub-bituminous coal from the Big Sky Mine located in Colstrip, Montana.
- o A supplemental fuel must be obtainable and available in adequate supply to amortize the cost of special handling, processing and other necessary facilities.

Alternative Assessment

The assessment of the supplemental fuel alternatives using the established criteria is presented in Table III2. All the alternative supplemental fuels are available and obtainable by MP&L except natural gas which cannot be used because of curtailments by the federal government. For oil and natural gas, the cost per Btu would be higher than for coal delivered at the Clay Boswell Station from the Big Sky Mine. The delivered cost per Btu is not known for peat, lignite, solid waste, waste wood residue, and coals (other than from the Big Sky Mine). However, it is expected that the delivered cost of these supplemental fuels could be comparable or lower than sub-bituminous coal delivered from the Big Sky Mine. All the supplemental fuels considered would be compatible with the primary fuel and facility equipment and operation. However, all the supplemental fuel except coal would require special handling, storage, and other facilities. All the supplemental fuel except coal would have a lower sulfur content than the coal from the Big Sky Mine. The sulfur content of a supplemental coal would depend on the specific coal. Transportation systems are available for all the supplemental fuel alternatives. The presently available transport systems, which include pipelines, railroads, and highway trucks, could be used to transport the supplemental fuel from its source to the Clay Boswell Station. None of the alternative supplemental fuels are likely to cause substantial adverse environmental impacts due to transport and storage. These supplemental fuels would use existing transportation systems and the technology exists to mitigate possible adverse impacts due to storage. However, the mining of peat or lignite could have substantially greater environmental impact than mining sub-bituminous coal from the Big Sky Mine. Oil, natural gas, and solid waste are not believed to be obtainable and available in adequate supply to amortize the cost of special handling and storage facilities. Peat, lignite,

TABLE III-2
SUPPLEMENTAL FUEL ALTERNATIVES

CRITERIA	Oil	Natural Gas	Peat or Lignite	Solid Waste	Waste Wood Residue (hogged fuel)	Coal (Other than Big Sky Mine Coal)
No substantial adverse environmental impacts due to transport and storage.	yes	yes	yes	yes	yes	yes
Compatible with primary fuel, facility equipment and operation.	yes	yes	yes	yes	yes	yes
Transport system available from source to facility.	yes	yes	yes	yes	yes	yes
Sulfur content lower than the primary fuel.	yes	yes	yes	yes	yes	?
Available and obtainable by MP&L?	yes	no	yes	yes	yes	yes
Cost per Btu/kw hr essentially same or lower than for MP&L's proposed primary fuel.	no	no	?	?	?	?
Supply obtainable and adequate to offset costs of special facilities.	no	no	?	no	?	?

and coal (other than from the Big Sky Mine) probably would be in adequate supply to amortize the cost of special facilities, but there is no particular advantage to using these as supplemental fuels. Waste wood residue (hogged fuel) may be in adequate supply to amortize the cost of special handling, storage, and processing facilities and there are environmental advantages to using waste wood residue as a supplemental fuel at the Clay Boswell Station. The forest products industry of northeastern Minnesota produces substantial waste wood residue. This waste wood residue presently is burned or deposited in land fills. Both these disposal practices result in adverse environmental impacts that would be eliminated by using the waste wood residue as a supplemental fuel at the Clay Boswell Station. Thus, the use of waste wood residue (hogged fuel) as supplemental fuel is considered a reasonable alternative for the Clay Boswell Station.

Primary Fuel Processing System Alternatives

Alternatives

The primary fuel processing systems considered as alternatives to the MP&L proposed expansion of the existing coal handling facilities for Units 1, 2, and 3 at the Clay Boswell Station, include 1) coal gasification, and 2) coal beneficiation.

Criteria

Criteria have been established for selecting reasonable alternatives to the MP&L proposed action. A reasonable alternative must be at least equally as acceptable as MP&L's proposed expansion of the existing coal handling facilities. These criteria are as follows.

- Disposal of solid waste from processing a primary fuel must have less adverse environmental impacts than disposal of solid waste from MP&L's proposed air quality control system.

- The technology for processing the primary fuel must be demonstrated to be reliable, adequate, and cost effective and to have a high sulfur removal efficiency.

- The fuel produced by processing the primary fuel must be compatible with existing Units 1, 2, and 3 at the Clay Boswell Steam Electric Station.

- The facilities used for processing the primary fuel must be compatible with generating facility equipment and operation at the Clay Boswell Steam Electric Station.

- Processing the primary fuel should produce a fuel having a sulfur content low enough to comply with Federal new stationary source performance standards.

Alternative Assessment

The assessment of primary fuel processing system alternatives using the established criteria is presented in Table III-3. It is difficult to assess the relative adverse environmental impacts associated with the disposal of solid

TABLE III-3
PRIMARY FUEL PROCESSING SYSTEM ALTERNATIVES

CRITERIA	Coal Gasification	Coal Beneficiation
Solid waste disposal has less adverse environmental impacts than solid waste disposal of MP&L's proposed air quality control system.	?	?
Technology demonstrated to be reliable, adequate, cost effective, and with a high sulfur removal efficiency.	no	yes
Processed fuel compatible with existing facility generating units.	no	yes
Processing facilities compatible with generating facility equipment and operation.	no	yes
Processed fuel has a sulfur content complying with the new source performance standards.	yes	?

waste from coal gasification, coal beneficiation, and MP&L's proposed air quality control system. The solid waste from coal gasification and beneficiation may contain mineral pollutants which are difficult to control. As an example, solid waste from coal beneficiation will contain pyrite or iron sulfide which easily oxidizes to form sulfuric acid. If not contained or neutralized, this acid can have substantial adverse environmental impacts. Because of Minnesota's abundance of ground water, streams, rivers, and lakes, the disposal of solid waste containing pyrite or other polluting minerals has a substantial potential for polluting Minnesota's waters. Thus it would be perferable that solid waste from gasification or beneficiation of coal from the Big Sky Mine be deposited at the mine near Colstrip, Montana, where the more arid climate lessens the potential for water pollution.

Coal gasification processes now being studied would produce a gaseous fuel having a lower sulfur content than the coal from the Big Sky Mine. However, gaseous fuel as the primary fuel would not be compatible with MP&L's existing coal-fired Units 1, 2, and 3 or the proposed Unit 4.

Preliminary coal beneficiation tests have been made using coal samples from the Big Sky Mine. These tests indicate a potential for processing the coal to reduce the sulfur content low enough to comply with Federal new stationary source performance standards (1). Beneficiated coal would be compatible with MP&L's existing Units 1, 2, and 3 and the proposed Unit 4. Coal beneficiation facilities located at the Clay Boswell Station could interfere with MP&L's proposed facilities. However, there would be no interference if the coal beneficiation facilities were located at the Big Sky Mine near Colstrip, Montana.

Coal gasification processes still are being studied and the gasification technology has not yet been demonstrated to be reliable and cost effective. Preliminary testing of coal samples from the Big Sky Mine (5) indicates the currently available and well developed coal beneficiation technology can reduce substantially the coal's sulfur content. However, additional testing would be required to evaluate more samples and finalize process design. Thus, coal beneficiation is considered a reasonable primary fuel processing system alternative.

Transportation of Primary Fuel Alternatives

Alternatives

The primary fuel transportation systems considered as alternatives to the MP&L proposed use of unit trains include transport by 1) water slurry pipeline, 2) methanol slurry pipeline, and 3) truck.

Criteria

Criteria have been established for selecting reasonable alternatives to the MP&L proposed action. A reasonable alternative must be at least equally as acceptable as MP&L's proposed action of using unit trains. These criteria are as follows.

- The adverse impacts of the vehicular traffic throughout the entire transportation route for the alternative primary fuel transportation system must not be substantially greater than for transportation by MP&L's proposed unit trains.

- The adverse environmental impacts throughout the entire transportation route due to noise and air pollution for the alternative primary fuel transportation system must not be substantially greater than for transportation by MP&L's proposed unit trains.

- An alternative primary fuel transportation system must not generate substantial adverse environmental impacts due to new construction.

- Potential fire and individual and public safety hazards must not be increased substantially by an alternative primary fuel transportation system when compared with transportation by MP&L's proposed unit trains.

- The technology of an alternative primary fuel transportation system must be demonstrated to be reliable, adequate, and cost effective.

- An alternative primary fuel transportation system must be capable of handling the needed quantities of primary fuel and transporting these quantities from the primary fuel source to the Clay Boswell Steam Electric Station.

- An alternative primary fuel transportation system must be flexible to meet changes in generating facility demand.

- An alternative primary fuel transportation system must be capable of seasonally continuous operation.

- An alternative primary fuel transportation system must be compatible with both the type of primary fuel used and the primary fuel mining, handling, and processing facilities.

- An alternative fuel transportation system must be compatible with the operation, generating equipment, and primary fuel handling equipment at the Clay Boswell Steam Electric Station.

- An alternative primary fuel transportation system must be operational by May 1, 1980.

Alternative Assessment

The assessment of the transportation of primary fuel alternatives using the established criteria is presented in Table III-4. Coal transport using a water slurry pipeline complies with most of the established criteria except that the pipeline would require new construction having substantial adverse environmental impact and the new pipeline could not be operational by May 1, 1980. The assessment of coal transport by methanol slurry pipeline is similar to the assessment for the water slurry pipeline. In addition, the technology for the methanol slurry pipeline has not been demonstrated to be reliable, adequate, or cost effective. Coal transport by truck can handle and transport

TABLE III-4
TRANSPORTATION OF PRIMARY FUEL ALTERNATIVES

CRITERIA	Water Slurry Pipeline	Methanol Slurry Pipeline	Truck
Adverse impacts due to vehicular traffic are not substantially greater than MP&L's proposed unit trains.	yes	yes	no
Impacts due to noise and air pollution are not substantially greater than MP&L's proposed unit trains.	yes	yes	no
New construction on the system will not have substantial adverse environmental impacts.	no	no	yes
No substantial increase in potential fire and individual and public safety hazards compared with MP&L's proposed unit trains.	yes	yes	no
Technology demonstrated to be reliable, adequate, and cost effective.	yes	no	no
Capable of handling and transporting the needed quantities of primary fuel.	yes	yes	yes
Flexible to meet facility demands.	yes	yes	yes
Capable of seasonally-continuous operation.	yes	yes	yes
Compatible with primary fuel and primary fuel mining, handling, and processing.	yes	yes	yes
Compatible with facility operation, equipment, and primary fuel handling equipment.	yes	yes	yes
System will be operational by May 1, 1980.	no	no	yes

coal quantities needed, is compatible with existing and proposed facilities, is technically reliable and adequate, is flexible to meet facilities demands, is capable of seasonally-continuous operation, would not require new construction with adverse environmental impacts, and can be operational by May 1, 1980. However, using trucks for coal transport would result in adverse environmental impacts due to increased truck traffic causing increased noise, air pollution, and vehicular traffic accidents and would not be cost effective. Thus, none of the alternatives considered for transportation of the primary fuel are a reasonable alternative to MP&L's proposed use of unit trains to transport the coal from the Big Sky Mine near Colstrip, Montana, to the Clay Boswell Steam Electric Station.

Cooling and Water Supply Alternatives

Alternatives

The cooling and water supply systems considered as alternatives to the MP&L proposed use of mechanical draft cooling towers include 1) a once-through cooling system, 2) cooling ponds and canals, 3) dry cooling towers, 4) wet/dry cooling towers, 5) natural draft towers, 6) spray ponds and canals, 7) utilization of ground water for make-up water, 8) on-site reservoir storage of water (during low water flow), and 9) off-site reservoir storage of water (during low water flow).

Criteria

Criteria have been established for selecting reasonable alternatives to the MP&L proposed action. A reasonable alternative must be at least equally as acceptable as MP&L's proposed action of using mechanical draft cooling towers. These criteria are as follows.

- The adverse environmental impacts on local lakes, ponds and marshes resulting from an alternative cooling and water supply system must not be substantially greater than MP&L's proposed cooling and water supply system.

- The adverse environmental impacts due to water supply intake or facility discharges from an alternative cooling and water supply system must not be greater than for MP&L's proposed cooling and water supply system.

- Water evaporation due to cooling in an alternative cooling and water supply system must not be substantially greater than for cooling by MP&L's proposed mechanical draft towers.

- Icing of public roads during meteorologically adverse periods from an alternative cooling and water supply system must not be greater than for cooling by MP&L's proposed mechanical draft tower.

- Potential individual and public safety hazards due to icing and fogging must not be substantially increased by an alternative cooling and water supply system when compared with MP&L's proposed mechanical draft cooling towers.

- The adverse visual aesthetics due to fogging resulting from an alternative cooling and water supply system must not be greater than MP&L's proposed mechanical draft cooling towers.

- An alternative cooling and water supply system must comply with existing Federal, State and local regulations and standards.

- Energy consumption of an alternative cooling and water supply system must not be substantially greater than for MP&L's proposed cooling and water supply system.

- The land use requirements for an alternative cooling and water supply system must not be substantially greater than for MP&L's proposed mechanical draft cooling towers.

- The technology of an alternative cooling and water supply system must be demonstrated to be applicable, reliable, and cost effective.

- The alternative cooling and water supply system must provide water of adequate quality and in sufficient quantity to meet facility needs for the life of the Clay Boswell Steam Electric Station.

- An alternative cooling and water supply system must be operational by May 1, 1980.

- An alternative cooling and water supply system must not incur substantially increased capital and/or operating costs when compared with MP&L's proposed cooling and water supply system.

Alternative Assessment

The assessment of the cooling and water supply alternatives using the established criteria is presented in Table III-5. Once-through cooling of the condensers does not comply with Federal Effluent Guidelines and Limitations which require closed-cycle cooling. Also, the potential adverse effects of constructing and operating a once-through intake system on Blackwater Lake could be significant.

Cooling ponds and canals would require a substantial amount of additional land. Also, construction of this type of cooling system could have substantial effects on existing ground water and marshes near the Clay Boswell Station.

Dry cooling towers would decrease substantially the amount of makeup water from Blackwater Lake required for MP&L's proposed wet mechanical draft cooling towers and essentially would eliminate any fogging which results from MP&L's proposed towers. While land use and noise impacts would increase, indications are that these would not be significantly different from MP&L's proposed action. The costs for dry cooling towers will be substantially greater than for MP&L's proposed wet mechanical draft cooling towers. Dry cooling towers of the size required for MP&L's proposed Unit 4 have not yet been constructed for electric generating facilities. However, dry cooling towers of the required size probably could be designed, engineered, and constructed for Unit 4.

Wet/dry cooling towers are considered for essentially the same reasons as the dry cooling towers. Wet/dry cooling towers will reduce fogging and water consumption, but not to the same degree as dry cooling towers. Also, the land use and noise impact for wet/dry cooling towers will not be significantly different from wet cooling towers. Cost of wet/dry cooling towers will be greater than for MP&L's proposed wet mechanical draft cooling towers, but this cost increase will depend on the amount of dry cooling included in the wet/dry cooling system. The cost evaluation will be dependent on the economic value placed on reduction of fogging and water consumption.

TABLE III-5
COOLING AND WATER SUPPLY ALTERNATIVES

CRITERIA	Once-through	Cooling Ponds and Canals	Dry Cooling Towers	Wet/Dry Cooling Towers	Natural Draft Cooling Towers	Spray Ponds and Canals	Utilization of Ground Water for Make-up	On Site Resevoir During Low Water Flow	Off Site Resevoir During Low Water Flow
Adverse impacts on local lakes, ponds, and marshes are not substantially greater than MP&L's proposed system.	yes	no	yes	yes	yes	no	no	no	no
Adverse environmental impacts due to cooling water supply intake and facility discharges not greater than MP&L's proposed system.	no	yes	yes	yes	yes	yes	yes	yes	yes
Water evaporation due to cooling not substantially greater than MP&L's proposed system.	yes	no	yes	yes	yes	yes	yes	yes	yes
Public road icing during meteorologically adverse periods due to cooling not greater than MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	yes	yes
Potential individual and public safety hazards due to icing and fogging are not substantially increased compared with MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	yes	yes
Adverse visual aesthetics due to fogging are not greater than MP&L's proposed system.	yes	yes	yes	yes	no	yes	yes	yes	yes
Complies with governmental and local regulations and standards.	no	yes	yes	yes	yes	yes	yes	yes	yes
Energy consumption is not substantially greater than MP&L's proposed system.	yes	yes	no	yes	yes	yes	yes	yes	yes
Land use requirements are not substantially greater than MP&L's proposed system.	yes	no	yes	yes	yes	no	yes	no	no
Technology demonstrated to be applicable, reliable, and cost effective.	yes	yes	yes	yes	yes	no	yes	yes	yes
Water of adequate quality and in sufficient quantity available to meet needs for the life of facility.	no	yes	yes	yes	yes	yes	no	yes	yes
System will be operational by May 1, 1980.	yes	yes	no	no	yes	yes	yes	yes	yes
Incurred capital and operating costs not substantially increased compared with MP&L's proposed system.	yes	yes	no	no	yes	yes	yes	no	no

Natural draft cooling towers are not significantly different from MP&L's proposed mechanical draft cooling towers. The advantage of natural draft over mechanical draft cooling towers is that the plume from the natural draft cooling tower would be much higher in elevation and would be less likely to cause icing on nearby roads. In contrast, however, the natural draft cooling tower and the resulting plume could result in adverse visual aesthetics. These trade offs indicate that the natural draft cooling tower would best be considered as a mitigating measure rather than an alternative.

Spray ponds and canals have the same disadvantages as cooling ponds and canals. Also, based on experience to date with spray cooling systems, the technology is not considered to be reliable.

