Stanley Consultants INC.

A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

Southern Montana Electric
Generation & Transmission Cooperative, Inc.
Billings, MT

Site Selection Study

Volume 1

Final

October 15, 2004

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Executive Summary

Southern Montana Electric Generation & Transmission Cooperative, Inc., (SME), selected four (4) possible sites for a proposed new 250 MW circulating fluidized bed (CFB) coal-fired power plant. SME engaged Stanley Consultants to perform a study focusing on the major factors that affect site selection. These factors include environmental impacts and the cost of mitigation; relative costs of site development, and projected production costs. The sites studied are comprised of parcels of land located near the cities of Great Falls (Salem), Circle (Nelson Creek), Hysham, and Decker, Montana. The purpose of the study is to determine the optimal site for the proposed new power plant.

The study includes the preparation of preliminary heat balance and water balance diagrams, an electrical one-line diagram, material handling diagrams, conceptual site plans for the plant configuration, and characterization of expected plant emissions. During the study, a summary level project schedule and a cost estimate were developed. This baseline data was utilized to assess the suitability of each possible site, considering the agreed-upon study parameters, and compliance with local, state, and federal regulations applicable to the permitting, construction, and operation of power generation facilities.

The study quantifies the potential generating sites in terms of:

- Heat rate, which considered the different types of coal and locations at which the coal would be utilized;
- Water consumption and wastewater discharge, including source and discharge points, and associated water rights issues;

- Environmental suitability which includes the existing land use, air quality concerns, proximity to state or national parks and wildlife areas, existing or planned airports, and Indian reservations;
- Site-specific costs for plant development and operation;
- Infrastructure improvements for both construction and operation, which included roads, railroads, water and natural gas pipelines, and transmission; and
- Cost and schedule benefits and impacts.

This report summarizes the study process, presents conclusions regarding the relative production costs and any risks associated with each site, and provides recommendations regarding the next phase of development. A cash flow analysis, permit schedule, and permit matrix for the project development is included.

The following summary table reflects the cost of project development and operation.

Table 1
Site Selection

Site Location	Total Installed Cost	Incremental Cost	Busbar Cost ¢/kWh[1]	Busbar Cost ¢/kWh[2]
Salem	$469,555,000	0	[redacted]	[redacted]
Salem (Industrial)	$481,100,000	$11,545,000	[redacted]	[redacted]
Decker	$553,096,000	$83,540,000	[redacted]	[redacted]
Hysham	$545,193,000	$75,637,000	[redacted]	[redacted]
Nelson Creek	$692,292,000	$222,737,000	[redacted]	[redacted]

[1] "Busbar" Costs are shown in ¢/kWh, which is levelized over a 30-year period at an annual capacity factor of 90% and 30-year debt service coverage.
[2] First year "Busbar" Costs are shown in ¢/kWh at an annual capacity factor of 90%.

The Nelson Creek site results is the biggest Busbar cost due to the high cost of installation and relatively lower heat rate.

The low probability of available water at the Hysham and Decker sites places these project sites at high risk. The Salem Industrial site (located in the Great Falls Industrial Park) has a higher capital cost as compared to the Salem site. Therefore, the resulting Busbar cost is incrementally higher for the Salem Industrial Site.

The Salem site is environmentally friendly, with an available water supply. It has the lowest total project cost, second best heat rate and the lowest "busbar" cost of the sites. The site determined to best satisfy the needs of SME is the Salem site, located just east of Great Falls, Montana.

Section 1

Introduction

Southern Montana Electric Generation & Transmission Cooperative, Inc., (SME), is a recently-formed generation and transmission cooperative which includes the following members:

- Beartooth Electric Cooperative, Inc., headquartered in Red Lodge, Montana.
- Fergus Electric Cooperative, Inc., headquartered in Lewiston, Montana.
- Mid-Yellowstone Electric Cooperative, Inc., headquartered in Hysham, Montana.
- Tongue River Electric Cooperative, Inc., headquartered in Ashland, Montana.
- Yellowstone Valley Electric Cooperative, Inc., with headquarters at Huntley, Montana.
- The City of Great Falls, Montana.

At present, all of the electrical power generation supplied to SME for distribution comes from existing power purchase agreements. These agreements are due to expire between 2008 and 2011. SME currently purchases approximately 80% of its power supply from Bonniville Power Administration and this portion cannot be renewed. The only purchase option to replace this portion of SME's supply portfolio is to obtain power from the open market. Market forces have caused prices to be highly volatile and higher than self generation. SME deemed it prudent to study the viability of locating a new power generation facility within its member distribution system territory to self-serve future power supply needs. SME selected four (4) potential sites and engaged the services of Stanley Consultants, Inc., to assess each site to determine the overall best location for a new power generation facility.

The design concept utilized as the basis for comparison at each site was determined to be a new 250 MW generation station utilizing circulating fluidized bed (CFB) combustion technology. Stanley Consultants' approach to the study developed a work breakdown structure, identifying a series of tasks organized in a logical sequence that considered all aspects of the site selection process, and would lead to the proper conclusion.

East Kentucky Power Cooperative's Spurlock Station, Gilbert Unit 3 was used as a model for this project. The Gilbert Unit is a 268 MW coal-fired circulating fluidized bed boiler generation plant, designed by Stanley Consultants, scheduled to go into commercial operation in April 2005.

The initial task involved gathering data from numerous sources. Stanley Consultants explored a variety of information from regulatory jurisdictions. Other sources of information, both public and private, were explored. The follow data was gathered and reviewed in this effort:

- Areas identified as:
  - Class 1 air basins.
  - Federal, state, and local non-attainment areas.
  - Class 1 wilderness areas.
  - Wetlands.
  - Visually-sensitive areas.
  - Critical habitat for threatened or endangered species.
  - Wildlife refuges.
  - Cultural resource areas.
  - Tribal lands.
  - Urban areas.
  - Military training areas.
- Available air emissions increments.
- Expected BACT and air modeling requirements.
- Availability of air and meteorological data.
- Hydrology.
- Soils.
- Other development in the area.
- Zoning restrictions.
- Availability and sources of transmission line and feasibility of interconnect.
- Availability and sources of fuel supply.
- Availability and sources of water resources required for operation.
- Availability and sources of transportation infrastructure.

Overall preliminary heat balance, water balance, electrical one-line, and material handling diagrams were developed for the new 250 MW generation station. These diagrams were modified as necessary to accommodate each site-specific arrangement. A conceptual site plan was developed for each of the four sites.

Stanley Consultants then reviewed each site for implications of site features, including:

- Performance and output variances from the generic site conditions. This analysis is included in the "Performance and Output" subsection of Section 2, "Site Selection."

- Analysis of required infrastructure enhancements and development of cost estimates for items, including roads, railroads, water, and transmission. This analysis is included in the "Infrastructure" and "Development Cost" subsections of Section 2, "Site Selection."

Compliance with environmental regulations was reviewed by Stanley Consultants to evaluate the impacts of the expected plant emissions to air, water, solid wastes, and land use for each of the selected sites. In conjunction with these evaluations, a Phase 1 environmental site assessment, summary permit matrix, permit cost estimate, and permit schedule was developed, and comparisons were analyzed. This analysis is included in Section 3, "Environmental Issues."

A detailed description of the proposed 250 MW CFB generation station was prepared and is included in Section 4, "Project Description." Based on the information developed in Sections 2, 3, and 4, a summary-level project schedule was prepared. The schedule is included in Section 5, "Project Schedule."

A capital cost estimate for each site was developed. Based on the project schedule developed in Section 5, a cash flow analysis was performed for the recommended site. The cost estimates and cash flow analysis are included in Section 6, "Cost Estimate."

Stanley Consultants determined the production costs associated with each site. Utilizing information collected for project capital costs, identifying the economic factors, and establishing the fuel and fixed and variable operations and maintenance costs, the sites were ranked by economic analysis. This analysis is described, and results presented in Section 7, "Economic Analysis."

A sensitive analysis was performed to determine risks associated with the development of the project. A relative ranking analysis, which assesses the risks associated with moving forward with project development at a given site, is included in Section 8, "Ranking Analysis and Conclusion."

Preliminary drawings and supporting documentation may be found in the appendices, and are referenced throughout the report text.

Section 2

Site Selection

Southern Montana Electric Generation & Transmission Cooperative, Inc., (SME), contracted with Stanley Consultants to perform a site selection study based on four (4) proposed sites identified by SME. These sites were selected through internal SME discussions concerning an optimum project site. SME had considered the ease of obtaining water, movement of electrical power, the load centers for the member cooperatives, and proximity to nearby fuel sources. Ability to obtain an environmental permit was an additional consideration. The sites selected for study are parcels of land located near the cities of Great Falls (Salem), Circle (Nelson Creek), Hysham, and Decker, Montana.

Locations

Site visits were conducted at each proposed site. During the Great Falls site visits, two (2) potential locations were reviewed. The first site was north of Malmstrom Air Force Base (AFB). The second was east of Great Falls at the intersection of Salem Road and an abandoned railroad siding. SME requested Stanley Consultants to review a third location -- the Great Falls Industrial Park, referred to on this report as the Salem Industrial site. Consideration of the site north of Malmstrom was immediately hindered by the location of the runway. Military air traffic would be returning or leaving directly over that proposed site. The cooling tower plume, stack, and the height of the building would be possible obstructions. It was determined that it would be extremely difficult to obtain a construction permit that close to the air base. If the site were relocated further to the north, the project would be located on property of significant historical activity -- the beginning of the trail for the portage route taken by Lewis & Clark. This site was dropped from further consideration.

The remaining two (2) Great Falls sites were studied, and are identified as the Salem site (intersection of Salem Road and an abandoned railroad siding), and the Salem Industrial site. The exact locations are as follows, and can be seen on the identified figures in the Phase I Environmental Site Assessment included in Appendix K.

- The Salem site is located in the Southwest ¼ of Section 36, Township 21 North, Range 5 East. The site location is shown on the Morony Dam topographic map (Figure 1).
- The Salem Industrial site is located in the Southern ½ of Section 30, Township 21 North, Range 4 East. The site location is shown on the Northwest Great Falls topographic map (Figure 5).

The Decker site is located in the Southwest ¼ of Section 1, Township 8 South, Range 39 East. The site location is shown on the Half Moon Hill topographic map (Figure 4) in the Phase I Environmental Site Assessment included in Appendix K.

During the Hysham site visit, two (2) potential locations were reviewed. The first location was 15.9 miles south of the Yellowstone River; the second was 8.8 miles south of the Yellowstone River. Both sites are located on the west side of Old Sarpy Road. The first location presented many challenges to project development. Road access was limited to a narrow and shallow tunnel under an existing Burlington Northern Santa Fe railroad. This site was high on a plateau surrounded by steep grades. Both site features would result in excessive construction costs in order to rectify the conditions. The first Hysham site was dropped from any further consideration.

The second Hysham site is located in the Southwest ¼ of Section 11, Township 6 North,Range 37 East. The site location is shown on the Scrapper Coulee topographic map (Figure 3) included in the Phase I Environmental Site Assessment included in Appendix K.

The Nelson Creek site is located within the Northwest ¼ of Section 36, Township 21 North, Range 43 East. The site location is shown on the Nelson Creek Bay topographic map (Figure 2) included in the Phase I Environmental Site Assessment included in Appendix K.

Descriptions

The proposed Salem site is located in Section 36, Township 21 North, Range 5 East at an elevation of approximately 3,354 feet above sea level. This site is primarily located east of the intersection of Salem Road and an abandoned railroad bed previously used by the Milwaukee, St. Paul, and Pacific railroad.

The Salem Industrial site is located just east of Highway 87, approximately three-quarters mile north of the Missouri River, and one-half mile east of a mobile home park.

The Decker site is located at an elevation of approximately 3,881 feet above sea level 30 miles east of Interstate 90, and east of Highway 314 near the North Fork Monument Creek.

The Hysham site is a former gravel borrow site located approximately eight (8) miles south of the Yellowstone River on the west side of Old Sarpy Road. Site elevation is approximately 2,870 feet above sea level.

The Nelson Creek site is located southeast of Nelson Creek Bay, just east of Highway 24, near mile marker 15. Elevation is approximately 2,322 feet above sea level.

All sites are located in rural settings, except the Salem Industrial site, which is undeveloped space near an industrial park. Primary past and current land uses on the sites, and in the areas immediately surrounding the sites, have been agriculturally related.

Performance & Output

Heat balance diagrams were developed for the project for the specific site locations and heat rate curves were developed from the diagram information. The heat rate curves were utilized in establishing the fuel cost component for the production cost analysis. A 100% load condition utilized the operation point of steam turbine valves wide open at rated conditions of 2400 psi, 1000° superheat, and 1000° reheat steam temperatures. This 100% summer operational condition establishes the size of the heat rejection equipment consisting of the condenser and cooling tower.

The information from the 100% load cases established fuel and air demands and annual emissions information for this study. The fuel demands established the sizing of fuel, ash, and limestone-handling equipment; bunker sizes; and fuel and limestone long-term material storage volumes. Fuel volumes, coal ash and sulfur analysis provided information used in sizing of solid waste disposal sites for spent bed material and fly ash. The coal-handling system, limestone-handling system, and ash-handling system diagrams were developed from this information. These material-handling diagrams provide a diagrammatic representation of the equipment, conveying methods, processing equipment, and storage facilities, in relation to the overall process. They also provide a basis for the capital cost estimate for each site.

A preliminary water balance diagram was developed for the project at the summer operational condition of 100% load. Preliminary water balances aided in the determination of water requirements. These water balances also aided in the development of tank and pump sizes, water treatment equipment size, and wastewater stream definition.

A conceptual electrical one-line diagram was developed, providing a diagrammatic representation of electrical generation and plant electrical distribution system. This diagram was used to develop the size of electrical equipment, supporting the identification of cost information.

Basic Plant Descriptions

The generating station will use coal to generate a net capacity of 250,000 kW of electricity. Each plant is projected to produce commercially-available power by November 2008. Each plant design consists of a circulating fluidized bed (CFB) boiler, single re-heat tandem compound steam turbine, seven (7) stages of feedwater heating, water-cooled condenser, wet cooling tower, flash dryer absorber, and baghouse. Limestone and ammonia are added to reduce air pollutants. Electricity produced will be transmitted on two (2) 230 kV transmission lines.

Salem Generating Station

A generating station built on either Salem site would use sub-bituminous coal from the Spring Creek or Decker Mine or other suitable supply from which comparable Powder River Basin coal supplies are produced. Electricity produced will be transmitted to the Great Falls Substation, located north of the Missouri River and the City of Great Falls. Make-up water for the plant will be pumped from an intake structure upstream of the Morony Dam on the Missouri River. Natural gas will be supplied to the power plant for start-up fuel from an existing nearby pipeline. Bulk materials, including coal, limestone, and ammonia, will be delivered to the facility by railroad. Ash waste disposal will be trucked to a landfill location on site or a suitable nearby site.

Using coal with a higher heating value of 9,310 BTU/lb, the boiler and steam turbine should be capable of generating a gross output of 270,100 kW of electricity on a 94°F day at 100% load. The gross heat rate, using higher heating value, is approximately 8,940 BTU/kW-hr. Auxiliary loads, totaling approximately 18,100 KW (6.7% of gross output) which includes transformer losses, reduce the net power output of the plant to approximately 252,000 kW, at an approximate net heat rate of 9,580 BTU/kW-hr. The fuel consumption at these conditions is estimated at 259,300 lb/hr, or 1,135,900 tons/yr. Limestone is consumed at a rate of approximately 5,780 lb/hr or 25,300 tons/yr.

Decker Generating Station

A generating station built at the Decker site would use sub-bituminous coal from the Decker Mine as a fuel source. Electricity produced will be transmitted to the existing Rosebud and the new Tongue River Substations, located southeast of the City of Rosebud, and east of the existing Colstrip Generating Station, respectively. Make-up water for the plant will be pumped from an intake structure on the west bank of the Tongue River Reservoir. No. 2 fuel oil will be delivered to the power plant for start-up fuel by truck. Bulk materials, including coal, limestone, and ammonia, will be delivered to the facility by railroad. Ash waste materials will be trucked back to the Decker Mine for disposal.

Using coal with a higher heating value of 9,535 BTU/lb, the boiler and steam turbine should be capable of generating a gross output of 270,200 kW of electricity on a 94°F day at 100% load. The gross heat rate, using higher heating value, is estimated to be 8,870 BTU/kW-hr. An auxiliary load, totaling approximately 18,650 kW (6.9% of gross output) which includes the transformer losses, reduces the net power output of the plant to approximately 251,550 kW, at an approximate net heat rate of 9,530 BTU/kW-hr. The fuel consumption at these conditions is estimated to be 251,400 lb/hr or 1,101,200 tons/yr. Limestone is consumed at a rate of approximately 6,420 lb/hr, or 28,200 tons/hr.

Hysham Generating Station

A generating station built at the Hysham site would use sub-bituminous coal from the Absaloka Mine as a fuel source. Electricity produced will be transmitted to the existing Rosebud and Custer Substations, located southeast of the City of Rosebud, and south of the City of Custer, respectively. Make-up water for the plant will be pumped from an intake structure located on the Yellowstone River, east of the City of Hysham. Natural gas will be supplied to the plant for start-up fuel from an existing pipeline. Bulk materials, including coal, limestone, and ammonia, will be delivered to the facility by railroad. Ash waste materials will be trucked to a landfill location on site.

Using coal with a higher heating value of 8,752 BTU/lb, the boiler and steam turbine should be capable of generating a gross output of approximately 270,900 kW of electricity on a 94° F day at 100% load. The gross heat rate, using higher heating value, is estimated to be 9,130 BTU/kW-hr. Auxiliary loads, totaling approximately 19,300 kW (7.1% of gross output) which includes the transformer losses, reduce the net power output of the plant to approximately 251,600 kW, at an estimated net heat rate of 9,830 BTU/kW-hr. The fuel consumption at these conditions is estimated to be 280,800 lb/hr or 1,230,000 ton/yr. Limestone is consumed at a rate of approximately 13,240 lb/hr or 58,000 ton/yr.

Nelson Creek Generating Station

A generating station built at the Nelson Creek site would use lignite coal from a new mine as a fuel source. The new mine is located east of the plant. The electricity produced will be transmitted to the existing Rosebud and new Tongue River Substations, located southeast of the City of Rosebud and east of the existing Colstrip Power Plant, respectively. Make-up water for the plant will be pumped from an intake structure located on Fort Peck Reservoir. No. 2 fuel oil will be delivered to the plant for start-up fuel by truck. Lignite coal will be delivered to the site by heavy-haul mine trucks. Bulk materials, including limestone and ammonia, will be delivered to the facility by over-the-road trucks. Ash waste material will be trucked back to the new mine for disposal.

Utilizing lignite coal with a higher heating value of 6,804 BTU/lb, the boiler and steam turbine should be capable of a gross output of 271,500 kW of electricity on a 94° F day at 100% load. The gross heat rate, using higher heating value, is estimated to be 9,310 BTU/kW-hr. Auxiliary loads, totaling approximately 19,920 kW (7.3% of gross output), which includes transformer losses, reduce the net power output of the plant to 251,600 kW, at a heat rate of approximately 10,040 BTU/kW-hr. The fuel consumption at these conditions is estimated to be 371,400 lb/hr or 1,626,800 ton/yr. Limestone is consumed at a rate of approximately 9,730 lb/hr or 42,700 ton/yr.

Summary

STEAM PRO™ is the thermodynamic software package utilized to calculate the expected heat balances and performances for each site. Heat balances were developed for four (4) load cases at three (3) ambient temperatures. Loads of 100%, 75%, 50%, and 38%, and ambient temperatures of 94°F, 45°F, and -20°F were used to determine the plant performance at each site. The following chart summarizes the expected performance outputs at 94°F, 27% relative humidity, and 100% load, for the different site locations.

Table 2-1
Performance Summary

Description	Units	Salem	Decker	Hysham	Nelson Creek
Gross Power Output	kW	270,100	270,200	270,900	271,500
Auxiliary Load	kW	18,100	18,650	19,300	19,920
	%	6.7	6.9	7.1	7.3
Net Power Output	kW	252,000	251,550	251,600	251,600
Gross Heat Rate (HHV)	BTU/kW-hr	8,940	8,870	9,130	9,310
Net Heat Rate (HHV)	BTU/kW-hr	9,580	9,530	9,830	10,040
Fuel HHV	BTU/lb	9,310	9,535	8,752	6,804
Fuel Consumption	lb/hr	259,300	251,400	280,800	371,400
	Tons/Year	1,135,800	1,101,200	1,230,000	1,626,800
Limestone Consumption	lb/hr	5,780	6,420	13,240	9,730
	Tons/Year	25,300	28,200	58,000	42,700
Ammonia Consumption	lb/hr	50	50	50	82
	Tons/Year	220	220	220	360
Ash Production	lb/hr	11,200	10,300	26,030	26,930
	Tons/Year	49,100	45,150	114,000	117,950

Site Plans

The site plans depict the overall placement of fuel supply, major equipment, structures, and their relationships to other facilities on the site. For each site, a site area drawing, site arrangement drawing, and site elevation drawing were developed. The site area drawing depicts the site arrangement, access roads, transmission lines, and rail spur from the main railroad on a topographic map of the area. The site arrangement drawing shows the general location of all equipment including boiler, turbine building, exhaust stack, coal yard, switch yard, cooling tower, and site roads. The sites were oriented according to prevailing wind patterns to minimize stack emission, coal dust, and cooling tower drift from blowing over the site. The site elevation drawing shows the relative height of the stack, boiler building, and steam turbine building. The proposed site drawings are included for each site arrangement in Appendix A.

Process Flow Diagram

Heat balance diagrams were developed for the project for the specific site locations. A process flow diagram was developed to show the major equipment and flow streams that are represented in the heat balance diagram. Major equipment includes the boiler, steam turbine, feedwater heaters, condenser, cooling tower, and pumps. The plant operating at 100% load during the summer ambient conditions establishes the size for the heat rejection equipment, including the condenser and cooling tower. Diagrams for ambient temperatures of 94°F, 45°F, and -20°F at 100% load for each site are included in Appendix B.

Coal/Limestone Handling Diagram

A coal/limestone handling diagram was developed to show the flow of coal or limestone from the unloading station to the bunkers. The differences in coal or limestone handling between the sites are minor, and include different equipment, different process, or different feed rates. The unloading station consists of either a track hopper or truck hopper that receives the material and transfers the product to a transfer tower. From the transfer tower, the material is conveyed to storage. Limestone is crushed before storing in a silo, while coal is crushed after it leaves the storage silo. From storage, the material is conveyed to the tripper deck inside the boiler building and into the bunkers. Coal/limestone handling diagrams for each site are included in Appendix C.

Water Balance Diagram

A water balance diagram was developed for each site at summer operational condition of 100% load, and a median temperature of 94° F. The preliminary water balance aided in the determination of water supply and wastewater discharge requirements. The water balance also aided in the development of tank, pump, and water treatment equipment sizes. The water balance diagrams are included in Appendix D.

Fly Ash-Handling Diagram

An ash-handling diagram was developed for each site, showing schematically the process for gathering and disposing of ash from either the CFB boiler or the flue gas stream. Once the ash is removed, it is mixed with water and trucked to either an on-site storage facility, to another site located in close proximity as allowed by state agencies in the permit process, or back to the coal mine. The bed/fly ash-handling diagram for each site is included in Appendix E.

Electrical One-Line Diagram

A conceptual electrical one-line diagram has been developed. The electrical one-line diagram provides a diagrammatic representation of electrical generation and plant electrical distribution system. The one-line diagram does not change between the proposed project sites, and is included in Appendix F.

Coal Supplies

Coal for the Salem sites could be provided from any area mine source, provided the coal has the proper characteristics and heating values. It is assumed the coal will need to be transported by rail. Stanley Consultants contacted Burlington Northern Santa Fe (BNSF), and transportation costs were identified. Fuel from the Decker, Spring Creek, or Absaloka Mines could be utilized. However, the fuel source is not limited to mines in Montana and any Powder River Basin fuel with the proper characteristics and heating values could be utilized.

Coal for the Decker site would be provided by the Decker Mine. Coal for the Hysham site would be provided by the Absaloka Mine. However, the fuel source for either of these sites is not limited to mines in Montana and any Power River Basin fuel with the proper characteristics and heating values could be utilized.

Lignite coal for the Nelson Creek site would be provided from a local mine, to be developed. This facility would be a mine mouth plant. No other fuel sources were evaluated due to the high cost of transportation of fuel over long distances.

Equipment Analysis

The project cost and performance calculations were based on equipment described in the project description, which includes using steam-driver boiler feed pumps. An option to use electric motor drives in lieu of steam turbine drives for the boiler feed pumps was studied. Changing from steam turbine drivers to electric motor drivers will save approximately $1,700,000 in capital costs. The trade-off is an increase of approximately 30 BTU/kW-hr in heat rate. To determine the best economical solution for the boiler feed pump drives, a more comprehensive study is required.

The current cooling system design uses a wet cooling tower with a water-cooled condenser. The other options available for this plant design are to use either an air-cooled condenser or a dry cooling tower with a water-cooled condenser. An air-cooled condenser is an option for sites that do not have access to a continuous supply of water. The cost increase to utilize an air-cooled condenser in lieu of the wet cooling tower is $71,000,000 or $286 per installed kilowatt. Using an air-cooled condenser also increases the net plant heat rate by approximately 450 BTU/kW-hr. A dry cooling tower and water-cooled condenser cooling system would cost approximately $207,000,000 more than the wet cooling tower and water-cooled condenser. In addition to the increased cost, there is also an estimated 1,050 BTU/kW-hr increase in heat rate. These options are not viable due to the large capital and operational costs.

The plant was originally designed with a separate condenser for the boiler feed pump steam turbine drivers. The exhaust steam can be either discharged into a dedicated condenser located under each steam turbine or ducted to the main condenser. The difference between the two designs is ducting exhausted steam to the main condenser or piping circulating water to the separate condensers. To use the main condenser in lieu of a separate condenser will increase the plant cost by $700,000, or $2.8 per installed kilowatt. In addition to the increase in plant cost, the net plant heat rate increases by approximately one (1) BTU/kW-hr. The small change in heat rate and installed cost are related to the plant layout and amount of piping required for each case. Without further investigation, these two (2) options should be considered equally.

SME noted that a steam host could be developed at the Salem Industrial site to supply steam to a malting facility. Stanley Consultants developed a scenario for the extraction of process steam from the low-pressure steam turbine at an assumed flow rate of 100,00 lb/hr, and a pressure of 100 psi dry steam. A mile of piping was assumed, and the capital cost for this installation was determined to be approximately $10,300,000, or $41 per installed kilowatt. This scenario also has a heat rate penalty of approximately 300 BTU/kW-hr. A more comprehensive study is required to determine if this arrangement provides for sufficient payback for steam energy to be sold to the malting facility.

Infrastructure

Transportation

Each site was reviewed and determination was made regarding required infrastructure improvements necessary for the delivery of fuel, limestone, and ammonia, and the major equipment during construction. These improvements included road and rail needs for the commodities and major equipment delivery.

Road access within the property lines of each site is estimated to be the same. Entrance road requirements, with the exception of the Nelson Creek location, are also all within approximately one-half mile in length and considered equal for each site.

All sites, with the exception of the Nelson creek location, are within reasonable distances from existing Burlington Northern Santa Fe (BNSF) Railroad main line track systems. It is estimated that eight (8) miles of new track installed on an existing railroad bed are required for the Salem site. Five (5) miles of new track and railroad bed would be needed for the Salem Industrial site. Delivery of coal to the Decker site would require the installation of four (4) miles of new track and railroad bed. It is estimated that the Hysham site will require approximately 1.5 miles of new track and railroad bed since this site is adjacent to one of the BNSF main line tracks.

At Nelson Creek, lignite coal would be delivered by way of heavy-haul trucks from the mine, an estimated distance of two (2) miles. In addition, it is estimated that over 45 miles of existing railroad track from Glendive to Circle would need to be upgraded to accommodate the delivery of major equipment. About 26 miles of road improvements would be needed to transfer major equipment by heavy-rigging trucks from the city of Circle, Montana, at the upgraded rail siding to the Nelson Creek site.

Requirements for start-up fuel deliveries were identified and any infrastructure improvements for natural gas and fuel oil were identified. Natural gas will be utilized at the Salem and Hysham sites. Infrastructure development included the installation of a natural gas pipeline from the pipeline source including a tap from the line, metering equipment, and a pressure reduction station on the site. Fuel oil would be utilized at the Nelson Creek and Decker sites. These sites would include a storage tank for oil, fuel oil unloading facilities to accommodate truck deliveries, and fuel-forwarding equipment, including pumps and controls.

Transmission

The purpose of this analysis was to estimate the transmission costs for each of the five (5) site alternatives. References are cited in the text, and are identified in the final part of this section. The transmission analysis is based on the estimated transmission capacity required for each site. This capacity is a function of the assumed maximum net unit output to the high-voltage system and the studies that were made available. The approach to the analysis is summarized below:

Maximum Plant Output Capacity

Each site was assumed to have a single generating unit with a maximum output to the transmission grid on the high-voltage terminals of the generator step-up transformer of 250 MW.

Reliability

The assumed reliability of transmission facilities at each site is based on the North American Electric Reliability Council definitions[1]. Using this criterion, the site must be capable of exporting its entire output with one (1) element (line, transformer, breaker, etc.) out of service (N-1). Therefore, the number of lines from any given site should equal the number of lines required for the total thermal capacity plus one line to allow for the single contingency outage.

Transmission Capacity and Construction

Based on a review of the Montana area transmission system, the following criteria was used to select transmission voltage:

- The voltage must be compatible with existing facilities in the state and not introduce new voltage levels that would require extensive transformations and added costs.
- The voltage should minimize the number of lines to connect the generation to the grid, and therefore, impact on land and environment, as well as being economical.
- The voltage must support a reasonable certainty of stability and capacity.

Using this approach, 230 kV was selected as the transmission voltage to connect the new SME unit with the transmission grid. As specific power flow, fault, and stability analyses are not being performed as a part of this analysis, an estimate of the capability of the proposed line(s) was determined. The maximum line capability is assumed to be the lesser of the line's thermal capability or 2.0 of its Surge Impedance Loading (SIL) for lines between 50 and 100 miles in length with a maximum classical stability angle. The loading limit for lines estimated to be less than 50 miles is 3.0 times SIL[2].

To maintain N-1 reliability, the 230 kV lines are assumed to be of a single-circuit H-frame construction occupying separate rights-of-way.

[1] North American Electric Reliability Council, NERC Planning Standards, Last Revised 2002.
[2] Transmission line Reference Book, 345 kV and Above, Second Edition, Electric Power Research Institute, Palo Alto, Ca, 1982..

Substation Configurations

To meet the criteria above, and to conform to common utility practice, all new substations assume a breaker-and-a-half configuration. If the initial number of breakers is less than required for "full implementation," the bus configuration assumes ring bus operation with eventual expansion to a breaker-and-a-half scheme in the future.

Note that some existing substations are main-and-transfer configurations. To avoid major reconstruction costs for existing facilities, substation additions continue with existing schemes.

There are two (2) separate substation types:

- The generation plant switchyard includes all generator step-up and auxiliary transformer supplies including all line terminals. Only 230 kV construction is assumed. No additional real estate is assumed to be necessary at any proposed location. Figure 2-1 is a preliminary switching diagram of the envisioned generation substation.
- The interconnection substation is defined as the substation at which the identified generation site transmission lines terminate. This is the substation at the opposite end of the lines from the generation substation. A breaker-and-a-half scheme is utilized with initial installation as a ring bus, and is required at any given location. If the interconnection substation is at an existing site, existing breakers are assumed to have sufficient fault capability for the generation additions.