Utilization of ground water for makeup to the cooling system has the disadvantages of the uncertainty of adequate supply and possible adverse effects on local lakes, ponds, and marshes. In addition, if the ground water table is connected directly to the Mississippi River, there is no benefit of using ground water instead of surface water.

Use of an on-site reservoir during low flow conditions in the Mississippi River would have increased capital costs; increased land requirements; and potential adverse effects on local lakes, ponds, and marshes. Use of an off-site reservoir during low flow conditions would have the same disadvantages as the use of an on-site reservoir.

In summary, only the dry cooling tower and wet/dry cooling tower are considered as reasonable alternatives for the Clay Boswell Station.

Air Quality Control System Alternatives

Alternatives

The air quality control systems considered as alternatives to the MP&L proposed use of wet particulate scrubbers and lime/limestone SO_2 spray tower absorbers include 1) hot-side electrostatic precipitators, 2) cold-side electrostatic precipitators, 3) a Wellman-Lord SO_2 scrubbing process, 4) a double alkali SO_2 scrubbing process, 5) a magnesium oxide SO_2 scrubbing process, 6) a citrate SO_2 scrubbing process, 7) dry absorption processes utilizing chemical injection and collection techniques, 8) mechanical collectors, 9) baghouse filters (fabric), and 10) other regenerative types of flue gas desulfurization processes.

Criteria

Criteria have been established for selecting reasonable alternatives to the MP&L proposed action. A reasonable alternative must be at least equally as acceptable as MP&L's proposed action of using wet particulate scrubbers and lime/limestone SO_2 spray tower absorbers. These criteria are as follows.

- Total pollutant discharge from an alternative air quality control system must not be greater than for MP&L's proposed air quality control system.

- Ground level pollutant concentrations resulting from an alternative air quality control system must not be greater than MP&L's system for air quality control.

- Adverse environmental impacts due to solid waste handling, solid waste disposal, or liquid discharges by an alternative air quality control system must not be greater than MP&L's proposed air quality control system.

- Water consumption by an alternative air quality control system must not be substantially greater than for MP&L's proposed air quality control system.

- An alternative air quality control system must comply with Federal, State and local regulations and standards.

- Energy consumption by an alternative air quality control system must not be substantially greater than for MP&L's proposed air quality control system.

- An alternative air quality control system must not substantially increase land use requirements when compared to MP&L's proposed air quality control system.

- The technology of an alternative air quality control system must be demonstrated to be reliable, flexible and cost effective and to have a high sulfur and particulate removal efficiency.

- An alternative air quality control system must be compatible with the primary fuel used at the Clay Boswell Steam Electric Station.

- An alternative air quality control system must be operational by May 1, 1980.

- An alternative air quality control system must not result in substantially increased capital and operating costs when compared with MP&L's proposed air quality control system.

Alternative Assessment

The assessment of the air quality control system (AQCS) alternatives using the established criteria is presented in Table III-6. Hot-side and cold-side electrostatic precipitators (ESP) would have increased capital and operating costs, and the hot-side or cold-side ESP in combination with a different type of SO_2 scrubber system would not change significantly the emissions and adverse environmental impacts associated with MP&L's proposed air quality control system for Unit 4.

Selection of an SO_2 emission control system involves a comparative evaluation of system costs, environmental impacts, and risks associated with using a relatively new technology. For large, coal-fired steam electric generating facilities, U.S. electric utilities have the greatest amount of experience with lime/limestone SO_2 emission control systems. Therefore, the lime/limestone SO_2 emission control system is considered to be the alternative with the lowest risk to MP&L and the State of Minnesota.

From an environmental viewpoint, lime/limestone SO_2 emission control systems are not as desirable as regenerative emission control systems (Wellman-Lord SO_2, double alkali SO_2, magnesium oxide SO_2, and citrate SO_2, scrubbing processes) because lime/limestone systems produce a solid waste by-product requiring disposal. Capital and operating costs for lime/limestone SO_2 emission control systems generally are defined better than for other SO_2 emission control systems because these other emission control systems are in an earlier stage of technical development. However, these other emission control systems generally are thought to be cost-competitive with lime/limestone SO_2 emission control systems.

TABLE III-6
AIR QUALITY CONTROL SYSTEM ALTERNATIVES

CRITERIA	Hot-side Electrostatic Precipitators	Cold-side Electrostatic Precipitators	Wellman-Lord SO_2 Scrubbing Process	Double Alkali SO_2 Scrubbing Process	Magnesium Oxide SO_2 Scrubbing Process	Citrate SO_2 Scrubbing Process	Dry Absorption Processes	Mechanical Collectors	Baghouse Filters (fabric)	Other Regenerative Flue Gas Desulfurization Processes
Total pollutant discharge is not greater than MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	no	yes	yes
Ground level pollutant concentrations are not greater than MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	no	yes	yes
Adverse environmental impacts due to solid waste handling and disposal and liquid discharges are not greater than MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Water consumption is not substantially greater than MP&L's proposed system.	yes	yes	?	?	?	?	yes	yes	yes	
Complies with governmental and local regulations and standards.	yes	yes	yes	yes	yes	yes	yes	no	yes	yes
Energy consumption is not substantially greater than MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Land use requirements are not substantially increased compared with MP&L's proposed system.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Technology demonstrated to be reliable, flexible, and cost effective and has a high sulfur/particulate removal efficiency.	yes	yes	no	no	no	no	no	yes	yes	no
Compatible with the primary fuel.	yes	?	yes	yes	yes	yes	yes	yes	yes	yes
System will be operational by May 1, 1980.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Capital and operating costs are not substantially increased compared with MP&L's proposed system.	no	no	yes	yes	yes	yes	yes	yes	yes	yes

While there are several air quality control system alternatives which show promise, none of these systems have an operating record on large coal-fired steam electric generating facilities which makes them directly comparable to the lime/limestone SO_2 mission control system. Therefore, these systems are not considered to be viable and reasonable alternatives.

Compliance with particulate emission standards could not be achieved with mechanical particulate collectors. Baghouse filter systems are a potential air quality control system for particulates. However, baghouse filter systems in combination with different types of SO_2 scrubbers have essentially the same particulate and SO_2 removal efficiency as MP&L's proposed air quality control system. Thus, there is no significant advantage to using a baghouse filter system in combination with a different SO_2 scrubber system.

In summary, none of the air quality control system alternatives are considered reasonable alternatives to MP&L's proposed wet particulate scrubber and spray tower absorbers.

Solid Waste Management System Alternatives

Alternatives

The solid waste management systems considered as alternatives to the MP&L proposed use of enlarged existing and new disposal ponds for ash and scrubber solids, include 1) commercial utilization of solid wastes (such as gypsum or building material), 2) disposal of solid waste with mining waste, 3) transport of solid waste to an off-site non-mining area, 4) disposal of solid waste in the current disposal area for Units 1, 2, and 3 by constructing higher dikes to increase disposal capacity, and 5) disposal of solid waste in an abandoned mine.

Criteria

Criteria have been established for selecting reasonable alternatives to the MP&L proposed action. A reasonable alternative must be at least equally as acceptable as MP&L's proposed use of existing and new disposal ponds for solid waste. These criteria are as follows.

- An alternative solid waste management system must have no more adverse environmental impacts than MP&L's proposed solid waste management system.
- An alternative solid waste management system must provide for storage of potential mineral resources recovered from MP&L's air quality control system and facility operations at the Clay Boswell Steam Electric Station.
- An alternative solid waste management system must not interfere with the recovery of potential mineral resources.
- An alternative solid waste management system based on utilization of the solid waste must utilize all solid waste such that the need for a separate solid waste disposal system is eliminated.
- An alternative solid waste management system must comply with Federal, State, and local regulations and standards.
- Energy consumption of an alternative solid waste management system must not be substantially greater than for MP&L's proposed system for disposal of solid waste.
- An alternative solid waste management system must adhere to existing land use policies and be compatible with good land use principles.
- An alternative solid waste management system must have a flexible design, providing for land-recovery and use.
- An alternative solid waste management system must be compatible with MP&L's air quality control system and facility operations at the Clay Boswell Steam Electric Station.

- The technology of an alternative solid waste management system must be demonstrated to be adequate, reliable, and cost effective.

- An alternative solid waste management system must be structurally stable, safe, and permanent.

- An alternative solid waste management system must be flexible to meet changes in the solid waste load resulting from MP&L's air quality control system.

- An alternative solid waste management system must be capable of seasonally continuous operation.

Alternative Assessment

The assessment of the solid waste management system alternatives using the established criteria is presented in Table III-7. All the alternative solid waste management systems could be compatible with the construction and operation of MP&L's proposed air quality control system and other facilities at the Clay Boswell Station. The ash and SO_2 sludge generated during the operation of the Clay Boswell Station are potential mineral resources which may have commercial uses in the future. It is considered poor policy to 1) dilute these potential resources with other waste and diminish the possibility of future economic use of the ash and sludge or 2) mix these potential resources with other potential resources and diminish the possibility of future economic use of both potential resources. It is not considered reasonable to mix and dispose of the solid waste from the Clay Boswell Station with mining waste or tailings from the western Mesabi Iron Range. Both of these solid wastes are potential mineral resources. The ash and sludge have potential construction uses. The mining waste contains substantial quantities of iron and has potential for processing to recover the iron.

All the alternative solid waste management systems would or could be constructed and operated to comply with governmental regulations and standards. Energy consumption probably would be greater for all the alternatives than for MP&L's proposed system, but the increased energy consumption probably would not be substantial for any of the alternatives. It is anticipated that disposal of the solid waste at an off-site non-mining area or in the current disposal area would have greater adverse environmental impacts than MP&L's proposed system. A survey of the area indicates possible off-site disposal sites probably would have more adverse environmental impacts because of destruction of productive forest lands, wildlife areas, recreation areas, marsh areas, and/or streams. Use of the current disposal area could have major adverse environmental impacts on the Mississippi River and Blackwater Lake, since these are adjacent to the current disposal ponds. The structural stability and safety of disposal in the existing ponds are questionable. Disposal of the solid waste in an abandoned mine may have adverse environmental impacts such as contamination of ground water aquifers. The transport of solid waste to an off-site area for disposal with mining waste or in an abandoned mine would have adverse effects. Pipeline transport appears to have the least adverse environmental impacts for relatively short transport distances while rail transport appears to be more desirable for longer distances. Transport by truck would be the least desirable for longer transport distances because of increased heavy truck traffic in communities and

TABLE III-7
SOLID WASTE MANAGEMENT SYSTEM
ALTERNATIVES

CRITERIA	Commercial Utilization of Solid Waste	Disposal of Solid Waste with Mining Waste	Transport Solid Waste to Off Site, Non-Mining Area	Disposal of Solid Waste in Current Disposal Area	Disposal of Solid Waste in an Abandoned Mine
Adverse environmental impacts are no more than MP&L's proposed system.	yes	yes	no	no	?
Provides for storage of potential mineral resources recovered by MP&L's air quality control system and facility operations.	yes	no	yes	yes	yes
No interference in the recovery of potential mineral resources.	yes	no	yes	yes	yes
Utilizes all solid waste such that need for a separate disposal system is eliminated.	no	yes	yes	yes	yes
Complies with governmental regulations and standards.	yes	yes	yes	yes	yes
Energy consumption is not substantially greater than MP&L's proposed system.	yes	yes	yes	yes	yes
Adheres to existing land use policies and is compatible with good land use principles.	yes	yes	no	yes	yes
Provides a flexible design for land recovery and use.	yes	yes	yes	yes	yes
Compatible with MP&L's air quality control system and facility operations.	yes	yes	yes	yes	yes
Technology demonstrated to be adequate, reliable, and cost effective.	no	?	yes	?	?
System is structurally stable, safe, and permanent.	yes	yes	yes	no	yes
Provides flexibility to meet changes in the solid waste load of MP&L's air quality control systems.	yes	yes	yes	yes	yes
Capable of seasonally continuous operation.	yes	yes	yes	yes	yes

the resulting noise, dust, and safety hazards. All the solid waste management system alternatives have adequate flexibility to meet changes in the solid waste disposal load and are capable of seasonally continuous operation, except where the transport distances are long.

The technology exists for the commercial utilization of ash and SO_2 sludge. However, this technology is not cost effective because of the remoteness of the Clay Boswell Station from large urban construction markets. For the disposal of solid waste at an off-site area, water slurry pipeline technology is adequate, reliable, and cost effective for transporting the solid waste relatively short distances. For the alternatives of disposal of the solid waste with mining waste or in abandoned mines, there may be technological problems in rail transport of the solid waste. Rail transport may require specially designed cars to minimize spillage, facilitate unloading, and avoid freezing during transport. The disposal of the solid waste in the current disposal area will require that the ultimate elevation of the current disposal area be increased at least 50 ft (15.2 m) above the now proposed ultimate elevation. This increase in dike height probably will result in unstable structures, with an unsafe and non-permanent solid waste disposal system. It is believed that stable, safe, and permanent structures could be constructed for all the other alternatives considered. Disposal of the solid waste with mining waste is the only solid waste management alternative which possibly would interfere in the recovery of potential mineral resources. Disposal in an abandoned mine would not interfere in the recovery of potential mineral resources since the mineral resources would already be mined from the abandoned mine. Thus, a distinction is made between abandoned and inactive mines with inactive mines being currently non-operating mines with potentially recoverable mineral resources.

All the alternative solid waste management systems could provide a flexible design for land recovery and use. The potential commercial markets for ash and SO_2 sludge are relatively small and distant from the Clay Boswell Station. Thus, commercial utilization of the solid waste could use only a small portion of the waste produced and is not an alternative which would eliminate the need for a solid waste disposal system. All of the alternatives, except the use of an off-site, non-mining area for disposal, would adhere to present land use policies and be compatible with good land use principles.

The evaluation of the solid waste management system alternatives using the established criteria results in the disposal of the solid waste in an abandoned mine being a reasonable alternative with both the possible adverse impacts and technology needing further analysis.

ALTERNATIVE - WASTE WOOD AS SUPPLEMENTAL FUEL

MP&L's Clay Boswell Steam Electric Station is located in a heavily wooded region in northern Minnesota. There are numerous producers of wood products located in the general vicinity of the Clay Boswell Station that use the available timber to produce lumber and wood products (i.e., paper).

The production of lumber and wood products requires mechanical energy which generally is provided by some combination of steam and/or electricity. Since the conversion of timber into final products yields some waste wood, utilizing this waste as an energy source has the potential for reducing the adverse environmental impacts associated with waste wood disposal. Many larger wood producers burn waste wood in a steam generator designed to produce steam needed for wood processing. This steam also may be utilized to produce electricity using a steam turbine-generator.

Many of the lumber mills near the Clay Boswell Station produce more than enough waste wood to meet their own energy requirements. If these wood producers used waste wood to supply all their own fuel requirements, they still would have excess waste wood. The excess waste wood could be used to produce electricity at the Clay Boswell Station, thus eliminating the need for land-filling, storing, or burning the waste.

The benefits of burning waste wood as fuel depend on many factors including the additional transportation requirements, increased petroleum consumption for transportation, reduction in coal consumption, decreased quantity of waste wood for disposal, better air pollution control equipment for burning at the electric generating facility than available at the waste wood disposal site, possible reduction in the total installed cost of fuel preparation equipment, and reduced air emissions from the electric generating facility.

Wood Supply

The production of lumber and paper from timber results in considerable waste wood. This waste wood could be utilized as fuel and has been partially identified by a canvassing of timber industries in close proximity to the Clay Boswell Station. Table III-8 is a summary of information on waste wood in the vicinity of the Clay Boswell Station.

TABLE III-8
WASTE WOOD SUPPLY IN VICINITY OF CLAY BOSWELL STEAM ELECTRIC STATION

Industry[a]	Distance[b]		Annual Quantities		Form
	miles	km	tons	mt	
St. Regis Paper Company	48	77	4,500	4,082	peeler waste and trim (pine and fir)
Tobiason Brothers Sawmill	23	37	2,760	2,504	sawdust and slabs
Remer Timber Company	23	37	15,000	13,608	bark (aspen)
Rajala Timber Company	10	16	28,500	25,855	sawdust, chips, shavings (pine, aspen, fir)
Marcell Mill and Lumber Company	34	55	37,500	34,019	sawdust and trim (aspen)
Boise Cascade Corporation	74	119	22,000	19,958	bark (hard and soft wood
Blandin Paper Company	5	8	26,000[c]	23,587[c]	sawdust and bark strips
Total			136,260	123,613	

[a] Data not included for one company within 75 miles (121 km) radius of Clay Boswell Steam Electric Station and for all companies further than 75 miles (121 km) from Clay Boswell Steam Electric Station.

[b] Approximate highway distance to mailing address location; not necessarily distance to transport waste wood to the Clay Boswell Steam Electric Station.

[c] Expect to utilize all of their own waste wood and purchase additional waste wood from nearby sources for fuel within 2 to 3 years.

Table III-8 shows that substantial quantities of waste wood currently are available. However, Blandin Paper Company's plan to use their waste wood as fuel casts considerable doubt on the continued availability of this fuel source. Since Blandin Paper Company intends to utilize their waste wood as fuel (presumably because of recent fuel price increases), it is reasonable to assume that others may do the same in the future.

In addition to the likelihood of increased use of waste wood as fuel by the timber industry, it is expected that other uses will be found for the waste wood. For example, some wood processors are using sawdust and chipped trimmings to make particle board. While the timber industry reasonably can be expected to expand total harvest, since an additional 1.1 million cords (4.0 million cu m) are available for harvesting (6), it does not necessarily mean increased supply of waste wood. Excluding the waste wood of the Blandin Paper Company, the total available waste wood supply is approximately 110,260 tpy (100,026 mtpy).