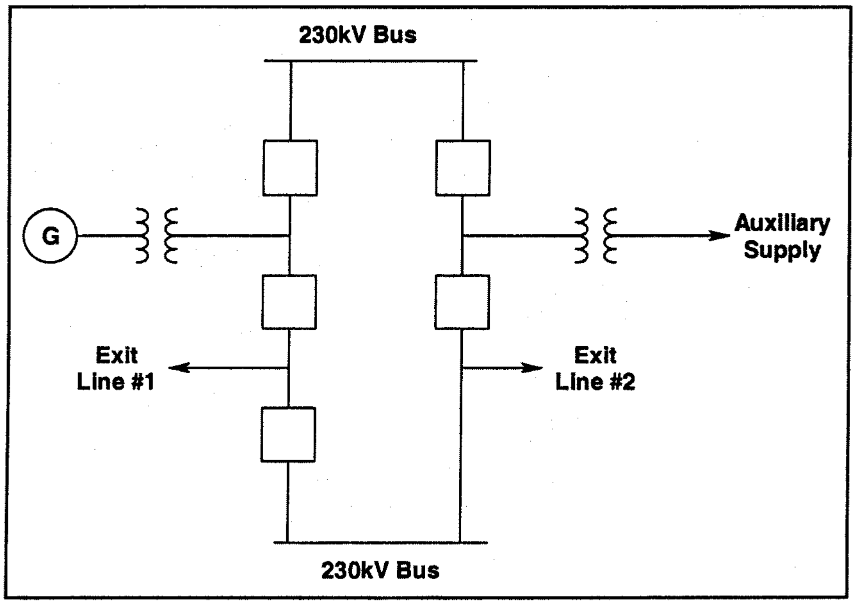

Figure 2-1

Generation Switchyard Conceptual Switching Diagram

General Transmission Support

As with any generation addition, transmission facilities are required to support the general system flows and/or provide alternate load service paths. The location of the new generation causes changes in overall system flow patterns. These facilities are in addition to those that form the actual physical generation connection to the system. For the SME project, there are two (2) major categories of general system requirements:

Subtransmission Support

For the purpose of this analysis, sub-transmission support is defined as the necessary facilities to support the 69 kV and 50 kV networks. These support items will alleviate potential overloads on the higher voltage system due to changing load service patterns. These facilities appear to be required regardless of SME generation location.

- *Crossover - Huntley 230 kV Line:* This 29-mile 230 kV line was identified to address potential overloads of the existing 230 kV system under contingency conditions. This line will require additions to the 230 kV ring buses at both Crossover and Huntley to accommodate the new line.
- *Alkali Creek - South Roundup 69 kV Line:* This 45-mile 69 kV line, with an associated new 69-50 kV autotransformer and 69 kV substation at South Roundup is necessary for service to Fergus Electric Cooperative.

These facilities are assumed "common" to all plans, and are not included in any cost estimates.

Additional support for service to Tongue River Electric Cooperative is envisioned. Tongue River is supplied from tertiary windings on an existing transformer at the existing Colstrip Substation. Alternate sources to improve reliability to this member cooperative are included in the specific transmission plans associated with each site.

High-Voltage Network Support

These facilities are defined as those necessary to support the interconnected transmission grid due to overriding high-voltage system characteristics. These are at voltages exceeding 161 kV. The Montana transmission grid has several issues that are inherent to the existing configuration, as noted in studies performed for various other projects.[3,4,55]

In summary, major power flows are from east to west, and autumn is the most critical season. Past studies have indicated that when total generation additions of approximately 900 MW, located east of the Broadview 500-230 kV Switchyard are installed, the transmission network becomes congested 100% of the time, and

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[3] NorthWestern Energy Stand-alone System Impact Study – entral Montana Electric Power Cooperative Generation Project, dated March 28, 2002.
[4] NorthWestern Energy, Co-existing System Impact Study – Central Montana Electric Power Cooperative Generation Project, dated March 7, 2003.
[5] R. L. McCornish Memorandum to SME Board of Directors, Very Preliminary Load Flow Screening Study for Proposed Nelson Creek Transmission Facilities, dated October 13, 2003.

results in thermal overloads at various system locations. Similarly, there appears to be a limit of approximately 200-250 MW additional generation in the same area to limit the adverse affect of system transient stability. Various additional facilities will need to be constructed, based on the exact location(s) and timing of the generation addition(s). [3,4,6] At minimum, these facilities would include:

- A 200-300 MVAR continuously-acting dynamic shunt reactive device (such as a STATCON) at the Broadview Substation.
- Increase series capacitors at the Broadview-Colstrip and Broadview-Garrison double circuit 500 kV from 2,000A rating to 3,000A rating.
- Install a third 500 MVAR 500-230 kV autotransformer in the Colstrip Substation for the addition of 500 MW in generator terminals at that location.
- Install an approximately 100 MVAR 230 kV switched shunt capacitor at the Crossover Substation.

The additional Colstrip autotransformer is possibly required with the entire generation required to flow at this location as an outlet. If the generation is assumed less and/or the terminals are not all located in the Colstrip switchyard, then this transformer may not be required. Since the studies were completed, NorthWestern Energy has established a policy that does not allow a Remedial Action Scheme (RAS) to be utilized to mitigate system response for a single-contingency outage. Facilities must be added to support the network for N-1.

In the northwestern Montana area, the thermal limitations are approximately the same, but transient stability issues do not appear until additions are made in the 300 MW range.

Based on the existing generation queue seniority, it appears that in-service dates for two (2) proposed projects will most likely precede the SME Project:

- *Big Horn County* -- Approximately 120 MW of coal-fired generation located in Big Horn County, connected to the Hardin Auto Substation.
- *Judith Gap Wind Power Project* -- Approximately 180 MW of wind power located in Judith Basin County will be interconnected at the existing Judith Gap 230-100 kV Substation.

These projects have a combined total output of approximately 300 MW. However, the Judith Gap project would not necessarily be included in eastern Montana transmission concerns. The Big Horn County project alone may not require all of the above-listed projects, but when combined with the SME Project, these minimum facilities would be needed. The relative timing of these projects is critical to which projects would be responsible for the majority of facility additions.

Based on relative project sizes, and the current generation queue project timing, the following facilities will be included for proposed project locations with generation interconnections east of Broadway Substation:

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[6] Telephone conversation with NorthWestern Energy, June 10, 2004.

- A 300 MVAR continuously-acting dynamic shunt reactive device located on the Broadview Substation 230 kV bus.
- Increased ratings for the 500 kV Broadview series capacitors.
- Install a 100 MVAR 230 kV switched shunt capacitor at Crossover Substation.

The Colstrip 500-230 kV autotransformer addition will be included for facilities that have total interconnection at Colstrip due to the 250 MW unit size.

Salem Sites

The two (2) Salem sites are located east and north-northeast of Great Falls, Montana. The area has existing 230 kV, 115 kV, 100 kV, and 69 kV facilities and transmission resources concentrated in the Rainbow and Great Falls Substations. The selected interconnection points are both in the existing Great Falls 230 kV Substation, because no other 230 kV substations are available in the area. Connection to Rainbow Substation would required establishment of a new 230 kV switchyard at significant cost, provided there is physical space. It is assumed that part of the existing Great Falls Substation breaker-and-a-half scheme is reconnected to maximize SME reliability with this arrangement, although not as advantageous as connections at two separate locations. No additional transformation is envisioned for the interconnection since the Great Falls Substation autotransformers currently serve City of Great Falls loads. Future load growth in the City may require upgrade of this transformation capacity as a normal course of system development.

It is assumed that the existing Rosebud Creek autotransformer 230 kV tap will be rebuilt to a 230 kV breaker-and-a-half substation, and expanded to provide an additional transformer to support a source to Tongue River as shown in Figure 2-2.

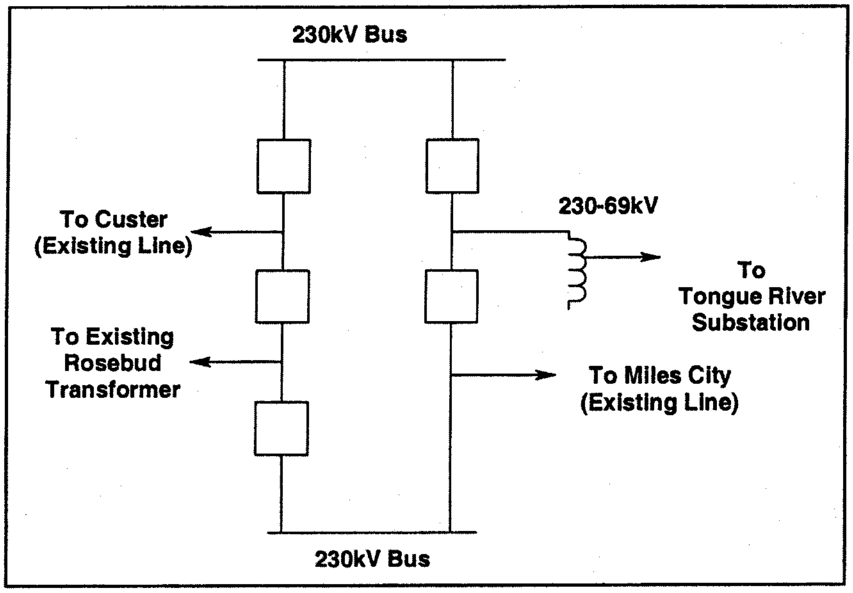


Figure 2-2
Switching Diagram for Rosebud Creek 230 kV Substation with Salem Sites

Decker Site

Due to its relative location on the transmission system, the Decker site has the same terminals as the Nelson Creek Site. The site is located approximately 75 miles south of the existing Miles City-Rosebud-Custer 230 kV transmission system. Transmission connections into Wyoming would not support SME native loads.

The proposed logical alternative to interconnection at Colstrip may be the existing Custer Substation. This would necessitate line routings on Native American lands with associated schedule uncertainties coupled with inherent institutional issues.

The proposed Decker site presents an opportunity to provide direct service to the Tongue River loads. The new Tongue River Substation is constructed with a 230 kV ring bus to provide added SME unit reliability. Full interaction with the Colstrip units must be explored in detail to determine the extent of facility additions.

Hysham Site

The Hysham site is just north of the Colstrip-Broadview 500 kV lines and south of the Rosebud-Custer 230 kV line. As such, it is located in an area of significant transmission resources. The 230 kV system is more advantageous to SME to serve native loads than the 500 kV network. Direct connection to the 500 kV system would be more costly, and have similar direct interaction issues with Colstrip. Selected interconnection points are the existing Rosebud Creek autotransformer 230 kV tap, and the existing Custer Substation. It is assumed that the existing Rosebud Creek autotransformer 230 kV tap will be rebuilt to a 230 kV breaker-and-a-half substation, and expanded to provide an additional transformer to support a source5 to Tongue River as shown in Figure 2-3.

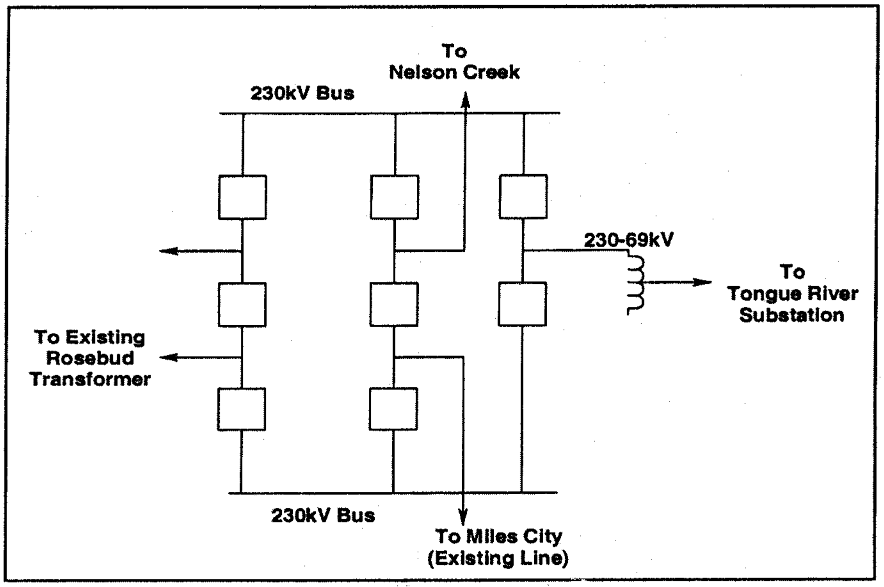


Figure 2-3

Switching Diagram for Expanded Rosebud Creek 230 kV Substation

The other 230 kV circuit is assumed to terminate at the Custer 230 kV main-and-transfer bus. This breaker arrangement is not as reliable as a breaker-and-a-half scheme, but a complete station rebuild would be a significant expense.

With this arrangement, the interaction with Colstrip is less than the Nelson Creek and Decker sites since the connection is through the 230 kV from Custer to Broadview, which has miles of transmission lines combined with the Broadview transformer and 500 kV system impedances. Reactive support at Crossover and Broadview will most likely be required, but the Colstrip autotransformer is not envisioned, since there is no connection to Colstrip.

The new Rosebud autotransformer provides direct service to the Tongue River loads and a new Tongue River Substation is constructed at the end of a radial 69 kV line. As in the other sites, the Tongue River low-voltage connections and transformer are not included in the estimates.

Nelson Creek Site

The Nelson Creek site is located approximately 90 miles north of the existing Miles City-Rosebud-Custer 230 kV system, and approximately 15 miles south of the Ft. Peck-Circle-Dawson County 230 kV transmission system.

Although physically closer to the 230 kV system to the north, utilizing the Ft. Peck area 230 kV system places the generation output on the east side of the Miles City HVDC tie, and would require significant operational changes to deliver capacity by way of the link to the SME loads. Additionally, northern loop flows are constrained due to a system voltage of 161 kV, rather than 230 kV. It would be most practical to connect SME Project output to the 230 kV system to the south of the site.

Transmission interconnection points at the existing Rosebud Creek autotransformer 230 kV tap and at the Colstrip 230 kV Substation have been selected to provide transmission paths to the City of Great Falls, and to support the SME cooperative members' native loads.

It is assumed that the existing Rosebud Creek autotransformer 230 kV tap will be rebuilt to a 230 kV breaker-and-a-half substation as shown in Figure 2-4.

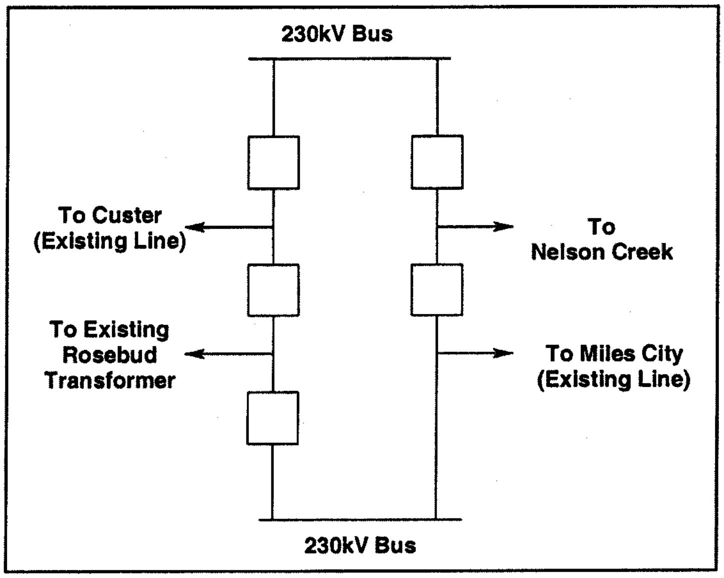


Figure 2-4

Switching Diagram for Rosebud Creek 230 kV Substation

It is assumed that the other 230 kV circuit will terminate at an existing available line terminal area in the Colstrip 230 kV Substation. As indicated in other studies, [3, 4] there is significant interaction between the Colstrip units and new generating facilities with direct connections to Colstrip. Other potential terminals have significant issues including, but not limited to:

- *Miles City* -- Direct interactions with the existing HVDC tie can cause SME transient stability concerns that could preclude this location.
- *Custer Substation* -- Right-of-way and institutional issues may have significant detrimental effect on project schedule.
- *Rosebud Creek* -- If both Nelson Creek 230 kV circuits terminate in the same substation, the result will be an impact to overall plant reliability without significantly mitigating reactions with the Colstrip units.

The Nelson Creek-Colstrip 230 kV line presents the opportunity to provide direct service to the Tongue River loads. The new Tongue River Substation is constructed with a 230 kV ring bus to provide added SME unit reliability. The new autotransformer at Tongue River is not included in the estimates, as full requirements are not known at this time. Full interaction with the Colstrip units must be explored in detail to determine the extent of facility additions.

As stated previously, the northwest Montana transmission system does not have as many restrictions as the generation locations on the eastern part of the state. However, it is envisioned that some added reactive support may be required for SME native load service at Crossover. These facilities are included.

Development Costs

Each of the five (5) locations studied for the proposed generation station requires different site improvements. These locations also have differing operating costs and transmission issues. This section outlines the differences between sites, including both operating and capital cost expenditures.

Fuel Transportation

The coal for the Salem, Decker, and Hysham sites will be supplied by way of rail car from Spring Creek, Decker, or Absaloka Mines, respectively. Each of these sites requires a rail spur from existing railroad tracks for coal supply and for equipment delivery during construction. The Salem site rail spur originates from just north of Malmstrom Air Force Base on an existing rail bed and is approximately eight (8) miles in length. The Salem Industrial site rail spur starts north of the Missouri River, and travels west to the site location. The distance from the site to existing track will require approximately four (4) miles of new track. The Decker site, located approximately four (4) miles north of the Decker mine, requires a new track installation from the existing track located at the mine. An operational railroad track, running north and south, is located immediately east of the Hysham site. The Hysham site requires a rail loop consisting of approximately one-and-one-half (1.5) miles of new track. The Nelson Creek site would utilize lignite coal that is supplied by heavy-haul mine trucks from a new mine located approximately two (2) miles east of the site.

It was determined that the installed cost for new railroad track is approximately $1,500,000 to $2,500,000 per linear mile of track. This price is highly dependant upon the terrain crossed. If a bridge is required for a road, railroad, or stream crossing, the cost is approximately $3,500 per linear foot. For each rail line, a right-of-way 300 feet wide is estimated, at average local land costs. Because there is an existing rail bed for the Salem site, the cost is reduced to $1,000,000 per mile. The results of the cost estimate for new track installation are documented in Table 2-3 entitled "Site Comparison Cost."

Coal cost ranges from $7.21 to $9.75 per ton, depending on the type and quality of coal supplied. Spring Creek Mine coal, used for both Salem sites, costs $7.50 per ton. According to Burlington Northern Santa Fe (BNSF), the cost to transport the coal from the Spring Creek Mine to either of the Salem sites is $10.00 per ton. The West Decker Mine coal costs follow current market value at $7.25 to $7.50 per ton. The current contract obligations are being fulfilled from the west mine. However, if additional contracts are signed, the East Decker Mine will be permitted and opened in order to fulfill the new obligation. This mine has strip ratios that are much higher than the west mine, and will force the cost of that coal to $9.75 per ton. Because the site is close to the mine, the cost for transporting the coal is $2.00 per ton as stated by BNSF. The Absaloka Mine coal costs were quoted at $7.95 per ton. Transportation costs for the Hysham site are the same as for the Decker Mine at $2.00 per ton. A newly-constructed mine at the Nelson Creek site would supply coal for $7.21 per ton. This cost includes the capital cost associated with opening a new mine. All of the coal pricing listed is current pricing, and is subject to escalation. Prices shown in the economic section of this report include escalation of the current prices to future costs.

Transmission

The Salem and Salem Industrial sites would be connected to the Montana distribution grid through the Great Falls Substation, located north of the Missouri River and Great Falls, Montana. The distance from the Salem site to this substation is approximately nine (9) miles. The Decker, Hysham, and Nelson Creek sites would be connected to the Montana distribution grid through the Rosebud Substation. The Rosebud Substation is located approximately 111 miles east of Billings, Montana, on Interstate 94. The Decker site is approximately 80 miles from the Rosebud Substation. The Hysham site is approximately 34 miles from the Rosebud Substation. The Nelson Creek site would require the greatest amount of transmission line to connect to the Rosebud Substation at a distance of 90 miles. The Hysham Site would also interconnect with the Custer Substation, which is located approximately 53 miles east of Billings, Montana. The Decker and Nelson Creek sites would also interconnect with a new Tongue River Substation, which would be located east of the existing Colstrip Power Plant. The transmission lines carry 230 kV power from the generating station to the respective substations.

The estimated construction costs are conceptual and representative of the upper Midwest. Cost estimates are based on the following:

- *Substations* – Includes estimated major equipment costs plus 20% undeveloped design details to account for unspecified equipment or facilities plus 15% contingency for variations in base costs.
- *Transmission Lines* – Includes estimated structures, conductor, and major line equipment costs plus 15% contingency for variations in the base costs. Substation terminations are included with the substation costs.
- *System Analysis* – Facilities identified in this analysis are representative of facilities for the type of generation being considered. The generation is assumed to be a network resource and require firm transmission service. No detailed system analysis was performed. Detailed analysis will be performed as part of specific system impact and facility studies. These specific studies may identify alternative and/or additional facility responsibilities based on the relative project generation and transmission queue and prevailing conditions at the time of the studies.

Table 2-2 illustrates the estimated cost to upgrade various transmission infrastructure components based on the proposed site selection. Transmission line costs reflect the approximate cost to install the transmission lines identified from the generating station to the substations.

Table 2-2
Transmission Facilities Cost Estimate

Facility (Substation)	Salem	Decker	Hysham	Nelson Creek
Great Falls	$2,000,000			
Rosebud Creek	$4,350,000	$4,350,000	$5,960,000	$4,350,000
Tongue River		$2,100,000		$2,000,000
Colstrip		$830,000		$830,000
Custer			$955,000	
Other[B]	$3,300,000	$33,700,000	$3,300,000	$33,700,000
Transmission Lines	$15,600,000	$45,860,000	$57,360,000	$63,970,000
Estimated Total[A]	**$25,250,000**	**$86,840,000**	**$67,575,000**	**$104,950,000**

[A] Cost estimates are for major equipment only and include a 15% contingency.

[B] Estimated "common" high-voltage facilities for sties located generally to the east of the Broadview 500-230 kV Substation.

The estimated transmission facility costs documented above are included in the Table 2-3 entitled "Site Comparison Cost."

Water Transportation

Make-up water for each plant location will be supplied from local rivers or reservoirs. The Salem sites would obtain water from an intake structure upstream of the Morony Dam on the Missouri River. The distance from this dam to the Salem and Salem Industrial sites is approximately 5 miles and 17 miles, respectively. The Decker site would utilize water from the Tongue River Reservoir located approximately 11 miles to the south of the proposed location. The water supply for the Hysham site would be from the Yellowstone River, located approximately 9 miles to the north of the proposed site. The Nelson Creek site requires a 41-mile pipeline to the Fort Peck Reservoir for the supply of make-up water. The intake location will be close to the reservoir dam site in order to maintain sufficient water level for the intake pumps.

The infrastructure required to supply water to the generating station includes an intake structure, vertical turbine pumps, supply pipeline, electrical equipment, cable, and duct bank. The estimated cost for an intake structure including excavation, shoring, concrete, electrical equipment, and pumps is approximately $1,500,000. Pipeline installation costs were estimated to be $45,000 per inch per mile or $540,000 per mile for the expected make-up water flow rate, documented on the preliminary water balance diagrams. This cost includes the equipment, material, trenching, construction, right-of-way, and project and construction management of this phase of the project. A second pipeline for discharge of the wastewater would be needed. This line would convey wastewater with expected quantities as documented on the preliminary water balance diagram from the plant locations to the river or reservoir used for make-up water. The total cost for installing both pipelines is approximately $810,000 per mile. The installation cost for the water transportation infrastructure is found in Table 2-3, entitled "Site Comparison Cost."

Each plant location required an expected make-up water quantity of 3,000 gallons per minute or 4,850 acre-feet per year. The water purchase cost for the Salem sites is $0.16 per 100 cubic feet or water. This equals an annual operations cost of approximately $337,300 for either Salem site. The cost to obtain water rights at the Decker, Hysham, and Nelson Creek sites is estimated at $1,250 per acre-foot for the life of the plant. This cost is reflected as a capital cost investment of $6,250,000.

Land

Land costs for each of the proposed sites vary from $731 per acre to $8,000 per acre. The Salem Industrial site, located in an area that has utility service from the City of Great Falls, Montana, has a high land cost at $8,000 per acre. The Salem site land cost is considerably less at just over $1,000 per acre. Land cost at Decker and Hysham averages at $731 per acre. The total land cost for the nelson Creek site is $750,000. Total land cost for each of the sites is documented in Table 2-3, "Site Comparison Cost."

General Infrastructure Cost

Miscellaneous costs associated with construction, equipment delivery, and coal handling are included as general infrastructure costs as documented in Table 2-3. Delivering coal to the plants requires the use of bottom-dump rail cars that must be purchased or leased. For this study, capital cost for the rail cars is estimated at $60,000 per car. For Powder River basin coal, deliveries are made utilizing a train composed of 110 cars. The capital expenditure for the proposed sites utilizing rail as the coal delivery method is approximately $6,600,000.

Housing facilities that would accommodate the construction craft trades during the construction activities near the Decker and Nelson Creek sites are limited. To accommodate expected construction personnel, a man-camp must be built to house and provide support facilities for construction crews. Approximately 250 construction personnel will require housing during construction. The cost for housing was based on double-occupancy, and 250 square feet per person. Estimated cost for housing is $100.00 per square foot, or a total cost of approximately $6,250,000.

Major equipment delivery to the Nelson Creek site is by rail to Circle, Montana, and road to the site. The rail track from Glendive, Montana, to Circle, Montana, is in need of repair, estimated at $500,000 per mile. The total cost for this repair is approximately $23,700,000. Road access to the Nelson Creek site is limited to two-lane State Highway 24, which necessitates road improvements for the major equipment and material delivery. The heavy-rigging truck traffic, which will be required for this delivery, will need to travel a different route to the site than State Highway 24. This route will be an unnamed gravel road, located north of the proposed site west of Circle, Montana. Cost included in the study for improvements to the access road from Circle, Montana, to the site, is estimated at $21,677,000.

Limestone, Ammonia, and Start-Up Fuel

Limestone delivery to each of the plants would be by rail or truck from the Montana Limestone Company. The cost of the limestone as quoted on the Montana Limestone website is $6.75 per ton. Delivery costs for each of the proposed sited would vary based on the type of transportation required. Costs range from $6.00 per ton as quoted by BNSF for rail transportation to $31.40 per ton as quoted by Warren Transportation in Billings, Montana, for truck transportation.

Delivered anhydrous ammonia from Agrium costs $325 per ton as delivered by rail to each site with the exception of Nelson Creek. The ammonia usage for each proposed plant site at full load is anticipated to be less than one (1) ton per day.

Start-up fuel for the Salem, Salem Industrial, and Hysham sites, will be supplied by existing natural gas pipeline located near each site location. Capital and operational costs were estimated for pipeline infrastructure and fuel for each site. The Decker and Nelson Creek sites will use No. 2 fuel oil for start-up operations. The fuel oil will be supplied by truck deliveries to the plant. Necessary infrastructure for unloading, storage, and forwarding of the oil to the CFB was developed and costs were estimated. The cost for fuel delivery and infrastructure is documented in Table 2-3, "Site Comparison Cost."

Table 2-3
Site Comparison Cost

Capital Costs	Units	Salem	Salem Industrial	Decker	Hysham	Nelson Creek
Plant Cost	USD	$ 376,100,000	$ 376,100,000	$ 373,100,000	$ 397,900,000	$ 419,700,000
Fuel Infrastructure	USD	$ 8,000,000	$ 7,800,000	$ 5,800,000	$ 1,500,000	$ -
Transmission Cost	USD	$ 25,600,000	$ 25,600,000	$ 88,600,000	$ 68,500,000	$ 107,000,000
Water Cost	USD	$ 5,100,000	$ 15,300,000	$ 10,100,000	$ 8,700,000	$ 36,600,000
Water Rights Cost	USD	$ -	$ -	$ 6,250,000	$ 6,250,000	$ 6,250,000
Land Cost	USD	$ 260,000	$ 2,040,000	$ 50,000	$ 150,000	$ 750,000
General Infrastructure Cost	USD	$ 6,600,000	$ 6,600,000	$ 12,900,000	$ 6,600,000	$ 51,700,000
Start-up Infrastructure Cost	USD	$ 600,000	$ 300,000	$ 117,500	$ 400,000	$ 117,500
Site Installation Cost[B]	**USD**	$ 46,200,000	$ 57,700,000	$ 123,900,000	$ 92,100,000	$ 202,500,000
Total Installed Cost[C]	**USD**	$ 422,300,000	$ 433,800,000	$ 497,600,000	$ 490,000,000	$ 622,200,000
Incremental Cost to Salem[A]	**USD**	$ -	$ 11,500,000	$ 75,300,000	$ 67,700,000	$ 199,900,000
Net Power Output	**KW**	252,000	252,000	252,000	252,000	252,000
Net Heat Rate (HHV)	**BTU/kW-hr**	9,580	9,580	9,530	9,830	10,040
Cost Per Installed KW	**USD/kW**	$ 1,676	$ 1,721	$ 1,975	$ 1,944	$ 2,469
Operating Cost						
Fuel Cost	USD/Ton	$17.50	$17.50	$11.75	$9.95	$7.21
Water Rights Cost	USD/Year	$340,000.00	$340,000.00	$0.00	$0.00	$0.00
Limestone Cost	USD/Ton	$15.64	$15,64	$26.55	$12.82	$38.15
Ammonia Cost	USD/Ton	$325.00	$325.00	$325.00	$325.00	$325.00
Start-up Fuel Cost	USD/mmBTU	$6.41	$6.41	$7.40	$6.41	$7.40

[A] Compared to the base case of the Salem site.

[B] Summaries are rounded up.

[C] Does not include Interest During Construction (IDC).

Schedule

Stanley Consultants reviewed each site to determine if any of the site development activities, fuel transportation, and transmission infrastructure improvements noted above would result in schedule impacts for the project. There are no schedule impacts which will affect the baseline project schedule developed in Section 5, "Project Schedule."

Section 3

Environmental Issues

This section defines the environmental issues for the proposed project, identified by Stanley Consultants. A discussion of the agencies having jurisdiction, and any rules that must be satisfied, is included. A permit matrix, including associated costs and a permit schedule, has been developed.

Montana Major Facility Siting Program

Regulated Activities

A Certificate of Environmental Compatibility may be required from the Montana Department of Environmental Quality (MDEQ) for major facilities that generate or transmit electricity, or transmit fuels or coal slurry by pipeline. Associated facilities, such as transportation links, aqueducts, diversion dams, transmission substations, and other facilities associated with the delivery of energy, are included.

In general, electrical transmission lines greater than 69 kV may be covered under the Siting Act if they meet certain criteria. All electrical transmission lines of 230 kV or more, and 10 miles or more in length, are covered under the Siting Act. Pipelines greater than 25 inches in inside diameter that are at least 50 miles long may be covered under the Siting Act, if they meet certain criteria. The following types of facilities are included.

- Electric transmission lines and associated facilities with design capacity of more than 69 kilovolts, except:
  - Electric transmission lines and associated facilities with design capacity of 230 kilovolts or less and 10 miles or less in length; or
  - Electric transmission lines with a design capacity of more than 69 kilovolts but less than 230 kilovolts, for which the entity planning to construct the line has obtained right-of-way agreements or options for a right-of-way from more than 75% of the owners who collectively own more than 75% of the property along the centerline; or

- Electric transmission lines less than 150 miles in length, extending from an electrical generation facility to the point at which the transmission line connects to a regional transmission grid at an existing transmission substation, or other facility for which the entity planning to construct the line has obtained right-of-way agreements or options for a right-of-way from more than 75% of the owners who collectively own more than 75% of the property along the centerline.

- Pipelines greater than 25 inches in inside diameter and 50 miles in length, and associated facilities except:
  - A pipeline that is used exclusively for the irrigation of agricultural crops or for drinking water; or
  - A pipeline greater than 25 inches in inside diameter and 50 miles in length for which the entity planning to construct the pipeline has obtained right-of-way agreements or options for a right-of-way from more than 75% of the owners who collectively own more than 75% of the property along the centerline

Application Requirements

An applicant for a certificate under the Montana Major Facility Siting Act must file an application with the MDEQ. Information concerning the need for the transmission line or pipeline, the proposed location, baseline data, and reasonable alternate locations, must be included in the application. Applications typically include the following information.

- A description of the proposed location and of the facility to be built.
- A summary of any pre-existing studies that have been made of the impact of the facility.
- A statement explaining the need for the facility, a description of reasonable alternate locations for the facility, a general description of the comparative merits and detriments of each location submitted, and a statement of the reasons why the proposed location is best suited for the facility.
- Baseline data for the primary and reasonable alternate locations.

An application must also be accompanied by proof that public notice of the application was given to persons residing in the county in which any portion of the proposed facility is proposed, or is alternatively proposed to be located, by publication of a summary of the application in those newspapers that will substantially inform those persons of the application.

Appeal of Department Decisions

Decisions of the MDEQ may be appealed to the Board of Environmental Review. Decisions of the Board of Environmental Review may be appealed to state district court.

Fees

The applicant for a certificate under the Montana Major Facility Siting Act is required to deposit a filing fee based on the estimated cost of the project in an earmarked revenue fund for use by the MDEQ to administer the act. The MDEQ may contract with the applicant for payment of the fee or the applicant must pay the fee in installments.

Findings for Certification

The MDEQ shall approve a transmission line or pipeline facility as proposed, or as modified, or an alternative to the proposed facility, if it finds and determines the need for the facility; the nature of probable environmental impacts; that the facility minimizes adverse environmental impact considering the state of available technology and the nature and economics of the various alternatives; what part, if any, would be located underground; that the location of the proposed facility conforms to applicable state and local laws; that the facility will serve the public interest, convenience, and necessity; that the MDEQ has issued all necessary decisions, opinions, orders, certifications and permits; and that the use of public lands for location of the facility is evaluated and public lands are selected whenever their use is as economically practicable when compared to the use of private lands.

Air Quality

The proposed facility will be subject to numerous Federal and State air quality regulations. This report section identifies the primary air quality regulatory requirements that must be addressed to construct and begin operation of the power plant. Furthermore, a screening analysis has been conducted as a preliminary assessment of impacts from these regulatory requirements; the results of which will be used in the overall site selection process. The environmental analysis considered the emissions from the proposed circulating fluidized bed (CFB) boiler only as this is the prime driver of the permitting and regulatory compliance requirements. Other emission sources, such as the dust generated by the coal, lime, and ash handling systems, auxiliary and/or emergency power systems, and road traffic, were not specifically quantified, but will need to be addressed as part of the overall environmental permitting of the facility.

For the most part, the identified air quality requirements are addressed through a permitting process administered by the MDEQ. However, there are some additional regulatory requirements that either do not need a permit, or only require the filing of a notification to the United States Environmental Protection Agency (USEPA). In addition, there are federal and state performance standards established for the control of pollutants from the proposed facility that must be incorporated into the engineering design. These requirements fall into the following general categories:

Permitting Requirements

- New Source Review – Prevention of Significant Deterioration (40 CFR Part 52.21 and Administrative Rule of Montana 17.8.800).
- Title IV Acid Rain Permit Program (40 CFR Part 72 & Part 75).
- Title V Operating Permit Program (40 CFR Part 70 and Administrative Rule of Montana 17.8.1200).
- Performance Standards.
- New Source Performance Standards; Standards of Performance for Electric Steam Generating Units Which Construction is Commenced After September 18, 1978 (40 CFR Part 60 Subpart Da).
- Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary

Sources: Electric Utility Steam Generating Units; Proposed Rule (40 CFR Part 60 & Part 63).

Regulatory Programs

- Risk Management Program (40 CFR 68)

Permitting Requirements

New Source Review – Prevention of Significant Deterioration

The New Source Review (NSR) program is the most significant air quality environmental driver for the construction of this project. The NSR program has two (2) primary categories of requirements, the applicability of which depends on the air quality of the region where the project is to be constructed. If the ambient air quality in the region of the project is in attainment with National Ambient Air Quality Standards (NAAQS), then the NSR Prevention of Significant Deterioration (PSD) program is applicable. If the ambient air quality in the region of the project is not in attainment with NAAQS, then the NSR Non-Attainment program requirements apply. Stanley Consultants has reviewed the attainment status of the Salem, Salem Industrial, Decker, Hysham, and Nelson Creek sites against the MDEQ non-attainment area listings. While several non-attainment areas do exist in Montana, none of the proposed project sites are within these non-attainment areas, or are likely to significantly impact a non-attainment area. Therefore, a facility sited in any of the proposed locations would be subject to the NSR-PSD program requirements only, and would not be subject to any NSR Non-Attainment program requirements. Areas of attainment are further subdivided into Classes I, II, and III areas. Class I areas are pristine areas, such as national parks, forests, and monuments; Class III areas are those areas where air quality is not a concern and substantial deterioration would be acceptable; Class II areas are all other locations, and make up the majority of the attainment areas within the U.S. All of the proposed project sites are in Class II areas. Impacts to Class I areas will need to be assessed as part of the NSR-PSD permitting program.

There are several elements of the PSD program that potentially impact the scope of the project, and, therefore, the selection of the most suitable site. These elements are specified by regulation both in the Code of Federal Regulation (CFR) and the Administrative Rules of Montana. Additional USEPA and MDEQ guidance policy is also applicable where the regulations are not specific or are otherwise unclear on these particular matters. Overall, the following major elements of the PSD program were reviewed for applicability and impact to the project.

- Identification of Best Available Control Technology (BACT)
- Analysis of Ambient Air Impacts and Consumption of PSD Increment
- Analysis of Visibility Impacts
- Performance of Ambient Air Monitoring

Identification of Best Available Control Technology

Any major stationary source or major modification subject to PSD must conduct an analysis to ensure the application of BACT. The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act (Act), in federal regulation

40 CFR 52.21(j), in regulations setting forth the requirements for State Implementation Plan (SIP), approval of a State PSD program at 40 CFR 51.166(j), and in the SIP's of the various states at 40 CFR Part 52, Subpart A - Subpart FFF. The BACT requirement is defined as:

> *"…an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."*

The evaluation and selection of appropriate emission controls is performed on a case-by-case, pollutant-by-pollutant basis within the PSD permitting process. This procedure involves five (5) steps:

- Identify all emission control technology alternatives and process alternatives.
- Eliminate any control options that are not technically feasible for use with the type of source being considered.
- Rank remaining emission control technologies from the most effective to the least effective.
- Determine the economic, energy and other environmental impacts of each control technology and eliminate any technology with unacceptable impacts.
- Select the remaining most effective control technology.

In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent, "top" alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

It is important to note that while a BACT analysis is done on a case-by-case basis that, after the location of the site has been established to be in an attainment area, the impact of the facility on ambient air is not considered in the BACT analysis. All other design factors remaining the same, the resulting BACT determination will not differ among the proposed project sites. Stanley Consultants conducted a review of the most recent BACT determinations for CFB boilers in the United States, which is summarized in Table 3-1. Although not a CFB boiler, the Roundup Power Project, owned by Bull Mountain Development Company, and located approximately 12 miles south-southeast of the town of Roundup, Montana, was also reviewed. This project is the most recently-permitted coal-fired boiler in Montana and provides a more site-specific comparison that may be indicative of MDEQ's and the local public's expectations.

A review of the BACT determinations shown in Table 3-1 indicates a general consensus among various State Agencies on emission limitations for each of the criteria pollutant emissions for CFB boilers. Some variability exists simply due to the averaging periods used to demonstrate compliance with the performance standard. For example, a higher standard is generally correlated to a shorter averaging period. One noticeable difference, however, are the two facilities with a significantly lower SO_2 emission standard than the others. Both the AES-Puerto Rico facility and the proposed NEVCO facility in Utah have established SO_2 emission rates of one-third or less of the otherwise consensus 0.15 lb/mmBTU emission rate. This may be due, in part, to the lower sulfur coal (0.5%S to 0.9%S) to be used at these facilities. Although the identified control technology for these two units is a "circulating dry scrubber," (CDS) upon closer technical review the CDS does not appear to be fundamentally different than the spray dry absorption specified on the other CFB boilers.

Table 3-2 documents the calculated emissions from the SME proposed CFB using the current consensus BACT emission limitations. SO_2 emissions are shown first using the 0.15 lb/mmBTU BACT rate. A second SO_2 emission rate was also calculated based on the Alstom Flash Dryer Absorber / Fabric Filter (FDA/FF) Flue Gas Desulphurization System Proposal, which specified an emission control performance of 20 ppmvd SO_2. The ultimate analysis of the various coals proposed for the SME facility indicates an expected sulfur content of 0.4 % by weight.

Table 3-1
Recent BACT Determinations for Circulating Fluidized Bed (CFB) Coal Fired Boilers

Facility Name	JAE Northside Generating Station	Kentucky Mountain Power	East Kentucky Power	AES-PRCP	Indeck-Elwood	NEVCO Energy	Roundup Power
State	Florida	Kentucky	Kentucky	Puerto Rico	Illinois	Utah	Montana
Permit Date	7/14/1999	4/19/2000	2/14/2002	4/2/2002	4/7/2003	9/10/2003	1/16/2002
Capacity	297.5 MW	250 MW	270 MW	227MW	330 MW	270 MW	780 MW
Technology	CFB	CFB	CFB	CFB	CFB	CFB	PC
Emission Rates							
NO_X, lb/mmBTU	0.09	0.07	0.10	0.10	0.10	0.10	0.10
CO, lb/mmBTU	--	0.27	0.15	0.10	0.10	0.12	0.15
PM_{10}, lb/mmBTU	0.011	0.015	0.015	0.015	0.015	0.016	0.015
VOC, lb/mmBTU	--	0.0072	--	--	0.004	0.005	0.003
SO_2, lb/mmBTU	0.2	0.13	0.2	0.022	0.15	0.05	0.15
Pollutant Controls							
NO_X	SNCR	SNCR	SNCR	SNCR	SNCR	SNCR	SCR
CO	GCP	GCP	GCP	GCP	GCP	GCP	GCP
PM_{10}	FF	FF	FF	FF	FF	FF	FF
VOC	GCP	GCP	GCP	GCP	GCP	GCP	GCP
SO_2	Not Available	NIDS	SDA	CDS	NIDS	CDS	DFGD

LEGEND

GCP	Good Combustion Practices
SNCR	Selective Non-Catalytic Reduction
FF	Fabric Filter (Baghouse)
NIDS	Natural Integrated Desulphurization System
SDA	NIDS + Spray Dry Absorber
CDS	NIDS + Circulating Dry Scrubber
DFGD	Dry Flue Gas Desulphurization

Table 3-2

Estimated Emission from SME Proposed CFB Boiler

		CASE			
Load		100%	100%	38%	38%
Season		Summer	Winter	Summer	Winter
Criteria Pollutants	**Units**				
NO_X Rate, Controlled (SNCR)	lb/mmBTU	0.1000	0.1000	0.1000	0.1000
NOx Rate, Controlled (SNCR)	lb/hr	239.68	239.68	91.08	91.08
NOx Rate, Controlled (SNCR)	ton/yr	1049.80	1049.80	398.93	398.93
CO Rate, Uncontrolled	lb/mmBTU	0.1500	0.1500	0.1500	0.1500
CO Rate, Uncontrolled	lb/hr	359.52	359.52	136.62	136.62
CO PTE, Uncontrolled	ton/yr	1574.70	1574.70	598.39	598.39
VOC Rate, Uncontrolled	lb/mmBTU	0.0030	0.0030	0.0030	0.0030
VOC Rate, Uncontrolled	lb/hr	7.19	7.19	2.73	2.73
VOC PTE, Uncontrolled	ton/yr	31.49	31.49	11.97	11.97
PM_{10} Rate, Controlled (FF)	lb/mmBTU	0.0150	0.0150	0.0150	0.0150
PM_{10} Rate, Controlled (FF)	lb/hr	35.95	35.95	13.66	13.66
PM_{10} PTE, Controlled (FF)	ton/yr	157.47	157.47	59.84	59.84
SO_2 Rate, Uncontrolled	lb/mmBTU	0.81804	0.81804	0.81804	0.81804
SO_2 Rate, Uncontrolled	lb/hr	1960.68	1960.68	745.06	745.06
SO_2 PTE, Uncontrolled	ton/yr	8587.79	8587.79	3263.37	3263.37
SO_2 Rate, Controlled	lb/mmBTU	0.1500	0.1500	0.1500	0.1500
SO_2 Rate, Controlled	lb/hr	359.52	359.52	136.62	136.62
SO_2 PTE, Controlled	ton/yr	1574.70	1574.70	598.39	598.39
SO_2 Control Efficiency	%	82%	82%	82%	82%
Alstom SO_2 Rate, Controlled	ppmvd	20.00	20.00	20.00	20.00
Alstom SO_2 Rate, Controlled	lb/hr	90.96	90.95	43.35	43.35
Alstom SO_2 Rate, Controlled	lb/mmBTU	0.0379	0.0379	0.0476	0.0476
Alstom SO_2 PTE, Controlled	ton/yr	398.38	398.37	189.86	189.87
Alstom SO_2 Control Efficiency	%	95%	95%	94%	94%
H_2S0_4 Rate, Controlled	lb/mmBTU	0.0064	0.0064	0.0064	0.0064
H_2S0_4 Rate, Controlled	lb/hr	15.34	15.34	5.83	5.83
H_2S0_4 PTE, Controlled	ton/yr	67.19	67.19	25.53	25.53

PTE – Potential To Emit
SNCR – Selective Non-Catalyic Reduction
FF – Fabric Filter

This results in an 82% SO_2 removal efficiency required to achieve 0.15 lb/mmBTU and a 95% removal efficiency to achieve 20 ppmv (equivalent to 0.038 lb/mmBTU). The Alstom proposal also specified a NO_X emission rate of 0.10 lb/mmBTU, which is consistent with the BACT consensus emission rate. Based on this review, it would appear that the CFB configuration, with the proposed emission control, meets the current consensus BACT emission limitations.

Analysis of Ambient Air Impacts

Any facility subject to PSD must demonstrate that the impacts from the facility emissions will not exceed any ambient air quality standards. These standards are established in the current Code of Federal Regulations and the Administrative Rule of Montana. There are three (3) area classifications for ambient air. Class I areas are the most highly protected areas and carry the strictest standards. The allowable pollutant increases are significantly less in a Class I area than a Class II area. Additionally, protection from visibility impairment is also provided to Class I areas. The following areas have been designated Class I areas within the State of Montana:

- Bob Marshall Wilderness Area;
- Anaconda Pintler Wilderness Area;
- Cabinet Mountains Wilderness Area;
- Gates of the Mountains Wilderness Area;
- Glacier National Park;
- Medicine Lake Wilderness Area;
- Mission Mountains Wilderness Area;
- Red Rock Lake Wilderness Area;
- Scapegoat Wilderness Area;
- Selway-Bitterroot Wilderness Area;
- UL Bend Wilderness Area; and
- Yellowstone National Park.

The following three (3) areas have been designated as Class I by EPA and may be re-designated to another class only by EPA:

- Northern Cheyenne Reservation;
- Flathead Reservation; and
- Fort Peck Reservation.

The remaining area in Montana is designated Class II (there are no Class III areas designated in Montana). All of the proposed study sites are located in Class II designated areas. The closest Class I area to each study is:

- Salem Site: 51.8 miles (83.3 km)
- Salem Industrial Site: 46.5 miles (74.8 km)
- Decker Site: 13.2 miles (21.3 km)
- Hysham Site: 37.4 miles (60.2 km)

- Nelson Creek Site: 34.2 miles (55.0 km)

Compliance with these standards is determined by performing air dispersion modeling and, if necessary, ambient air monitoring, in accordance with Federal and State regulations and agency guidelines. Air dispersion modeling results establish the predicted increase in concentration of pollutants in the ambient air from the operation of the proposed facility. These increases are first evaluated pollutant by pollutant to determine if they are significant impacts. If increases are below significant impact levels, then compliance with the ambient air quality standard has been satisfactorily demonstrated. If instead, the predicted increased pollutant concentration is above significant impact levels then further analysis is necessary. To complete this analysis, the predicted increase from the new sources must be added to all other third-party increases and decreases that have occurred since the establishment of the baseline date. This effort usually requires obtaining emission inventory data from the state agency and performing air dispersion modeling for the entire study area. The modeled increases are then compared to the "allowable PSD increment" to ensure that unacceptable ambient air quality degradation will not occur (e.g. "Prevention of Significant Deterioration"). Second, these calculated project increases are added to the area baseline pollutant concentrations in the ambient air and compared to the associated ambient air quality standard for each criteria pollutant. The level of baseline pollutant concentrations is determined by ambient air monitoring, which is normally required prior to the construction of the facility.

Different air dispersion modeling techniques are often required when evaluating impacts to Class I areas at less than 50 km or greater than 50 km. In particular, this is necessary when assessing potential impairment to the Class I area visibility standards and when compliance with the allowable Class I PSD increment consumption is being assessed from facilities that are more than 31 miles (50 km) away. This analysis of Class I impacts is further discussed later in this section.

To determine the area baseline pollutant concentrations, site-specific ambient air monitoring may be required. USEPA and Montana regulations specify threshold values where, if air dispersion modeling indicates an exceedance, requirements for pre-construction ambient air monitoring are triggered. Otherwise, other available regional ambient air monitoring data may be used. If required, the amount and duration of ambient air monitoring is determined in coordination with the regulatory agency. The Administrative Rule of Montana stipulates that a minimum of four (4) months is required and up to twelve (12) months of pre-construction ambient air monitoring data may be necessary.

Stanley Consultants utilized the calculated emission rates in Table 3-2 to assess the potential impacts to ambient air from the CFB at the Salem, Salem Industrial, Decker, and Hysham sites. The analysis includes results using the consensus BACT and Alstom proposed SO_2 emission rates previously identified. Site-specific terrain and meteorological data were used in the modeling study. The results of the modeled impacts within the Class II areas are shown in Table 3-3 and compared to the appropriate significant impact levels, PSD allowable increment consumption, and ambient air monitoring thresholds previously described. Impacts to the Class I areas are addressed later in Table 3-4.

Analysis of Consumption of PSD Increment

Table 3-3 documents the Class II area modeled ambient air impacts from the CFB emissions. From this analysis, the following conclusions can be made:

- Both Salem sites and the Hysham site are below significant impact thresholds for CO, NO_X, PM_{10}, and SO_2 at the 20 ppm SO_2 emission rate.

- If the permitted SO_2 emission rate is closer to the PSD BACT consensus limit of 0.15 lb/mmBTU, then additional modeling to evaluate compliance with the PSD increment and ambient air quality standards for SO_2 would be required for all sites.
- The Decker site would need to perform additional modeling analyses to demonstrate compliance with PSD increment for both NO_X and SO_2 emissions. Compliance with the PSD increment standard would depend on the PSD increment consumed by other emission sources in the area, which were not analyzed within this study. This preliminary analysis also indicates that ambient air monitoring would likely be required for the Decker site under the 0.15 lb/mmBTU SO_2 emission rate.
- Both Salem sites show the least impact to the ambient air. Given that the same boiler configuration is used for all study sites, the differences are attributable to the flatter terrain in the region and local meteorology of the Salem area. Because the Salem sites consume much less of the available increment, there is the greatest room for future growth of the facility in these two locations.

It is very important to note that this analysis only includes the emissions from the CFB and does not include emissions from other sources at the proposed facility. These activities, which might include coal handling and storage, are predominantly sources of PM/PM_{10} emissions. It is possible that with the addition of these emission sources, additional air dispersion modeling for PM/PM_{10} may still be required at any of the sites.

Table 3-3
Class II Area Air Quality Impact Analysis

Pollutant	CO		H_2SO_4	NO_X	PM_{10}		SO_2			SO_2		
Emission Rate	0.15 lb/mmBTU		0.0064 lb/mmBTU	0.10 lb/mmBTU	0.015 lb/mmBTU		0.15 lb/mmBTU			0.0379 lb/mmBTU (20 ppmvd)		
	1-hr	8-hr	1-hr	Annual	24-hr	Annual	3-hr	24-hr	Annual	3-hr	24-hr	Annual
Site												
Decker	156.16	39.38	6.66	1.08	2.53	0.16	79.71	25.29	1.62	20.14	6.39	0.41
Hysham	118.28	27.91	5.05	0.60	1.12	0.09	60.14	11.15	0.91	15.20	2.82	0.23
Salem	62.62	14.61	2.67	0.98	0.71	0.15	34.85	7.13	1.46	8.81	1.80	0.37
Salem Industrial	52.35	12.45	2.23	0.72	0.88	0.11	22.37	8.79	1.07	5.65	2.22	0.27
Ambient Air Standards & PSD Thresholds												
Significant Impact Level	2000	500	N/A	1.00	5.00	1.00	25.00	5.00	1.00	25.00	5.00	1.00
PSD Class II Increments	N/A	N/A	N/A	25.00	30.00	17.00	512	91.00	20.00	512	91.00	20.00
PSD Pre-Construction Monitoring Trigger Concentrations	N/A	575.0	N/A	14.00	10.00	N/A	N/A	19.00	N/A	N/A	19.00	N/A
National Ambient Air Quality Standards	35 ppm	9 ppm		0.053 ppm	150 ug/m^3	150 ug/m^3	0.5 ppm	0.14 ppm	0.03 ppm	0.5 ppm	0.14 ppm	0.03 ppm
Montana Air Quality Standards	23 ppm	9 ppm	0.05 ppm	0.05 ppm	150 ug/m^3	50 ug/m^3		0.010 ppm	0.02 ppm		0.010 ppm	0.02 ppm

(All values in ug/m^3 unless otherwise shown)

Analysis of Visibility Impacts

PSD regulations require that all Class I areas within 62.1 miles (100 km) of a proposed site be evaluated for potential ambient air and visibility impacts. While this regulation still remains, Federal Land Managers (FLM) have unilaterally extended the analysis area up to 186.4 miles (300 km), presumably using their authority under the Clean Air Act to object to the issuance of PSD permits. By example, the Bull Mountain project performed an impact analysis for Class I areas up to 124.3 miles (200 km) of their facility and other projects outside of Montana have evaluated Class I impacts up to the full 186.4 miles (300 km). For this study, Stanley Consultants analyzed impacts only upon the closest Class I area. A 300 km study radius at the Salem site, for example, would include eleven Class I areas, each of which may potentially require an impact analysis during the PSD permitting analysis.

The Federal Land Manager Air Quality Related Values Work Group (FLAG) has provided guidance in the form of recommendations, specific prescriptions, and interpretation of results for assessing visibility impacts of sources near Class I areas. The guidance addresses assessments for sources proposed for locations at large distances (greater than 50 km) from these areas. It also recommends impairment thresholds and identifies the conditions for which cumulative analyses of all increment-consuming sources would be necessary. This guidance and procedure has been adopted within the past few years as the methodology to assess visibility and Air Quality Related Values (AQRV) for all Class I areas. In prior years, only a VISCREEN modeling analysis and an increment consumption analysis was required for Class I area evaluations for most new sources.

In general, FLAG now recommends that an applicant:

- Consult with the appropriate regulatory agency and with the FLM for the affected Class I area(s) or other affected area for confirmation of preferred procedures and for the need for a cumulative analysis.
- Obtain Federal Land Manager recommendation for the specified reference levels (estimate of natural conditions) and, if applicable, FLM recommended plume/observer geometries and model receptor locations.
- For regions of the Class I area where visibility impairment from the source could cause a general alteration of the appearance of the scene (generally 50 km or more away from the source or from the interaction of the emissions from multiple sources), apply a non steady-state air quality model with chemical transformation capabilities (currently considered to be CALPUFF), which yields ambient concentrations of visibility-impairing pollutants. At each Class I receptor: calculate the change in extinction due to the source being analyzed, compare these changes with the reference conditions, and compare these results with the thresholds developed by FLAG. If necessary, calculate the cumulative change in extinction due to new source growth.

The new methodology involves an extensive analysis utilizing the CALPUFF dispersion model. The CALPUFF evaluation is very time-consuming and labor intensive. The development of the meteorology alone for the CALPUFF model requires a highly-skilled meteorologist to interpret various meteorological factors. It is recommended that this refined analysis should be conducted only at the time of the permit application and not as a screening method for this evaluation.

To initially evaluate the impact on visibility, the VISCREEN model was run for Decker, Hysham, and Salem sites to determine if the new sources would trigger a requirement for additional visibility analyses. The results of the VISCREEN model indicate that there are no conditions that would result in the exceedance of the acceptable change in extinction or the change in contrast for either sky or terrain within and outside of the Class 1 area.

To better reflect the current accepted methodology required by the FLMs, a recommended screening approach using the CALPUFF model was used to evaluate the emissions and locations associated with power generation at the four (4) alternate locations. This approach was outlined by the Interagency Workgroup on Air Quality Modeling and published in the report "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts"[21.] Within that report, the following screening methodology is recommended:

1. Generate five years of ISCST3 input meteorology using PCRAMMET.
2. Generate an ISCST3 control file and use the ISC2PUF conversion program to create the CALPUFF control file.
3. Use the CALPUFF Graphical User Interface to finalize the CALPUFF control file before running the CALPUFF model.
4. Place Receptors at least every two degrees on rings that encircle the source and pass through the Class 1 area of interest.
5. Run CALPUFF with the ISCMET.DAT data option
6. For haze, use maximum 24-hour SO_4, NO_3, and HNO_3 values; assume 90% relative humidity, calculate extinction coefficients for each pollutant; and compute the percent change in extinction using the FLM supplied background extinction.
7. For total sulfur or nitrogen deposition, convert deposition flux to kg/ (hectare-year) using maximum values of annual SO_2, SO_4, NO_3, HNO_3, and NO_X.

CALPUFF was run using default options and the ring of receptors as recommended. Estimated annual average natural background levels of aerosols for western states was taken from Table 2.B-2 of the "The Federal Land Manager Air Quality Related Values Work Group (FLAG) Phase 1 Report, December 2000." Other specific parameters for humidity were taken from data collected at Gates of the Mountains Wilderness Area.

To interpret the results of the modeling, FLAG recommends the following:

- If the estimated increase in visibility impairment attributed to the proposed project is equal to or greater than 10%, compared against natural conditions, for at least one modeled day, then the FLM will consider the magnitude, frequency, duration, and other factors to assess the impact, but is likely to object to the issuance of the permit.
- If the estimated increase in visibility impairment attributed to the proposed project is equal to or greater than 10%, then the analysis should proceed to the next step (Note that if the single-source contribution is always <0.4%, no further analyses are required).
- If a cumulative analysis does not exist, and if there are no other requirements for a cumulative analysis, and if a new or modified source can demonstrate that its contribution to a change in extinction is less than 5.0%, compared against natural

[1] EPA 454/R-98-019, December, 1998

conditions, for all days, then the FLM is not likely to object to the issuance of the PSD permit based on visibility impacts.

- If the single-source contribution to a change in extinction is equal to or greater than 5.0% or if a cumulative analysis already exists or is required for some other reason, then the analysis should proceed to the next step and estimate its contribution to cumulative impacts.

The results of the CALPUFF screening analysis of the four (4) alternative sites are shown in Table 3-4. The model pollutant concentrations are significantly below the Class I Area PSD increment thresholds and, while this analysis does not include the contributions from other sources toward the consumption of the PSD Class I increment, it does indicate a strong likelihood that each facility would be able to demonstrate compliance with this PSD requirement. For visibility, the screening analysis indicates that there may be conditions that will exceed FLAG recommended levels for visibility. Interestingly, the Decker site shows the lowest number of exceedances even though it is the closest to a Class I area. While more analysis is necessary to fully understand this outcome, it is perhaps likely due to the elevation differences between the facility and Class I areas. Decker is at a higher elevation than the Class I area while the other sites are at a lower elevation relative to the nearest Class I area. Obviously this analysis is a very conservative approach, since it considers all wind directions, maximum terrain height, and steady-state meteorology. If the 0.0379 lb/mmBTU (20 ppm) SO_2 emission rate is achievable, then the exceedances are rather few and likely could be eliminated with the full CALPUFF analysis. This determination is based on the very conservative assumptions used in this screening analysis and the steady-state meteorology required for the screening model, combined with observations based upon previous visibility evaluations involving coal-fired power plants. Under the 0.15 lb/mmBTU, SO_2 emission rate, the Hysham and Salem Industrial sites will not cause extinction changes in excess of 5% or 10%. In all instances, this screening analysis indicates that the full CALPUFF analysis will probably be required for any option to obtain PSD approval from the FLM to construct the plant.

Table 3-4
Class I Area Air Quality Impact Analysis

	Decker	Hysham	Salem	Salem Industrial	PSD Class I Increment
Distance to Nearest Class I Area	21.3 km	60.2 km	83.3 km	74.8 km	
NO_X annual	0.17 μg/m^3	0.09 μg/m^3	0.05 μg/m^3	0.09 μg/m^3	2.5 μg/m^3
PM_{10} 24-hr 1st high	0.33 μg/m^3	0.15 μg/m^3	0.10 μg/m^3	0.91 μg/m^3	N/A
PM_{10} 24-hr 2nd high	0.24 μg/m^3	0.12 μg/m^3	0.08 μg/m^3	0.85 μg/m^3	8 μg/m^3
PM_{10} annual	0.04 μg/m^3	0.02 μg/m^3	0.01 μg/m^3	0.14 μg/m^3	4 μg/m^3
SO_2 at 0.0379 lb/mmBTU (20 ppmv)					
SO_2 3-hr 1st high	2.14 μg/m^3	1.39 μg/m^3	0.90 μg/m^3	1.17 μg/m^3	N/A
SO_2 3-hr 2nd high	1.73 μg/m^3	1.22 μg/m^3	0.80 μg/m^3	0.92 μg/m^3	25 μg/m^3
SO_2 24-hr 1st high	0.43 μg/m^3	0.37 μg/m^3	0.25 μg/m^3	8.77 μg/m^3	N/A
SO_2 24-hr 2nd high	0.40 μg/m^3	0.28 μg/m^3	0.18 μg/m^3	0.25 μg/m^3	5 μg/m^3
SO_2 annual	0.04 μg/m^3	0.05 μg/m^3	0.03 μg/m^3	0.05 μg/m^3	2 μg/m^3
Visibility Delta-Deciview ≥ 0.5	6 days	16 days	11 days	13 days	
Visibility Delta-Deciview ≥ 1.0	0 days	1 days	1 days	1 days	
Visibility Extinction Change ≥ 5%	6 days	18 days	12 days	12 days	
Visibility Extinction Change ≥ 10%	0 days	1 days	1 days	1 days	
SO_2 at 0.150 lb/mmBTU					
SO_2 3-hr 1st high	8.44 μg/m^3	5.51 μg/m^3	3.54 μg/m^3	4.63 μg/m^3	N/A
SO_2 3-hr 2nd high	6.85 μg/m^3	4.83 μg/m^3	3.16 μg/m^3	3.63 μg/m^3	25 μg/m^3
SO_2 24-hr 1st high	1.71 μg/m^3	1.45 μg/m^3	0.99 μg/m^3	1.37 μg/m^3	N/A
SO_2 24-hr 2nd high	1.57 μg/m^3	1.10 μg/m^3	0.71 μg/m^3	1.00 μg/m^3	5 μg/m^3
SO_2 annual	0.32 μg/m^3	0.20 μg/m^3	0.12 μg/m^3	0.18 μg/m^3	2 μg/m^3
Visibility Delta-Deciview ≥ 0.5	10 days	32 days	22 days	35 days	
Visibility Delta-Deciview ≥ 1.0	0 days	3 days	3 days	7 days	
Visibility Extinction Change ≥ 5%	11 days	33 days	25 days	36 days	
Visibility Extinction Change ≥ 10%	0 days	4 days	3 days	8 days	

Performance of Ambient Air Monitoring

The Administrative Rules of Montana also contain regulations for determining ambient air monitoring requirements, which establish visibility conditions within the Class I area prior to construction and operation. The rule does provide agency discretion for requiring visibility monitoring, however, the following waiver is codified as follows:

> "The department may waive the requirements of (1), (2), and (3) of this rule if the value of "V" in the equation below is less than 0.50 or, if for any other reason which can be demonstrated to the satisfaction of the department, an analysis of visibility is not necessary.
>
> $$V = (\text{Emission})\ ½ \div \text{Distance}$$
>
> Where: Emissions = emissions from the major stationary source or major modification of nitrogen oxides, particulate matter, or sulfur dioxide, whichever is highest, in tons per year.
>
> Distance = distance, in kilometers, from the proposed major stationary source or major modification to each federal Class I area."

From Table 3-2, the highest annual emission rate is for NO_X at 1049 tons/year. At this emission rate, the minimum distance to qualify for the waiver is 64.77 km. As shown in Table 3-4, both Salem sites are more than this distance from a Class I area. The Hysham site is just within this threshold distance and the Decker site is well within this threshold distance. Therefore, the possibility of preconstruction visibility monitoring for the Decker is likely while the need for preconstruction visibility monitoring for the Hysham site is uncertain. It is unlikely that preconstruction visibility monitoring for either Salem site would be necessary.

Title IV Acid Rain Permit Program

Title IV of the Clean Air Act Amendments of 1990, established the regulatory basis governing SO_2 and NO_X emissions, the precursors of acid rain, from fossil fuel-fired power plants. Also known as the Acid Rain Program, the Act set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants.

Phase I began in 1995 with a total number of affected units currently at 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on the large, higher emitting plants and set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing over 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 megawatts and all new utility units. The Act also called for a 2 million ton reduction in NO_X emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers through the installation of low NO_X burner technologies in order to meet the new emissions standards. The CFB proposed by Alstom will have a NO_X performance standard that meets the current NO_X emission standards under the Acid Rain Program.