Wood Characteristics

Wood identified as being processed in the vicinity of the Clay Boswell Station includes both softwood (principally evergreens) and hardwood (broad-leafed) timber. The processing is completed on native timber and timber shipped in from the west coast. The species identified as being processed are balsam fir, douglas fir, red pine, jack pine, and aspen (7).

The waste wood is predominantly bark. For processors not utilizing their sawdust or trimmings, the bark would be supplemented with sawdust, slabs up to 6 ft (1.83 m), end trim up to 16 in. (41 cm) in diameter, and other trim and shavings.

The waste wood contains 45 to 55% moisture, with the average being 50% moisture (8). The waste wood contains an estimated 0.21% ash with an estimated heating value of 4,300 Btu per lb (2,389 kg-gal per kg) as produced. The estimated heating value of the waste wood on a dry basis is 8,900 Btu per lb (4,944 kg-cal per kg) (9).

Wood is sold as timber on the basis of volume. The standard volume measure is a cord, defined as being 8 ft (2.44 m) long, 4 ft (1.22 m) wide, and 4 ft (1.22 m) high. The volume of a cord, which is 128 cu ft (3.625 cu m), includes air space which varies depending on the size of the wood making up the cord.

Table III-9 identifies the characteristics of the wood processed in the vicinity of the Clay Boswell Station based on 80 cu ft (2.265 cu m) of solid wood, as reported by the Forest Products Laboratory (10).

Recognizing that the quantities and sources of waste wood will vary during the year and to even a greater extent during the life of the generating unit, it is necessary to generalize the waste wood characteristics. Thus, the waste wood characteristics presented in Table III-10 have been assumed for purposes of determining fuel requirements, emissions, and solid waste production.

Wood Transportation

Transportation of the waste wood from the timber processing plant to the Clay Boswell Station can be by either truck or rail. Many of the nearby wood processors do not have a rail spur or already are trucking the waste wood to a landfill for disposal. Transportation from nearby producers without rail access could logically be by truck to avoid double handling. Transportation of the bulky material for great distances probably could be done only by rail.

TABLE III-9

WOOD CHARACTERISTICS

Parameter	Aspen	Douglas Fir	Pine, Eastern White	Pine, Southern Yellow
Weight, green				
lb per cord	3,440	3,200	2,880	4,000
kg per cu m	430	400	360	501
Weight, 20% moisture				
lb per cord	2,160	2,400	2,080	2,600
kg per cu m	270	300	260	325
Heating value, green				
10^6 Btu per cord	10.3	13.0	12.1	14.2
10^6 kg-cal per cu m	0.72	0.91	0.84	0.99
Heating value, 20% moisture				
10^6 Btu per cord	12.5	18.0	13.3	20.5
10^6 kg-cal per cu m	0.87	1.25	0.93	1.43

TABLE III-10

ASSUMED WASTE WOOD CHARACTERISTICS

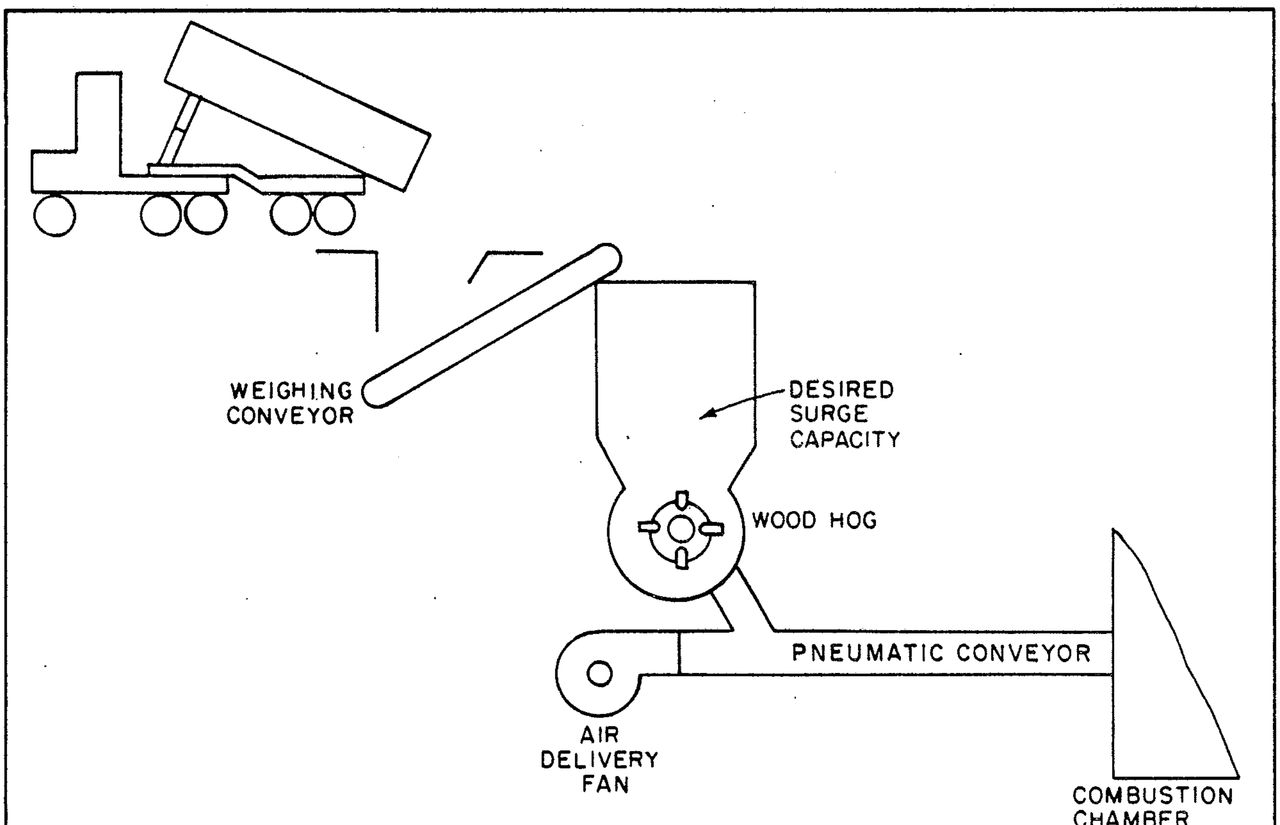
Parameter	"As Received"
Heating value	
Btu per lb	4,300
kg-cal per kg	2,389
Moisture, %	50
Ash, %	0.11
Sulfur, %	trace
Density	
lb per cu ft	25
g per cc	0.40

Based upon a coal density of 84 lb per cu ft (1.35 gm per cu cm) (11), and the assumed density of the waste wood, a typical 100 ton (90.7 mt) coal rail car could haul approximately 30 tons (27.2 mt) of waste wood. The 136,260 tons (123,613 mt) of waste wood currently available annually would, therefore, require approximately 18 rail carloads daily if delivered uniformly on a 5 day work week basis. Trucks carrying 20 tons (18.1 mt) each could deliver this same quantity of wood in the 5 day work week with approximately 26 truck loads per day.

Wood Handling

Waste wood, whether delivered by rail or truck, could be received at the Clay Boswell Station by a ground level hopper. The waste wood could be weighed on the conveyor from the hopper to the sizing machinery. The sizing machinery would reduce the waste wood to a size which can be handled by the pneumatic conveyor and efficiently burned in the boiler.

The sizing machinery probably will be a wood hog, which has been standard equipment for wood sizing for many years. The wood hog could be sized to process only the oversize pieces by classifying the waste wood by size prior to feeding it to the sizing equipment. This classification step would be proctical if it were necessary to store the waste wood at the Clay Boswell Station. Pieces large enough to require further size reduction could be stored outside with little protection, whereas sawdust would require extensive protection to prevent it from becoming windborne. It is assumed that storage of the waste wood could be handled by the producer rather than the utility and that the handling system at the Clay Boswell Station will not require significant storage capacity. The system for handling the waste wood is shown in Figure III-1.



WASTE WOOD PROCESSING AND HANDLING SYSTEM — **FIGURE III-1**

Facilities Operation

Power Generation Cycle

Utilization of waste wood as a supplemental fuel will affect only the steam generator in the power generaton cycle. Combustion Engineering, Incorporated (CE), manufacturer of the steam generator for MP&L's proposed Unit 4 at the Clay Boswell Station, has stated that wood can be burned in the unit which is currently being manufactured (12). Their stated restrictions for burning 20 to 22 railroad carloads of waste wood per day are:

> "CE has made a preliminary evaluation and determined that wood burning in the subject unit can be accomplished by introducing the wood chips through one nozzle per windbox assembly (total of 4) which would be located in the upper most auxiliary air compartment at elevation 1,412 ft 4 in. The wood will have to be properly prepared and sized not to exceed 1/4 in. and would then be transported to the furnace with 0.5 lb of air per lb of wood. The maximum heat input in the form of wood will be limited to 10% of MCR heat input and in addition, wood burning would be restricted to boiler loads above 50% MCR."

The wood handling system must be designed to meet the above requirements without exceeding currently available equipment operating characteristics.

Based on the design net heat rate of 10,200 Btu per kw (2,574 kg-cal per kw), the 504,000 kw unit will require approximately 5.14×10^9 Btu per hr (1.297×10^9 kg-cal per hr). If the available wood supply of 110,260 typ (100,026 mtpy) were burned on the basis of uniform combustion during the 8 hr delivery, 5 days each week, it would produce 0.46×10^9 Btu per hr (0.116×10^9 kg-cal per hr). This heat input is less than the 10% maximum listed by Combustion Engineering. However, extra hours burning may be necessary after generating unit outages to consume the buildup of waste wood without exceeding the maximum. Ingnoring minor differences in combustion efficiency, the 110,260 tons (100,026 mt) of waste wood would displace approximately 55,000 tons (49,895 mt) of coal per year.

The cost of coal delivered to the Clay Boswell Station was approximately $9.90 per ton in January, 1977 (13). The fuel savings would, therefore, be about $544,500 annually, if the timber processors delivered their waste to the electric generating facility at no charge to MP&L for waste wood or transportation.

Raw Materials Handling

The waste wood processing and handling facilities have been estimated to cost approximately $6,500,000.

This cost was estimated quickly, without detailed design. It includes in-place cost, (including overheads and interest during construction) for wood receiving, processing and storage, and steam generator modifications after initial operation. This cost is probably greater than that required by the final design, but may be required for the "retrofit" basis of this fuel supply. These facilities would require approximately 4,200 kw of auxiliary power during the average operation of 53 tons per hr. It is further anticipated that 2 additional men would be required for handling the waste wood processing system. Based on depreciating the capital cost of the modifications to the original system on a straight line basis over 20 years and applying a 10% annual interest rate, the first 10 years average annual cost of capital would be $828,750. The annual cost of auxiliary power at $0.01 per kw-hr would be $87,400. The two wood handlers costing $12,000 per year would total $24,000 each year. These total wood handling costs, excluding escalation, are $940,150 per year.

Water Systems

Firing of waste wood could affect the water system. If the wood preparation utilized a wood pulper and subsequent cone press moisture removal, rather than the dry wood hog, makeup water to the recirculating hydraulic conveying system will be required. This system is considered unlikely.

The reduction of total ash and sulfur to be realized by supplemental waste wood firing will reduce, by practically insignificant amounts, the amounts of ash sluice water and scrubber system makeup water.

Solid Waste Production

Solid waste from Unit 4 will consist of collected ash (both bottom ash and fly ash) and SO_2 scrubber waste. At least 15% of the coal ash will be bottom ash while none of the wood ash is assumed to be bottom ash. Consequently, 85% of the coal ash will be fly ash while 100% of the wood ash is assumed to be fly ash. Approximately 2.8 lb (1.3 kg) of dry SO_2 scrubber waste will be generated for every pound of SO_2 removed. Table III-11 shows the quantity of solid waste produced by Unit 4 when using available waste wood as a supplemental fuel.

Air Quality Control Systems (AQCS)

MP&L's proposed Unit 4 will employ a wet particulate scrubber and SO_2 absorbers for particulate and SO_2 control, respectively. The AQCS will remove approximately 99.6% of the flue gas fly ash and nearly 90% of flue gas SO_2. However, with 5% of the boiler flue gas used as stack gas reheat, the overall SO_2 removal efficiency is estimated at 85%. Since the waste wood has very little ash and essentially no sulfur, the boiler emissions of particulates and SO_2 are expected to be reduced in direct proportion to the portion of total heat input (to the boiler) being supplied by the waste wood. The waste wood ash (0.10%) is all assumed to become fly ash and will be collected with the same efficiency as the coal fly ash.

Products of combustion will exhaust to the atmosphere through the new 700 ft (213 m) stack for existing modified Units 1, 2, and 3, and through MP&L's proposed 600 ft (183 m) stack for Unit 4.

Emissions, Effluents, and Waste Production

Air Emissions

Particulate, NO_x and SO_2 emissions from the boiler will be reduced as a result of burning waste wood. Tables III-12, III-13, and III-14 present the estimated air emissions for MP&L's proposed Unit 4 when utilizing waste wood as a supplemental fuel. The basis for these estimated air emissions is burning waste wood with a heating value of 4,300 Btu per lb (2,389 kg-cal per kg) at a rate of 5 days per week, 8 hr per day with 10% of the maximum boiler heat input being provided by waste wood firing.

Wastewater Effluents

Wastewater effluents will not be significantly affected by using waste wood as a supplemental fuel. Reduced ash quantities will result from reduced coal consumption and low ash content of the waste wood. This will result in reduced sluicing water requirements. However, this reduction will occur only during the 8 hr operating day in which waste wood is burned.

ALTERNATIVE - COAL BENEFICIATION

Beneficiation of the sub-bituminous coal from the Big Sky Mine near Colstrip, Montana, probably could result in a cleaned coal so that the MP&L Clay Boswell Steam Electric Station would comply part of the time with new source emmission standards without flue gas desulfurization. Coal beneficiation will require the construction of a coal preparation plant to beneficiate enough coal to supply all coal-fired steam generating units at the Clay Boswell Station. This coal preparation plant could be located either in Montana at the Big Sky Mine or in Minnesota at the Clay Boswell Station. This alternative will consider a coal preparation plant located at the Big Sky Mine only. The adverse environmental impact due to disposal of coal cleaning rejects or waste is expected to be less with disposal at the Big Sky Mine than with disposal at the Clay Boswell Station. The arid climate at the Big Sky Mine decreases the potential for surface and ground water contamination by coal rejects or waste. During winter months, the coal must be partially dried prior to loading into unit trains to eliminate possible freezing of the coal during transit.

Coal Preparation

The raw coal to be beneficiated in the coal preparation plant will be western sub-bituminous coal from Peabody Coal Company's (Peabody) Big Sky Mine located near Colstrip, Montana. This is the same coal supply that MP&L proposes to use as the primary fuel for the Clay Boswell Steam Electric Station. The coal supply, information regarding coal agreements between MP&L and Peabody, and coal reserve estimates and analyses for the Big Sky Mine, have been described in Chapter II - Proposed Action.

Coal washability data from tests conducted by the U.S. Bureau of Mines (14) and the John T. Boyd Company (5) indicate that both the Rosebud and McKay coal seams have potential for producing a cleaned coal which will comply with new source emission standards of 1.2 lb SO_2 per million Btu (2.2 kg per million kg-cal) input. Based on this washability data, the estimated coal cleaning results for the Rosebud seam, McKay seam, and a composite for both seams are presented in Tables III-15, III-16, and III-17, respectively.

TABLE III-11

ESTIMATED FUTURE SOLID WASTE OR ASH AND SO_2 SCRUBBER WASTE PRODUCTION WITH COAL AND WASTE WOOD - UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Solid Waste	Unit 4
Bottom ash[a]	
Maximum daily	
Coal[b]	
tons	254
metric tons	230
Waste wood	
tons	0
metric tons	0
Total	
tons	254
metric tons	230
Average annual	
Coal[c]	
tons	25,248
metric tons	22,905
Waste wood	
tons	0
metric tons	0
Total	
tons	25,248
metric tons	22,905
Fly ash and SO_2 scrubber waste[a d]	
Maximum daily	
Coal[e]	
tons	2,709
metric tons	2,458

Solid Waste	Unit 4
Fly ash and SO_2 scrubber waste[a d]	
Coal[f] (continued)	
Total	
tons	187,002
metric tons	169,646
Solid Waste[a]	
Average annual	
tons	[illegible]2,250
metric tons	192,551
Waste wood	
tons	1
metric tons	1
Total	
tons	2,710
metric	2,459
Average annual	
Coal[f]	
tons	186,892
metric tons	169,546
Waste wood	
tons	110
metric tons	100

[a] Based on waste wood being burned 8 hr per day, 5 days per week or 110,260 tpy (100,026 mtpy) of waste wood burned; 10% of the maximum boiler heat input obtained during the typical 8 hr day by waste wood firing.

[b] Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 20% to 80%.

[c] Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 15% to 85%.

[d] Based on a particulate removal efficiency of 99.6%; a ratio of dry SO_2 absorber waste to SO_2 removed of 2.8; and burning waste wood producing only fly ash.

[e] Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 15% to 85%.

[f] Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 20% to 80%.