SO_2 allowance trading is the centerpiece of EPA's Acid Rain Program and allowances are the currency with which compliance with the SO_2 emissions requirements are achieved. An allowance authorizes a unit within a utility or industrial source to emit one ton of SO_2 during a given year or any year thereafter. At the end of each year, the unit must hold an amount of allowances at least equal to its annual emissions, i.e., a unit that emits 5,000 tons of SO_2 must hold at least 5,000 allowances that are usable in that year. However, regardless of how many allowances a unit holds, it is never entitled to exceed the limits set under Title I of the Act to protect public health.

Allowances are fully marketable commodities. Once allocated, allowances may be bought, sold, traded, or banked for use in future years. Allowances may not be used for compliance prior to the calendar year for which they are allocated. Units that began operating in 1996 or later are not allocated allowances. Instead, they have to purchase allowances from the market or from the EPA auctions and direct sales to cover their SO_2 emissions.

The EPA SO_2 allowance auction is a blind auction hosted by the Chicago Board of Trade. Allowances can be bought for the current year or a future credit can be bought, usable in the 7th year. The highest price of the winning bid in 2004 was \$300 per ton SO_2 for the current year and the highest price of a winning bid for the 7-year future was \$129.11. A total of 125,000 tons was available for auction in 2004 and SME would only need about 400 tons operating at maximum capacity for 8,760 hours per year. SO_2 allowances can also be bought on the spot market, the price of which varies much like any other commodity in response to market demand and availability.

Based on the SO_2 emission rate of 0.038 lb/mmBTU (20 ppmvd) and an SO_2 credit price of \$300 per ton per year, the SO_2 allowance cost is \$0.006 per million BTU per year. Operating at a full load of 8,760 hours per year, the current SO_2 allowance cost would be approximately \$120,000 per year.

EPA's role in allowance trading is to record allowance transfers that are used for compliance and to ensure at the end of the year that a unit's emissions do not exceed the number of allowances it holds. To accomplish this, EPA maintains an Allowance Tracking System (ATS). Each affected utility unit, corporation, group, or individual holding allowances has an account in the ATS. Parties must notify EPA to have transfers recorded in their ATS account, but it is not necessary to record all transfers with EPA until such time that the allowances are to be used to meet a unit's SO_2 emissions limitation requirement. ATS accounts are, however, the official records for allowance holdings and transfers used for compliance purposes. To facilitate tracking and recording, EPA assigns every account an identification number and every allowance a serial number.

Title V Operating Permit

Congress created the operating permit program to ensure better compliance and to allow for more thorough air pollution control. Prior to 1990, the federal Clean Air Act required permits only for new construction. With Title V of the 1990 Clean Air Act Amendments, Congress adopted measures that require all states to develop and implement operating permit programs. In doing so, Congress hoped to eliminate any potential confusion associated with the various air pollution emission reduction programs required by the federal Clean Air Act and different state and local regulations. Under Title V, EPA established minimum elements to be included in all state and local operating permit programs. EPA modeled its air pollution operating permit program after pre-existing state and local operating permit programs and after a similar program which has proven successful under the Clean Water Act for permitting the discharge of water pollutants. EPA officially launched the operating permit effort in 1992 with regulations for implementing such programs. Nationally, an estimated 22,000 sources of air pollution are required to obtain permits under operating permit programs administered by 113 state, territory, and local permitting authorities.

All "major" stationary sources emitting regulated air pollutants are required to obtain operating permits. Whether a source meets the definition of "major" depends on the type and amount of air pollutants it emits and whether the facility is located in an attainment or non-attainment area. In an attainment area, major sources include those stationary facilities that emit 100 tons or more per year of a regulated air pollutant or they have the potential to emit 25 tons per year of all Hazardous Air Pollutants (HAP) or 10 tons of any single HAP.

The purpose of Title V permits is to reduce violations of air pollution laws and improve enforcement of those laws. Title V permits do this by:

- Recording in one (1) document all of the air pollution control requirements that apply to the source. This gives members of the public, regulators, and the source a clear picture of what the facility is required to do to keep its air pollution under the legal limits.
- Requiring the source to make regular reports on how it is tracking its emissions of pollution and the controls it is using to limit its emissions. These reports are public information.
- Adding monitoring, testing, or record keeping requirements, where needed to assure that the source complies with its emission limits or other pollution control requirements.
- Requiring the source to certify each year whether or not it has met the air pollution requirements in its Title V permit. These certifications are public information.
- Establishing the terms of the Title V permit as federally enforceable. This means that EPA and the public can enforce the terms of the permit, along with the State.

Based on the calculated emissions in Table 3-1, the SME facility will require a Title V Operating Permit. Montana has chosen an approach for Title V permitting that combines the application process together with the preconstruction (PSD in this case) permit application. Therefore, one (1) submittal encompassing both the PSD and Title V permitting requirements will be necessary. While this may create additional work initially in the process, it does offer the benefit of a more streamlined approach by reducing the redundancy of the overlapping requirements between the two (2) permitting programs including the public comment provisions.

Performance Standards

In addition to the permitting requirements identified in this report, the proposed facility will be subject to several air quality-related performance standards codified in federal regulation pursuant to the Clean Air Act. The two (2) primary regulations affecting SME are the New Source Performance Standards (NSPS), 40 CFR Part 60, and the National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63.

New Source Performance Standards

A series of NSPS have been promulgated regulating boiler emissions. The applicability of the standards depends on the size and construction date of the boiler. For the SME CFB, the applicable NSPS standard is 40 CFR 60 Subpart Da – Standards of Performance for

Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. This NSPS regulation establishes performance standards for emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NO_X) from boilers with a heat input greater than 250 mmBTU/hr. The PSD regulations stipulate that, "In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61." Therefore, NSPS establishes the minimum standard that must be met. Table 3-5 shows the NSPS limits and, when compared to the consensus BACT determinations in Table 3-2, it is apparent that the BACT determination for the SME CFB will likely result in much lower emission limits than stipulated by NSPS Subpart Da.

Table 3-5

NSPS Standards for Boilers > 250 mmBTU/hr When Firing Solid Fuel

Pollutant	Standard	Alternate Standard
PM	0.03 lb/mmBTU *and* 1 % of potential combustion concentration (99% reduction).	N/A
SO_2	1.20 lb/mmBTU *and* 10% potential combustion concentration (90% reduction).	0.60 lb/mmBTU and 30% potential combustion concentration (70% reduction).
NO_X	0.50 lb/mmBTU for Subbituminous coal 0.60 lb/mmBTU for Bituminous coal 0.06 lb/mmBTU for Anthracite coal *and* 65% reduction of potential combustion concentration	N/A

In addition NSPS specifies requirements for initial startup notification, stack testing, compliance monitoring (including continuous emission monitoring e.g. CEMS), recordkeeping, and reporting as measures for ensuring ongoing compliance with the emission standards.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

The Clean Air Act requires EPA to regulate emissions of toxic air pollutants from a published list of industrial sources referred to as "source categories." As required under the Act, EPA has developed a list of source categories that must meet control technology requirements for these toxic air pollutants. The EPA is required to develop regulations for all industries that emit one or more of the pollutants in significant quantities. Electric Steam Generating Units have been identified as a source category and the EPA has currently proposed standards regulating HAP emissions from these units, which is currently open for public comment until June 29, 2004. The NESHAP, as proposed, intends to regulate mercury emissions from coal fired boilers and nickel emissions from oil fired boilers. Because the final rule has not been promulgated, it remains unclear exactly what form the final standards will take. This is particularly true for standards for mercury emissions where alternative rules to mercury reduction are being proposed including a “cap and trade” program whereby mercury emission allowances would be bought and sold in a manner similar to SO_2 allowances under the Acid Rain Program. EPA believes that market factors would then be used to drive the installation and reduction of mercury emissions rather than establishing source specific control requirements.

Until the EPA finalizes this NESHAP, a site-specific determination would be necessary for the SME facility in accordance with Section 112(j) of the Clean Air Act. This rule requires states to establish case-by-case maximum achievable control technology (MACT) in a source’s permit, if EPA has not finalized the air toxics standard that applies to the source before the permit is issued. Case-by-case MACT requires the state to set emission limits on a facility-by-facility basis. In order to do so, SME may need to submit a “Part 2 application” as part of its PSD/Title V permit application. The proposed rule currently has identified a nickel emission standard of 0.008 lb/MWh when firing fuel oil. For coal combustion, the mercury emission standard is based on the coal type as shown in Table 3-6.

Table 3-6
Propose Hg Emission Limit Coal-Fired Electric Steam Generating Units

Coal Type	Hg Emission Limit (10^{-6} lb/MWh)
Bituminous-fired	6
Sub-bituminous-fired	20
Lignite-fired	62
IGCC unit	20
Coal refuse-fired	1.1

Several case-by-case MACT determinations have been performed for other recently permitted coal fired boilers including those listed in Table 3-1. These determinations, including the one for the Bull Mountain facility in Montana, have concluded that the emission control technologies applied as BACT have met the case-by-case MACT determination standard and that no additional control technologies were required. Based on this precedent, it would appear that additional mercury controls will not be required for the SME facility in order to comply with the Proposed NESHAP for New and Existing Stationary Sources: Electric Utility Steam Generating Units.

Regulatory Programs

There are several regulatory programs that the SME facility will be subject to once operations begins. One air quality program, known as the Risk Management Program Rule, requires the development of plans and regulatory submittals prior to operation of the unit and therefore additional information is provided herein.

Risk Management Program

When Congress passed the Clean Air Act Amendments of 1990, it required EPA to publish regulations and guidance for chemical accident prevention at facilities using extremely hazardous substances. The Risk Management Program Rule (RMP Rule) was written to implement Section 112(r) of these amendments. The rule, which built upon existing industry codes and standards, requires companies of all sizes that use certain flammable and toxic substances to develop a Risk Management Program, which includes a(n):

- Hazard assessment that details the potential effects of an accidental release, an accident history of the last five (5) years, and an evaluation of worst-case and alternative accidental releases;
- Prevention program that includes safety precautions and maintenance, monitoring, and employee training measures; and
- Emergency response program that spells out emergency health care, employee training measures and procedures for informing the public and response agencies (e.g. the fire department) should an accident occur.

Compliance includes the requirement to prepare a summary of the facility's risk management program (known as a "Risk Management Plan" or "RMP") and submit the RMP to EPA, which will make the information publicly available. The plans must be revised and resubmitted every five (5) years. For a new facility, the owner/operator must have the RMP complete and submitted to the EPA prior to the delivery on-site of the regulated flammable or toxic substances regulated by the RMP Rule.

The Risk Management Program is about reducing chemical risk at the local level. This information helps local fire, police, and emergency response personnel (who must prepare for and respond to chemical accidents), and is useful to citizens in understanding the chemical hazards in communities. EPA anticipates that making the RMPs available to the public stimulates communication between industry and the public to improve accident prevention and emergency response practices at the local level.

Based on the BACT review (Table 3-2) it can be expected that the CFB will require add-on NO_X control in the form of selective non-catalytic reduction (SNCR). SNCR requires the injection of ammonia into the flue gas stream to reduce NO_X to N_2 and H_20. The ammonia used may be one of several forms such as anhydrous, aqueous, or urea. Ammonia in the anhydrous or aqueous form is subject to the RMP rule if stored at levels above the threshold quantity.

Water Supply

Appropriation Process

Water rights in Montana are guided by the prior appropriation doctrine, that is, first in time has the first in right. A person's right to use a specific quantity of water depends on when the use of water began. The first person to use water from a source established the first right, the second person could establish a right to the water that was left, and so on. During dry years, the person with the first right has the first chance to use the available water to fulfill that right. The holder of the second right has the next opportunity. Water users are limited to the amount of water that can be used beneficially.

Any person planning a new or additional development for a beneficial use of water from surface water or ground water after June 30, 1973, must obtain a Permit to Appropriate Water, or file a Notice of Completion of Ground Water Development to obtain a Certificate of Water Right. The permit system is administered by the Department of Natural Resources and Conservation (DNRC). Beneficial uses of water include domestic, livestock, irrigation, lawn and garden, mining, municipal, industrial, commercial, agricultural spraying, fisheries, wildlife and recreation.

The DNRC administers the portions of the Montana Water Use Act that relate to water uses after June 30, 1973. The DNRC trains water commissioners and determines water measuring techniques. The DNRC also provides technical information and assistance to the Water Court, which is responsible for adjudicating water rights that existed before July 1, 1973. The Water Court decides any legal issues certified to it by the DNRC that may arise in connection with processing permit or change applications or in disputes filed in the District Courts. A District Court can issue injunctive relief while it certifies water rights issues to the Water Court for a decision. The DNRC also maintains a central records system for all permits, changes, and certificates issued after June 30, 1973, and for all existing water rights filed as part of the statewide adjudication.

Surface Water

An applicant must apply for and receive a Permit to Appropriate Water before beginning to construct diversion works or diverting water from a surface water source. The applicant for a permit must provide the following evidence:

- The design and operation of the proposed system.
- The physical availability of water within the source.
- The effects of the proposed use on existing water rights.
- A demonstration that water quality will not be adversely affected.
- An analysis of the effects of existing water rights on the water supply within the source.

The exception to this law is for small livestock pits or reservoirs located on non-perennial flowing streams that will hold less than 15 acre-feet of water with an annual appropriation of less than 30 acre-feet and will be located on a parcel of land 40 acres or larger, provided that the reservoir will not adversely affect prior water rights.

Additional criteria must be addressed if the application is for appropriations of 4,000 or more acre-feet and 5.5 or more cubic feet per second (cfs). These include clear and convincing evidence that:

- The criteria described above are met.
- The rights of a prior appropriator will not be adversely affected.
- The proposed appropriation is a reasonable use.

A finding must be based on a consideration of the following:

- The existing demands on the state water supply, as well as projected demands, such as reservations of water for future beneficial purposes, including municipal water supplies, irrigation systems, and minimum stream flows for the protection of existing water rights and aquatic life
- The benefits to the applicant and the state
- The effects on the quantity and quality of water for existing beneficial uses in the source of supply
- The availability and feasibility of using low-quality water for the purpose for which application has been made
- The effects on private property rights by any creation of or contribution to saline seep
- The probable significant adverse environmental impacts of the proposed use of water as determined by the DNRC

The application process includes the submission of DNRC Forms 600 and 600B and the required supplemental information necessary to demonstrate that the above criteria have been met. The DNRC also requires the completion of an environmental impact statement under the provisions of Title 75, chapter 1, for applications that would result in the consumption of 4,000 acre-feet a year or more and 5.5 cubic feet per second or more of water. This would be in addition to the forms and information usually required.

Ground Water

An applicant does not need to apply for a permit to develop a well with an anticipated use of 35 gallons a minute or less, not to exceed 10 acre-feet a year. Following submission of appropriate notice to the Bureau of Mines and Geology and information submitted to the DNRC, a Certificate of Water Right will be issued to the well owner for the specified use.

An applicant anticipating to use more than 35 gallons a minute or 10 acre-feet a year of ground water is required to obtain a Permit to Appropriate Water before any development begins or water is used. A prospective water user must follow the procedure described above (for surface water) to acquire a water use permit. As with surface water additional criteria must be addressed if the application is for appropriations of 4,000 or more acre-feet and 5.5 or more cfs.

The Surficial aquifers are often very productive, and yield high quality water. Bedrock aquifers, although widely used throughout Montana, are generally less productive and yield lower quality water.

There are geologic formations within the general age groups that are not used as aquifers. They are either impermeable and do not transmit water readily, or they contain water that is unfit for use. East of the Rocky Mountains, there are large expanses of land underlain by impermeable shale. One of these areas is north of Great Falls.

In general, the highest quality and most accessible ground water comes from aquifers contained in unconsolidated sediments and there are a number of aquifers that are widely used and considered principal sources of ground water in Montana. These aquifers consist of Quaternary and Tertiary age unconsolidated sediments, typically sand and gravel called surficial aquifers, and consolidated sedimentary rocks of three principal age groups, referred to as Cenozoic rocks, Mesozoic rocks, and Paleozoic rocks collectively called bedrock aquifers. Aquifers can occur as individual geologic layers, entire geologic formations, or groups of formations.

All these aquifers are at or near the land surface, and are called surficial aquifers. These aquifers are composed mostly of unconsolidated sediments deposited by streams, glaciers, or meltwater from glaciers. Included in this group are alluvial aquifers found in major stream valleys throughout the state; glacial till and outwash aquifers found in many tributary stream valleys; and terrace and pediment gravel aquifers scattered throughout central and eastern Montana. Surficial aquifers can be tapped by shallow wells and typically provide adequate water supply for most domestic and agricultural purposes. The availability of sufficient water for industrial purposes varies between locations.

In the central and eastern Montana project area, surficial aquifers are found within the valleys of major rivers and their tributaries. These include the Yellowstone, Tongue, and Missouri Rivers, among others. Alluvium in the river valleys consists of gravel, sand, silt, and clay. Deposits of these sediments vary in thickness from a few feet to over 100 feet, and in many of the larger stream valleys, are potentially several miles in width. Surficial aquifers typically yield 5 to 50 gallons per minute (gpm), although yields as high as 1500 gpm are possible in some locations where alluvial deposits are both thick and extensive and along major river systems.

The surficial aquifers closest to any of the potential sites are reported to be directly adjacent to the nearest large river system, within the river valley. In other words the surficial aquifer nearest to the Salem, and Nelson Creek sites are alluvial deposits along the Missouri River, the surficial aquifer nearest the Hysham site is alluvial deposits along the Yellowstone River, and the surficial aquifer nearest to the Decker is alluvial deposits adjacent to the Tongue River.

Aquifers within consolidated geologic formations are called bedrock aquifers. These are generally composed of siltstone, sandstone, and limestone. These geologic formations are found at various depths below the land surface, varying from hundreds to thousands of feet. Bedrock aquifers are frequently used for water supply in central and eastern Montana, typically in those parts of the state where surficial unconsolidated aquifers are limited in thickness or absent.

The principal bedrock aquifers in the project area are situated within Cenozoic, Mesozoic, and Paleozoic age rocks, listed from youngest to oldest respectively. Various individual rock formations within these age groups serve as the water sources.

Wells finished in Cenozoic rocks typically vary in depth from 50 to 300 feet, although depths of over 1000 feet are reported, and typically yield 15 to 25 gpm, although yields of over 100 gpm have been reported. Water quality is reportedly fair to poor. The Decker site is located in an area where Cenozoic rocks are the uppermost bedrock aquifer.

Mesozoic rocks would be found below the Cenozoic rocks. Wells finished in Mesozoic rocks typically vary in depth from 100 to 1000 feet, although depths of over 5000 feet are reported, and typically yield 5 to 30 gpm, although yields of over 200 gpm have been reported. Water quality is reportedly fair to poor. The Salem, Hysham, and Nelson Creek sites are located in areas where Mesozoic rocks are the uppermost aquifer, although the Salem Industrial site is located along the boundary between the Mesozoic aquifer system and the shale layer north of Great Falls which does not serve as a water supply.

All of the proposed project sites are underlain by Paleozoic age rocks. These underlie the Mesozoic age rocks and are extensive throughout central and eastern Montana. Wells finished in Paleozoic rocks typically vary in depth from 500 to 3000 feet, although depths of over 7000 feet are reported, and typically yield 20 to 6000 gpm. The highest yields are reported in karst areas, which are areas with extensive sinkholes and springs. Water quality is reportedly fair to very bad, with the lowest quality water reported in northeast Montana.

Some controlled groundwater areas have additional restrictions. The Decker site is located in the Powder River Basin Controlled Groundwater Area. In a controlled groundwater area, anyone wishing to drill a well must first apply for and receive a Permit for Beneficial Water Use. This applies to any size and type of appropriation, including wells to be used at less than 35 gallons per minute (GPM) and less than 10 acre-feet per year. In the case of the Decker site the restriction includes all formations above the Lebo member of the Fort Union Formation (Cenozoic age rocks), and applies only to wells designed and installed for the extraction of coal bed methane.

Changes in Water Use

To protect all water rights, prior approval from the DNRC is required before changing an existing water right, permit, certificate or water reservation in any of the following ways:

- Point of diversion
- Place of use
- Purpose of use or
- Place of storage

An applicant must submit an Application for Change of Appropriation Water Right, form 606, to the DNRC and include information on the water right to be changed and the proposed change. In addition, the applicant must provide evidence that the criteria for appropriations described above are satisfied. An application for change follows the same general process for notice and hearing as a new appropriation. If a proposed change in purpose or place of use for a diversion results in 4,000 or more acre-feet and 5.5 or more cubic feet per second of water being consumed, the applicant must prove the criteria described for new appropriations.

Potential Water Sources

The following section summarizes the information obtained from the DNRC and other sources, regarding available water near each of the proposed sites. The water quantity required for this project is a continuous flow of approximately 3000 gallons per minute, or approximately 7 cfs, or approximately 5000 ac-ft per year.

Water allocations are issued for both flow rate and total annual usage. Accordingly an irrigation collective may have a high flow allocation but relatively low total annual allocation because they are a seasonal user. Municipalities and industrial users have an annualized (or balanced) allocation as this would better suit their usage patterns. This will limit the source of users who may have allocations a power plant can buy or lease, as a guaranteed continuous flow is necessary to prevent the facility from being shut down during dry weather by a senior user (one with an earlier claim).

Salem

The most likely water source for this site is an intake on the Missouri River near the proposed sites. One proposed project site location was south of the Morony Dam (the Section 36 location), which will require the installation of an intake near the dam. The other proposed project site location is upstream in Great Falls, which will require the installation of an intake near that site. According to the DNRC, any diversion above Morony Dam is subject to the Upper Missouri River Closure, a statutorily closed area for new appropriations. A new diversion below the dam lies out of the closed area and the DNRC described the chances for successfully obtaining an allocation as fairly good. The DNRC regional office director indicated that if the project needed to purchase or lease water rights ARCO in Great Falls has some water rights that may be available. The US Bureau of Reclamation has rights to water in the Canyon Ferry Reservoir (upstream) that may be available (he said probably only a slim chance though). He also indicated that the City of Great Falls might be able to lease or sell the necessary flow. The file information indicates Great Falls has sufficient rights for the project. ARCO Environmental Remediation also has rights, which are sufficient to satisfy the project requirements. Subsequent contact with the City of Great Falls indicated that the City could sell the necessary quantity of water for the project.

Decker

The most likely potential water source for this site is an intake at the northern end of the Tongue River Reservoir. This location is served by the smallest watershed of any of the sites. A review of the DNRC file information suggests that this stream appears to be heavily allocated. Average daily flow at the Tongue River dam during 2002 (a dry year) was 136 cfs. Allocations and claims on file total more than the average daily flow such that many junior users received less water than they wanted or were cut off during that time. Releases from the reservoir may have been increased during low flows to satisfy some of the downstream needs. Major allocations on the Tongue include DNRC (the largest of the allocations, most likely for environmental purposes), the Northern Cheyenne Tribe, the US Government (BIA), and several large irrigators. The coal mines in the area all have allocations, but all are insufficient for use by the proposed project.

Hysham

The most likely potential water source for this site is an intake on the Yellowstone River a few miles downstream from Hysham. According to DNRC, there is a large appropriation of water in the Yellowstone River. In other words much of the available water is already allocated. The large allocations are the Yellowstone River Water Reservations granted in 1978 to the Department of Fish, Wildlife and Parks for in stream flows, Conservation Districts for Irrigation, and municipalities all within the Yellowstone River basin system. If the flows in the Yellowstone River fall below the in-stream flow amounts established by the Board of Natural Resources in 1978 and the Department of Fish, Wildlife and Parks make a call for this water, then all junior water users (post 12/15/1978) could not legally divert or use water from this source during their call.

According to DNRC, an off stream storage structure, or arrangement, would most likely be necessary to guarantee the necessary flow. The Colstrip power facility has purchased water from the Yellowtail Reservoir and are dependent upon the flows in the Yellowstone River. When the flows in the Yellowstone River reach a minimal level, they must make a call for stored water (in Yellowtail) to be delivered to their intake near Forsyth. The DNRC states there may also be additional contract water available from either the Crow Tribe or Bureau of Reclamation from the Yellowtail Reservoir. The DNRC suggested we contact them. Based on our review of available information, the DNRC files also indicate large water allocations to PP&L, two refineries along the river (near the Billings area), several large allocations to the City of Billings and 250 cfs continuous to the Colstrip Units (six individual users) and the City of Colstrip. In a discussion with the City of Colstrip staff, indications were made that the bulk of the allocation belongs to the six power plant facilities, as do the two pipelines and intake from the Yellowstone to the City. The City obtains approximately 2 cfs from the pipeline by agreement with the power plant facilities.

Nelson Creek

The proposed power plant site is along the eastern arm of the Fort Peck Reservoir of the Missouri River. The most likely water source for this site is an intake on the reservoir near the Fort Peck Reservoir dam site. According to the DNRC the Corps of Engineers has filed several water right claims for basically the capacity of the Fort Peck reservoir. The State of Montana has issued water rights (permits) to individuals for use at home and cabin sites and the Corps has not objected, however the proposed project appropriation is considerably larger in flow rate and volume.

According to the DNRC in addition to filing for a permit there are other options for obtaining water. While it historically has not been done, there is the possibility that a portion of the McCone County Conservation Districts water reservation may be able to be changed for industrial use. However, their reservation could only be put to use between April 1 and October 15 so a permit, or other source of water, would be required for the remainder of the year. The Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation have reserved water out of Fort Peck Lake with an 1888 priority date. They may be interested in leasing a portion of their water rights. There is also the possibility of contracting with the Bureau of Reclamation for water out of Lake Elwell, moving that water down the Marias River, into the Missouri River and diverting it out of Fort Peck Lake.

Summary

Based on information provided by the DNRC, the quantity of water necessary for the project appears most probable and available along the Missouri River at the Fort Peck Reservoir (the Nelson Creek site) and near the City of Great Falls (the Salem sites). The water at the Salem sites may be available through the permitting process from below the Morony Dam; however water rights may have to be negotiated with an existing permit holder. The City of Great Falls has indicated that they can provide the necessary water for the Salem sites. The necessary quantity of water appears available from the Missouri River at the Nelson Creek site although discussions with the US Army Corps of Engineers at Fort Peck would likely be necessary due to the flow requirements for the power plant.

Water availability at both the Decker and Hysham sites is less certain as the project needs are a significant fraction of the historic low flow levels of the Tongue River and due to the Yellowstone River water rights being fully allocated. Therefore, no water rights may be available. The Decker site is located in the smallest watershed. The required flow for the project (7 cfs) is approximately five percent of the annual flow of the Tongue River experienced in the year 2002. Negotiations with existing water rights holders would be necessary to assure the required flow.

Montana Pollutant Discharge Elimination System (MPDES)

The 1972 amendments to the Federal Water Pollution Control Act, later referred to as the Clean Water Act (CWA), prohibit the discharge of any pollutant to waters of the United States unless the discharge is authorized by a National Pollutant Discharge Elimination System (NPDES) permit. In Montana, the DEQ is authorized to administer the NPDES Program through the MPDES Program.

The purpose of the Montana Pollutant Discharge Elimination system (MPDES) program is to protect water quality by controlling point source discharges of wastewater. The required levels of water quality are set forth in the Water Quality Standards (WQS). The Montana Department of Environmental Quality (MDEQ) administers this program. All point sources of wastewater discharge are required to obtain and comply with MPDES permits. The effluent limitations and other conditions contained in MPDES permits are based upon preservation of the WQS. Some categories of wastewaters must also be treated to federally-specified minimum levels (technology-based treatment) in addition to the WQS requirements. Permit requirements are based on the average design wastewater flow and the seven-day, ten-year low stream flow in the receiving stream. New wastewater sources are also subject to non-degradation rules. These rules prohibit increases in discharge of toxic and/or deleterious materials to state waters, unless it is affirmatively demonstrated to the MDEQ that a change is justifiable as a result of necessary economic or social development and will not preclude present and anticipated use of these waters. Some common pollutants that are limited under the non-degradation requirements are nutrients, heavy metals, and toxic organic pollutants. Each MPDES permit issued is designed to protect the receiving stream quality at the point of discharge. In addition, MPDES permits also address stream reach or basin wide pollution. A process called total maximum daily load (TMDL) is used to apportion allowable pollutant discharge levels among the various dischargers. If reductions of a given pollutant in a stream or basin are necessary to meet WQS, the TMDL process is used to apportion the reductions among the dischargers in that reach or basin.

Montana Ground Water Pollution Control System (MGWPCS) Permitting Process

The Ground Water Program of the Water Pollution Bureau of MDEQ administers a program that issues Montana Ground Water Pollution Control System (MGWPCS) permits to the owners or operators of potential sources of pollution to state ground waters. The current list of permitted sources includes operations such as custom metal ore milling companies, petroleum distribution companies, soil remediation facilities, and agricultural producers. The structures from which waste materials are discharged include tailings ponds, waste treatment and storage ponds, spill clean-up systems and soil treatment cells that potentially discharge to ground water.

An on site ash disposal facility would be required to apply for a MGWPCS permit.

Storm Water Requirements

Construction Activity

Effective March 10, 2003, construction activity which results in the "disturbance" of equal to or greater than 1 acre of total land area will need to obtain permit coverage under the General Permit for Storm Water Discharges Associated with Construction Activity (called "General Permit"). Construction activity includes the disturbance of less than 1 acre of total land area that is part of a larger common plan of development or sale if the larger April 2003 common plan will ultimately disturb 1 acre or more (such as subdivisions with phased work over years). Operators requiring coverage under the General Permit for their storm water discharges associated with construction activity obtain this permit coverage by the MDEQ's Storm Water Program. The operator will send to the MDEQ the following Notice of Intent (NOI) Package items by the proposed construction start date:

- NOI form with all requested items completed.
- Storm Water Pollution Prevention Plan (SWPPP) addressing all requested items in the General Permit.
- Application fee and first year annual fee based on the number of discharges and type of construction project.

All NOIs require a Notice of Termination (NOT) form to be submitted when the construction activity is complete and the site has achieved final stabilization. Final stabilization means the time at which all soil disturbing activities at a site have been completed and a vegetative cover has been established with a density of at least 70% of the pre-disturbance levels, or equivalent permanent, physical erosion reduction methods have been employed. Final stabilization using vegetation must be accomplished using seeding mixtures or forbs, grasses and shrubs that are adapted to the conditions of the site. Establishment of a vegetative cover capable of providing erosion control equivalent to pre-existing conditions at the site will be considered final stabilization.

Industrial Stormwater Permits

Industrial Stormwater Discharge Permits are required for all new and existing point source discharges of storm water associated with industrial activities as defined in 40CFR, Part 122.26(b) (14). The Permit does not cover typical construction, mining, and oil and gas extraction activities, which are covered under separate General Permits, and storm water discharges subject to effluent limitations, covered under a separate MPDES Permit. Electric generating facilities are considered industrial facilities for the purposes of these regulations.

The owner or operator of an industrial facility must submit an application to the MDEQ at least thirty (30) days prior to the anticipated date of discharge. The required SWPPP must be submitted with the application form. Requirements for industrial stormwater permits and SWPPP's are similar to those for construction activities, but typically include additional requirements for best management practices and stormwater monitoring.

Other Permitting Requirements

The following water quality related permits may be required for this project. The permits can be applied for by submission of a joint application. Any project work in streams, lakes, and wetlands requires a permit. The application form is available from the Montana DNRC.

Federal Clean Water Act Section 404 Permit

Any person, agency, or entity, either public or private, proposing a project that will result in the discharge or placement of dredged or fill material into waters of the United States must apply for a 404 permit. Waters of the United States include lakes, rivers, streams, wetlands, and other aquatic sites. The U.S. Army Corps of Engineers (Corps) is the primary agency responsible for administration of these requirements. The U.S. Environmental Protection Agency also has regulatory review and enforcement functions under the law. An application must be submitted to the Corps for review.

Federal Rivers and Harbors Act Section 10 Permit

Any person, agency, or entity, either public or private, proposing any alteration of, or any construction activity in, on, or over any federally listed navigable water of the United States must apply for a Section 10 permit. The construction of any structure in or over any federally listed navigable waters of the United States, the excavation from or depositing of material in such waters, or the accomplishment of any other work affecting the course, location, condition, or capacity of such waters. Navigable waters in Montana are the Missouri River from Three Forks downstream to the Montana-North Dakota border, the Yellowstone River from Emigrant downstream to its confluence with the Missouri River, and the Kootenai River from the Canadian border downstream to Jennings, Montana. The Corps is the primary agency responsible for administration of these requirements.