TABLE III-12
ESTIMATED AIR EMISSIONS WITH COAL AND WASTE WOOD - UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 4
Full load/electrical output	
Gross MW/net MW	554/504
Heat input rate	
Btu x 10^6 per hr	5,141
kg-cal x 10^6 per hr	1,297
Fuel consumption	
Average[a]	
Coal	
lb per hr	534,000
kg per hr	242,218
Waste wood	
lb per hr	120,000
kg per hr	54,431
Maximum[b]	
Coal	
lb per hr	616,000
kg per hr	279,413
Waste wood	
lb per hr	120,000
kg per hr	54,431

Parameter	Unit 4
Products of combustion	
Average	
Mass flow rate, lb per hr	5,678,400[c]
Mass flow rate, kg per hr	2,575,498[c]
Volume flow rate, actual cfm	1,500,313
Volume flow rate, actual cu m per min	42,484
Temperature, °F	155
Temperature, °C	68
Emissions at full load[d]	
Average	
Particulate, lb per hr	514
Particulate, kg per hr	233
NO_x, lb per hr	3,598
NO_x, kg per hr	1,632
SO_2 at 38(%S),[e] lb per hr	6,169
SO_2 at 38(%S),[e] kg per hr	2,798
Worst case	
Particulate, lb per hr	514
Particulate, kg per hr	233
NO_x, lb per hr	3,598
NO_x, kg per hr	1,632
SO_2 at 38(%S),[e] lb per hr	7,988
SO_2 at 38(%S),[e] kg per hr	3,623

[a] Fuel consumption rate based on heating values of 8,610 Btu per lb (4,783 kg-cal per kg) for coal and 4,300 Btu per lb (2,389 kg-cal per kg) for waste wood, with 10% of maximum boiler heat input obtained by waste wood firing.

[b] Fuel consumption rate based on heating values of 7,509 Btu per lb (4,172 kg-cal per kg) for coal and 4,300 Btu per lb (2,389 kg-cal per kg) for waste wood.

[c] Assumed products of combustion per pound of fuel ratio is 9.6 for coal and 4.6 for waste wood (approximately 25% excess air).

[d] See Tables III-13 and III-14 for emission criteria.

[e] SO_2 emissions at 38(%S) assumes that 5% of the SO_2 will be retained in the boiler and particulate emissions control solid waste (bottom and fly ash). The AP-42 emission factor for pulverized bituminous coal-fired units is 38(%S).

TABLE III-13
ASSUMED AVERAGE AIR EMISSION CRITERIA WITH COAL AND WASTE WOOD
UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 4
Coal	
Heating value	
Btu per lb	8,610
kg-cal per kg	4,783
Ash content	
%	9.35
Sulfur content	
%	1.03
Waste wood	
Heating value	
Btu per lb	4,300
kg-cal per kg	2,389
Ash content	
%	0.10
Sulfur content	
%	trace
Emission Control Equipment	
Particulate removal efficiency[a b]	
%	99.7
SO_2 removal efficiency[c]	
%	85.0
Emissions[d]	
Particulates[e f]	
lb per million Btu input	0.10
kg per million kg-cal input	0.18
NO_x [g]	
lb per million Btu input	0.70
kg per million kg-cal input	1.26
SO_2 at 38(%S)[h i]	
lb per million Btu input	1.20
kg per million kg-cal input	2.16

[a] Particulate removal efficiency is assumed to be the same for coal and waste wood firing.

[b] Particulate removal is for both the wet particulate scrubber and spray tower absorbers.

[c] SO_2 removal efficiency is for the entire air quality control system, including the wet particulate scrubber, and spray tower absorbers, and 5% stack gas bypass for reheat of scrubbed combustion products.

[d] Emissions based on 10% of maximum boiler heat input obtained by waste wood firing.

[e] Assumes bottom ash to fly ash ratio of 15% to 85%.

[f] Unit 4 needs 98.8% particulate removal efficiency to comply with MPCA regulations.

[g] NO_x emissions should be less than 0.70 lb per million Btu (1.26 kg per million kg-cal) input because of lower N_2 content of waste wood.

[h] SO_2 emissions at 38(%S) assumes that 5% of the SO_2 will be retained in the boiler and particulate emission control solid waste (bottom and fly ash).

[i] Unit 4 needs only 46% SO_2 removal efficiency to comply with MPCA regulations.

TABLE III-14
ASSUMED WORST CASE AIR EMISSION CRITERIA WITH COAL AND WASTE WOOD
UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Unit 4
Coal	
Heating value	
Btu per lb	7,509
kg-cal per kg	4,172
Ash content	
%	15.99
Sulfur content	
%	4.55
Waste Wood	
Heating value	
Btu per lb	4,300
kg-cal per kg	2,389
Ash content	
%	0.10
Sulfur content	
%	trace
Emission control equipment	
Particulate removal efficiency[a b]	
%	99.7
SO_2 removal efficiency[c]	
%	85.0
Emissions[d]	
Particulates[e f]	
lb per million Btu input	0.10
kg per million kg-cal input	0.18
NO_x[g]	
lb per million Btu input	0.70
kg per million kg-cal input	1.26
SO_2 at 38(%S)[h i j]	
lb per million Btu input	1.55
kg per million kg-cal input	2.79

a Particulate removal efficiency for the wet particulate scrubbers and spray tower absorbers is assumed to be the same for coal and waste wood firing.

b Particulate removal is for both the wet particulate scrubber and spray tower absorbers.

c SO_2 removal efficiency is for the entire air quality control system, including the wet particulate scrubber, spray tower absorbers, and 5% stack gas bypass for reheat of scrubbed combustion products.

d Emissions based on 10% of maximum boiler heat input obtained by waste wood firing.

e Assumes bottom ash to fly ash ratio of 15% to 85%.

f Unit 4 needs 99.4% particulate removal efficiency to comply with MPCA regulations.

g NO_x emissions should be less than 0.70 lb per million Btu (1.26 kg per million kg-cal) input because of lower N_2 content of waste wood.

h SO_2 emissions at 38(%S) assumes that 5% of the SO_2 will be retained in the boiler and particulate emission control solid waste (bottom and fly ash).

i MPCA regulations limit SO_2 emissions to 1.2 lb per million Btu (2.2 kg per million kg-cal) input.

j Unit 4 needs 88.4% SO_2 removal efficiency to comply with MPCA regulations.

TABLE III-15
ESTIMATED COAL CLEANING RESULTS - ROSEBUD COAL SEAM - BIG SKY MINE

Parameter	Raw Coal Dry	Raw Coal "As Received"	Cleaned Coal Dry	Cleaned Coal Air Dry	Cleaned Coal "As Received"
Heating value					
Btu per lb	11,439	8,579	12,000	9,000	8,340
kg-cal per kg	6,355	4,766	6,667	5,000	4,633
Moisture, %	-	25.00	-	25.00	30.50
Ash, %	12.98	9.74	9.19	6.89	6.39
Sulfur					
%	1.14	0.86	0.71	0.53	0.49
lb per million Btu input	1.00	1.00	0.59	0.59	0.59
kg per million kg-cal input	1.80	1.80	1.06	1.06	1.06
Btu recovery, %	100.0	100.0	92.5	92.5	92.5
Yield, %	-	88.2	-	88.2	95.2

TABLE III-16
ESTIMATED COAL CLEANING RESULTS - McKAY COAL SEAM - BIG SKY MINE

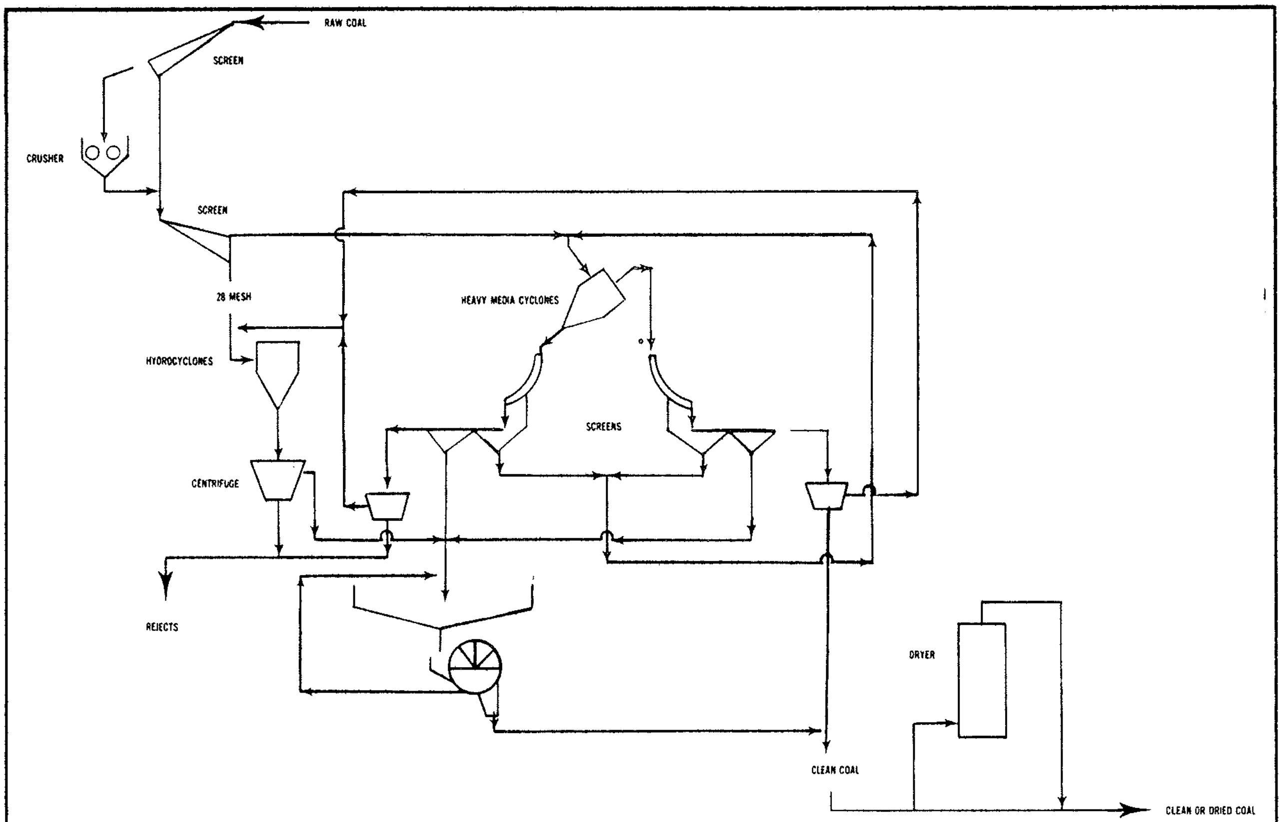
Parameter	Raw Coal Dry	Raw Coal "As Received"	Cleaned Coal Dry	Cleaned Coal Air Dry	Cleaned Coal "As Received"
Heating value					
Btu per lb	11,613	8,710	12,000	9,000	8,340
kg-cal per kg	6,452	4,839	6,667	5,000	4,633
Moisture, %	-	25.00	-	25.00	30.50
Ash, %	10.95	8.21	9.41	7.06	6.54
Sulfur					
%	2.04	1.53	0.68	0.51	0.47
lb per million Btu input	1.76	1.76	0.57	0.57	0.57
kg per million kg-cal input	3.17	3.17	1.03	1.03	1.03
Btu recovery, %	100.0	100.0	92.5	92.5	92.5
Yield, %	-	100.0	-	89.5	96.6

TABLE III-17
ESTIMATED COAL CLEANING RESULTS - ROSEBUD AND McKAY COAL SEAMS COMPOSITE
BIG SKY MINE

Parameter	Raw Coal Dry	Raw Coal "As Received"	Cleaned Coal Dry	Cleaned Coal Air Dry	Cleaned Coal "As Received"
Heating value					
Btu per lb	11,483	8,612	12,000	9,000	8,340
kg-cal per kg	6,379	4,784	6,667	5,000	4,633
Moisture, %	-	25.00	-	25.00	30.50
Ash, %	12.47	9.35	9.25	6.94	6.43
Sulfur					
%	1.37	1.03	0.70	0.53	0.49
lb per million Btu input	1.19	1.19	0.58	0.58	0.58
kg per million kg-cal input	2.14	2.14	1.04	1.04	1.04
Btu recovery, %	100.0	100.0	92.5	92.5	92.5
Yield, %	-	100.0	-	88.5	95.5

Since the Rosebud and McKay coal seams are mined separately and probably will be processed separately, it is expected that the two seams also will be burned separately at the Clay Boswell Station. Thus, cleaned coal from each coal seam must comply with the new source emission standards. Based on the sulfur contents for cleaned coal in Tables III-15 and III-16 and the assumption that 5% of the sulfur in the cleaned coal will remain in the ash when the coal is burned, the estimated sulfur dioxide emissions for the Rosebud and McKay coal seams are 1.12 and 1.07 lb SO_2 per million Btu (2.02 and 1.93 kg SO_2 per million kg-cal) input, respectively. The estimated sulfur dioxide emission for the composite Rosebud and McKay coal seams is 1.12 lb SO_2 per million Btu (2.02 kg SO_2 per million kg-cal) input. Thus, the estimated average sulfur dioxide for life of the Clay Boswell Station using cleaned coal from the Big Sky Mine is 93% of that allowed for the new source emission standards.

A conceptual flowsheet for the coal preparation plant is shown in Figure III-2 (5). The flowsheet indicates heavy media cyclones for treatment of 1-1/4 in. by 28 mesh (3.18 cm by 28 mesh) raw coal and hydrocyclones for treatment of the minus 28 mesh raw coal. Heavy medium circuitry provides flexibility in treatment of variable quality raw coal. Within limits, dependent upon the raw coal, the washing specific gravity can be adjusted to produce a cleaned coal



CONCEPTUAL FLOWSHEET FOR COAL PREPARATION

FIGURE III-2

with specified qualities. During winter months, when there is potential for freezing in the railroad cars during transit between the Big Sky Mine and the Clay Boswell Station, the cleaned coal will be partially dried to about 25.0% moisture (air dry) using a continuous direct contact type dryer.

Various types of coal dryers could be used, including centrifugal-mechanical dryers, flash dryers, and fluidized bed dryers. Fluidized bed dryers of the type manufactured by Dorr-Oliver, Inc. were selected as the type of dryer to be utilized (15). Heat is produced in the dryer using pulverized coal firing. Air is combined with the heated air to provide the total drying air flow. The wet cleaned coal introduced into the drying compartment is maintained in a fluidized state and immediately is brought to the desired temperature, which vaporizes the surface moisture. The fluidized bed is maintained by a substantial pressure drop across a deep bed. Particles carried upward by the air flow are collected by mechanical cyclone collectors followed by wet particulate scrubbers.

The partially dried cleaned coal will be loaded into unit trains for transport to the Clay Boswell Station. If the raw coal cannot be beneficiated to produce a cleaned coal of uniform quality, a blending system may be necessary for blending or mixing of the cleaned coal prior to loading into unit trains.

The conceptual flowsheet incorporates water clarification equipment so that process water can be clarified and reused. This closed process water minimizes new or makeup water requirements. The major water losses are due either to water being transported with the cleaned coal or to evaporation during the partial drying of cleaned coal. Coal rejects or waste possibly can be deposited with the overburden from mining or in a separate waste disposal basin.

The coal preparation plant should have 4 parallel independent processing circuits. The coal preparation plant should have a design capacity for 1,400 tons per hour (tph) (1,271 metric tons per hour) (mtph) of raw coal or 350 tph (318 mtph) of raw coal for each circuit. This design capacity will be in excess of the capacity required to meet MP&L's annual coal requirements for delivery to the Clay Boswell Station. This design capacity is based on the coal preparation plant operating 3 shifts per day for 5 days per week, 2 circuits being shut down one shift per day for maintenance, and the plant having 85% availability. When operating at design capacity, the coal preparation plant will produce cleaned coal before partial drying at the estimated average rate of 1,337 tph (1,213 mtph) or 334 tph (303 mtph) for each circuit. A typical cleaned coal will have an estimated 8,340 Btu per lb (4,633 kg-cal per kg) and contain 6.4% ash, 0.49% sulfur, and 30.5% moisture. When operating at design capacity, the preparation plant will produce partially dried cleaned coal at the estimated average rate of 1.239 tph (1,124 mtph) or 310 (281 mtph) for each circuit. The partially dried cleaned coal will have an estimated 9,000 Btu per lb (5,000 kg-cal per kg) and contain 6.9% ash, 0.53% sulfur, and 25.0% moisture.

The drying of cleaned coal containing 30.5% moisture to partially dried cleaned coal containing 25.0% moisture is estimated to require 16 tph (14.5 mtph) of raw coal when the coal preparation plant is operating at design capacity. Partially drying the estimated average of 1,751,072 tpy (1,588,546 mtpy) of cleaned coal during the 5 winter months will require an estimated 20,955 tpy (19,010 mtpy) of raw coal having 8,610 Btu per lb (4,783 kg-cal per kg). Over the estimated life of the Clay Boswell Station, an estimated 0.66 million tons (0.60 million metric tons) (mt) of raw coal will be required for coal drying.

The coal preparation plant will have adequate capacity to beneficiate up to almost 6.0 million tons (5.4 million mt) annually of raw coal, resulting in up to 5.3 million tons (4.3 million mt) annually of cleaned coal. To meet coal delivery requirements, the coal preparation plant will beneficiate an average of 4.4 million tons (4.0 million mt) annually of raw coal to produce an average of 2.5 million tons (2.2 million mt) annually of cleaned coal and 1.6 million tons (1.5 million mt) annually of partially dried cleaned coal. To supply cleaned coal for the estimated life of the Clay Boswell Station, 135 million tons (122 million mt) of raw coal have to be beneficiated to produce the required 119 million tons (108 million mt) of cleaned coal.

When operating at design capacity, the coal preparation plant will produce coal rejects or waste at the estimated average rate of 161 tph (146 mtph) or 40 tph (37 mtph) for each circuit. These coal rejects will have an estimated surface moisture content of 25%. Coal rejects or waste will be produced at an estimated average rate of 505,556 tpy (458,633 mtpy) for a total of 15.5 million tons (14.0 million mt) of coal waste during the estimated life of the Clay Boswell Station.