401 Water Quality Certification for Other Federal Permits & Licenses

Under Section 401 of the federal Clean Water Act, states and tribes can review and approve, condition, or deny all Federal permits or licenses that might result in a discharge to State or Tribal waters, including wetlands. The major Federal licenses and permits subject to Section 401 are Section 402 and 404 permits (in non-delegated states), Federal Energy Regulatory Commission hydropower licenses, and Rivers and Harbors Act Section 9 and 10 permits. States and tribes may choose to waive their Section 401 certification authority. States and Tribes make their decisions to deny, certify, or condition permits or licenses primarily by ensuring the activity will comply with state water quality standards. In addition, states and tribes look at whether the activity will violate effluent limitations, new source performance standards, toxic pollutants, and other water resource requirements of state/tribal law or regulation.

Montana Natural Streambed and Land Preservation Act 310 Permit

Any private, nongovernmental individual or entity that proposes to work in or near a stream on public or private land must apply for a 310 permit. Any activity that physically alters or modifies the bed or banks of a perennially flowing stream is included. The Board of Supervisors of the conservation district in which the project takes place is the primary agency responsible for administration of these requirements. A person planning a project must contact the conservation district office to obtain a permit application prior to any activity in or near a perennially flowing stream. Once an application is accepted, an on-site inspection may be conducted by a team that consists of a conservation district representative, a Department of Fish, Wildlife and Parks biologist and the applicant. The team makes recommendations to the conservation district board. Local rules also apply.

Montana Floodplain and Floodway Management Act - Floodplain Development Permit

Anyone planning new construction within a designated l00-year floodplain must apply for a floodplain development permit. This includes new construction such as placement of fill, roads, bridges, culverts, transmission lines, irrigation facilities, storage of equipment or materials, and excavation; new construction, placement, or replacement of buildings.

Floodplain Development Permits are available from the local floodplain administrator, who may be the city/county planner, sanitarian, building inspector, town clerk, or county commissioner. Permit applications are available from the local floodplain administrator or from the Department of Natural Resources and Conservation. Application fees are established by the local government and vary widely throughout the state.

Short Term Water Quality Standard for Turbidity - 318 Authorization

Any entity, either public or private, initiating construction activity that will cause short-term or temporary violations of state surface water quality standards for turbidity must apply for a 318 authorization. The Department of Environmental Quality is the primary agency responsible for administration of these requirements. A 318 Authorization must be obtained prior to initiating a project. The authorization may be obtained from the Department of Environmental Quality, or may be waived by the Department of Fish, Wildlife and Parks during its review process under the Natural Streambed and Land Preservation Act (310 Permit).

Montana Land Use License or Easement on Navigable Waters

Any entity proposing a project on lands below the low water mark of navigable waters must apply. Covered activities include the construction, placement, or modification of a structure or improvements in, over, below, or above a navigable stream. The DNRC is the primary agency responsible for administration of these requirements. A DNRC land-use license or easement application, along with the nonrefundable application fee and the Application for Licensing Structures & Improvements on Navigable Water Bodies (Form DS-432), must be submitted to the appropriate Land Office. DNRC staff will review the application, conduct a field investigation if necessary, and file an environmental action checklist. A written report and recommendation is then submitted to the Special Use Management Bureau, which makes the final determination and recommends stipulations as necessary.

County Septic System Regulations

These requirements apply to anyone proposing to construct, alter, extend, or operate a sewage treatment and disposal system. Conventional systems must be 100 feet from the 100-year floodplain and 6 feet from groundwater. Alternative designs that are 4 to 6 feet from groundwater must be approved. The County Sanitarian is the primary agency responsible for administration of these requirements.

Solid Waste

The MDEQ regulates solid waste facilities in Montana. These include municipal landfills, construction and demolition of waste landfills and septic tank land application sites. Solid waste management activities performed by MDEQ include technical review and licensing of solid waste treatment and disposal facility design and operational plans, inspections of solid waste management facilities, technical assistance to maintain compliance, and training for owners and operators of solid waste disposal facilities. According to the Administrative Rules of Montana, ash produced as a byproduct of coal combustion is listed Group II wastes. Group II wastes are managed at Class II landfills. Municipal landfills are Class II landfills.

At the current time, ash from electrical generating facilities is exempt from the requirements of the Solid Waste Management Act (SWMA). These facilities were formerly regulated under the Major Facilities Siting Act (MFSA) which had jurisdiction over the design. The 2003 Montana Legislature removed most electrical generating facilities from regulation under the MFSA, but, in an apparent oversight, did not remove the solid waste exemption in the SWMA. Thus there is a regulatory void with regard to management of coal combustion ash.

If the ash is placed in a permitted coal mine facility, it would be regulated under the mining permit. If the facility has the potential to discharge to groundwater, then a groundwater discharge permit will be required. Groundwater discharge permits are discussed in the section regarding water issues. Either of those permits could impose design requirements which may vary depending on the characteristics of the disposal site selected. The design requirements would likely have to meet requirements similar to those established for Class II landfills.

If the 2005 Legislature chooses to place coal combustion ash under the SWMA, then the requirements for Class II landfill design would apply. These requirements are the same as the Subtitle D RCRA [40 CFR Part 258] requirements with state flexibility for alternative designs.

According to MDEQ, the mining facility permit writers typically utilize the solid waste rules when evaluating coal ash disposal requirements at mining projects, thereby maintaining consistency throughout the state. It is likely that a stand alone ash disposal facility will need to be sited in accordance with Class II requirements and may require construction with a composite liner in order to meet Montana groundwater protection requirements.

Typical Class II landfill requirements include general location requirements that all landfills must meet, as well as requirements specific to Class II landfills. Some of the requirements include the following:

- Sufficient acreage of suitable land must be available for solid waste management.
- Facilities may not be located in a 100 year floodplain.

- Facilities may be located only in areas which will prevent the pollution of ground and surface waters and public and private water supply systems.
- Facilities must be located to allow for reclamation and reuse of the land.

Some of the special requirements for Class II landfills include the following:

- Class II landfills must confine the solid waste and leachate to the disposal facility unless department approval is obtained for treatment at another facility.
- Adequate separation of Group II wastes from underlying or adjacent water must be provided.
- The extent of the separation required must be established on a case-by-case basis, considering terrain, type of underlying soil formations and facility design.
- Class II landfills must be constructed to be protective of groundwater quality.

Any owner or operator wishing to establish a solid waste management system is required to submit an original application and three (3) copies for a license to the department. The application typically includes the following types of information;

- General facility and owner information.
- Location and local land use information.
- Water quality information.
- Detailed geological, hydrological, and soil information.
- An evaluation of the potential for impacts to existing surface water and ground water quality.
- A ground water monitoring plan.
- Technical design plans and specifications for construction, operation, and closure.

Hazardous Waste Program

The MDEQ is responsible for permitting, compliance assurance and technical assistance for hazardous waste management in Montana. The Program is divided into two units, Regulatory and Permitting. The Waste Management Unit is responsible for regulating storage, treatment, transport and disposal of hazardous waste and used oil for all hazardous waste generators in the State of Montana. In addition, the unit provides technical assistance to and conducts inspections of hazardous waste generators of all sizes throughout Montana.

Permitting

A permit from the MDEQ is required to construct or operate a hazardous waste treatment, storage, and disposal facility in the State. Permits are issued to ensure hazardous waste facilities are operated in a manner that protects human health and the environment. Persons who transport hazardous wastes are required to notify the MDEQ and to obtain an identification number. Persons who generate hazardous waste (with certain exceptions) are required to maintain an annual generator registration and to pay a registration fee each year in addition to obtaining an identification number. The MDEQ has adopted hazardous waste regulations that are equivalent to those promulgated by EPA. Other state government agencies or city/county regulatory agencies may have requirements as well. For example, the Department of Transportation has requirements for transporting hazardous waste. The

Administrative Rules of Montana (ARM) provide the regulations for hazardous waste generators in Montana. These regulations require a generator of a waste to determine if that waste is a hazardous waste. If the waste is a hazardous waste, it becomes the generator's responsibility to determine their generator size and to adhere to all applicable hazardous waste regulations. Hazardous waste can be of two types: characteristic and listed.

Listed Hazardous Wastes

These hazardous wastes have been determined to be harmful to human health and the environment. Listed hazardous waste appear on one of four (4) lists, "F", "K", "P", or "U".

Characteristic Hazardous Wastes

These hazardous wastes are hazardous due to having any of four (4) characteristics: ignitability, corrosivity, reactivity, or toxicity.

- Ignitable wastes have a flash point below 140° F.
- Corrosive wastes have a pH greater than or equal to 12.5, or less than or equal to 2.
- Reactive wastes readily explode or create toxic fumes when exposed to water.
- Toxicity wastes can leach toxic compounds into groundwater.

A hazardous waste generator is any person, by site, whose act or process produces hazardous waste or whose act first causes a hazardous waste to become subject to regulation. Hazardous waste generators fall into one of three categories depending upon the total amount of hazardous waste generated in any calendar month, or how much hazardous waste has been accumulated on site. These categories are:

- Conditionally Exempt Generators
- Small Quantity Generators
- Large Quantity Generators

Conditionally Exempt Generators (CEG)

These generators produce less than 220 pounds of non-acute hazardous waste within any calendar month or no more than 2.2 pounds of acute hazardous waste in any month. If the CEG accumulate more than 2,200 pounds of hazardous waste, all hazardous waste on site becomes subject to regulation as if generated by a small generator. Requirements for a CEG are:

- Determine which generated wastes are hazardous.
- Keep records of waste analysis for three (3) years.
- Dispose hazardous waste only at a legitimate recycling facility, a permitted Treatment Storage and Disposal Facility (TSDF), or a Class II landfill.
- May treat, recycle, or reclaim waste on-site.

Small Quantity Generators (SQG)

These generators produce between 220 pounds and 2,200 pounds of non-acute hazardous waste in any calendar month. SQG may not generate more than 2.2 pounds of acute hazardous waste in any month. SQG may accumulate up to 13,228 pounds of hazardous waste on-site. However, accumulation time limits, as described below, must be adhered to. Requirements for a SQG are:

- SQG must obtain an EPA identification number and register with the Montana Department of Environmental Quality.
- Small and large generators of hazardous waste must submit a completed Notification of Regulated Waste Activity Form (EPA Form 8700-12) and a payment of a $95.00 registration fee, in accordance with Montana Hazardous Waste Administrative Rules.
- Hazardous waste may be accumulated on-site for up to 180 days. If the waste must be transported more than 200 miles for recovery, treatment, or disposal, it may be accumulated for up to 270 days.
- Hazardous waste must be transported to a permitted TSDF.
- A hazardous waste manifest, or tolling agreement, must be used for any shipments of hazardous waste off-site.
- Emergency contacts and phone numbers must be posted next to telephones. In addition, locations of fire extinguishers and spill control material must also be posted by phones.
- Annual reports are required to be completed and submitted to MDEQ by March 1 of each year.
- Copies of annual reports, manifests, and waste analysis must be maintained on-site for three years.

Large Quantity Generators (LQG)

These generators produce more than 2,200 pounds of non-acute hazardous waste in any calendar month, or more than 2.2 pounds of acute hazardous waste in any month. Requirements for a LQG are:

- Adhere to all small generator hazardous waste requirements.
- Hazardous waste may be stored for up to 90 days without a permit.
- Written contingency plans must be maintained on site and submitted to local police and fire departments, hospitals, and emergency response teams.
- Additional emergency requirements are detailed in 40 CFR Part 265 subparts C and D.

It is anticipated that the proposed facility will be a conditionally exempt small quantity generator as it is likely that routine maintenance activities will result in small quantities of wastes that would meet the definition of characteristic hazardous wastes. Some non-routine maintenance activities could cause the infrequent generation of larger quantities of some potentially hazardous wastes. Accordingly the facility may wish to complete EPA Form 8700-12 to obtain a registration number as a potential small quantity generator.

Phase I Environmental Site Assessment

A Phase I Environmental Site Assessment (ESA) was conducted at four (4) different locations within the state of Montana. The area of the study comprises five distinct properties, delineated as follows:

- Salem
- Salem Industrial
- Decker
- Hysham
- Nelson Creek

The Salem site is located in the Northwest ¼ of Section 36, Township 21 North, Range 5 East on the Morony Dam topographic map. The Salem Industrial site is located in the Southern 1/2 of Section 30, Township 21 North, Range 4 East on the Northwest Great Falls topographic map. The Decker site is located in the Southwest corner of Section 1, Township 8 South, Range 39 East on the Half Moon Hill topographic map. The Hysham site is located in the Southwest ¼ of Section 11, Township 6 North, Range 37 East on the Scraper Coulee topographic map. The Nelson Creek site is located within the Northwest ¼ of Section 36, Township 21 North, Range 43 East on the Nelson Creek Bay topographic map.

The Phase I Environmental Site Assessment was completed in general accordance with the procedures outlined in American Society for Testing and Materials (ASTM) E1527-00, Standard Practice of Environmental Site Assessments: Phase I ESA.

The ESA included evaluation of individual properties within and adjacent to the assessment area. The evaluation included assessment of historical information pertaining to the area including historic aerial photographs, historic topographic mapping, available fire insurance mapping for the area, a review of regulatory records for the area, and visual evaluation of the assessment area. Historically, activities conducted within the assessment areas have been for agricultural purposes, much as they are today.

There were no environmental conditions or concerns identified during the site assessment at any of the properties in question.

Permit Matrix

The following matrix summarizes the applicable regulatory requirements that require a permit, notification, and/or approval from the authorizing agency. The lead authorizing agency is identified as at the Federal, State, or Local government. However, multiple agencies may have authority to review, comment, object, or even overrule the lead agency for any given permit or associated requirement. Environment regulatory requirements identified in this report that do not require a regulatory approval or notification are not shown in the permit matrix.

The time to prepare each regulatory submittal and the anticipated time for the lead agency to provide authorization is provided. Additionally, where submittals or approvals have a linkage to another activity, then this linkage is identified as a potential critical path issue.

Finally, the estimated cost to complete the application and/or notification, through agency review and receipt of approval, is shown.

Permit Schedule

The Permitting Schedule is organized according to the types of permits being prepared, with the major activities identified as Environmental Impact Statement (EIS), Water Quality Permits, Solid and Hazardous Waste Permits, and Air Quality Permits.

The permit schedule is based on the permitting effort commencing immediately following the Board Meeting on July 19, 2004. The EIS being performed by others is critical to the start of construction in November, 2005. Stanley Consultants estimates that the EIS could be completed as early as April, 2005, if comments are resolved quickly, or as late as January, 2006, if the review and comment process is held up by appeals or unresolved issues. The late date for completion of the EIS in January, 2006, would mean a delay of 2-3 months from the planned start of construction and commercial operation of the project.

There are currently fifteen (15) Water Quality permits identified by Stanley Consultants. The water quality permits are projected to start as soon as preliminary engineering documents have progressed to the point that will support the permit application process. It is anticipated that the majority of these permits would be prepared in the 4th quarter of 2004 and 1st quarter of 2005. The permits are not expected to have an impact on the start of construction.

There are two (2) Solid and Hazardous Waste permits identified. The application activity is projected to start in late 2004 and should not impact the construction dates.

The Air Quality Permits will start with PSD pre-construction ambient air monitoring. The monitoring efforts should last between 4 and 12 months. For the purpose of the schedule, a monitoring period of nine months was allowed. Based on this monitoring period, the critical air permits for PSD and Acid Rain should be received by end of October, 2005, which is prior to the planned start of construction.

Table 3-7
Permitting Matrix

REGULATORY PERMIT OR NOTIFICATION	AGENCY	PREPARATION	AGENCY REVIEW	CRITICAL PATH	COST TO COMPLETE
Montana Major Facility Siting Act	MDEQ	90 days	9 Months to review, then 1 month to issue certificate of approval.	Can not be issued until all necessary decisions, opinions, orders, certifications, and permits have been obtained	$15,000
WATER QUALITY					
MPDES Individual Industrial Wastewater Treatment and Discharge	MDEQ	90 days	90 to 120 days, appeals may add 60 to 80 days to total	Must submit minimum of 180 days before discharge begins	$20,000
MPDES General Stormwater, Construction Related	MDEQ	30 days	30 days	Must be issued before site construction begins.	$5,000
MPDES General Stormwater, Industrial Facilities	MDEQ	30 days	30 days	Must be issued before industrial discharge begins.	$6,000
MGWPCS Groundwater Pollution Control	MDEQ	60 days	90 to 120 days, appeals may add 60 to 80 days to total	Must submit minimum 180 days before discharge begins	$20,000
Montana 310 Permit, Work in or near Surface Water	Local Conservation District	30 days	30 to 60 days	Must be issued before site construction work begins.	$500
Montana 318 Permit, Surface Water Turbidity Related to Construction	MDEQ	30 days	30 days	Must be issued before site construction work begins.	$500
Floodplain Permit, Work in Designated Floodplains	County Floodplain Administrator	30 days	60 days	Must be issued before floodplain related construction begins.	$500
Section 404/Section 10, Work in Surface Water, or Wetlands	USACE	30 days	30 to 120 days	Must be issued before in-stream/wetland construction begins.	$500
Section 401 Water Quality Certification, Surface Water/Wetlands	MDEQ	30 days	Concurrent with Sections 404/10 evaluations	Must be issued before in-stream/wetland construction begins.	$500
Navigable Rivers Land Use License / Easement, Projects in, on, under, or over Navigable Waters	MDNRC	30 days	60 to 90 days	Must be issued before stream related (in, on, under, over) construction begins.	$1,000
Non-Transient, Non-Community Water Treatment System Permit	MDEQ	30 days	60 days	Must be issued before water treatment unit construction begins.	$5,000
Septic Disposal System, On Site Sanitary Wastewater Disposal	County Health Department	30 days	60 days	Must be issued before septic system construction begins.	$2,000
Beneficial Water Use Permit (Surface Water Rights Allocation)	MDNRC	60 days	180 days to 2 years	Must be issued prior to water diversion.	50,000
Beneficial Water Use Permit (Groundwater Rights Allocation)	MDNRC	60 days	180 days to 2 years	Must be issued prior to groundwater diversion.	50,000
SOLID & HAZARDOUS WASTE					
Hazardous Waste Generator Status	MDEQ	10 days	30 Days	Must be obtained prior to generation of hazardous waste.	$2,000
Solid Waste Disposal Ash Landfill	MDEQ	30 days	180 to 210 days	Must be issued before landfill construction begins.	$100,000

REGULATORY PERMIT OR NOTIFICATION	AGENCY	PREPARATION	AGENCY REVIEW	CRITICAL PATH	COST TO COMPLETE
AIR QUALITY					
Prevention of Significant Deterioration (PSD) – Permit Development - Emission Calculations - BACT Analysis - Class I/Class II Air Dispersion Modeling - Additional Impact Analysis - MDEQ PSD Construction and Title V Operating Permit Application - Acid Rain Permit Application - Agency Meetings - Public Comment Period	MDEQ	3 months	9 months, including 30 day public comment period.	Agency cannot issue final permit without completion of ambient air monitoring. Cannot begin until preliminary engineering design is complete.	$255,000
Prevention of Significant Deterioration (PSD) – Preconstruction Ambient Air Monitoring	MDEQ	3 months to develop plan, select sub, and field setup Conduct Monitoring: - Min. 4 months - Max. 12 months 1 month for data reduction and reporting.	30 days to validate results and that Data Quality Objective's were met.	Can be performed during PSD permit development and agency review, but must be completed before permit can be issued.	$250,000 for a 3-site preconstruction network operating for 1 year.
Acid Rain Permit Program					
- ORIS Code Application	Energy Information Agency	1 week	2 weeks	ORIS Code must be received prior to submitting Acid Rain Permit Application and Certificate of Representation.	$5,000 for all three permitting tasks.
- Acid Rain Permit Application	MDEQ	1 week	Concurrent with PSD Application	Must be submitted 24 months prior to commencement of plant operation.	
- Certificate of Representation				Must be obtained during the year that they are used (e.g. first year of operation)	
Purchase of SO2 allowances	EPA	1 week	Notification only	Must be obtained during the year that they are used (e.g. first year of operation)	
	EPA/Chicago Board of Trade	Auction held last Monday of March each year.	Bidders must send sealed offers to CBOT no later than 3 business days prior to the auction.		$120,000 per year
Risk Management Program Plan	EPA	3 months	None	Cannot be completed until engineering design is completed. Must be completed prior to receipt of ammonia or other RMP regulated chemicals on-site.	$40,000

Section 4

Project Description

The project consists of one (1) coal-fired electric generating station designed to produce 250,000 net kilowatts of electric power for Southern Montana Electric Generating & Transmission Cooperative, Inc. (SME). This section provides detailed information on major equipment, describes the process, and summarizes the electrical and control systems of the power plant.

The plant consists of a circulating fluidized bed (CFB) boiler, single re-heat tandem compound steam turbine, seven (7) stages of feedwater heating, water cooled condenser, wet cooling tower, flash dryer absorber, baghouse, and material handling system. The electrical system consists of a generator step-up transformer, a unit auxiliary transformer, a start-up transformer, switchyard, and a unit auxiliary power system. The plant is controlled by way of a distributed control system (DCS) located in a central control room, which integrates the instruments, control valves, and programmable logic controllers provided by equipment manufacturers.

Plant Mechanical Systems & Equipment

Steam Generator

The steam generator will utilize circulating fluidized bed (CFB) technology in a totally enclosed building to produce steam for 250 MW net output single reheat condensing steam turbine. The steam generator will use either sub-bituminous or lignite coal, depending upon plant location. Steam generation will range from 100% base load to 40% load, while maintaining steam pressure and temperature. The overpressure condition of 5% will need to be investigated during the design development stage.

Heat exchanger sections of the steam generator include an economizer, steam drum, membrane water tube boiler, convective super-heater, radiant super-heater, second convective super-heater, convective re-heater, radiant re-heater, and second convective re-heater. Each section is complete with steam soot blowers used to remove gas-side boiler ash and slag deposits from the heat transfer surface area. All pressure-containing components of the steam generator are designed and built in accordance with the latest edition of ASME Boiler and Pressure Vessel Code.

Two (2) primary air (PA) fans will supply air for initial combustion of the coal in the CFB furnace. Similarly, two (2) secondary air (SA) fans will supply secondary air for continued combustion in the CFB furnace. To properly operate the CFB, solids density and recycle rates must be maintained during operation. As the unit load is decreased, the SA is initially reduced and then the fluidizing (PA) air is reduced. For the CFB to operate at 50% load, the PA flow will have a capacity of 70-80% of the full load primary air flow. Each stream of air flow will use a regenerative air heater to pre-heat the inlet air using flue gas as the heating source.

The combustion process takes place in the furnace section of the boiler. Flue gas leaves the furnace and enters the three (3) cyclones after passing through the radiant super-heater and re-heater sections. The cyclone spins the flue gas to remove large solid particles from the gas stream. The gas stream continues through the convective heater sections, regenerative air heater, and fabric filter (baghouse). The two (2) 60% capacity-induced draft fans pull the flue gas through these sections of the CFB boiler, and force the gas stream out the exhaust stack. The exhaust stack will be approximately 360 feet tall and constructed of concrete.

Using secondary combustion air at a higher elevation in the furnace section of the boiler facilitates staged combustion of the fuel, resulting in a reduction in the amount of unburned fuel leaving the boiler and a reduction in the amount of nitrogen oxide (NO_X) emissions produced. To further reduce the NOX emissions, a selective non-catalytic reduction system will inject ammonia into the flue gas in the furnace volume. The ammonia (NH_3) will reduce the NO_X to nitrogen (N_2) and water vapor (H_2O). The system is designed to reduce NO_X to a maximum of 0.10 lb NO_X/mm BTU.

Combustion Air Preheat

The primary and secondary combustion air is pre-heated using two different methods. During cold weather, the air will first pass through a steam coil air heater (SCAH) to pre-heat both primary and secondary combustion air to a temperature of 150°F. Four (4) SCAH units are installed downstream of the primary air fans and secondary air fans. The heating steam used in the SCAH is extracted from the low-pressure turbine inlet stream at a temperature of 590°F. During a cold weather start-up, when the low-pressure steam is not available from the turbine, an auxiliary boiler will provide steam to the SCAH. Condensate from the heating steam is returned to the condenser hotwell.

The second heater is a Ljungstrom regenerative rotary drum air heater, used to heat both the primary and secondary combustion air. The rotating drum uses flue gas at the exit of the economizer and upstream of the baghouse to heat the inlet combustion air.

Turbine Generator & Auxiliaries

The steam turbine consists of a tandem single shaft (3600 rpm), high-pressure (HP), single reheat, intermediate pressure (IP) and condensing turbine with compound low-pressure (LP) sections. The steam turbine has seven (7) extraction ports for feedwater heating. The low-pressure turbine exhausts to a water-cooled condenser. The turbine generator is a conventional hydrogen-cooled generator, sized for an overpressure operation condition of 5% increase in main steam pressure.

The steam turbine auxiliary systems, consisting of the main lube oil, generator seal oil, hydrogen cooling, gland seal steam, turning gear, turbine hydraulic and control are included. The steam turbine, generator, and auxiliary systems are designed for 100% load with a turndown to 40% load. The plant is designed to bypass steam to the condenser until the boiler reaches the minimum operating load of 40%. Auxiliary systems are designed in a similar manner to facilitate start-up at reduced boiler loads.

Critical Steam Piping Systems

Main steam piping will transport the high-pressure (2400 psig), high-temperature (1000°F) steam from the outlet of the steam generator to the main stop valve at the inlet of the HP turbine. Steam leaving the high-pressure turbine is returned to the steam generator for reheat. Steam leaving the reheat section of the boiler is then routed to the IP turbine inlet stop valve. After the steam passes through the intermediate steam turbine, the low-pressure steam (115 psig) is directed to the compound LP turbine. The steam leaving the low-pressure turbine is exhausted to the surface condenser.

Steam attemperation is provided from the boiler feedwater pump discharge to the main steam and hot reheat piping. The steam is attemperated to 1000°F to ensure proper function of, and prevent any damage to, the piping and steam turbine from excessive temperatures. High-pressure, cold reheat, hot reheat, and low-pressure steam lines are sloped away from the steam turbine and boiler to an adequately-sized drip leg, to aid in the prevention of water damage to the steam turbine. Gland seal steam is supplied to the steam turbine from the main steam or the auxiliary boiler on start-up. Pipe design and fabrication, including pipe stress analysis, is in accordance with the latest edition of ASME B31.1 "Power Piping." Pipe stress analysis is performed to ensure the compliance with code requirements and to ensure nozzle loads on the equipment connections are within manufacturer acceptable limits.

Main Condenser

The main condenser maintains 2.00 in HgA backpressure when operating at the design ambient temperature of 94°F and 250,000 kW net capacity output. The condensed steam will collect in the condenser hotwell, where makeup water from the water treatment system is added. Two (2) 100% capacity vacuum pumps are provided to create the vacuum in the condenser. The following table illustrates the performance conditions of the condenser at 100% load at the three design cases.

Table 4-1
Condenser Parameters Summary

	Summer Case	Average Case	Winter Case
Ambient Dry Bulb Temperature, °F	94	45	-20
Ambient Wet Bulb Temperature, °F	68	33.6	-20.9
Turbine Exhaust Flow, lb/hr	1,138,900	1,124,700	1,080,900
ELEP, BTU/Lb	1000.1	987.1	968.5
UEEP, BTU/lb	1008.5	1003.8	1008.0
Condenser Duty, MBTU/hr	1071.3	1063.7	1063.7
Condenser Backpressure, in HgA	2.00	1.53	0.59

Condensate System

The condensate system is designed to collect the condensed steam from the steam turbine, auxiliary steam systems, and gland seals, and transport the treated water through the feedwater heaters to the steam generator. Two (2) 100% capacity condensate pumps (vertical turbine), with minimum flow protection, will forward the condensate from the condenser hotwell through the gland steam condenser to a condensate polisher. The condensate polisher is provided to remove impurities in the condensate and control the concentration of dissolved solids.

Once the condensate leaves the polisher, it flows through four (4) low-pressure condensate heaters. Each condensate heater has piping which is installed with valves for a full bypass. The condensate heaters are constructed using 304 stainless steel tubes for improved reliability, and provided with sufficient storage capacity to ensure an appropriate level of sub-cooling of the condensed steam where applicable. The condensate heaters are designed to sub-cool the heating steam to within 9°F of the incoming condensate.

The first of the condensate feedwater heaters is a pump forward heater, where the heating steam from the low-pressure turbine is condensed in the heat exchanger and then pumped into the condensate leaving the first condensate heater. The next two (2) condensate heaters are flash-back heaters with drain coolers. In these heaters, the heating steam is condensed and then further sub-cooled in the heat exchanger before the sub-cooled water is sent to the previous condensate heater. The first three (3) condensate heaters all have a terminal temperature difference (TTD) of 3°F. The last condensate heater is similar to the second and third condensate heaters, except that a de-superheating section is added before the condensing section of the heat exchanger. This enables the heater to take full advantage of the superheated steam supplied to the heater from the low-pressure turbine extraction. This design allows for a TTD of 0°F.

A direct-heating feedwater heater (deaerator) is provided to remove dissolved oxygen and other non-condensable gases from the feedwater. During a boiler cold start, the deaerator will provide water at a temperature and oxygen content in compliance with boiler requirements using auxiliary steam. The deaerator storage tank is sized for seven (7) minutes of storage at a flow rate equal to full load conditions. The deaerator is located along-side the boiler at an elevation to provide sufficient net positive suction head for the boiler feed pump. Deaerator level will be controlled by a condensate level control valve.

Feedwater System

The elevated deaerator supplies two (2) 60% capacity boiler feed pumps with saturated water at a temperature of 351°F. The boiler feed pumps are driven by a condensing steam turbine whose supply steam is extracted from the intermediate turbine exhaust. During low load conditions or warm up periods, the required steam is drawn from the auxiliary boiler until the steam turbine can produce sufficient amounts of steam. The exhausted steam is discharged to a separate smaller condenser. The condenser operates in parallel with the main condenser using circulating water as a cooling medium. Once condensed, the condensate is pumped to the main condenser hotwell. The boiler feed pumps are horizontal, multi-stage, double-case, barrel-type centrifugal pumps that supply high-pressure water through two feedwater heaters to the steam generator economizer inlet. The pumps also supply high-pressure water to the main steam and reheat steam attemperators. For start-up, the plant uses a single electric motor-driven pump capable of 40% capacity.

The boiler feedwater pumps and drivers are complete with pre-lube oil, post-lube oil, and auxiliary oil backup for start-up and coast-down periods. Lubrication systems contain pumps, drives, shell and tube coolers, duplex filters, safety relief valves, isolating valves, pressure switches, temperature gauges, pressure gauges, and flow indicators as required for proper operations and monitoring of the systems.

Feedwater is heated in the high-pressure feedwater heaters by turbine extraction steam from the HP turbine exhaust and an intermediate extraction port on the IP turbine. Each feedwater heater is a horizontal flash-back heater with drain cooler and de-superheating section. The first feedwater heater following the boiler feed water pump is designed for a TTD of 0°F and a drain cooler approach temperature (DCA) of 9°F. The last feedwater heater is designed for a TTD of -5°F and a DCA of 9°F. The construction of both feedwater heaters is the same as those of the condensate heaters, with 304 stainless steel tubes, drain cooler storage capacity and located to permit cascading drains. The heaters are provided with an impingement plate to prevent tube erosion and a desuperheating section. The tubes are welded to the tubesheets to prevent excess vibration and contain baffles for tube support.

Auxiliary Steam System

An auxiliary steam system, designed to furnish steam for gland seals, deaerator pegging, combustion air preheating, building heat, and other plant auxiliaries, is provided. During normal unit operations, the auxiliary steam is supplied by an extraction from the steam turbine. An auxiliary boiler will provide the steam using either natural gas or No. 2 fuel oil. The auxiliary system generates, and boiler operates, during standby, start-up, or low-load unit operations. During start-up and commissioning, this boiler will facilitate hydrostatic testing and chemical cleaning. The auxiliary boiler conforms to all requirements of the latest edition of the ASME Boiler and Pressure Vessel Code.

Heater Vents & Drains

Feedwater heaters, condensate heaters, and steam coil air heaters are equipped with drains to recover the condensed extraction steam. The drain from the high-pressure feedwater heaters cascades to the next lower pressure feedwater heater, and finally to the deaerator. Each condensate heater drain cascades to the next lower pressure condensate heater. At the lowest pressure heater, two (2) 100% heater drain pumps pump the condensate back into the process between the first and second condensate heater. An alternate flow path is provided to drain the heaters to the main condenser for start-up, and during emergency operation. Condensate from the SCAH is pumped to the main condenser hotwell. Each feedwater heater and condensate heater is provided with proper venting to remove corrosive non-condensable gases. All heaters are designed to operate within the plant operating range including load variations. Feedwater heaters and condensate heaters are provided with pressure safety valves (PSV) to prevent overpressure of the heater shell in accordance with the ASME codes. The tube side of the feedwater heaters and condensate heaters are provided with a thermal PSV to prevent over-pressurization.

Auxiliary Closed Cooling System

An auxiliary closed-loop cooling system continuously re-circulates a treated water solution to provide cooling for various plant equipment and systems. The following equipment is cooled using this system:

- Boiler feed pump lube oil coolers
- Boiler feed pump turbine lube oil coolers
- Turbine generator lube oil coolers
- Turbine generator hydrogen coolers
- Chemical sampling coolers
- Exciter cooler
- Main turbine control oil cooler
- Hydrogen seal oil cooler
- Air compressor coolers
- Other equipment coolers, as required

The water is pumped through the individual equipment coolers, in a parallel arrangement, and through a plate and frame heat exchanger. The heat collected in the water is transferred to the open circulating water system. This system provides adequate pressure and heat rejection for the coolers.

Service Water System

A service water system provides water to the raw water tank and pre-treatment filters by way of a clarifier for the following uses:

- Cooling tower water make-up
- Lubrication to water pumps at start-up

- Plant make-up water treatment systems
- Fire protection system
- Air heater wash
- Station air compressors (emergency cooling)
- Plant miscellaneous hose stations
- Other services

The service water system receives make-up from either a reservoir or river, depending upon the plant site location. The majority of makeup water will be used for cooling tower make-up, due to the large evaporation, drift, and blowdown losses. The raw water tank will provide an on-site storage for service water and cooling tower make-up usage. The tank is a field-erected carbon steel tank designed for 100% plant usage over a twenty-four (24) hour period, complete with roof, electric tank heaters, and insulation, and is vented to atmosphere. Two (2) 100% capacity pumps are used to supply service water to the plant.

Fire Protection Systems

The fire protection system utilizes both manual and automatic fire fighting systems. During the detailed design phase, and in accordance with National Fire Protection Association (NFPA) 850 "Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations," a complete fire risk evaluation will be performed. All local, state, and NFPA codes will be incorporated into the design.

Pressure for the fire suppression system is supplied by a fire water pump house. The pump house contains a diesel engine-driven fire pump, an electric motor-driven fire pump, and an electric motor-driven jockey pump. Each of the fire pumps are horizontal, in-line, centrifugal, split-case pumps, capable of supplying 100% of the required capacity. The diesel engine is supplied with a 300-gallon, double-walled fuel tank in compliance with NFPA requirements. All pump suctions are supplied from the raw water tank and discharged to an underground fire protection loop. The raw water tank contains a dedicated storage capacity of approximately 250,000 gallons in addition to the service water requirements for a twenty-four (24) hour period. The dedicated storage capacity is sized based on two (2) hours of operation at full flow conditions, in accordance with NFPA 850.

The electric motor-driven jockey pump will be designed to maintain a water pressure of 135 to 150 psig in the fire protection loop. The jockey pump maintains this pressure when the system is not in use. The underground fire protection loop is routed throughout the site and supplies water to the following deluge stations:

- Generator step-up transformer
- Unit auxiliary transformer
- Start-up transformer
- Turbine oil tanks
- Hydrogen seal oil unit
- Main turbine oil room
- Underground coal handling areas

- Cooling tower

The same fire protection loop supplies water to outside yard hydrants, inside standpipes, hand hose reels, and other types of fixed fire suppression systems for manual fire suppression. All equipment and materials used in the system will be approved by a nationally-recognized testing agency, such as Underwriters' Laboratories, Inc., or Factory Mutual.

Service & Instrument Air System

The service and instrument air system is comprised of two (2) 100% capacity air compressors, one (1) service air receiver, two (2) 100% heatless desiccant air dryers, and one (1) instrument air receiver. The system is designed to meet the maximum air demand for normal continuous plant operations, start-up, and maintenance periods with additional margin to meet peak demands at a pressure of 120 psig. The compressed air is stored in the service air receiver and ring header around the boiler building and steam turbine building. Smaller supply lines, which branch off of risers, provide air to specific equipment. The risers also provide service air for general plant use with air hose connections throughout the plant.

Station air compressors are single-stage, oil-injected rotary screw compressors, with air after-cooler. The after-cooler uses ambient air to cool compressed air within 20°F of ambient conditions. A high-efficiency moisture separator is provided to remove condensed liquids from the compressed air stream. The compressor, motor, and after-cooler will be located inside a sound-attenuating enclosure. Additional connections to and from the compressed air system are provided to add operating versatility.

Each air dryer will be a twin-tower, heatless, desiccant type to provide oil-free, clean, dry air for pneumatic instruments, control equipment, and air-operated valves. The air is dried to a -40°F dew point. Each air dryer is provided with two (2) 100% capacity pre-filters and two (2) 100% capacity after-filters. The pre-filters are designed to remove some moisture from the compressed air stream, while the after-filters are designed to entrain any crushed desiccant leaving the air dryer. The compressed dry air is stored in an instrument air receiver and ring header. Similar to the service air header, the instrument air header will be routed throughout the boiler and steam turbine buildings. The instrument air system working pressure will be 70 to 115 psig. Instrument air quality will be specified to satisfy requirements of ISA-S7.3 with respect to dust content, oil content, and dew point.

Bulk Gas Systems

A nitrogen system with high-pressure bulk storage tank cylinders is provided to purge equipment and prevent intrusion of oxygen during outage periods. Purged equipment includes the super-heater, re-heater, economizer, water wall, condensate and feedwater heaters, steam coil air heater and gland seal steam condenser. The nitrogen system provides an inert environment during outage periods. Nitrogen supply tanks and distribution piping will be routed to the boiler and steam turbine building equipment. The system is designed to supply proper capacity from storage for two (2) outage periods.

A hydrogen system to supply the generator hydrogen cooling system is provided with features to ensure safe generator filling and venting. Low-pressure bulk hydrogen storage is provided in a convenient and safe area. Supply and distribution piping with proper supply and vent capacity is provided to the main generator. Hydrogen storage and system equipment is designed in compliance with applicable federal, state and local regulations and standards. Storage is designed for 30 days of normal consumption plus two (2) complete generator fills.

A carbon dioxide system to purge hydrogen gas from the generator is provided. The system will provide for safe purging and venting of the hydrogen gas from the generator. Bulk carbon dioxide storage is provided in a convenient and safe area. Supply and distribution piping with proper supply and vent capacity is provided to the main generator. Carbon dioxide storage and system equipment is provided for two complete generator purges. The storage tank will be located inside the turbine building.

Ammonia Handling and Storage

The anhydrous ammonia handling and storage system will be designed to allow injection of ammonia vapor into the CFB furnace volume as a reagent for reducing NO_X. The ammonia reacts with NO_X and excess oxygen to form water vapor and excess nitrogen. At ambient temperature and pressure, anhydrous ammonia is a gas; however, shipments of ammonia are made as a pressurized liquid by truck or rail transport. A truck or rail unloading station is designed to transfer ammonia from trucks or rail car to a horizontal storage tank. For rail car unloading, forwarding pumps are provided to transfer the ammonia. Transfer pumps located on the delivery trucks will be used for truck unloading.

The storage tank is sized for a 30-day supply, one (1) tanker truck freeboard, and 10% margin for vapor space. Two (2) 100% capacity pumps transport ammonia from the storage tank to a vaporizer skid, where steam is used to evaporate the liquid ammonia. Vaporized ammonia leaves the vaporizer and mixes with dilution air prior to injection into the boiler. Anhydrous ammonia concentrations required for NO_X reduction are regulated automatically by the ammonia control system.

The system design includes features for safe operation and required risk management, including separation distances, leak detection, spray and fogging systems, shower and eyewash stations, and containment barriers. Since ammonia is classified as a hazardous material in the Code of Federal Regulations, appropriate operating and risk management procedures are required, and will be utilized in the event of an accidental discharge.

Coal Unloading, Stock Out and Reclaiming System

Because of differences in delivery methods, availability, and usage requirements, the unloading system for each site is different. For the Salem, Decker, and Hysham sites, coal is delivered at regular intervals in 100 to 110 bottom-dump rail car trains. The rail cars empty into a track hopper, which feeds the coal to a transfer tower. The transfer tower moves coal to either a coal silo or a coal storage pile. The coal storage pile is sized for a 20-day storage of coal with a reclaim hopper and feeder. The reclaim feeder moves the coal back to the transfer tower and to the coal silo.

For the Nelson Creek site, coal is delivered by heavy haul mine truck to a truck hopper located at the generating facility. Coal is emptied into the truck hopper and crushed using feeder breakers before transport to a transfer tower. From the transfer tower, the coal is moved to either a coal storage pile or a coal silo. The coal storage pile is sized for a 20-day storage of coal, with a reclaim hopper and feeder. The feeder moves the coal back to the transfer tower and to the coal silo, which will be sized for 10 days of storage. Because of the close proximity of the plant to the mine the coal is supplied on a continuous basis.

Coal stored in a silo is easily reclaimed with two (2) 100% capacity feeders. The feeders direct the coal to the coal crusher building on two (2) belts, which houses a surge bin and two (2) 100% capacity coal crushers. Coal crushers are designed to supply coal at ¼” x 0 size. The crushed coal is feed to a second transfer tower and on to the tripper deck above the coal bunkers. The tripper conveyer dumps the crushed coal into one (1) of four (4) coal bunkers using a traveling tripper system. The delivery system to the coal bunkers is designed to supply 24 hours of coal in 8-hour hour period.

Limestone Unloading, Stock Out and Reclaiming Systems

Limestone will be delivered by truck or rail depending on facilities available at each site. For the Salem, Decker and Hysham sites, where a track hopper is available, the limestone is delivered via bottom dump rail car trains. The rail cars empty their loads into a track hopper, which feeds the limestone to a transfer tower. The transfer tower moves the limestone to a limestone crusher building. The limestone crusher building contains a surge bin and a crusher designed to reduce the limestone to ¼” x 0 size. From the limestone crusher building the limestone is transported to a limestone silo. The silo is designed for a 30-day storage, with a reclaim hopper and feeder.

For the Nelson Creek site, limestone is delivered by truck to the same truck hopper used for coal deliveries. Limestone is emptied into the truck hopper and flows through feeder breakers before transport to a transfer tower. From the transfer tower, the limestone is moved to a limestone crusher building. The limestone crusher building contains a surge bin and a crusher designed to reduce limestone to ¼” x 0 size. From the limestone crusher building the limestone is transported to a limestone silo. The silo is designed for a 30-day storage, with a reclaim hopper and feeder.

Limestone stored in a silo is easily reclaimed with one (1) 100% capacity feeder. The feeder directs the limestone to a second transfer tower and on to the tripper deck above the limestone bunkers. The tripper conveyor dumps the crushed limestone into one (1) of two (2) coal bunkers using a traveling tripper system. The delivery system to the limestone bunkers is designed to supply 24 hours of limestone in a one-hour period.

Particulate Control Equipment

A flash dryer absorber and pulse jet baghouse (fabric filter) is installed downstream of the boiler to further reduce sulfur dioxide levels and remove fly ash in the flue gas stream. The sulfur dioxide removal portion of this process occurs in the flash dryer absorber where a mixture of water and fly ash will be inserted. A portion of the existing fly ash, removed by the fabric filter, is treated with waste water and re-injected into the flue gas stream. Water and residual calcium oxide (CaO) from the furnace mix to form calcium hydroxide ($Ca(OH)_2$). Calcium hydroxide reacts with the sulfur dioxide in the flue gas stream and is removed by the fabric filter. The baghouse collects the fly ash for disposal and is designed for an emission level of 0.015 lb/mmBTU. Flue gas enters the baghouse through an inlet plenum, and the particulate matter is collected on the outside surface of the bags. Pulsating air is used to remove the ash from the filter media and discharge the ash to the baghouse hoppers.

Ash Handling Systems

Bed ash is removed from the fluidized bed and cooled in the fluidized bed ash cooler. Feedwater from the high-pressure feedwater is used to cool the bed ash. The bed ash is further cooled in a second bed ash cooler by closed cooling water. Cooled bed ash is carried by an air transport stream and forced into the filter separator above the bed ash silo. The air is exhausted through a dust collector to atmosphere. Bed ash is separated from the air stream and transferred to a transfer hopper. The hopper discharges the bed ash into a storage silo, which is sized for 3-day storage. Bed ash is released through a rotary air lock valve to a paddle mixer, where wastewater is used as a dust control agent. Once bed ash is sufficiently mixed with wastewater, it is trucked to an ash storage landfill, where the wet ash will solidify. For the Decker and Nelson Creek sites, the bed ash is trucked back to the mine.

The fly ash is removed from the baghouse and transported to a filter separator. Fly ash is transferred to a transfer hopper and into the fly ash storage silo. The fly ash silo is designed for 3-day storage. To prevent the fly ash from caking inside the silo, air blowers are used to force air into the bottom of the silo. The air fluidizes the ash and exits through the transfer hopper and filter separator. Vacuum pumps draw the air through the filter separator and dust collector. Fly ash is released from the storage silo, through a rotary air lock valve to a paddle mixer, where wastewater is used as a dust control agent. Once fly ash is sufficiently mixed with wastewater, it is trucked to an ash storage landfill, where the wet ash will solidify. For the Decker and Nelson Creek sites the fly ash is trucked back to the mine.

Activated Carbon Injection

The Environmental Protection Agency continues to develop a standard to limit mercury emissions from coal-fired power plants. The degree of the future emissions limitations is not known at this time. Emissions of mercury from combustion processes are due to the presence of mercury in the fuel. When the fuel is burned the mercury is emitted either as particulate, gaseous elemental mercury, or gaseous ionic mercury. If necessary, a carbon absorption system will be installed and utilized to reduce the emissions of all forms of mercury generated in the combustion of coal. Powdered Activated Carbon Injection (PAC) upstream of the baghouse will likely be the least cost mercury control alternative. PAC is a process that removes elemental mercury and mercury compounds by injecting porous carbon into the flue gas. The mercury adsorbs onto the surface of the porous carbon and is collected in the baghouse. The plant will be configured to accommodate the future installation of a PAC system.

Plant Electrical Systems & Equipment

General

The electrical system consists of a generator step-up transformer (GSU), a unit auxiliary transformer (UAT), a start-up transformer (SAT), switchyard and a unit auxiliary power system that provides electrical power to the unit auxiliary loads.

The generator is connected to the substation through the GSU. During plant start-up, the unit auxiliary power system receives power from the switchyard, through the SAT. During normal unit operation, when the generator is on-line, the unit auxiliary power system receives power from the UAT. Transfer from the SAT to the UAT is via an automatic fast transfer scheme. The unit auxiliary power system consists of medium-voltage (13.8 kV and 4.16 kV) switchgear, medium-voltage motor control center (MCC), 480 V switchgear, 480 V MCCs, power transformers and all other electrical equipment necessary to provide a complete and operational system.

Generator & Auxiliaries

The rated capacity and maximum continuous rating of the generator is designed to match the maximum continuous rating of the turbine with a 0.85 power factor plus a small design margin. The generator is furnished with standard generator manufacturer auxiliary equipment.

Generator Step-Up Transformer

The GSU will step up the generator's voltage to the switchyard voltage. The GSU is rated to deliver the maximum continuous output of the generator with the UAT out of service and the SAT providing the auxiliary power load plus a small design margin. The GSU is provided with a ± 5% manual (no-load) tap changer. The tap changer range is selected to permit operation of the generator at nominal voltage over the full active and reactive power capability of the generator when the switchyard bus varies between –7.5% to +5% of the nominal operating bus voltage.

The main leads between the generator and the GSU are isolated phase bus. Tee-off connections as required to the unit auxiliary transformers, exciter transformer, surge arrestors and voltage transformer cubicles are also isolated phase bus.

Unit Auxiliary Transformer And Start-Up Auxiliary Transformer

The UAT is direct connected to the generator isolated phase bus and steps down the generator's voltage to the unit auxiliary power system's medium-voltage switchgear. The UAT is sized to provide all of the unit auxiliary power with 15% extra capacity for future load growth. The UAT is in service during normal operation when the generator is on-line. The UAT is provided with ± 5% manual (no-load) tap changer.

The SAT steps down the switchyard voltage to the unit auxiliary system's medium-voltage switchgear. The SAT is sized to provide all of the unit auxiliary power with 15% for future load growth. The SAT will be in service during start-up when the generator is off-line or when the unit is on-line and the UAT is out of service. The UAT is provided with ± 5% manual (no-load) tap changer.

Unit Auxiliary Power System

The electrical auxiliary supply system for the plant is designed to distribute power to the unit auxiliary power system. The unit auxiliary power system is designed to handle auxiliary load requirements under all plant operating modes and under the contingency of the loss of any of its auxiliary power transformers. The final design of the auxiliary system is based on detailed evaluations of transformer, switchgear and load parameters to ensure acceptable performance. This evaluation consists of short circuit, load flow, and voltage profile analysis including motor starting calculations, under design-limiting operation modes. The unit auxiliary power supply system consists of power transformers, medium-voltage switchgear, medium-voltage MCC, low-voltage switchgear, low-voltage MCC, low-voltage panel boards, motors and other electrical loads.

The main medium-voltage switchgear and MCC is designed to provide power to the medium-voltage motors and the high voltage side of the low-voltage power transformers. Dependant upon site arrangement additional medium-voltage switchgear is fed from the main medium-voltage switchgears to support local loads. The main medium-voltage switchgear will be double ended with tie breakers to limit the possibility of a single fault causing the inoperability of the unit. Medium-voltage MCC is utilized for large motors with frequent on/off requirements.

Low-voltage (480 V) switchgear, in a double-ended configuration, will be supplied from power transformers fed from the medium-voltage switchgear. The number, location and size of switchgear will be determined during detailed design and based on site arrangement and location of loads. Each 480 V power transformer and associated switchgear will be rated to carry, continuously, 100% of the load of both ends of the double ended configuration. A 10% margin for future load growth is provided. The 480 V MCC will be fed from the 480 V switchgear. The MCC will be located and sized as necessary to provide power to smaller auxiliary loads and motors. All MCCs are radial feed with no interconnecting ties between the MCC buses, except for the essential service MCC. A 10% margin for future load growth will be provided.

Two (2) 480 V emergency diesel generators will be provided to supply power to the essential service MCC. The emergency diesel generators will be sized during the detailed design. Essential service type loads are connected to the MCC. These loads may include turbine and generator lube oil pumps, turning gear motors, emergency lighting, plant elevators etc. Unit black start capability will not be provided by these generators.

DC Power Supply

The DC power supply system is ungrounded and consists of one (1) battery. The battery is sized to handle the duty cycles determined during detailed design. The battery has an additional 20% design margin for future loads. Batteries are 25-year lead calcium, general purpose, wet cell stationary type. Two (2) 100% battery chargers fed from different power sources are furnished and provide power to the batteries. The batteries are installed in a designated, ventilated, temperature controlled battery room. The battery system is monitored for ground faults.

Uninterruptable Power System

The uninterruptible power system (UPS) consists of one (1) complete system, which provides regulated power to vital loads during normal and emergency operations. The UPS provides power to vital loads in the event the normal AC power sources fail. The UPS includes solid-state input rectifier, inverter, bypass power supply, static transfer switch, manual bypass switch and a distribution panel board. Power to the UPS will be provided from local a MCC and from the DC Power Supply battery.

Electrical Relaying & Protection

A protective relaying system will be designed to protect the unit's electrical equipment including the generator, GSU, SAT, UAT, switchyard and unit auxiliary power system. The protective relay system protects equipment by quickly de-energizing faulted equipment during abnormal conditions. The relaying system will be coordinated such that the removal of equipment during abnormal conditions is limited to only the equipment necessary. Relays for the switchyard equipment will be located in a switchyard control house.

Communications

The communication system consists of a wired phone communications system capable of connection to an offsite telephone line. Phones are provided in strategic locations throughout the plant to assist plant personnel in communicating internally. In addition, a plant wide paging system will be provided and interconnected to the phone system. A network computer data highway will be provided plant wide to allow for connection in strategic locations.

Lighting and Convenience Power System

The lighting and convenience power systems consist of normal AC lighting, emergency AC lighting, 480 V welding receptacles and 120 V convenience receptacles. The lighting system provides personnel with illumination for plant operation under normal plant operating conditions, means of egress under loss of normal power conditions, and emergency lighting in critical areas for minimal plant operations during a power outage. Emergency lighting will be powered from a dedicated emergency lighting UPS system, the emergency lighting fixtures will be energized via this UPS and will form a part of the normal lighting system. Power used to supply lighting fixtures will be at 277 V. Power used to supply roadway and area lighting installed on poles will be 277 or 480 volts depending on detailed design requirements. Panel boards will be located indoors and in non-hazardous protected areas where possible.

Grounding System

The station grounding system consists of an interconnected network of buried bare copper conductor and copper-clad ground rods. The system will be designed to protect plant personnel and equipment from hazards which can occur during power system faults, and lightning strikes, and to assist in the relaying system's ability to detect line-to-ground faults. A separate grounding grid will be provided for the plant area and the switchyard area. The two grounding systems are isolated from each other in order to avoid transferring step and touch potential from the switchyard to the general plant areas. The grounding grids will be designed with grid spacing such that safe voltage gradients are maintained. All energized equipment will be bonded to the ground system.

Lightning Protection System

Lightning protection design will be in accordance with NFPA 780. In general, lightning protection for buildings and structures consists of air terminals installed around the top of the structure. The air terminals will be connected together with copper cable and connected to the plant ground grid with copper down conductors. Air terminals will be arranged to provide protection for roof penetrating devices, such as piping, air moving equipment, ladders etc.

Cathodic Protection System

The need for a cathodic protection system will be reviewed during detailed design, and if required, will be provided. The system will be used for corrosion control of buried metallic piping, structural parts and grounding grid. Requirements for cathodic protection will be determined during detailed design and depend upon soil type and amount of buried metallic equipment. Cathodic protection system will be of the sacrificial type.

Freeze Protection Systems

A freeze protection system will be provided for outdoor piping, instruments, and equipment subject to freezing in cold weather. The freeze protection system will be designed to accommodate both normal plant operations and extended plant shutdowns in cold weather. Heating elements for freeze protection will be of the self-limiting type. Distribution panel boards will be fed from local MCCs, which furnish power to the freeze protection circuits. Power to freeze protection circuits will be controlled and monitored by ambient thermostats.

Plant Control Systems & Equipment

General

The instrument and control system will be composed of a modern microprocessor-based DCS, analog instruments, discrete sensors, network links to remote control systems, programmable logic controllers (PLC), and control devices. The integrated control system performs the functions of modulating, and discrete control, equipment protection, process interlocking, component diagnostic, unit/process upset analysis, maintenance guidance, and data archiving of the entire unit. The system will be designed to operate and control under all normal and abnormal operational conditions, assuring safe, environmentally compliant, and efficient operation of the unit.

The operating, monitoring and management functions will be carried out in a central control room at work stations, with critical items having hardwired stations. The functions of control, protection, and interlock will be distributed to redundant microprocessor controllers or programmable logic controllers.

The various control elements will be designed for high reliability to maintain the unit in a fully automatic mode of operation. Furthermore, the control system will be designed to allow normal operations to be carried out exclusively within the control room, reducing the workload on the operators. Plant controls do not, however, accommodate fully automatic or remote start-up control functionality and start-up sequences do require manual operation of system elements and active interaction with the control room operators. Control schemes will be provided to maximize the available control functionality during these critical operating conditions and certain Unit start-up, shutdown, normal operation, and emergency actions and other operating conditions will be able to be performed automatically in the unit control room at any time.

Monitoring and control of some relatively independent auxiliary systems, such as the water treatment system, will be self-contained, and require only limited monitoring and control interfaces. The auxiliary systems will be controlled through programmable controllers via local control panels. Important data and control signals, along with system diagnostic information, will be sent to the DCS utilizing network communications. Local control stations and local operator stations will be developed in accordance with a control system design criteria to be developed during the detailed engineering phase. This provides standardized interface graphic for operating and monitoring conventions.

The fundamental functions of control alarm, monitoring, interlock and protection will be segregated to the greatest practicable extent, so that the failure of a function does not result in the failure or loss of control of a parallel or redundant piece of equipment. The DCS will have self-diagnosing abilities, so that internal faults can be detected within the system and may be repaired with minimal impact to plant operations. Where critical systems will be involved, the protection and interlock systems will be provided with redundant channels and multipoint measurement, as well as self-diagnosing functions and adequate test facilities. Diagnostic aids will be developed within the DCS graphics to include dynamic device permissive screens, manual reject cause screens, process overview, and control system status screens.

The control system will be designed with a fault-tolerant architecture. No single fault within the control system will cause the complete failure of any system, or cause the boiler or turbine/generator protection system to initiate a plant shutdown sequence. Process measurement redundancy will be provided for all critical parameters that may directly cause a unit safeguard function to activate. Redundancy in the control system structure will be provided so that no single fault within a control system will cause failure of the controlled equipment or cause the standby equipment to be unavailable. In case of in-service equipment failure, the standby equipment will start automatically without any operator action. Critical components will be designed to function in parallel with the DCS to assure independent control. For example, the Turbine DC Emergency Oil Pump will automatically start if certain conditions exist, independent of any DCS control.

The control room will be arranged in such a manner that the unit may be operated by a single control room operator. Sufficient operator work stations will be provided to allow an operator to see plant system control screens while still displaying relevant alarm and trend screen on adjacent monitors. During periods of unit start-up, shutdown, and upset conditions, additional personnel may be required to operate the DCS systems.

The DCS workstation configuration will allow plant technical staff to perform tuning and control configuration changes via one (1) console in the control room designated as the engineering work station (EWS). This will allow for direct communications between the DCS configuration within the control nodes and the DCS technician.

Local indications will be provided on all remotely operated valves/dampers, analog transmitters, and auxiliary system local control panels. Local audible alarms will be provided for remote independent systems when warranted for system or personnel safety, or system troubleshooting.

The uses of pneumatic and motor operated actuators will be evaluated on a control loop basis. Considerations for actuators include cost, fail-safe requirements, and the environment around the device.

Control Room & DCS Arrangement

Incorporated within the control room will be DCS control consoles, unit monitoring control panel, engineering workstation, trending and alarm monitors. Additionally, a mimic panel will be provided which includes pistol grip generator breaker control switches, generator and turbine lockout relays, emergency trip pushbuttons, synchroscope/auto-synchronization devices, revenue meters, turbine control panel/monitor, and generator control panel/monitor, as required.

Independent control panels will be provided for plant fire protection and alarming, plant paging communications, and emergency diesel generator control. A separate control station will be provided for the continuous emission monitoring system.

The operator's keyboards and mimic panel will be centrally located, designed, and integrated for optimal operating and human factors conditions, providing an ergonomic environment for unit control. The arrangement of the control room will include sufficient space for operator work stations to support unit start-up, shutdown, and upset periods of operation. Communications equipment will be integrated into the control room to allow for ease of operation while maintaining communications with other resources. Printers will be provided for use as sequence of event (SOE) reports, shift reports, monitor screen copies, and data trend copies. All operator workstations will have the capability to monitor and control all functions within the integrated unit DCS. Engineering workstations will be capable of permitting specific functions based upon user login.

The majority of cabinets for the DCS processors, network components, other electronic equipment cabinets, electronic equipment of the generator, the main transformer protection system, and power distribution panels will be arranged in the relay room. Remote DCS cabinets will be placed in environmentally controlled cabinets or rooms to allow for proper electronic component protection. Interconnecting network communication cable will utilize fiber optic media where appropriate. Auxiliary systems containing PLC and operator interface equipment will be mounted within enclosures to maintain full operation and execution of the control systems.

The DCS will be provided with an archiving sub-system (historian). The historian will allow operational and supervisory review of the plant operations. Additionally the DCS will be provided with a plant optimization/performance-monitoring computer. This system will provide real-time feedback to the DCS of operational adjustments needed to maintain efficient operation. The DCS hardware for this functionality will be placed in the relay room adjacent to the DCS control processors and networking equipment. Detailed specifications for these systems will be developed during detailed engineering.

Data communications to the RTO/ISO control center will be provided via hard wired command signals to the DCS for remote control interface signals and via Ethernet for limits and related operational information.

Power distribution to the DCS and critical control-related components will be from dual distribution panels receiving their power from a full function uninterruptible power supply with inverter.

Plant Protection & Interlock System

The plant protection and interlock system will be designed to monitor the validity of the trip and interlock signals and respond to the valid trip and interlock signal immediately so that specific responses or actions can be attained. Each tripping function circuit will be designed with adequate redundancy to ensure the correctness of a trip action, and minimize the possibility of false trips. Each protecting circuit and tripping function will be designed with the capability for on-line testing, and the protection function remains active during functional tests and maintenance. Tripping signals will be sent to the DCS for use as alarming functions, data archiving functions, and SOE functions. The initial recording signal will be maintained in a first out cause of trip (FOCT) window graphic to identify the primary cause of the trip.

Unit protection and interlock items will include, but not limited to:

- Boiler emergency shutdown protection (Master Fuel Trip).
- Turbine fault shutdown protection.
- Generator main protection action shutdown protection.
- Generator lockout relay protection.
- Turbine water induction protection.
- Auxiliary power lockout protection.
- Interlock and protection of important auxiliaries, such as feed water pump, primary air fan, induced draft fan, and secondary air fan.

Specific tripping signals not originated within the DCS will be wired to initiate the required tripping functions independent of the DCS. In general, a parallel signal will be brought into the DCS in these cases to provide alarm and logging of the trip. DCS originated tripping signals will utilize redundant trip output signals to ensure reliability of the trip signals.

The processor based protective relays utilized within the electrical distribution and major equipment systems will be networked to the DCS utilizing either serial communications or Ethernet connections. This will allow for detailed data analysis of archived data within the DCS.

Combustion Control System

The combustion control system will provide all modulating control (analog) functions for the unit controls. The majority of the control loops will be to support the boiler, turbine auxiliary, and balance of plant control loops.

The boiler control system will include, but not limited to, the following components:

- Boiler-turbine coordination control
- Fuel quantity control
- Air flow quantity control
- Furnace pressure control
- Feed water flow control
- Limestone preparation and injection control
- Ammonia preparation and injection control
- Primary air flow control

- Super-heater and reheater steam temperature control
- Air heater discharge temperature control
- Deaerator water level control
- Condenser water level control
- Turbine oil temperature control
- Feedwater condensate heater level controls
- Auxiliary boiler control
- Turbine bypass controls (if required)
- Chemical feed control

To ensure control flexibility, at least four (4) operating modes will be provided for the coordination control system, including manual operating mode, turbine follow mode, boiler follow mode, and coordinated control mode (with remote dispatch from the RTO/ISO).

Burner Management System

The burner management system will provide start-up/shutdown control, operating control of the igniting devices, and furnace safety monitoring and protection in accordance with the most recent edition of NFPA 85 as it applies to circulating fluidized bed combustion.

As a minimum, the system will control the following functions:

- Furnace purge
- Solids admission & interlocking
- Igniting device and combustion start-up/shut-down monitoring
- Coal, limestone, and igniter tripping
- Provide necessary interlocking for the coal, limestone, igniter, and bed conditions
- Provide necessary interface for combustion control system and the plant protection system
- Implosion protection of furnace and flue gas duct

The Auxiliary Boiler will be an independent burner management system in accordance with NFPA 85. The Auxiliary Boiler will have provisions for local start-up and operations.

The burner management system portion of the DCS will provide FOCT for the master trip signals and will incorporate signal input quality logic to minimize spurious unit trips. Signals that may require maintenance during normal operation will have multiple sensors provided to allow for two-out-of-three trip logic.

Turbine Digital Electrohydraulic Control System

The turbine control system (TCS) will be designed to provide automatic turbine speed control from turning gear to target load at maximum rate compatible with the thermal state of the turbine, steam inlet conditions and allowable expenditure of turbine life expectancy. The system will perform load control functions, load limit and rate limit functions, speed control, steam admission mode control, and turbine monitoring functions; and will provide redundant electronic overspeed protection by means of electronic governor controls.

The TCS will utilize redundant field signals to evaluate and initiate a turbine trip signal. The trip logic will be coordinated with boiler controls to ensure proper unit operations.

The operator interface to the TCS will be via the DCS with direct control utilizing the turbine vendor's insert panel, depending on final turbine vendor selection. All signals will be archived in the DCS and allow full integration of the TCS with the plant DCS coordinated control strategy.

Vendor specific control loops will be provided including speed loop, pressure loop, and megawatt loop for smooth operation of the turbine generator.