The estimated makeup water requirements for the coal preparation plant are 19 gallons per ton (gal per ton) (83 liter per metric ton) (l per mt). Based on operating at design capacity, the coal preparation plant will need an estimated 436 gpm (1,650 lpm) of makeup water. This makeup water replaces approximately 45 gpm (170 lpm) loss with the coal rejects or waste and 392 gpm (1,484 lpm) loss either by evaporation during partial drying of the cleaned coal or by being transported with the cleaned coal. This makeup water could be supplied from several possible sources. These possible sources include the Yellowstone River, mine drainage waters, sewage effluent from Colstrip's sewage treatment facilities, and discharge water from the electric generating facilities at Colstrip. These electric generating facilities at Colstrip presently have a total gross generating capacity of 716 MW and expansion is planned for the future.

The estimated capital cost to construct the proposed coal preparation plant is $38,000,000 (1977 cost) including interest during construction. This capital cost excludes facilities for raw coal handling and clean blending and loadout, since these facilities exist already or will be required without coal beneficiation. The estimated time required for construction of the coal preparation plant is 2 years. The estimated total cost for coal cleaning is $2.38 per ton ($2.62 per mt) of cleaned coal. The estimated total cost for coal drying is $0.98 per ton ($1.08 per mt) of cleaned coal. The depreciation was estimated using the straight-line method and a 20 year life. Interest was based on a 20 year loan at 10% interest for the entire capitalized cost of $38,000,000. The loan will be repaid by equal annual principal payments. The interest cost is the average for the first 10 years of the loan.

The available coal washability data are very limited and substantial additional testing is needed to confirm the available data. This testing program for the Big Sky Mine should include:

- Extensive drill core sampling to determine fluctuations of coal quality for the coal reserves committed to MP&L's Clay Boswell Steam Electric Station;

- Detailed washability testing of drill core samples;

- Pilot coal preparation plant (washing and drying) testing of bulk samples of both the Rosebud and McKay coal seams; and

- Boiler burning studies to determine the ash characteristics, sulfur balance, sulfur emissions, and potential burning problems.

A minimum of 12 months will be required to complete the testing program. The testing program will provide data necessary to determine the technical feasibility and economic prudence of constructing and operating a commercial coal preparation plant for beneficiation of the sub-bituminous coal from the Big Sky Mine. After completion of the testing program, a minimum of 6 months will be required to complete engineering for the coal preparation plant.

Coal Transportation

Approximately 4.1 million tpy (3.7 mtpy) of cleaned coal from the coal preparation plant located at the Big Sky Mine will be delivered to the Clay Boswell Station via Burlington Northern Railroad. These coal deliveries will consist of an average of 1,622,660 tons (1,472,052 mt) partially dried cleaned coal containing 25.0% moisture during the 5 winter months and of 2,451,514 tons (2,223,976 mt) of cleaned coal containing 30.5% moisture during the 7 other months. Maximum cleaned coal deliveries will be 5.6 million tons (5.0 million mt) annually. The delivered coal tonnages are essentially the same tonnages that will be delivered under MP&L's proposed action. Of the average 4,074,174 tpy (3,696,028 mtpy) of cleaned coal delivered to the Clay Boswell Station, an average of 350,290 tpy (317,777 mtpy) will be reloaded into railroad cars for transfer to MP&L's Laskin Station.

The coal will be transported to the Clay Boswell Station in the same unit trains to be used for MP&L's proposed action. An average 7.5 and 8.1 unit trains per week will arrive at the Clay Boswell Station during the 5 winter months and the 7 other months, respectively. The train routing will be the same as for MP&L's proposed action.

Coal Consumption

Coal consumption for Units 1, 2, 3, and 4 is based on the net ratings and estimated operating parameters listed in Tables II-14 and II-33. Based on the cleaned coal having an "as received" heating value of 9,000 Btu per lb (5,000 kg-cal per kg) during the 5 winter months and 8,340 Btu per lb (4,633 kg-cal per kg) during the 7 other months, the coal consumption rates are presented in Table III-18.

Coal Handling

Cleaned coal for the Clay Boswell Steam Electric Station will be delivered, unloaded, conveyed, stockpiled, and stored using the same materials handling

TABLE III-18
ESTIMATED COAL CONSUMPTION RATES - COAL BENEFICIATION
UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Five Winter Months					
Average hourly					
tons	25.5	24.2	153.3	203.9	406.9
metric tons	23.1	22.0	139.0	185.0	369.1
Maximum hourly					
tons	39.4	39.4	198.3	285.6	562.7
metric tons	35.7	35.7	179.9	259.1	510.4
Average 5 months					
tons	93,018	88,501	559,374	744,302	1,485,195
metric tons	84,385	80,287	507,456	675,219	1,347,347
Maximum 5 months					
tons	143,725	143,725	723,780	1,042,440	2,053,670
metric tons	130,385	130,385	656,602	945,686	1,863,058
Seven Other Months					
Average hourly					
tons	27.5	26.2	165.4	220.1	439.2
metric tons	24.9	23.7	150.0	199.6	398.2
Maximum hourly					
tons	42.5	42.5	249.9	308.2	643.1
metric tons	38.5	38.5	226.7	279.6	583.3
Average 7 months					
tons	140,531	133,707	845,097	1,124,485	2,243,820
metric tons	127,488	121,297	766,659	1,020,115	2,035,559
Maximum 7 months					
tons	217,138	217,138	1,276,765	1,574,909	3,285,950
metric tons	196,984	196,984	1,158,262	1,428,733	2,980,963
Annual					
Average annual					
tons	233,549	222,208	1,404,471	1,868,787	3,729,015
metric tons	211,872	201,584	1,274,115	1,695,335	3,382,906
Maximum annual					
tons	360,863	360,863	2,000,545	2,617,349	5,339,620
metric tons	327,369	327,369	1,814,864	2,374,419	4,844,021
Total					
tons	3,922,912	3,418,622	44,958,317	65,406,533	117,706,384
metric tons	3,558,806	3,101,322	40,785,499	59,335,809	106,781,436

facilities as for MP&L's proposed action. The annual tonnages of coal to be handled are essentially the same for the alternative of using beneficiated coal as for MP&L's proposed action.

Facilities Operation

The power generation cycle and the water systems will be essentially the same for the coal beneficiation alternative as for the MP&L's proposed action. Because of the lower quantity of ash in the cleaned coal, less water may be necessary to sluice the bottom and fly ash to the disposal ponds.

Air Quality Control Systems (AQCS)

The steam generators or boilers for both Units 1 and 2 will be equipped with baghouse filters to control particulate emissions. The collection efficiency is estimated at 99.4% (by weight) for the baghouse systems. Unit 3 is equipped with a wet particulate scrubber. The estimated removal efficiencies for particulates and sulfur dioxide are 96.6% and 15% (by weight), respectively. The flue gas from Units 1, 2, and 3 will discharge to the atmosphere through a new 700 ft (213 m) stack.

The steam generator or boiler for Unit 4 will be equipped with wet scrubbers for particulate control and spray tower absorbers for sulfur dioxide control. For flue gas reheat, 5% of the boiler's flue gas will bypass the wet scrubbers and absorbers and flow to an electrostatic precipitator to remove particulate matter, and then into the stack. Flue gas reheat should raise the flue gas temperature from 129 to 155°F (54 to 68° C). Discharge to the atmosphere is through a 600 ft (183 m) stack.

While burning beneficiated or cleaned coal, it may not be necessary to operate the spray tower absorbers for SO_2 control to meet the new source performance standards. It is assumed that 80% of the cleaned coal will have a sulfur content low enough so that the coal can be burned and the absorbers bypassed. Considerable savings are expected when the absorbers are bypassed. It also is assumed that an additional 5% of the cleaned coal will meet new source emission standards if the SO_2 absorbers are used as a water spray system (additional SO_2 removal by water). Also, it is expected that the wet scrubber will remove sufficient particulates so that new source emission standards can be achieved without operation of the spray tower absorber. The flue gas should be routed through the demisters, if possible. The demisters are needed to remove excess flue gas moisture and possibly reentrained particulates. Finally, the cleaned coal should nearly guarantee that existing Units 1, 2, and 3 will comply with MPCA regulations for SO_2 emissions.

Emissions, Effluents, and Waste Production

Air Emissions

Estimated particulates, NO_x, and SO_2 stack emissions from modified existing Units 1, 2, and 3, and MP&L's proposed Unit 4 are presented in Table III-19 and III-20 respectively. A typical analysis for cleaned coal is presented in Table III-17. Tables III-19 and III-20 present only annual average or typical air emissions.

Wastewater Effluents

Wastewater effluents from existing modified Units 1, 2, and 3, and MP&L's

TABLE III-19
ESTIMATED AIR EMISSIONS WITH CLEANED COAL
UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Units 1, 2, and 3	Unit 4	Total
Full load/electrical output			
Gross MW/Net MW	519/488	554/504	1073/992
Heat input rate			
Btu x 10^6 per hr	4,984	5,141	10,125
kg-cal x 10^6 per hr	1,258	1,297	2,555
Fuel consumption[a]			
Average			
lb per hr	597,602	616,427	1,214,029
kg per hr	271,068	279,607	550,675
Emissions at full load[b]			
Average			
Particulate, lb per hr	2,198	514	2,712
Particulate, kg per hr	997	233	1,230
NO_x, lb per hr	5,332	3,599	8,931
NO_x, kg per hr	2,419	1,632	4,051
SO_2, lb per hr	4,965	5,739	10,704
SO_2, kg per hr	2,252	2,603	4,855

[a] Based on cleaned coal having a heating value of 8,340 Btu per lb (4,633 kg-cal per kg).

[b] See Table III-20 for emission criteria.

proposed Unit 4 are not expected to be affected significantly by the use of beneficiated or cleaned coal. This occurs mainly because the ash disposal for Units 1, 2, and 3 and MP&L's proposed bottom ash and SO_2 scrubber sludge disposal for Unit 4 already include closed-cycle water systems (only makeup water is added to the system to replace water lost by evaporation, in voids in the fly ash and SO_2 scrubber waste, and by seepage). Bottom ash sluice water could be slightly affected by the reduced ash. Units 1, 2, and 3 fly ash sluice water losses would likely be reduced in the same proportions as fly ash production is reduced.

Solid Waste Production

The primary source of solid waste from existing Units 1, 2, and 3 is ash contained in the cleaned coal. Bottom ash and fly ash are collected and sluiced to the disposal site. Based on the "as received" cleaned coal analysis in Table III-17 and the estimated cleaned coal consumption in Table III-18, the estimated solid waste or ash production for Units 1, 2, and 3 is presented in Table III-21.

The major sources of solid waste from MP&L's proposed Unit 4 are bottom and fly ash and SO_2 scrubber waste. Both the bottom and fly ash will be collected

TABLE III-20
ASSUMED AVERAGE AIR EMISSION CRITERIA WITH CLEANED COAL
UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Units 1, 2, and 3	Unit 4
Coal[a]		
Heating value		
Btu per lb	8,340	8,340
kg-cal per kg	4,633	4,633
Ash content		
%	6.43	6.43
Sulfur content		
%	0.49	0.49
Emissions		
Particulates		
lb per million Btu input	0.44[b]	0.10[c]
kg per million kg-cal input	0.79[b]	0.18[c]
NO_x[d]		
lb per million Btu input	1.07	0.70
kg per million kg-cal input	1.68	1.26
SO_2 at 38(%S)[e]		
lb per million Btu input	1.00	1.12
kg per million kg-cal input	1.80	2.02

[a] Cleaned coal moisture content is 30.5%.

[b] Particulate emissions for Units 1 and 2 based on 99.4% collection efficiency and bottom ash to fly ash ratio of 15% to 85%. Unit 3 particulate emissions estimated at 0.6 lb per million Btu.

[c] Unit 4 emissions based on new source performance standards of 0.10 lb per million Btu (0.18 kg per million kg-cal).

[d] NO_x emissions may be lower due to possible reduced fuel nitrogen content of cleaned coal.

[e] SO_2 emissions at 38(%S) assumes 5% of the SO_2 will be retained in the bottom ash and fly ash.

and sluiced to the disposal site. Little SO_2 scrubber waste will be generated with the burning of cleaned coal. Since the emissions without SO_2 collection are estimated to be 1.12 lb SO_2 per million Btu, the absorber can be bypassed 80 to 85% of the operating time. However, SO_2 scrubber waste will be generated approximately 15% of the operating time. The quantity of scrubber waste can only be estimated by assuming a typical high sulfur coal during operation of the SO_2 absorber. It is assumed that this typical high sulfur coal will contain 1.5% sulfur, which probably is high. Since the quantity of scrubber sludge generated is much smaller than the quantity of bottom and fly ash collected, the total quantity of estimated solid waste should not be greatly in error on an annual basis. The estimated solid waste production for Unit 4 is presented in Table III-22. Based on the remaining capacity of the existing bottom and fly

TABLE III-21
ESTIMATED FUTURE SOLID WASTE OR ASH PRODUCTION WITH CLEANED COAL
UNITS 1, 2, AND 3 - CLAY BOSWELL STEAM ELECTRIC STATION

Solid Waste[a]	Unit 1	Unit 2	Unit 3	Total
Bottom Ash				
Maximum daily[b]				
tons	13.1	13.1	66.1	92.3
metric tons	11.9	11.9	60.0	83.8
Average annual[c]				
tons	2,328	2,149	13,978	18,455
metric tons	2,112	1,950	12,681	16,743
Fly Ash[d]				
Maximum daily[c]				
tons	55.3	55.3	271.2	381.8
metric tons	50.2	50.2	246.0	346.4
Average annual[c]				
tons	13,112	12,103	76,518	101,733
metric tons	11,895	10,980	69,415	92,290
Solid Waste				
Average annual[c]				
tons	15,440	14,252	90,496	120,188
metric tons	14,007	12,930	82,096	109,033

[a] Based on estimated coal cleaning results in Table III-17 and estimated coal consumption ratio in Table III-18.

[b] Based on a bottom ash to fly ash ratio of 20% to 80%.

[c] Based on a bottom ash to fly ash ratio of 15% to 85%.

[d] Based on particulate collection efficiencies of 99.4% for Units 1 and 2 and 96.6% for Unit 3.

ash ponds (Table II-55), MP&L's proposed new ash and SO_2 sludge disposal ponds could be reduced substantially in volume and still provide adequate volume for Unit 4 solid waste disposal using cleaned coal.

Economic Analysis

A potential for cost savings exist by using cleaned or beneficiated coal which does not require operation of MP&L's proposed SO_2 spray tower absorber to remove SO_2. If the sulfur content of the cleaned coal is low enough so that uncontrolled SO_2 emissions meet new source performance standards, then operating costs can be reduced since it is not necessary to operate the SO_2 absorber. If the cost reduction associated with the operation of the SO_2 absorber is greater than the capital and operating costs associated with the coal beneficiation, then possible cost savings will occur for the Clay Boswell Station.

TABLE III-22
ESTIMATED FUTURE SOLID WASTE OR ASH AND
SO_2 SCRUBBER WASTE PRODUCTION WITH CLEANED COAL
UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Solid Waste[a]	Unit 4
Bottom Ash	
Maximum daily[b]	
tons	95.1
metric tons	86.3
Average annual[c]	
tons	18,593
metric tons	16,867
Fly Ash[d] and SO_2 Scrubber Waste	
Maximum daily[c f]	
tons	786.1
metric tons	713.1
Average annual[c g]	
tons	126,015
metric tons	114,319
Solid Waste	
Average annual[c]	
tons	144,608
metric tons	131,186

[a] Based on estimated coal cleaning results in Table III-17 and estimated coal consumption rates in Table III-18.

[b] Based on bottom ash to fly ash ratio of 20% to 80%.

[c] Based on bottom ash to fly ash ratio of 15% to 85%.

[d] Based on particulate collection efficiency of 99.6%.

[e] Based on 2.8 lb (1.27 kg) of waste per lb (0.45 kg) of SO_2 removed.

[f] Based on coal containing 1.5% sulfur and SO_2 emissions of 1.2 lb per million Btu (2.2 kg per million kg-cal) input.

[g] Based on operating SO_2 spray tower absorbers 15% of the time only.

When burning cleaned coal, it is assumed that the SO_2 absorber will be bypassed 80% of the time because of the low sulfur content of the cleaned coal. It is assumed that the SO_2 absorber will be operated 15% of the time with lime for SO_2 removal since some of the cleaned coal may not have a sulfur content low enough for uncontrolled SO_2 emissions to meet new source performance standards. It also is assumed that the SO_2 absorber will be operated 5% of the time with only water (without lime) to remove particulates. Operating as a water spray system (without lime) will remove 15% of the SO_2 in the stack gas so that emissions meet new source performance standards. Based on these assumptions, a cost comparison for operating MP&L's proposed spray tower absorbers using both raw and beneficiated or cleaned coal is presented in Table III-23. This comparison indicates that the use of cleaned coal will increase MP&L's costs by an estimated $1,959,000 annually. Thus, there is no economic incentive for MP&L's economic advantage to burn cleaned coal only if it was not necessary for MP&L to construct an SO_2 removal system.

TABLE III-23
COST COMPARISON FOR MP&L'S PROPOSED SPRAY TOWER ABSORBERS
USING RAW AND BENEFICIATED COAL
UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Raw Coal	Beneficiated Coal
Coal Consumption		
Annual		
Units 1, 2, and 3		
tons per year	1,853,569	1,778,143[a]
metric tons per year	1,681,529	1,613,104[a]
Unit 4		
tons per year	1,867,239	1,786,325[a]
metric tons per year	1,693,931	1,620,527[a]
Costs		
Annual		
SO_2 removal with lime	$10,643,000[b]	$1,608,000[c]
SO_2 removal without lime	-	268,000[d]
Coal cleaning	-	9,155,000[e]
Coal drying	-	1,571,000[f]
Total cost	$10,643,000	$12,602,000
Incremental cost	-	$ 1,959,000

[a] Based on equivalent tonnage with a moisture content of 25%.

[b] Based on 95% of the stack gas flowing to the SO_2 absorber with an operating cost of $6.00 per ton of coal.

[c] Based on 15% of the stack gas flowing ot the SO_2 absorber with an operating cost of $6.00 per ton of coal.

[d] Based on 5% of the stack gas flowing to the SO_2 absorber with an operating cost of $3.00 per ton of coal (absorber operated without lime addition).

[e] Based on coal cleaning total cost of $2.38 per ton ($2.62 per mt) of cleaned coal for 3,846,548 tons (3,489,529 mt) of coal annually containing 30.5% moisture.

[f] Based on coal drying total cost of $0.98 per ton ($1.08 per mt) of cleaned coal for 1,602,728 tons (1,453,970 mt) of cleaned coal annually to be dried from 30.5% to 25.0% moisture.

ALTERNATIVE - DRY COOLING TOWERS

Introduction

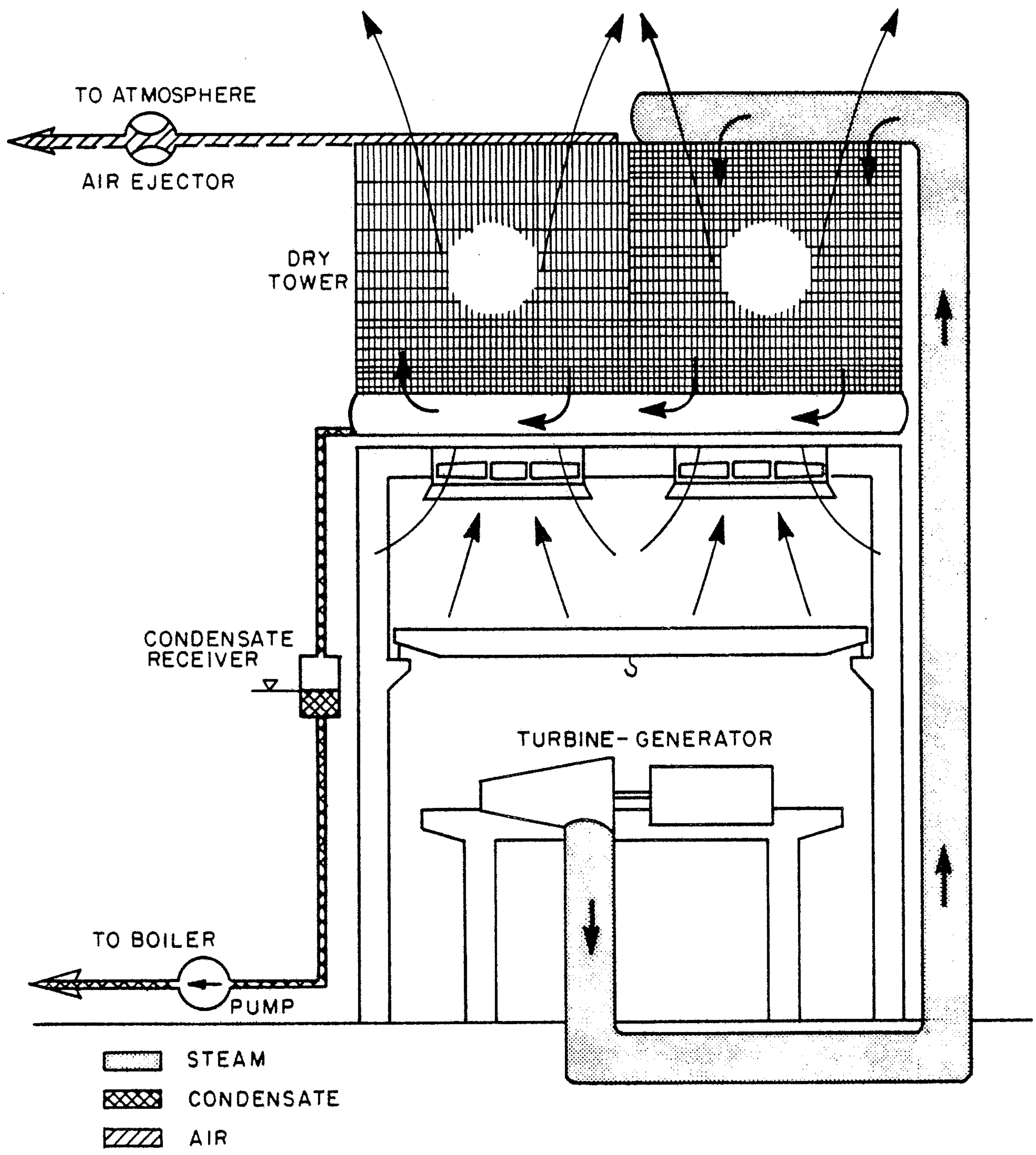
Dry cooling towers use a finned-tube heat exchanger to transfer heat from the steam turbine exhaust steam directly to the atmosphere. Consequently, the water losses associated with evaporative systems are eliminated. Dry cooling towers have considerably higher capital costs than evaporative systems and sometimes adversely affect the efficiency of electric generating facilities. However, dry cooling towers offer some environmental advantages such as minimal water consumption and elimination of visible vapor plumes, icing problems, and salt deposition, which may outweigh their economic disadvantages.

There are two types of dry cooling towers, direct and indirect. Direct condensation systems convey turbine exhaust steam to the dry tower for heat exchange, thus eliminating the need for a separate condenser. Heat is transferred from the exhaust system to the air by convection as the air is forced over large bundles of finned heat exchanger tubes in the tower. The direct dry cooling tower system is considered to be a more economical method for small and intermediate size steam turbines in cool climates. As steam turbine-generator capacity increases to a range of 300 to 800 MW, the indirect system becomes more economically attrative. A schematic diagram of a direct dry cooling tower is presented in Figure III-3.

The indirect dry cooling tower uses either a surface condenser or a contact spray condenser to condense the steam adjacent to the turbine. These are widely used outside the United States. Pumps direct the hot condensate to finned-tube coils in the dry cooling tower assembly where the heat is transferred to air flowing over the tubes. A schematic diagram of an indirect dry cooling tower is presented in Figure III-4.

Utilities in the United States generally are hesitant to install dry cooling systems for two major reasons. First, electric utilities in the United States have had limited experience with dry cooling towers. Second, an optimized dry cooling system for a unit such as the proposed Unit 4 at the Clay Boswell Station could be at least twice as expensive to install as MP&L's proposed wet cooling system. The proposed wet cooling tower system has an estimated capital cost of approximately $15 million while the dry tower is estimated to cost $30 to $40 million (16). In addition, a dry system could result in some generating capacity losses during the summer. However, replacement of lost capacity may not be a problem, since MP&L's annual system load factor is relatively constant with a minimal summer peak. It also is possible that the heat rate for MP&L's proposed Unit 4 may increase for the optimized dry system, thus decreasing the unit's overall efficiency. Due to MP&L's relatively low fuel cost, this may not affect cooling system selection based on lowest total evaluated cost (primarily a combination of fuel cost, makeup water cost, capital cost, and replacement capacity cost in relation to a particular location, load profile, and fixed charge rate).

Energy requirements of the dry cooling towers also will be greater than for MP&L's proposed wet cooling towers. Based on the heat rate for the dry cooling tower ranging from 1 to 10% above that for MP&L's proposed Unit 4, the increased



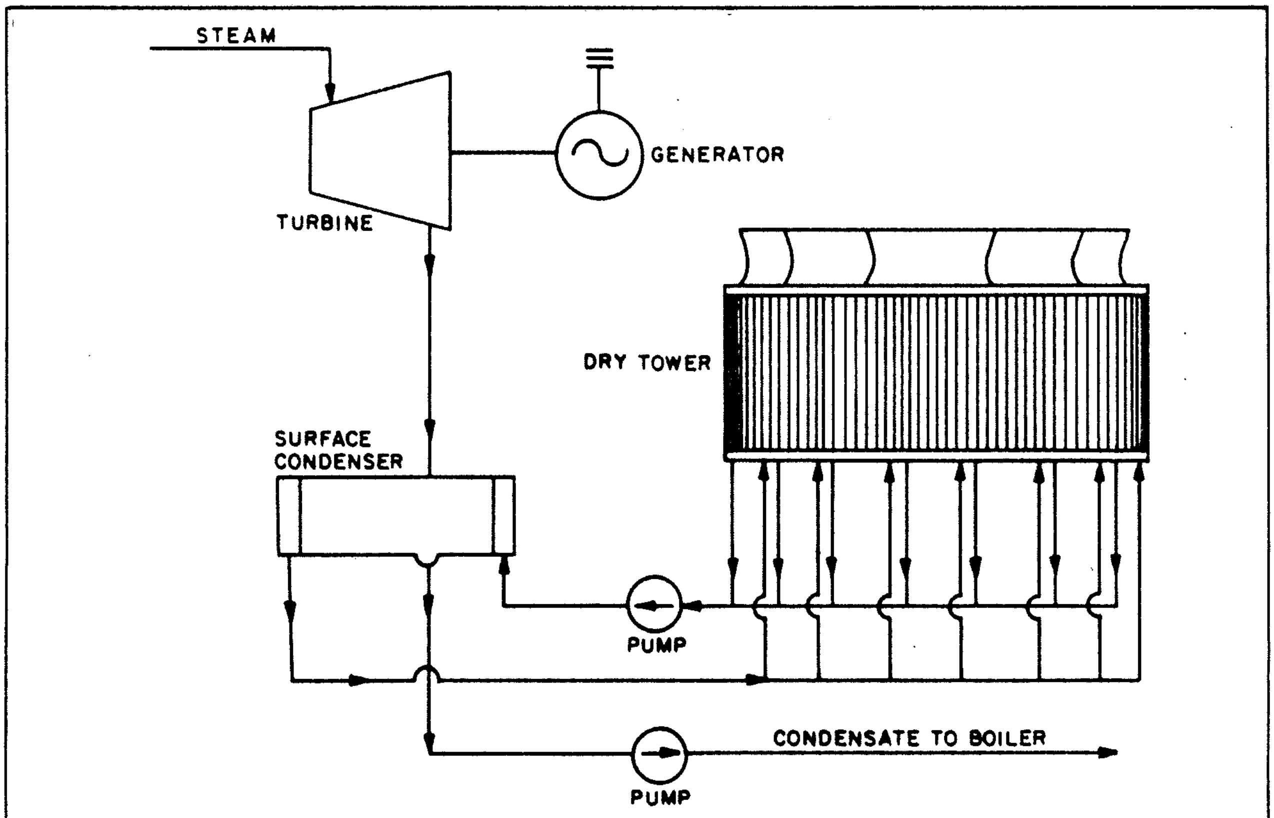
DIRECT, AIR-COOLED CONDENSER – DRY COOLING TOWER

FIGURE III-3

capacity required for replacement and auxiliary capacity will range from 5 to 50 MW. This is approximately 1 to 10% of the net generating capacity for MP&L's proposed Unit 4.

Raw Materials

Using a dry cooling tower system with MP&L's proposed Unit 4 potentially could increase Unit 4 coal consumption due to decreased unit efficiency caused by higher backpressures in the steam turbine. Depending on the dry cooling tower design and its optimization with MP&L's proposed Unit 4 steam turbine and condenser, the annual coal consumption could be increased 10,000 to 100,000 tpy (9,072 to 90,178 mtpy). This is based on heat rates being from 1 to 10% higher than for MP&L's proposed Unit 4 design. Also, if Unit 4 maximum generating capability were limited by using a dry cooling tower, the reduced or lost generating capability will have to be made up by a different generating unit which also will consume additional coal.



INDIRECT STEAM CONDENSING CYCLE WITH SURFACE CONDENSER - DRY COOLING TOWER	FIGURE III-4

The other raw materials affected by using dry cooling towers will be lime and chlorine. Lime consumption in MP&L's proposed Unit 4 SO_2 absorber will be increased by approximately the same amount as coal consumption, which is 0.5 to 5.0%. The chlorine is used as a biocide in MP&L's proposed wet cooling tower. Due to the near elimination of cooling water requirements, except for auxiliary cooling, the use of chlorine will be reduced to a small portion of that required by MP&L's proposed action.

With increased coal consumption, the coal handling system will be affected; however, this is not expected to be significant. Assuming 100,000 tpy (90,718 mtpy) additional coal, it will be necessary to unload three additional coal cars per day. The capacity of the proposed coal handling system is adequate to handle this additional coal.

Increased lime consumption will result in increased lime handling requirements. However, MP&L's proposed lime handling facility will be adequate to handle this additional lime.

Reduction of chlorine usage will reduce chlorine handling requirements. However, this is not significant since the proposed action handling requirements are quite small.

Facilities Operation

Power Generation Cycle

A dry cooling tower will have major effects on MP&L's proposed steam condenser and steam turbine-generator in the power generation cycle. However, a steam condenser and steam-turbine generator could be designed to minimize the effects of using a dry cooling tower.

Installation of dry cooling towers with MP&L's proposed steam condenser and turbine could result in considerable capacity reduction for the turbine-generator under summer conditions. Capacity reductions result from the dry cooling tower (assuming the indirect type) not cooling the condenser cooling water to as low a temperature as a wet cooling tower. This causes higher temperatures in the steam condenser which in turn causes higher backpressure in the steam turbine. (The backpressure increase would also occur with a direct condensing system.) This high backpressure reduces the unit's maximum capacity and also decreases the unit's efficiency which requires more coal to be burned per kilowatt-hour produced. The unit's lost capacity most likely will be made up by a different generating unit which also consumes additional coal.

Water Systems

Water systems affected by using dry cooling towers are the intake system, condenser cooling water system, auxiliary cooling water system, and the discharge system.

Intake System. Water requirements for MP&L's proposed Unit 4 will be reduced approximately 3,465 gal per min (13,116 lpm) by using dry cooling towers. Dry cooling towers essentially will eliminate the normal cooling tower makeup water which is associated with MP&L's proposed wet cooling towers. With dry cooling towers, the estimated water consumption is reduced to about 1% of the water required by MP&L's proposed wet cooling towers. The small amount of water required for the dry cooling system is necessary for the small auxiliary wet cooling tower which cools water for auxiliary equipment. This reduction in water requirements essentially will eliminate the required pump changes and upgradings described in Chapter II - Proposed Action for the existing intake structure.

Condenser Cooling System. Dry cooling towers eliminate the need for condenser cooling water.

Auxiliary Cooling System. Because dry cooling towers condense steam at higher temperatures than evaporative or wet cooling towers, the condensate from the dry cooling towers is too hot to be used as a cooling medium for the various plant support equipment such as oil coolers, generator hydrogen coolers, and air compressors. Therefore a small auxiliary evaporative cooling tower usually is employed to provide a source of colder water to cool this equipment. This tower, although much smaller than the evaporative or wet cooling twoers which would be required to cool the entire plant, consumes some energy and requires some makeup water for proper operation.

Discharge System. Substantial reductions will occur for MP&L's proposed Unit 4 discharge water. Normal cooling tower blowdown will be eliminated and only the small blowdown from the auxiliary cooling tower will be required. This blowdown could be combined with the central waste treatment facility discharge and the existing Units 1, 2, and 3 discharges as described in Chapter II - Proposed Action.

Air Quality Control System (AQCS)

The Air Quality Control System (AQCS) will not be affected significantly by using dry cooling towers. Reduced turbine-generator efficiency caused by the dry cooling towers could cause the generation of additional quantities of particulates and SO_2. These will be removed by the wet particulate scrubber and SO_2 absorber. On an annual basis, the additional quantities of particulates and SO_2 may be up to 5% greater than that generated by MP&L's proposed action. This increase is expected to have little effect on MP&L's proposed AQCS.

Emissions, Effluents, and Waste Production

Air Emissions

Dry cooling towers will eliminate the estimated drift and salt emissions from MP&L's proposed Unit 4 cooling tower which was presented in Table II-50 of Chapter II - Proposed Action.

Water Effluents

Water effluents will be changed by the elimination of Unit 4 cooling tower blowdown. Table II-51 in Chapter II Proposed Action indicates the composition of the final effluent stream. Table III-24 detials the water effluent from

TABLE III-24
WASTEWATER EFFLUENTS WITH UNIT 4 DRY COOLING TOWERS[a]
UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Central Waste Treatment Effluent	Unit 3 Cooling Tower Blowdown[b]	Treated Unit 3 Fly Ash Blowdown	Sanitary Wastes	Total Wastewater Effluent
Flow					
gpm	3,055	650	1,360	20	5,085
lpm	11,564	2,460	5,148	76	19,248
pH	6 to 9	7.8	6 to 9	7	6 to 9
Total dissolved solids (TDS), mg per liter	293	900	2,400	200	932
Total suspended solids (TSS), mg per liter	4	30	-	30	10
Oil and grease, mg per liter	1	nil	nil	nil	nil
Sulfates, mg per liter	15	35	2,000	-	623
Chlorides, mg per liter	42	516	-	-	93
Calcium (as $CaCO_3$), mg per liter	103	180	50	-	100
Magnesium (as $CaCO_3$), mg per liter	56	67	10	-	45
Iron, mg per liter	3	nil	-	-	1.8

[a] Without Units 1 and 2 cooling water.
[b] Excluding effluent fron auxiliary cooling tower for Unit 4.