Motor Controls

The motor and discrete system controls will be incorporated within the DCS. Start permissive status and sequential interlocks will be included in the logic. Auxiliary systems, such as fly ash, bag house, electro hydraulic control (EHC) skids, and ammonia injection will have operator interface through the DCS, even where local PLC will be utilized for the actual control system strategy.

The motor controls will be segregated so that no single DCS component can cause the non-operability of redundant components. Specific PLC based systems will have the capability for local or remote operation. Automatic operations of redundant components, such as EHC fluid pumps, will be incorporated into the control strategy to maintain system reliability.

The DCS cabinets will be located as near to the controllable devices as practical, and will be based upon the quantity of signals needed. In general, all MCCs will be provided with an adjacent DCS I/O rack for wiring of signals.

Alarm Management System

All alarm items in the scope of the DCS will be displayed on monitors available at any operator or supervisory workstation. The control system design criterion will include specific requirements for the assignment and configuration of the alarm management system.

The DCS will be capable of presenting alarms in a clear concise manner; including the ability of the operator to place a specific workstation into an "Alarm Filter" mode to allow for quick response to major process upsets.

The DCS will archive alarms for retrieval in a file format to allow for review of events on a historical basis.

The DCS will have the capability to configure the routing of alarms to a printer.

Section 5

Project Schedule

A summary-level engineering, procurement, construction, and commissioning schedule was developed for the project. A conventional design, bid, build approach was assumed with major equipment contracts of steam turbine, CFB boiler, chimney, cooling tower and material handling contracts developed on a furnish-and-erect concept. The schedule establishes the major milestone dates for the project.

The Project Schedule has an overall duration of 51 months from start of preliminary engineering to commercial operation of the plant. A phased approach to the work was utilized in the schedule development. This approach allows construction to begin early on site preparation, foundations and underground utilities, while design of the above-ground mechanical, piping, buildings, structures, and electrical systems is being developed.

The Schedule is based on a notice-to-proceed for preliminary engineering immediately following the Board Meeting on July 19, 2004. During the preliminary engineering phase, the initial designs of the plant will be completed, and the boiler and turbine generator contracts will be bid and awarded. The award of these major contracts is anticipated in December 2004 and January 2005, and is vital to the completion of the detailed design and balance-of-plant procurement for the project.

Detailed design will start December 1, 2004. The schedule documents the major design activities by discipline and work package. It is anticipated that detailed design will be complete by September 2006. The design has been staged to support bidding of the major construction contracts as required to implement the project activities in the appropriate schedule durations.

Procurement of the balance-of-plant equipment will begin in December 2004, upon notice-to-proceed for Phase 3, and be completed before the end of 2005. Vendor design from the procurements will provide specific information, which will be incorporated into the design documents being prepared by Stanley Consultants for the following construction contracts. Deliveries of the balance-of-plant equipment have been planned based upon the expected field-required dates for each piece of equipment.

Construction activities will begin in November 2005, with site grading and site preparation activities. Foundation construction will begin in January 2006, and will continue for approximately one (1) year. Foundation installations will begin with the boiler foundations being completed first. Boiler construction will commence as soon as foundations are available, which is anticipated to be May 2006. The boiler and baghouse construction will be completed in approximately two (2) years, and is the critical path of the project. The boiler and baghouse construction will be complete in May 2008. The turbine generator erection will begin in January 2007 and take one (1) year to complete.

The furnish-and-erect contracts for the cooling tower, chimney, and material-handling systems will be awarded in early 2005, which allows for vendor design information to be incorporated into the substructures and other construction contracts. Construction for each of these contracts is planned to start in mid to late 2006. The balance of the mechanical (M) and electrical (E) work will be accomplished under the General M/E contract, which will be awarded by September 2006.

Duration for plant start-up activities is eight (8) months, which will commence in February 2008, and will be complete in October 2008. Commercial operation is planned for October 29, 2008.

Section 6

Cost Estimate

Cost estimates for the project were developed based on the conceptual design. Budgetary estimates for major equipment were obtained from suppliers to support the cost estimate effort. A single site cost estimate was utilized as the baseline information for the production cost calculations. Any site-specific costs identified at the proposed sites were developed as noted in the site-specific task activities in the “Development Costs” subsection of Section 2 entitled “Site Selection.”

Capital Cost Estimate

Capital cost estimates were developed for installation of a new coal-fired power plant as described in Section 4 entitled “Project Description,” utilizing Stanley Consultants’ experience with similar projects, manufacturer cost data, and the cost database and information obtained from the STEAM PRO™ software. The detailed cost estimate for each site can be found in Appendix K – “Capital Cost Estimate.”

For each cost category, there are two columns of data. The first column documents the reference cost and the second column documents the estimated cost. The reference cost pertains to a hypothetical “Reference US Site” which is the basis for all calculations. The estimated cost is the actual site cost after regional cost adjustments are made. The regional adjustments are documented on the cost multiplier page. These adjustments to the reference costs have a basis of adjustment for the State of Montana.

Project Cost Summary Sheet

This summary sheet reflects the breakdown by category of all estimated costs for the new power plant. The total project cost is itemized into nine (9) categories, seven (7) hard cost categories, in which each category has an associated detailed summary of costs, and two (2) soft cost categories, with an associated detailed summary of costs provided in the “Soft & Miscellaneous Costs” section. The “Project Cost Summary” sheet for each proposed site summarizes the estimated contractor and owner total cost, along with the costs in terms of

$/kW for the estimated coal-fired generation station as a function of net plant output. It should be noted that the “Specialized Equipment” and “Other Equipment” costs are totaled in the contractor’s estimated cost. STEAM PRO™ software assumes the project to be built utilizing an Engineer, Procure and Construct (EPC) approach to the project.

Stanley Consultants revised the project estimate output based upon a conventional design, bid, and build project approach where procurement of the major equipment would be by Southern Montana Electric Generation & Transmission Cooperative, Inc. (SME). This approach provides for the least cost project for SME, but does place some additional risk on SME. Therefore, the contractor’s contingencies noted for this equipment are based on providing the necessary handling of the equipment and the resulting costs, and not the profit mark-up experienced when procuring the major equipment with the EPC contracting approach.

Specialized Equipment Sheet

This section includes the major equipment costs, such as the boiler; steam turbine, feedwater heaters, condenser, baghouse, stack, and other supporting auxiliary equipment. There is no cost adjustment between the reference cost and the estimated cost as this sheet lists the cost of the equipment. The estimated cost is the total cost excluding such items as foundations, rigging, erection, and installation, which appear separately under the civil, mechanical, and electrical categories. The boiler, steam turbine, and condenser costs were verified utilizing vendor pricing estimates.

Other Equipment Sheet

This section includes the balance-of-plant (BOP) equipment required for the plant -- pumps, tanks, basic material handling equipment, and other auxiliary equipment. The estimated cost is the total reference cost with no adjustment. Items such as foundations, rigging, erection, and installation appear separately under the civil, mechanical, and electrical categories. The cost for “Miscellaneous Equipment” is determined by adding 5% to the cost summary of this section. Stanley Consultants has added line items to include the cost for a condensate polisher and material handling equipment. The “Extra Material Handling Equipment” includes the cost for transfer towers, coal silos, limestone crusher, limestone silos, and conveyors.

Civil Sheet

The civil category is divided into several separate categories including “Site Work”, “Excavation & Backfill,” “Concrete,” and “Roads, Parking, & Walkways.” “Site Work” is one lump sum price for clearing the site, grading, fencing, and general site conditioning. “Excavation & Backfill,” as the title for this item implies, includes the costs of excavation and backfill for foundations and underground piping. The material costs include equipment rental costs for earth moving equipment such as backhoes and bulldozers, as well as the cost of commodities such as sand and gravel. “Concrete,” in the material cost column, includes all costs necessary for forms, reinforcing steel, grout, and concrete. The work covered within this section includes labor, subject to regional cost variances. The estimated cost contains a cost multiplier on the labor portion of the reference cost.

Mechanical Sheet

The mechanical category is divided into several separate categories including “On-Site Transportation & Rigging,” “Equipment Erection & Assembly,” “Piping” and “Steel.” “On-Site Transportation & Rigging” includes cost of the rental of cranes and other equipment required for moving and rigging heavy items onto their foundations. This item includes the associated costs for crane operators and support crews, and is a lump sum price. It is not itemized for each heavy component to be rigged. The STEAM PRO™ software treats the requirement for cranes and crews as a lump sum since heavy rigging equipment and construction workers will be on site performing a variety of tasks over a relatively long period, making it difficult to allocate hours to each individual task. “Equipment Erection & Assembly” includes the costs of labor and field material to erect and assemble the major mechanical equipment. This does not include the cost of the equipment being installed. These costs were listed previously in the categories of “Specialized Equipment” or “Other Equipment.” This cost item includes field materials, such as bolts & nuts, welding rod, shim and stock material, oxygen and acetylene gas cylinders and fuel to run machinery such as compressors and generators. This cost item is estimated as a function of the number of hours of labor required for each activity. “Piping” includes the costs of pipe and all associated materials including welding supplies, fittings, valves, and insulation. The piping material cost includes chrome molybdenum pipe for the critical steam piping systems. This cost item also includes the labor to install the piping including the regional labor cost multiplier. “Steel” includes the costs for pipe racks, pipe supports, and access platforms as required for the installation. This cost item also includes the labor to install the material with the regional labor cost multiplier.

Electrical Sheet

The electrical category is divided into two (2) different categories “Controls” and “Assembly & Wiring.” These categories include all materials and labor to install and wire the electrical equipment, but do not include the main electrical equipment. The main electrical equipment costs can be found on the “Specialized Equipment” or “Other Equipment” sheets. The labor portion of the estimated cost includes the regional labor cost multiplier.

Buildings Sheet

This cost category lists all major buildings, the floor area of each, and its referenced cost, which is calculated based on the area. The area calculated cost is adjusted for climate to accommodate for snow loads, insulation, and heating requirements for all buildings in the northern climates. The buildings include the boiler, steam turbine, administration, warehouse, shops, water treatment and guard house. The turbine and boiler building are estimated based on equipment size and arrangement. The area for the remaining buildings is based on the plant’s size and complexity. The cost multiplier to adjust the reference cost to the estimated cost is based on the average of the regional labor cost multiplier and the regional commodity multiplier. The program estimates that roughly half of the building cost is due to labor and half to materials.

Engineering & Start-up Sheet

“Engineering” costs include the cost of detailed plant design drawings, process and instrument diagrams (P&IDs), heat balances, operation and instruction manuals, electrical one-lines, and system descriptions. This cost item includes preparation of specifications, engineering support of procurement and construction, and expenses for engineering personnel located at the project site. "Start-Up" costs include the sum of materials, equipment, labor, and overhead costs incurred during the period identified as the completion of the construction and the beginning of commercial operation of the plant.

Soft & Miscellaneous Costs Sheet

The "Soft & Miscellaneous Costs" category is divided into "Contractor's Soft Costs" and "Owner's Soft Costs." The percentages used for this estimate are listed on the last page of the STEAM PRO™ cost sheets. Included on this page are the regional multiplier adjustment factors utilized for cost estimating. "Contractor's Soft Costs" include cost calculated utilizing the percentages listed on the last page of the cost sheets of the relevant category times the subtotal of all hard costs (which are listed and identified above) for the project. "Owner's Soft Costs" include cost calculated utilizing the percentage listed on the last page of the cost sheets of the total Contractor's Cost times the Contractor's soft costs, or places a fixed amount identified in the list into the sum of the cost of the project.

Contingency

A contingency factor of 10% was added to the "Contractor's Soft Costs" for specialized equipment, other equipment, and commodities. In a conventional design, bid, build project, the Owner procures the specialized equipment and other equipment as described above. The 10% contingency provides contingency for additional risks associated with procuring these items.

The table below summarizes the capital cost requirements for project development at each site. The project costs do not include any specific site improvements discussed in Section 2 – "Site Selection" in the "Development Cost" subsection, nor interest during construction. The estimated owner's capital cost and the relevant cost of the project, stated in terms of dollars invested per net output for the proposed project sites, are documented below. The difference in cost between the sites represents the different types of coals utilized. The lower the higher heating value (HHV) of the coal, the higher the capital cost and cost per net output.

Table 6-1
Capital Cost Estimate Summary

Description	Salem	Salem Industrial	Decker	Hysham	Nelson Creek
Estimated Owner's Cost (x 1,000)	$376,100	$376,100	$438,200	$397,900	$419,700
Estimated Owner's Cost ($/kW)	1,504	1,504	1,753	1,592	1,679

Cash Flow

A cash flow of expected expenditures by SME was developed. The cash flow documents cash outlays by SME on the month that the money would be paid out, which is generally 30 days after billing by the contractor or vendor. Progress payments to equipment vendors for items such as award, engineering completion, procurement of materials for fabrication, and final delivery of equipment have been factored into the cash flow projections. For construction contracts, payment to the contractor for completion of major milestones or events within the sequence of the work has been factored into the cash flow projections.

The first major payment by SME occurs in January 2005, with award of the boiler contract. At that point in the project schedule, cash requirements are approaching $10 million. By July 2005, the project is well into the procurement process and payments by SME will be over $25 million. When construction starts in November 2005, payments are projected to reach $57 million. In October 2006, the curve will reach $125 million, and the slope of the cash flow curve becomes much steeper. At that point in the project schedule, major contractors will be well into construction activities. Cash requirements for the final two years of the project average approximately $13 million per month.

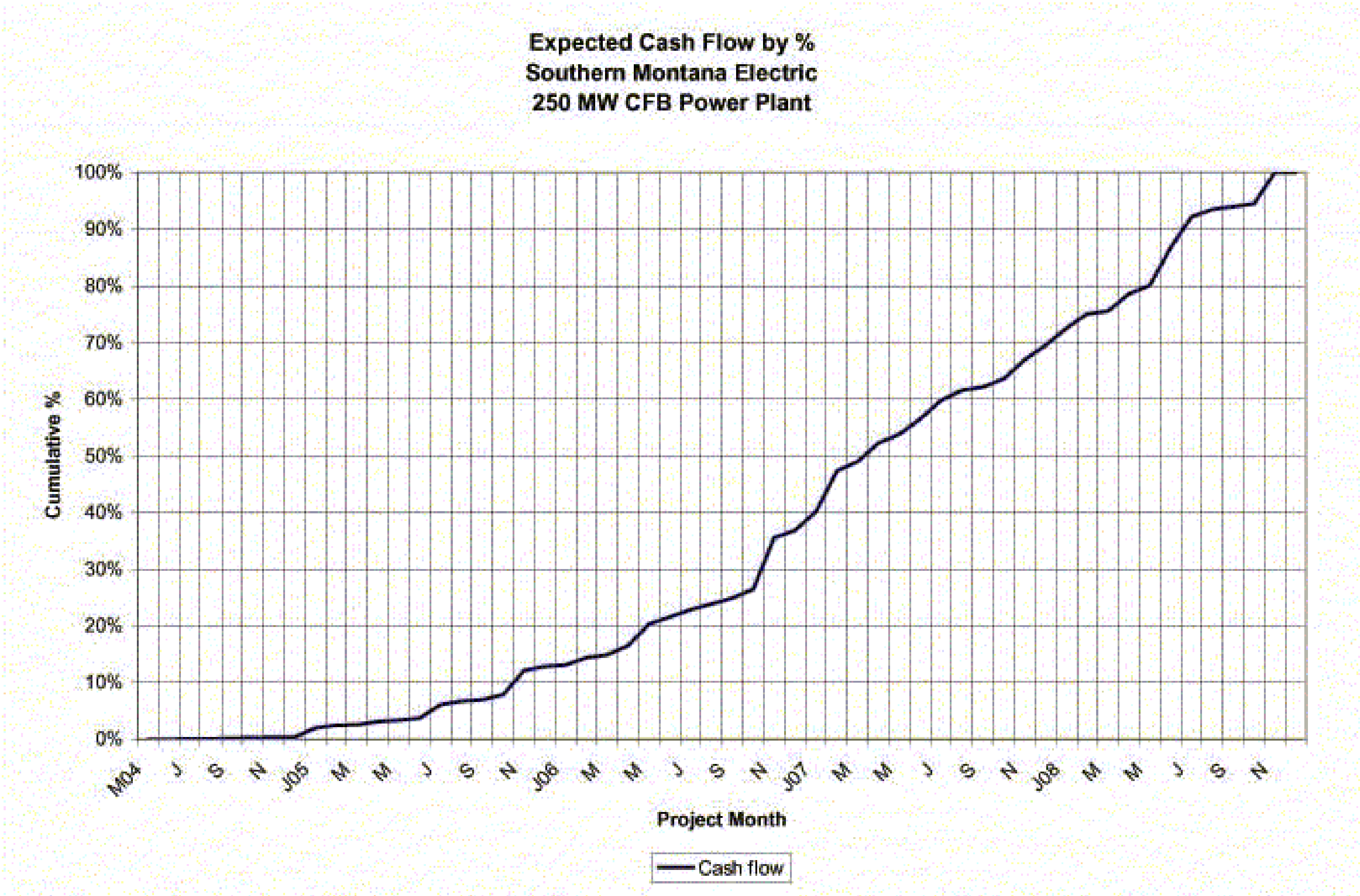


Figure 6-1

Expected Cash Flow by %

Section 7

Economic Analysis

The purpose of the economic analysis is to compare the total annual fixed and variable costs of the generation plant at each of the proposed project sites over a future 30-year period. The results of the evaluation will be used as an aid in selecting the most economical site for the new plant. The plant is assumed to start operation on January 1, 2009, and consequently the evaluation period covers the operational time beginning 2009 and ending in 2038.

The following individual costs were projected at each site:

- Fuel Costs
- Administrative & General Expense
- Fixed O&M Costs
- Transmission O&M Expense
- Variable O&M Costs
- SO2 Emission Allowance Cost
- Debt Service Payment
- Property Taxes and Insurance

The total of the above noted costs are referred to throughout this study as "busbar" costs. The dollar "busbar" costs are converted into cents per kilowatt-hour (kWh) of plant output to compare the costs for each of the proposed sites.

Projections were made for two (2) different alternates at all locations. Alternate 1 assumes the plant is fully loaded at 250 MW at the time of system peak and operates at an annual capacity factor of 90%. Alternate 2 assumes the plant is 80% loaded (200 MW) at the system peak and operates at an annual capacity factor of 65%. While the fixed costs will not change for the two alternates, the fuel costs and variable O&M costs will change significantly resulting in a considerable change in the busbar costs.

Comparison of the resulting costs between the two alternates will indicate if anticipated plant loading will have a significant role in the decision making process.

The projections for both alternates at the proposed sites were made for an assumed set of "base parameters" (Base Case). Additionally, "Sensitivity Cases," which tested the impact on total costs for changes in the estimated installed capital costs and coal cost escalation rates, were developed.

Parameters

The parameters used in the study are divided between the two (2) categories of "site-specific" parameters (costs that vary by site location) and "common" parameters (costs that remain constant at all locations). Consequently, the site-specific parameters are the most critical in comparing individual plant site costs since the common costs are common to all proposed project sites. The common parameters were identified, and provide an indication of how these parameters may impact the total busbar costs.

The site-specific parameters consist of the following:

- Generation Plant Capital Costs ($1000)
- Heat Content of Coal (BTUs/lbs.)
- Transmission Capital Costs ($1000)
- Variable O&M (¢/kWh)
- Delivered Coal Costs ($/ton)
- Net Plant Heat Rate (BTUs/kWh)
- Fuel Costs (¢/kWh)
- Limestone Flow (lbs/hr)
- Delivered Limestone Costs ($/ton)

The common parameters consist of the following:

- Administrative & General Expense ($1000/yr)
- Transmission O&M (% transmission investment)
- Property Taxes & Insurance (% total investment)
- Financing Interest Rate (%)
- Earned Interest Rate (%)
- SO_2 Emission Allowance Costs ($/ton)
- SO_2 Emissions (lbs/million Btus)
- Escalation Rates (%)

A summary of parameters by site is documented on Table 7-1. The majority of site-specific parameters and SO_2 emissions and costs have been discussed in previous sections of this report. Fixed and variable O&M costs are based on previous studies, and a review of publicly available operating cost information of systems of similar design. Variable O&M costs include a base cost of 0.235¢ per kWh. An additional allowance was added to the base to accommodate for limestone costs.

Long-term financing costs and loan period were based on a review of RUS's web site. From this web site, information was obtained relative to interest rates on money. The percent interest earned is based on judgment and is used in computing interest during construction.

Estimates of administrative and general expenses, transmission operation and maintenance expenses, and property taxes and insurance are based on information obtained from publications of the Energy Information Administration (EIA) regarding financial statistics.

The majority of the escalation rates are based on general inflation for the area. Coal cost escalation rates were based on a review of EIA's most recent "Annual Energy Outlook." This report documents coal costs in terms of constant 2002 dollars, and reflects relatively constant escalation over the study period. An escalation factor of 1.0% per year was utilized to account for inflation, and is considered conservative.

A review of the summary table indicates that an obvious statement regarding which site will have the lowest "busbar" costs cannot be made without performing financial projections. The site with the lowest capital cost (Salem) has the highest variable related costs, and proposed sites with lowest fuel costs have the highest capital costs.

Table 7-1

Summary of Parameters					
Site Specific	**Salem**	**Salem Industrial**	**Decker**	**Hysham**	**Nelson Creek**
Capital Costs ($1,000)					
Generation Plant	[redacted]				
Interest During Construction	[redacted]				
Subtotal	[redacted]				
Transmission Plant	[redacted]				
Interest During Construction	[redacted]				
Subtotal	[redacted]				
Total	[redacted]				
Net Heat Rate, Btu/kWh	[redacted]				
Alternate 1	[redacted]				
Alternate 2	[redacted]				
Fuel Characteristics	[redacted]				
Heat Content, Btu/kWh	[redacted]				
Delivered Costs, $/ton	[redacted]				
¢/Millikon Btu's	[redacted]				
¢/kWh	[redacted]				
Alternate 1	[redacted]				
Alternate 2	[redacted]				
Plant (O&M)	[redacted]				
Fixed ($/kW/year)(1)	[redacted]				
Variable (¢kWh)(2)	[redacted]				
Alternate 1	[redacted]				
Alternate 2	[redacted]				
Common to All Sites					Escalation Rates (%/year)
Transmissio O&M	[redacted]				
Property Taxes & Insurance	[redacted]				
Long Term Financing	[redacted]				
Interest	[redacted]				
Loan Term	[redacted]				
Interest Earned	[redacted]				
SO_2 Emissions	[redacted]				
SO_2 Emissions	[redacted]				
2009-2015	[redacted]				
2016-2038	[redacted]				

(1) Used $27.5 for Alternate 2 so that fixed costs of Alternate 1 and 2 would be the same.

(2) Includes base cost of 0.235 ¢/kWh. Difference between total and base is due to limestone costs.

Study Results

Stanley Consultants' financial computer model was modified for use in this study. Some of the input and output values are shown as zero in this study when these particular parameters or costs were not utilized. The model was run for the base case and the following sensitivity cases.

- Case S1   10 % increase in capital costs
- Case S2   15 % increase in capital costs
- Case S3   3.0 % coal cost escalation

Input sheets and the results summary tables are included in Appendix J. One set of summary tables documents a breakdown of the total dollar "busbar" costs into individual cost components as well as total cents per kWh cost for the first 10 years of the study. These tables show that, by far, the single largest cost component is the debt service payment (principal and interest). The next two largest components are fuel costs and property taxes and insurance, with the relative position of the two varying between sites.

The other set of summary tables shows the total "busbar" costs in cents per kWh for each year of the study as well as the "30 Year Levelized Cost." This value is a convenient way of comparing the costs of each proposed project site considering the total 30-year planning period. If this value is assumed constant over the entire 30-year period, the sum of the present value for each of the 30 years would be equal to the total 30-year present value cost for the site being examined.

In evaluating any alternative, both individual annual costs and levelized cost need to be examined. Selection of an alternative based solely on the levelized value places significant emphasis on the long-term projected costs. For example, in some cases one alternative may not become the economic choice (have the lowest annual cost) until 10 or 15 years with the result that the levelized cost over the entire period is the lowest cost of all alternatives.

Table 7-2 provides a summary of the 30-year levelized costs for each site for both Alternates 1 and 2, utilizing output in Appendix J. The following observations are made upon review of this table for Alternative 1. This alternative assumes the unit is fully loaded at the system peak and operates at an annual 90% capacity factor.

For base case conditions (Alternative 1), the Salem site has a levelized cost of [redacted] kWh. Hysham, Decker, and Nelson Creek sites have the highest cost in all base cases by significant amounts with the Nelson Creek site, by far, having highest cost.

The Salem site will have the lowest cost in all years for a 1.0% per year coal escalation rate. However, for a 3.0% annual coal escalation, fully loaded at system peak and annual 90% capacity factor (Alternative 1), the Hysham and Decker sites will have the lowest 30-year levelized cost, and will become the lowest cost site in 2017 and 2026 respectively.

A review of the costs for Alternate 2 with a 3.0% annual coal escalation, which assumes the unit is loaded at 80% at the system peak and operates at a 65% annual capacity factor, the Salem site has the lowest 30-year levelized costs. There is a crossover in lowest "busbar" cost at year 2035 from the Salem site to the Hysham site.

The following summary is made regarding site selection when considering only “busbar” costs:

- The economic choice is the Salem site.
- The Salem site will have the lowest costs under those conditions where the unit is not fully loaded for a significant period of time during the year.
- It is only when coal costs escalate higher than expected, and when the unit is virtually fully loaded, that there is a significant cost advantage of the Hysham site compared to the Salem site.

Table 7-2

Summary of 30-year Levelized Busbar Costs (¢/kWh)						
	Alternate 1 - Unit Fully Loaded at System Peak					
	Salem	Salem Industrial	Decker	Hysham	Nelson Creek	Cross Over (1)
Base Case	[redacted]					
Case S1-10% Capital Cost Increase						
Case S2-15% Capital Cost Increase						
Case S4-3.0% Coal Escalation	[redacted]					2017-Hysham 2026-Decker
	Alternate 2 - Unit 80% Loaded at System Peak					
Base Case	[redacted]					
Case S1-10% Capital Cost Increase						
Case S2-15% Capital Cost Increase						
Case S4-3.0% Coal Escalation	[redacted]					2035-Hysham

(1) Year in which Hysham or Decker busbar costs become smaller than Salem's busbar cost.

Section 8

Ranking Analysis & Conclusion

Stanley Consultants identified and reviewed the risks associated with the project, listed and discussed in this section. A project site ranking analysis is also provided. This analysis will identify risks of developing the project. Finally, the proposed project site will be compared for risks and costs, with a recommendation made.

Ranking Analysis

Several site-specific risks were identified with potential to cause detrimental impact to project outcome. These risks include:

- Ability to obtain air quality permits
- Ability to obtain MPDES permit
- Ability to obtain other water permits
- Ability to obtain solid waste permits
- Availability of fuel supply
- Water resources required for operation
- Availability of transportation infrastructure
- Availability of transmission lines and the feasibility of interconnection

These risks are summarized in the following table, and ranked in accordance with the documentation provided in previous sections of the report. Cumulative risk for each site was determined, and the site with lowest evaluated risk was identified.

Table 8-1
Risk Analysis[5]

Activity or Risk	Salem	Decker	Hysham	Nelson Creek
Air Permits	1	1	2	4
MPDES	1	1	1	1
Other Water Permits	1	1	1	1
Solid Waste Permits	1	1	1	1
Fuel Supply	1	1	1	2
Water Resource	1	3	3	2
Transportation	1	1	1	3
Transmission	1	2	1	2
Cumulative Summary Risk	8	11	11	12

[1] Low risk in obtaining a permit / relatively easy to obtain commodity or develop infrastructure.
[2] Normal risk to obtain permit / normal activity to obtain commodity or develop infrastructure.
[3] High risk in obtaining a permit / difficult to obtain commodity or develop infrastructure.
[4] Nelson Creek was not assessed for air permitting risk as the dispersion model was not performed.
[5.] Salem includes both sites Salem & Salem Industrial

Other activities and risks which may impact the project are:

- *Capital Cost Estimate – Material Cost Escalation*

  Stanley Consultants identified the potential for major increases in steel, aluminum, copper, and other material costs. This potential for material cost escalation is not reflected in the capital cost estimated included in this report. Estimated costs for the steam turbine generator, CFB boiler, condenser, and cooling tower are provided by equipment suppliers at current prices. As such, prices have some adjustment for the recent increases noted, and are included in the cost estimate.

- *Schedule Impacts – Winter Construction Activity*

  The current project schedule starts site work in late fall, and reflects the need to install major foundations during winter months of January and February 2006. Due to the severely cold weather during these months, additional resources will be required at an additional cost. Resulting additional cost for winter construction activities has not been included in the cost estimate or reflected in possible schedule delays.

- *Project Performance Risks*

  A contracting approach of design-bid-build was identified in the schedule and cost of the project. With this project approach, SME will assume more of the project-related performance and warranty risks, as individual equipment suppliers are responsible for their equipment performance and warranties only. Should SME elect to perform the project as an engineer-procure-construct approach, the project will result in higher project costs, as the contractor will include additional money to cover additional risks of performance.

Conclusion

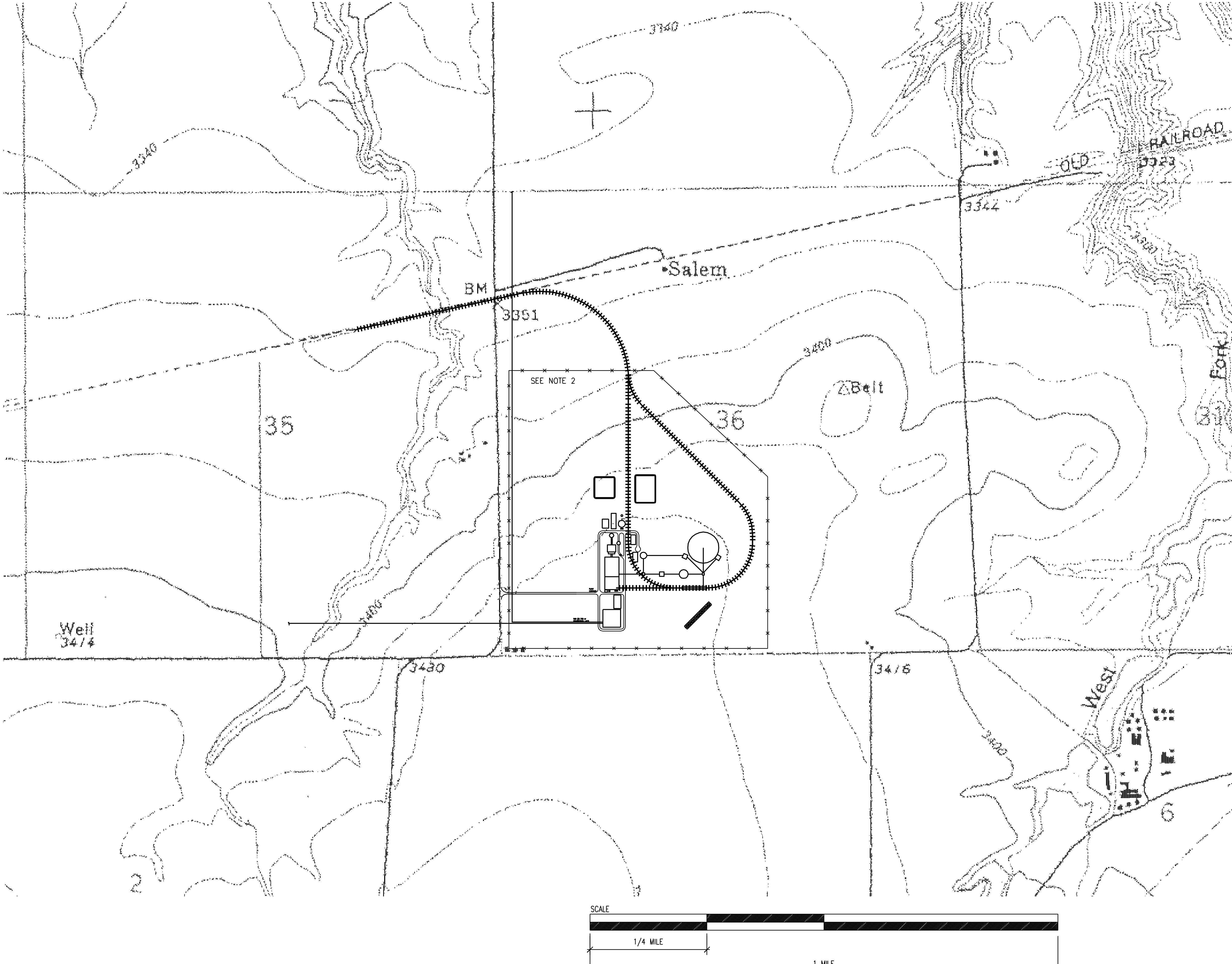
Stanley Consultants has addressed the major components, which are necessary for development of a coal-fired power plant project. The components consist of transmission and transportation infrastructure development, equipment, fuel sources, water supplies, and permitting of the proposed facility. The proposed site development costs were identified and compared, relative to other sites. An economic analysis of "busbar" costs was performed. The economic and risk comparisons of each site results in the recommendation of the Salem site.