MP&L's proposed Unit 4 with dry cooling towers. Using the dry cooling tower eliminates the Unit 4 cooling tower blowdown of 875 gal per min (3,313 lpm).

Waste Production

Solid waste production will be affected by using dry cooling towers. Additional ash and scrubber sludge will be generated because of increased coal consumption. Also, the sediment which must be periodically removed from the wet cooling towers will be eliminated with the use of dry cooling towers.

Assuming the coal consumption increases 10,000 to 100,000 tpy (9,072 to 90,718 mtph), bottom ash production will be increased 140 to 1,403 tpy (127 mtpy to 1,272 mtpy), and fly ash and SO_2 scrubber sludge will be increased 1,083 to 10,829 tpy (982 to 9,822 mtpy).

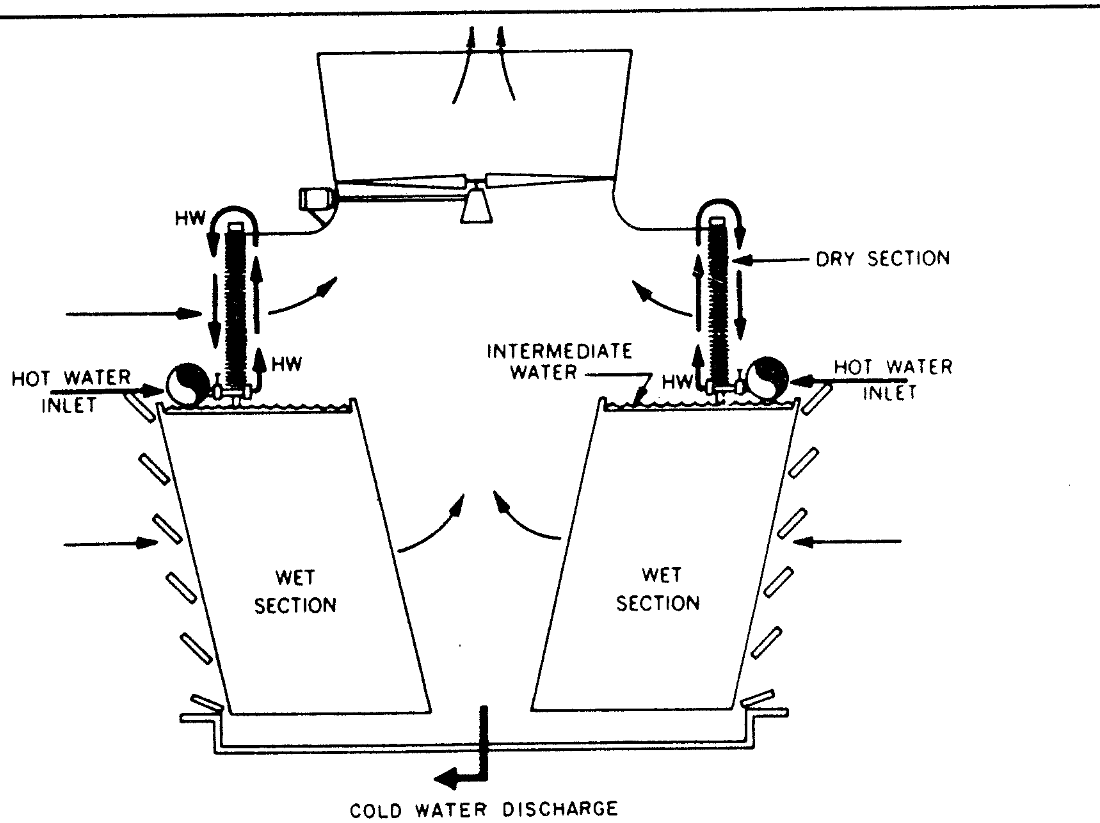
ALTERNATIVE - WET/DRY COOLING TOWERS

Introduction

A wet/dry cooling tower incorporates a radiator-type heat exchanger in a dry section as well as a conventional evaporative wet cooling tower section. In the dry section air flows around heat exchanger tubes, removing heat from the water flowing within the tubes by convection. In the wet section of the tower, air and water are brought into direct contact with each other as they pass through the tower. The heat is removed by evaporation with some sensible cooling of the water by the cooler air. Figure III-5 illustrates a wet/dry cooling tower.

The ratio of wet to dry cooling depends on the design parameters for a particular application. Wet/dry cooling towers have been designed for water conservation in areas such as the western United States. These towers generally have small wet sections, and possibly separate wet and dry towers. Wet/dry cooling towers also have been designed for plume abatement or to reduce fogging in areas such as the northeastern United States. This type of tower generally has a small dry section, with the wet and dry cooling towers normally combined in a single structure. This reduces the evaporation rate and mixes the saturated plume from the wet section with the dryer plume from the dry section. Wet/dry cooling towers designed for plume abatement requirements, and of the size necessary for MP&L's proposed Unit 4, are in operation in the United States. However, those installed have been located in water short areas and were not designed for fog control.

Installation of wet/dry cooling towers with MP&L's proposed steam condenser could result in some reduction in Unit 4 generating capacity. To avoid this reduction, a wet/dry cooling tower could be designed to insure that



PARALLEL - PATH WET/DRY COOLING TOWER | **FIGURE III-5**

maximum capacity will not be limited. However, the dry portion of this wet/dry cooling tower may be very costly. Thus, the most feasible solution may be to allow some capacity limitation.

Another option is to design the Unit 4 cooling towers with adequate wet cooling for the unit's maximum cooling requirements and then adding enough dry cooling to resolve any possible fogging problems. This assumes that fog control is the major reason for wet/dry cooling towers. With this option, the capacity limitation will not be necessary.

The other variable in operating a wet/dry cooling tower system is the steam turbine-generator design. It is possible that the capacity of MP&L's proposed steam turbine-generator for Unit 4 will not be limited by wet/dry cooling towers. Thus, the only difference between MP&L's proposed wet cooling towers and alternative wet/dry cooling towers will be the additional capital and operating costs including increased auxiliary energy requirements.

Based on wet/dry cooling towers sized for 80% wet or evaporative and 20% dry, the wet/dry cooling towers will require 170,000 more tower units than MP&L's proposed wet cooling towers. (A tower unit is a term used by the utility industry to define cooling tower capacity.) Assuming an incremental capital cost of $10 to $25 per tower unit (17), the wet/dry cooling towers would require an estimated $2 million to $4 million additional capital expenditure when compared to the capital cost for MP&L's proposed wet cooling towers. Based on an estimated capital cost of $15 million for MP&L's proposed wet cooling towers, the alternative wet/dry cooling towers will have a capital cost of $17 million to $19 million.

Increased energy requirements for replacement capacity and auxiliaries will be approximately 0.5 to 5.0 MW more for wet/dry cooling towers when compared to wet cooling towers. This increase is based on Unit 4 heat rates being 0.1 to 1.0% higher with wet/dry cooling towers than with MP&L's proposed wet cooling towers.

Raw Materials

The use of wet/dry cooling towers for MP&L's proposed Unit 4 could cause increased coal consumption due to decreased unit efficiency resulting from high backpressures in the steam turbine. Using wet/dry cooling towers with MP&L's proposed Unit 4 steam turbine and condenser could increase annual coal consumption by 1,000 to 10,000 tpy (907 to 9,702 mtpy). This is based on heat rates ranging from 0.1 to 1.0% higher for wet/dry cooling towers than for MP&L's proposed Unit 4 design and also on a wet/dry cooling tower sized for 80% wet or evaporative and 20% dry. In addition, Unit 4 maximum capacity may be limited during summer conditions with the use of wet/dry cooling towers. This lost capacity probably will be produced by a different generating unit which also will consume additional coal.

The other raw materials affected by using wet/dry cooling towers will be lime and chlorine. Lime consumption in MP&L's proposed Unit 4 SO_2 absorber will be increased by 0.05% to 0.5%, approximately the same amount as the coal consumption increase. This increase in lime consumption is based on the increased heat rates (0.1 to 1.0% higher) and a wet/dry cooling tower design of 80% wet or evaporative and 20% dry. Chlorine requirements may decrease slightly for the wet/dry cooling towers but this decrease is expected to be insignificant.

The coal handling system will be affected with increased coal consumption. However, this is not expected to be significant. With the maximum estimated increased coal consumption of 10,000 tpy (9,072 mtpy), one additional rail car load of coal will be required every 3 days.

Increased lime consumption will result in additional lime handling requirements. It is anticipated that MP&L's proposed lime handling facility will be adequate to handle this additional lime.

Facilities Operation

Power Generation Cycle

Wet/dry cooling towers could affect the steam condenser and steam turbine-generator in the power generation cycle. The result may be a capacity reduction resulting from wet/dry cooling towers not cooling the condenser cooling water to a temperature as low as is achieved by wet cooling towers. This results in higher temperatures in the steam condenser which causes higher backpressures in the steam turbine. The higher backpressure reduces the maximum capacity of the steam turbine-generator and also decreases the unit's efficiency. Thus, it will be necessary to burn more coal per kilowatt-hour (kw hr) generated. The lost capacity most likely will be made up by a different generating unit which will consume additional coal.

To avoid a reduction in capacity, wet/dry cooling towers could be designed to insure that maximum capability will not be limited. However, the cooling towers may have high capital costs and it may be more feasible to allow some capacity limitation.

Water Systems

Water systems affected by using wet/dry cooling towers are the intake system, condenser cooling water system and the discharge system.

The effects on the intake system are dependent on the wet/dry cooling tower design. The dry portion of the tower reduces total water consumption, and the intake water quantities will be reduced accordingly. Assuming wet/dry cooling towers with 80% wet or evaporative and 20% dry, the water consumption for MP&L's proposed Unit 4 will be reduced by approximately 20%. If the wet/dry cooling towers are designed to eliminate capacity reductions and provide for approximately the same evaporative cooling as MP&L's proposed wet cooling towers; then no changes will occur for the intake system and the intake water quantities. A cooling tower design with the dry portion actually carrying part of the cooling load will result in reduced condenser cooling water flows. The auxiliary cooling water system probably will not change, with the auxiliary cooling water used as makeup for the cooling towers, as MP&L proposes.

Air Quality Control Systems (AQCS)

The air quality control system (AQCS) will not be significantly affected by using wet/dry cooling towers. Potential reduced efficiency caused by the wet/dry cooling towers could result in the emission of additional quantities of particulates and SO_2 due to increased energy generation. Most of these will be removed by the wet particulate scrubber and SO_2 absorber. On an annual basis, the additional quantities of particulates and SO_2 will be about 0.5% greater than that generated by MP&L's proposed action. This increase is expected to have little effect on MP&L's proposed AQCS.

Emissions, Effluents, and Waste Production

Air Emissions

Wet/dry cooling towers could eliminate the majority of the fogging and drift associated with MP&L's proposed Unit 4 cooling tower. While both fogging and drift will nearly be eliminated, salt deposition will not be eliminated. The salt emissions identified in Table II-50 will be decreased by approximately 20% based on the same reduction as for water consumption.

Wastewater Effluents

Wet/dry cooling towers will reduce wastewater effluents because of the reduction in cooling tower blowdown. Table III-25 presents the composition of wastewater effluents from MP&L's proposed Unit 4 with wet/dry cooling towers.

TABLE III-25
WASTEWATER EFFLUENTS WITH UNIT 4 WET/DRY COOLING TOWERS[a]
UNITS 1, 2, 3, AND 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Parameter	Central Waste Treatment Effluent	Units 3 and 4 Cooling Tower Blowdown	Treated Unit 3 Fly Ash Blowdown	Sanitary Wastes	Total Wastewater Effluent
Flow					
gpm	3,055	1,350	1,360	20	5,785
lpm	11,564	5,110	5,148	76	21,898
pH	6 to 9	7.8	6 to 9	7	6 to 9
Total dissolved solids (TDS), mg per liter	293	900	2,400	200	928
Total suspended solids (TSS), mg per liter	4	30	-	30	10
Oil and grease, mg per liter	< 1	nil	nil	nil	nil
Sulfates, mg per liter	15	35	2,000	-	552
Chlorides, mg per liter	42	516	-	-	144
Calcium (as $CaCO_3$), mg per liter	103	180	50	-	110
Magnesium (as $CaCO_3$), mg per liter	56	67	10	-	47
Iron, mg per liter	3	nil	-	-	1.5

[a] Without Units 1 and 2 cooling water.

The wastewater effluents for wet/dry cooling towers are based on the assumption that there will be a 20% reduction in Unit 4 cooling tower blowdown when compared to MP&L's proposed Unit 4 wet cooling towers.

Waste Production

Solid waste production will be affected by using wet/dry cooling towers. Based on maintaining the same generating output, additional ash and scrubber sludge will be generated because of increased coal comsumption of 1,000 to 10,000 tpy (907 to 9,072 mtpy). Bottom ash production will be increased 14 to 140 tpy (13 to 127 mtpy), and fly ash and SO_2 scrubber sludge will be increased 108 to 1,083 tpy (98 to 982 mtpy).

ALTERNATIVE - DISPOSAL OF SOLID WASTE IN AN ABANDONED MINE

Solid waste produced by MP&L's proposed Unit 4 at the Clay Boswell Steam Electric Station possibly could be deposited in abandoned open pit iron mines located on the western end of the Mesabi Iron Range. The solid wastes which could be deposited are bottom ash, fly ash, and SO_2 scrubber waste. Depositing these wastes in an abandoned mine within the vicinity of the Clay Boswell Station will eliminate the need for the new ash and SO_2 sludge pond that MP&L proposes to construct just northwest of the electric generating facility.

There are a variety of ways in which abandoned mines could be utilized for waste disposal. A rigorous definition and evaluation of all conceivable methods has not been made. Rather, one general alternative or method, which may be applicable, is described and evaluated.

The alternative method of solid waste disposal, shown in Figure III-6, will require dewatering, chemical fixation, curing, and loading into railroad cars of the solid waste at the electric generating facility; transporting the solid waste by rail to the abandoned mine site; and unloading of rail cars, stockpiling, transferring to disposal area, placing and compacting, and eventual vegetation of the solid waste at the abandoned mine site. This method allows for handling a dry or nearly dry solid waste, minimizing transport and disposal facilities.

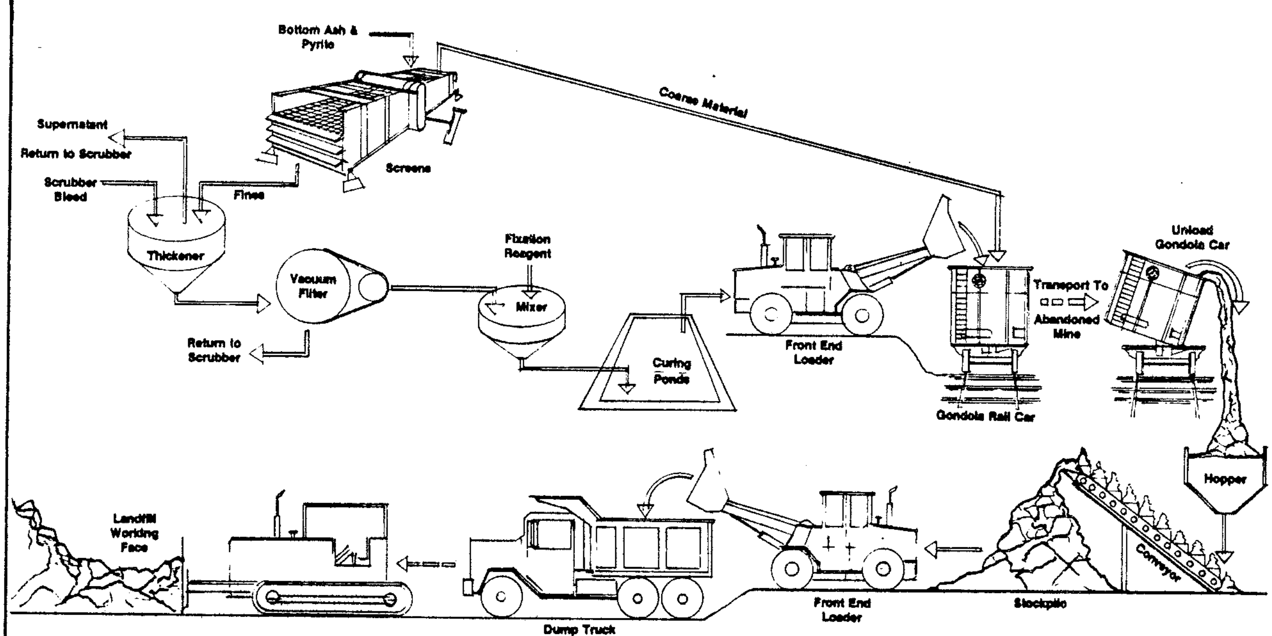
Raw Materials

The supply, transportation, handling, and consumption of coal for Unit 4 will not be affected by disposal of the bottom ash, fly ash, and SO_2 scrubber waste in an abandoned mine. However, unloading, storage, and handling facilities will have to be constructed for chemical reagents required for chemical fixation of the solid waste. The chemical fixation reagents could be delivered to the Clay Boswell Station by rail or truck, depending on the quantities required and the source. Assuming the amount of chemical reagent needed is about 10% of the weight of dry solids in the waste, the consumption of chemical fixation reagents is estimated to range from 23,000 to 32,000 tpy (20,865 to 29,030 mtpy).

Facilities Operation

The power generation cycle for Unit 4 will be essentially the same for the alternative of solid waste disposal in an abandoned mine as for MP&L's proposed action. The water systems for Unit 4 also will be essentially the same as for MP&L's proposed action except that the bottom ash, fly ash and SO_2 sludge handling systems will be changed to incorporate dewatering as shown in Figure III-6. The fly ash and SO_2 sludge from the reaction tank will flow to a thickener (clarifier) for partial dewatering. Bottom ash from the bottom ash hopper and the pyrites (from the pulverizers) from the pyrites tank will be sluiced to a screen where the coarse bottom ash and pyrites will be separated from the fine ash, pyrites, and water. The coarse ash and pyrites then will be conveyed to the rail cars. The fine bottom ash and pyrites from the screen underside will flow to the same thickener as the fly ash and SO_2 sludge. The thickener supernatant will be recycled to the scrubber/ absorber system.

The thickener underflow (concentrated sludge) will be pumped to a vacuum filter for further dewatering. The filtrate will be recycled to the scrubber/absorber system. The filtered sludge will then be mixed and conditioned with chemical fixation reagents and conveyed to the curing ponds.



SOLID WASTE MANAGEMENT SYSTEM - DISPOSAL IN ABANDONED MINE

FIGURE III-6

Sludge will be stored in the curing ponds until the mixture has set up and can be handled dry (approximately 30 days). After curing, the fixed sludge will be excavated from the ponds and loaded into rail cars for transport to the mine. Three ponds will be provided and used alternately: one will be filling while one is being emptied and the other being used for curing.

Since there will not be a Unit 4 bottom ash pond, the Unit 4 bottom ash pond overflow will be eliminated as a inflow to the central waste treatment facility. However, it will be necessary for all or a portion of the bottom ash hopper cooling and seal water to be treated by the central waste treatment facility.

Emissions, Effluents, and Waste Production

The stack and cooling tower emissions for proposed Unit 4 will not be affected by disposal of the bottom ash, fly ash, and SO_2 scrubber solid waste in an abandoned mine. The effluents for proposed Unit 4 will be reduced slightly or modified as a result of this alternative. Since the new ash and SO_2 sludge pond will not be constructed, the seepage from this pond will be eliminated.

The disposal of chemically fixed solid waste in an abandoned iron mine may cause groundwater contamination through permeable sections of the Biwabik Iron Formation. The extent of seepage and related groundwater contamination at an abandoned mine site will have to be determined by a detailed site specific investigation. However, seepage for this alternative is expected to be less than the estimated seepage for the proposed new ash and SO_2 sludge pond. Surface water pollution for this alternative may be greater than for MP&L's proposed new pond since this alternative requires increased intermediate solid waste handling and storage.

Solid Waste Production

For the alternative of disposing of the solid waste in an abandoned mine, the Unit 4 solid waste will be comprised of chemically fixed bottom ash, fly ash, and SO_2 scrubber solid waste. The estimated dry quantities of ash and scrubber waste produced by Unit 4 are not affected by the disposal of the solid waste in an abandoned mine. It is estimated that the total dry solid waste will be about 10% greater for this alternative because of the addition of the chemical fixation reagents. However, because of the additional dewatering accomplished, the volume of waste to be disposed of may be reduced. Based on the estimated bottom ash, fly ash, and SO_2 scrubber solid waste production for MP&L's proposed steam generator and air quality control system, the estimated solid waste production for the alternative of solid waste disposal in an abandoned mine is presented in Table III-26. It is estimated that the chemically fixed solid waste will have an average dry bulk in place density of 70 lb per cu ft (1.12 g per cc).

Solid Waste Handling

The chemically fixed solid waste excavated from the curing ponds at the Clay Boswell Station will be placed by front-end loader into railroad cars for transport to the abandoned mine for disposal. The curing ponds probably will be located just north of the Unit 4 generating facility or in the fly ash

TABLE III-26

ESTIMATED FUTURE SOLID WASTE OR ASH AND SO_2 SCRUBBER WASTE PRODUCTION WITH FIXATION OF SOLID WASTE - UNIT 4 - CLAY BOSWELL STEAM ELECTRIC STATION

Solid Waste[a]	Unit 4
Bottom Ash	
Average daily[b]	
tons	78.9
metric tons	71.6
Maximum daily[c]	
tons	252.0
metric tons	228.7
Average annual[b]	
tons	28,807
metric tons	26,133
Maximum annual[d]	
tons	53,794
metric tons	48,802
Average total[b]	
tons	1,008,239
metric tons	914,659
Maximum total[d]	
tons	1,344,319
metric tons	1,219,546
Fly Ash and SO_2 Scrubber Waste	
Average daily[b]	
tons	609.4
metric tons	552.8

Solid Waste[a]	Unit 4
Fly Ash and SO_2 Scrubber Waste (continued)	
Maximum daily[e]	
tons	1,142.6
metric tons	1,036.5
Average annual[b]	
tons	222,416
metric tons	201,772
Maximum annual[b]	
tons	311,506
metric tons	282,593
Average total[b]	
tons	7,784,543
metric tons	7,062,019
Maximum total[b]	
tons	7,784,543
metric tons	7,062,019
Solid Waste	
Average annual[b]	
tons	251,222
metric tons	227,905
Average total[b]	
tons	8,792,782
metric tons	7,976,678

a Based on the amount of chemical reagent required for fixation being 10% of the weight of dry solids in the waste.

b Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 15% to 85%.

c Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 20% to 80%.

d Based on coal containing 9.35% ash and a bottom ash to fly ash ratio of 20% to 80%.

e Based on coal containing 15.99% ash and a bottom ash to fly ash ratio of 15% to 85%.

reclamation area southeast of the existing facility. If necessary, a railroad spur will be constructed from the existing rail trackage into the Clay Boswell Station. The railroad cars will be rotary coupled, open gondola cars of 100 short ton (91 mt) capacity. This alternative will require the loading of 10 to 21 railroad cars per day. These cars will be made into a train with one train transporting solid waste to the abandoned mine at convenient intervals. At the abandoned mine, the railroad cars will be dumped using a rotary dumper. The dumped solid waste then will be conveyed to a stockpile. The solid waste in the stockpile will be picked up and loaded into waiting end-dump off-highway trucks using a frontend loader. The off-highway trucks will transport the solid waste to the fill working face where the solid waste will be dumped and compacted. When a specific dump site has been filled, the surface will be reclaimed and made suitable for vegetation.

This solid waste handling concept allows for handling the solid waste in a dry or nearly dry state, minimizing transport and disposal difficulties. Even with this concept, complications may arise because of residual moisture retained in the dewatered solid waste. During winter, this residual moisture could result in the solid waste freezing in conveyors, within railroad cars, or in the stockpile at the abandoned mine disposal site. The dewatering, chemical fixation, rail transport, and handling of the solid waste for this alternative will consume more energy and incur additional capital and operating costs than MP&L's proposed solid waste handling and disposal system.

Abandoned Mine Disposal Sites

Potential abandoned mines for disposal of solid waste produced by MP&L's proposed Unit 4 were determined using the following guidelines:

- Surface or open pit mines only will be considered for disposal sites;
- Rail transport is the only feasible and prudent method for transport of the solid waste from the Clay Boswell Station to the mine site;
- The mine site or sites must be serviced by existing railraod trackage;
- The mine site or sites must be less than approximately 20 miles (32.2 km) by rail from the Clay Boswell Station;
- The mine site or sites must have sufficient volume capacity, either individually or in combination with adjacent mine sites, to receive and dispose of the solid waste volumes produced by MP&L's proposed Unit 4; and
- The mine must be exhausted or mined out to the extent that solid waste disposal will not interfere with future ore extraction.

The mine site or sites must have an available volume equal to or greater than 5,900 acre-ft (7,277,543 cu m).

There are numerous iron ore mines of various sizes within a 20 mile (32.2 km) rail distance of the Clay Boswell Station as shown in Figure III-7. Available data for exhausted open pit iron ore mines within a 22 mile (35.4 km) limit are presented in Table III-27. The data indicate that only 7 exhausted mines are within 22 miles (35.4 km) of the Clay Boswell Station and that these

TABLE III-27
EXHAUSTED OPEN PIT IRON ORE MINES NEAR CLAY BOSWELL STEAM ELECTRIC STATION (1)

Mine Name	Approximate Haulage Distance via Railroad mile	km	Approximate Distance to Rail Access at Mine ft	m	Storage Capacity[a] %
1. Jessie No. 1	11	18	500	152	5.2
2. Holman-Cliffs (Bingham)	18	29	Direct access		14.1
3. Judd	18	29	1,500	457	5.3
4a. Majorca[b]	22	35	3,000	914	6.8
4b. Barbara[b]	22	35	5,000	1,524	1.7
4c. Draper[b]	22	35	5,000	1,524	1.1
4d. Draper Annex	22	35	5,000	1,524	7.7
Total					41.9

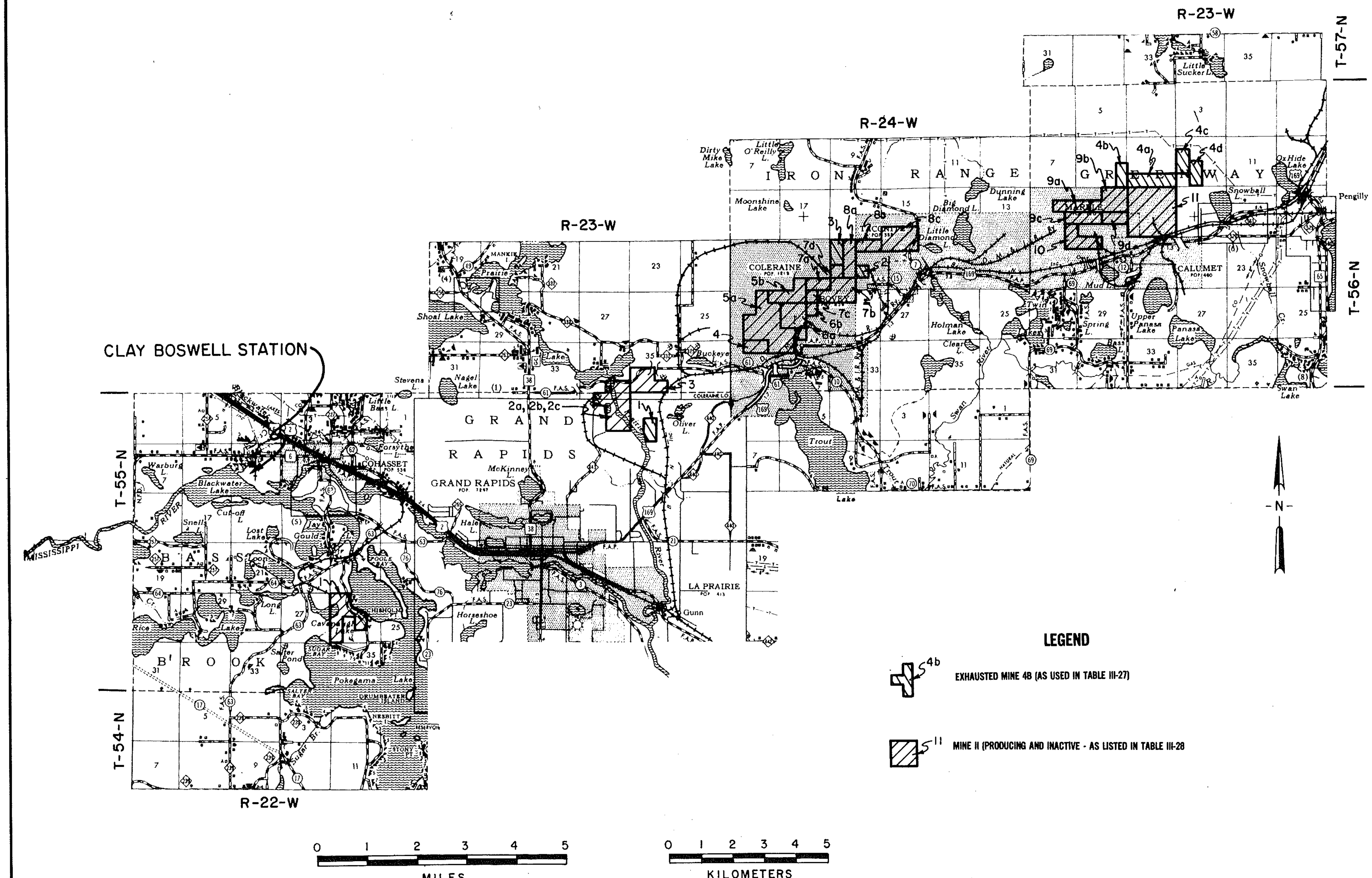
[a] Storage capacity is shown as a percent of the required volume that would be available at MP&L's proposed pond for Unit 4. Storage capacity at the proposed pond is 5,900 acre-ft (7,277,543 cu m).

[b] Owned by the State of Minnesota.

mines, either individually or in combination, have inadequate volume capacity required to dispose of the solid waste produced by MP&L's proposed Unit 4 during the expected 35 year life of the unit. Collectively, these exhausted mines only can provide 42% of the required total volume capacity. The largest individual exhausted mine can accommodate only 14% of the projected solid waste volume. Therefore, there are no suitable exhausted mines for disposal of the solid waste produced by MP&L's proposed Unit 4 at the Clay Boswell Station.

Available data for producing and inactive open pit iron ore mines within the 22 mile (35.4 km) limit are presented in Table III-28. Based on past rates or iron ore production from these mines and the remaining estimated iron ore reserves, some of these mines may be exhausted or nearly exhausted by 1980. A few individual mines listed in Table III-28 can accommodate a large percentage of the expected solid waste. One mine has nearly 40% more volume capacity than will be necessary for the projected 35 year life of Unit 4. Several groupings of individual mines where concurrent development would be advantageous, also provide additional volume capacity.

Most of the producing and/or inactive mines are privately owned and may be difficult for MP&L to acquire. However, 10 of these sites lie within 6 to 15 rail miles (9.7 to 24.1 km) of the Clay Boswell Station. Collectively, these have the potential to provide 396% of the necessary volume capacity. In addition, 13 other mines are located within 15 to 22 rail miles (24.1 to 35.4 km) of the Clay Boswell Station. Most of these mines have large individual volume capacities and could be investigated if the nearer sites were not readily available. Before a mine site is used as a solid waste disposal site, a method should be established for final determination that the mine site is indeed exhausted. When the dumping of solid wastes commences at the mine site, the possibility of mineral recovery will diminish.



IRON ORE MINES WITHIN 20 MILES (32.2 KM) RAIL DISTANCE OF CLAY BOSWELL STEAM ELECTRIC STATION

SOURCE OF MINING INFORMATION: TRETHEWAY, W.D., "MINING DIRECTORY ISSUE - MINNESOTA", 1974, UNIVERSITY OF MINNESOTA BULLETIN, DECEMBER 31, 1977, PP. 1-183

FIGURE III-7

TABLE III-28
PRODUCING AND INACTIVE OPEN PIT IRON ORE MINES NEAR CLAY BOSWELL STEAM ELECTRIC STATION (1)

Mine Name[a]	Approximate Haulage Distance via Railroad mile	km	Approximate Distance to Rail Access at Mine ft	m	Storage Capacity[b] percent
1. Tioga No. 2[c]	6	10	Direct access		17.1
2a. Lind-Greenway[d] (Greenway)	11	18	Direct access		30.2
2b. Lind-Greenway[c] (Lind)	11	18	Direct access		14.0
2c. Lind-Greenway[c] (Marr Adair)	11	18	Direct access		6.8
3. West Hill	11	18	Direct access		31.6
4. Hunner	14	23	Direct access		36.5
5a. Canisteo[d]	15	24	Direct access		153.1
5b. Canisteo (Morrison Lease)	15	24	Direct access		30.0
6a. Walker[d]	15	24	Direct access		71.4
6b. Fletcher	15	24	1,000	305	5.4
7a. Danube[d] (Danube)	16	26	500	152	32.9
7b. Danube[d] (Orwell)	16	26	500	152	54.5
7c. Lewis	16	26	2,000	610	28.7
7d. Sally	16	26	500	152	14.1
8a. Plummer	18	29	1,000	305	68.3
8b. Holman-Cliffs[d] (North Star)	18	29	1,000	305	16.5
8c. Diamond	18	29	2,000	610	56.5
9a. Walker Hill No. 6	21	34	2,000	610	7.2
9b. Hill-Trumbull (Hill)	21	34	3,000	914	57.1
9c. Hill-Trumbull (Trumbull)	21	34	Direct access		49.9
9d. Delaware No. 1	21	34	3,000	914	36.1
10. Gross-Marble	21	34	Direct access		31.7
11. Hill Annex[c d]	22	35	Direct access		240.0
Total					1,089.6

[a] These mines were listed as either active or inactive during 1974. Because of their ore reserves and production rates for previous years, they may be mined out and should be considered in conjunction with known exhausted mines as alternative disposal sites.

[b] Storage capacity is shown as a percent of the required volume that would be available at MP&L's proposed pond for Unit 4. Storage capacity at the pond is 5,900 acre-ft (7,277,543 cu m).

[c] Owned by the State of Minnesota.

[d] Questionable whether these mines are presently exhausted, but because of their potential storage area, they should be investigated further.

Iron ore mines with acceptable capacities for disposal of solid waste from MP&L's proposed Unit 4 are available within a reasonable distance from the Clay Boswell Station. Collectively or individually, these mines can be used as disposal sites and are connected by a railroad network with short spurs. This method of solid waste disposal represents an alternative to MP&L's proposed ponding of wastes at the Station. However, the foreseeable problems of development, mine acquisition, operation, higher energy consumption, and higher cost in large measure detract from the feasibility of disposing of solid waste in an abandoned mine.

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