The following advantages are noted for the proposed Salem site:

- The site is considered environmentally-friendly. Obtaining air and water permits will be achievable. The air permit will utilize the previous information to the extent possible, and a previous permit obtained for a project permit.
- Water is available from the Missouri River through the City of Great Falls, Montana, water rights allocation.
- The project has the lowest capital cost of $469,600,000, which results in an installed cost of $1,878 per installed net capacity (kW).
- The site has the second best heat rate of 9,580 BTU/kWh when utilizing Spring Creek coal and the best heat rate of 9,530 BTU/kWh when using Decker coal.
- The project has the lowest "busbar" cost, with the first year cost of [redacted] and a 30-year levelized cost of [redacted] for an equivalent annual capacity factor of 90%.

Appendix A

Site Plans



NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. FENCED SITE AREA IS 195 ACRES.

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
SALEM GENERATING STATION
SITE AREA

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: AS NOTED

NO. 17180

S1-GA01 REV. A

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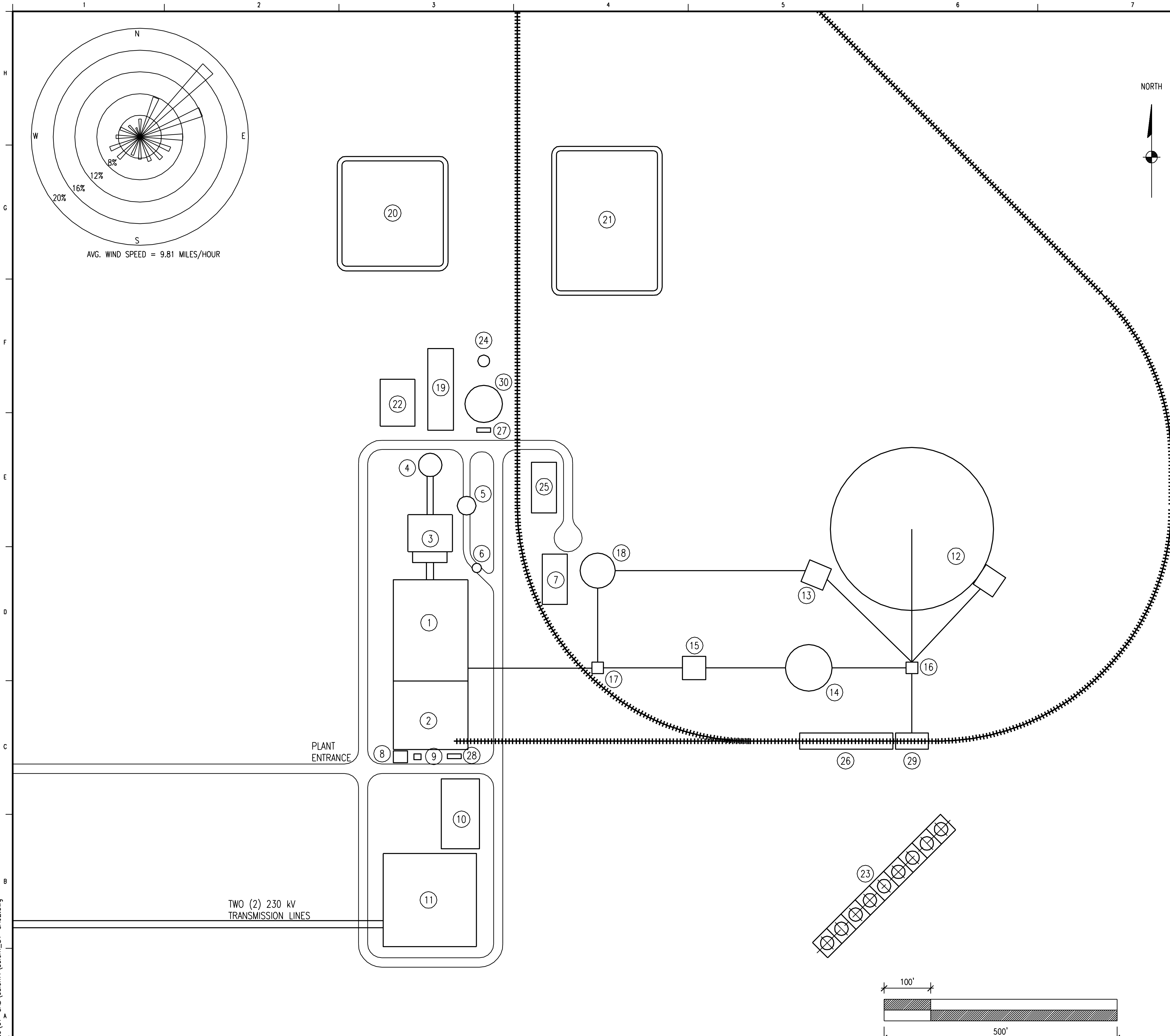

NO.	DESCRIPTION
1	CFB BOILER
2	TURBINE BUILDING
3	BAGHOUSE
4	STACK
5	FLYASH SILO
6	BED ASH SILO
7	AMMONIA STORAGE
8	MAIN POWER TRANSFORMER
9	AUX TRANSFORMER
10	WAREHOUSE & ADMIN BUILDING
11	SWITCHYARD
12	COAL PILE STORAGE & RECLAIM HOPPER
13	LIMESTONE CRUSHER HOUSE
14	COAL SILO
15	COAL CRUSHER HOUSE
16	TRANSFER TOWER
17	TRANSFER TOWER
18	LIMESTONE SILO
19	WATER TREATMENT BUILDING
20	EVAPORATION POND
21	STORMWATER RUNOFF POND
22	WASTE WATER TREATMENT
23	COOLING TOWER
24	CLARIFIER
25	COAL HANDLING MAINTENANCE BUILDING
26	COAL CAR THAWING SHED
27	FIRE PUMP HOUSE
28	EMERGENCY GENERATOR
29	TRACK HOPPER
30	RAW WATER TANK

NOTES

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PRELIMINARY

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A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
SALEM GENERATING STATION
SITE ARRANGEMENT

DESIGNED P. EGGERS
DRAWN P. EGGERS
CHECKED T. FREEMAN
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: 1"=60'
NO. 17180
S1-GA02
REV. A

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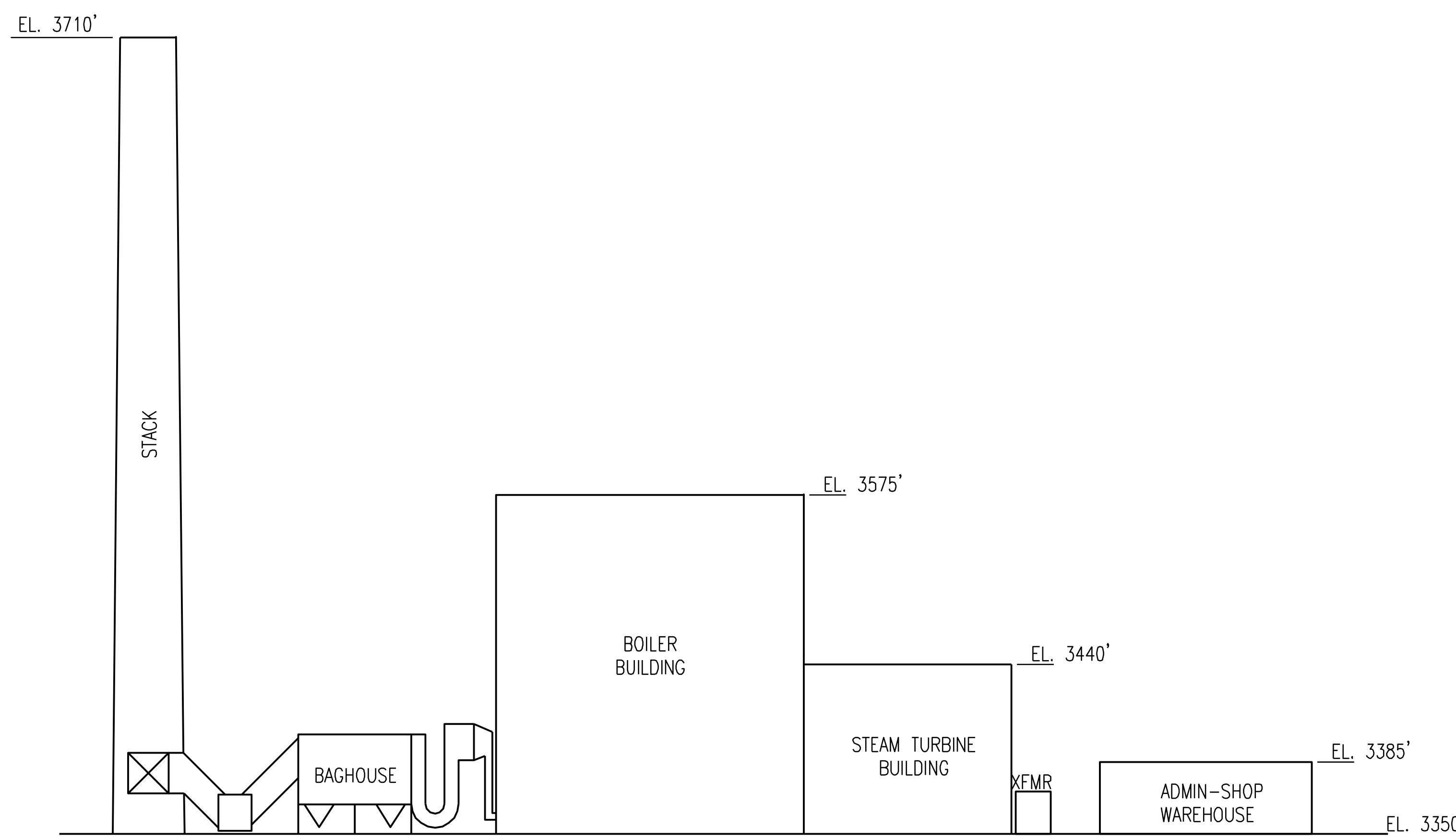
CADD D1-R3

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.



PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	60-04-04

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MONTANA - 43 - SOUTHERN SALEM GENERATING STATION SITE ARRANGEMENT ELEVATION

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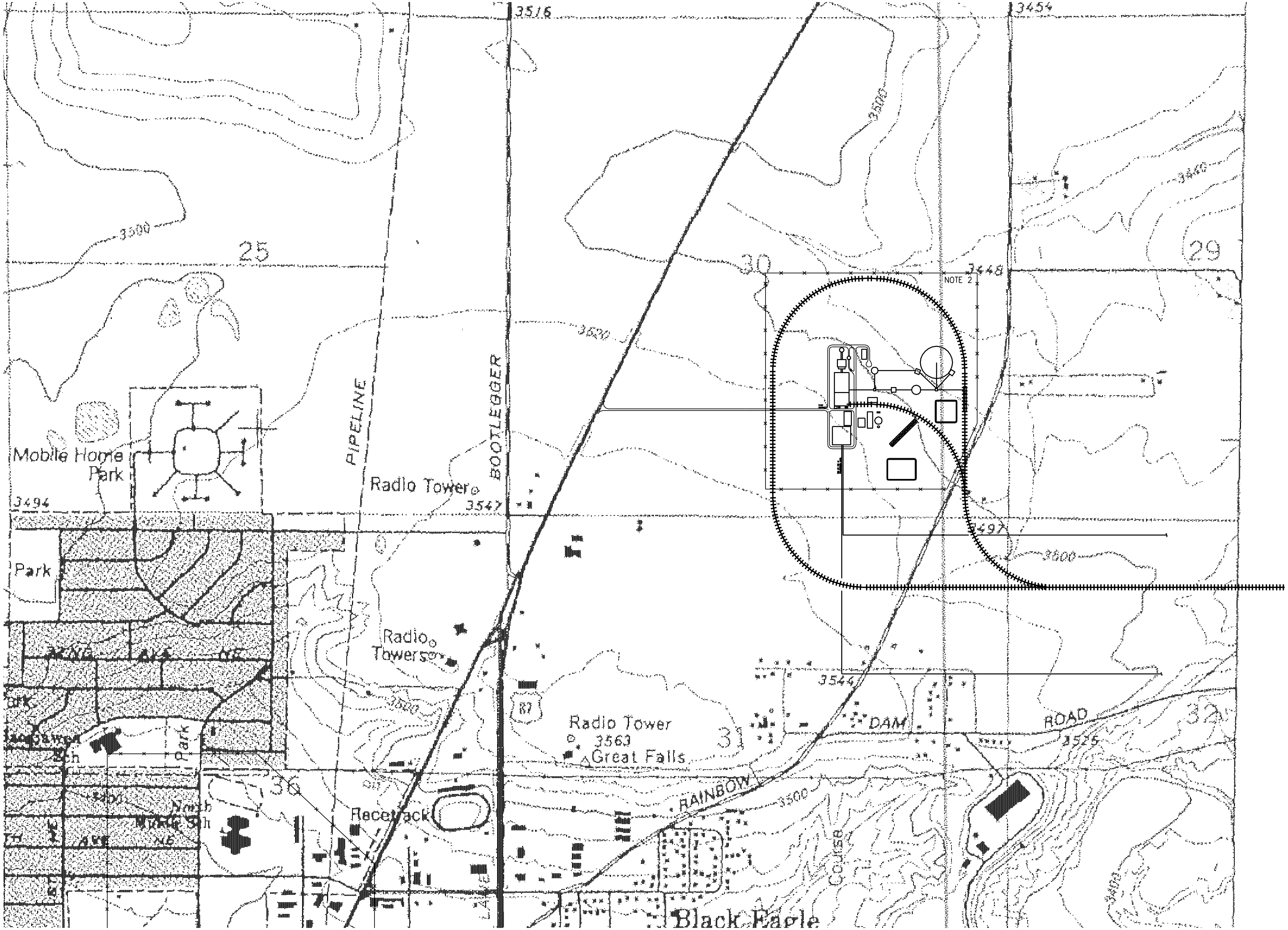
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: 1"=60'
NO. 17180
S1-GA03
REV. A

K:\06-Studies\07-CAD\salem1\salem_S1-GA03.dwg
CADD D1-R3



NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. FENCED SITE AREA IS 124 ACRES.

SCALE

1/4 MILE

1 MILE

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
SALEM INDUSTRIAL GENERATING STATION
SITE AREA

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: AS NOTED

NO. 17180

S2-GA01 REV. A

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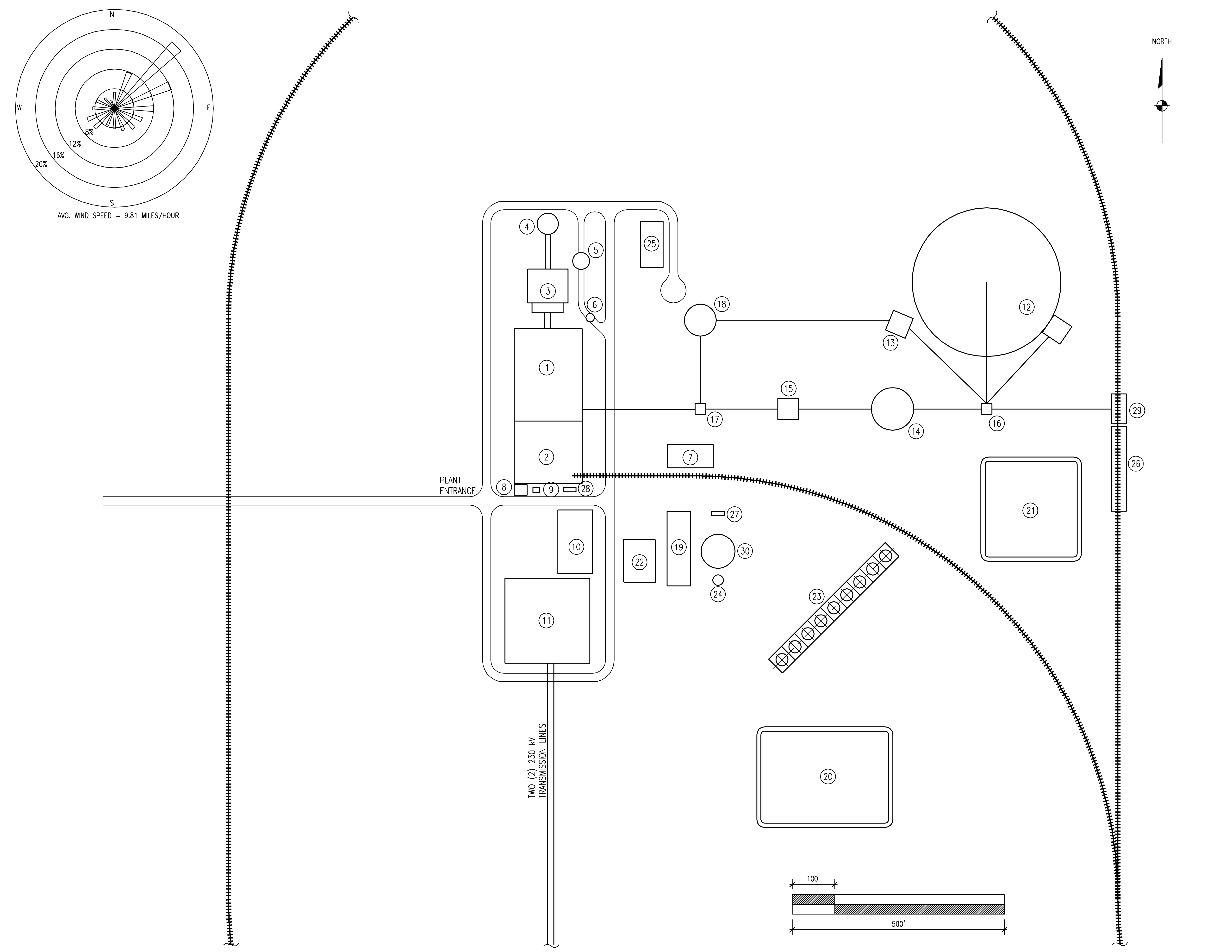
K:\06-Studies\07-CAD\salem ind\salem_S2-GA01.dwg
CADD D1-R3



NO.	DESCRIPTION
1	CFB BOILER
2	TURBINE BUILDING
3	BAGHOUSE
4	STACK
5	FLYASH SILO
6	BED ASH SILO
7	AMMONIA STORAGE
8	MAIN POWER TRANSFORMER
9	AUX TRANSFORMER
10	WAREHOUSE & ADMIN BUILDING
11	SWITCHYARD
12	COAL PILE STORAGE & RECLAIM HOPPER
13	LIMESTONE CRUSHER HOUSE
14	COAL SILO
15	COAL CRUSHER HOUSE
16	TRANSFER TOWER
17	TRANSFER TOWER
18	LIMESTONE SILO
19	WATER TREATMENT BUILDING
20	EVAPORATION POND
21	STORM WATER RUNOFF POND
22	WASTE WATER TREATMENT
23	COOLING TOWER
24	CLARIFIER
25	COAL HANDLING MAINTENANCE BUILDING
26	COAL CAR THAWING SHED
27	FIRE PUMP HOUSE
28	EMERGENCY GENERATOR
29	TRACK HOPPER
30	RAW WATER TANK

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.

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NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
SALEM INDUSTRIAL GENERATING STATION
SITE ARRANGEMENT

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: 1"=60'

NO. 17180

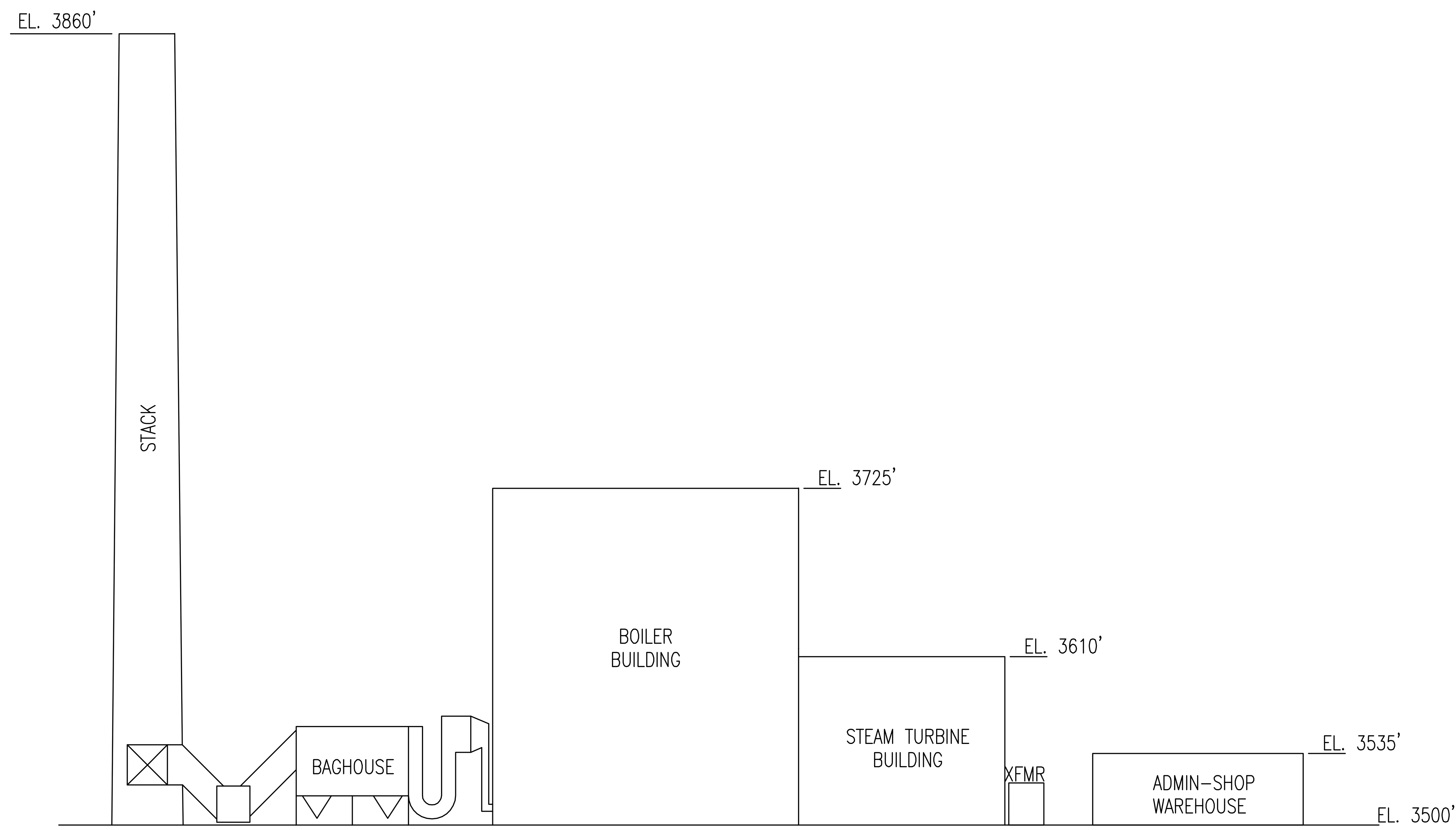
S2-GA02

REV. A

K:\06-Studies\07-CAD\salem Ind\salem_S2-GA02.dwg
CADD D1-R3

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.



PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
SALEM INDUSTRIAL GENERATING STATION
SITE ARRANGEMENT ELEVATION

DESIGNED P. EGGERS
DRAWN P. EGGERS
CHECKED T. FREEMAN
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: 1"=60'
NO. 17180
S2-GA03
REV. A

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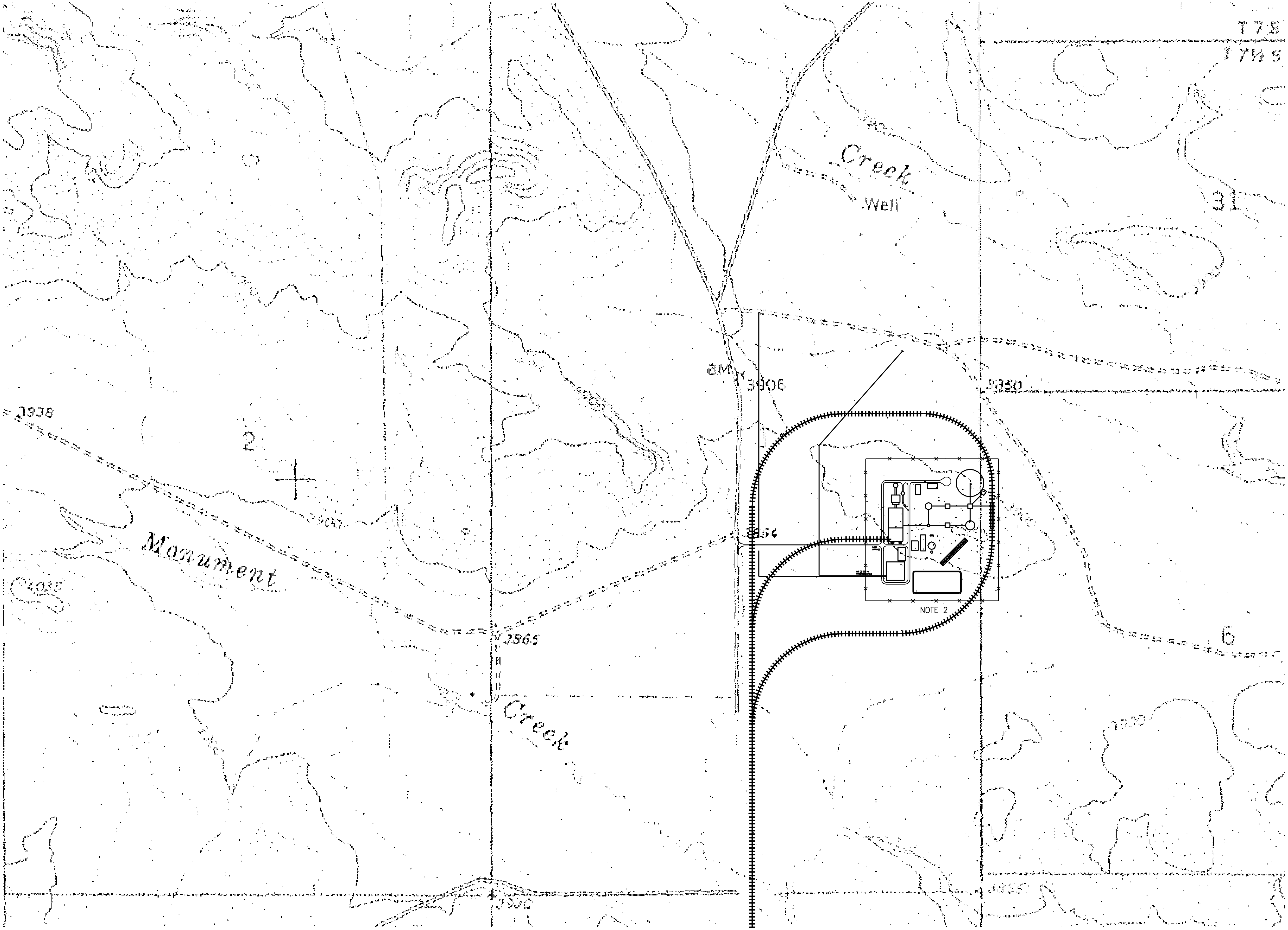
Q:\17180\06-Studies\07-CAD\salem Ind\salem_S2-GA03.dwg

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. FENCED SITE AREA IS 55 ACRES



SCALE

1/4 MILE

1 MILE

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
DECKER GENERATING STATION
SITE AREA

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: AS NOTED

NO. 17180

DK-GA01

REV. A

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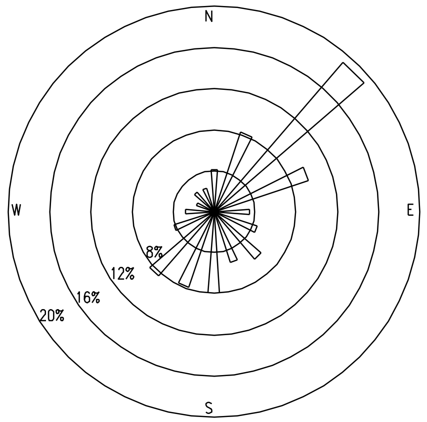
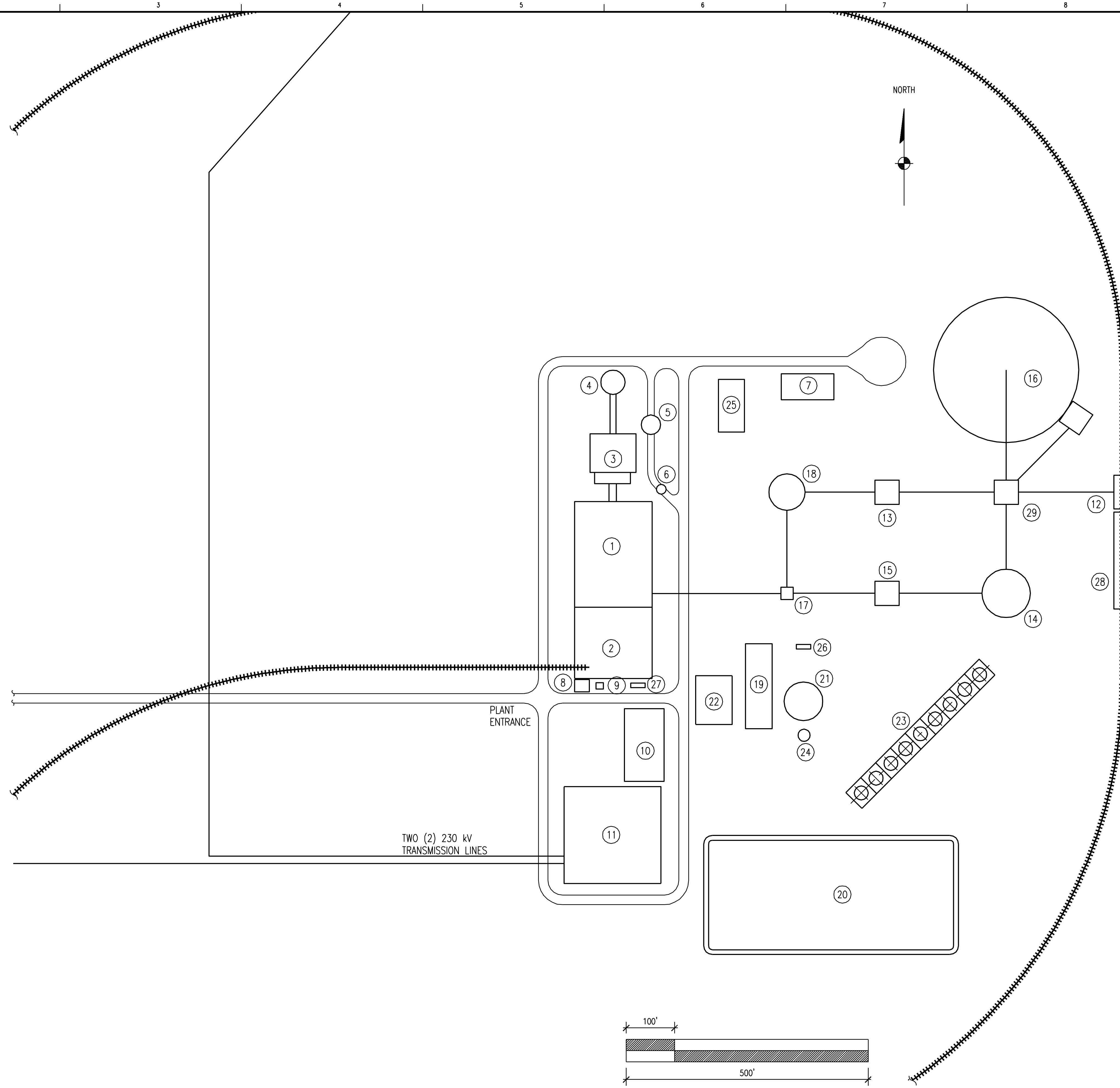
K:\06-Studies\07-CAD\DECKER\decker_DK-GA01.dwg
CADD D1-R3



AVG. WIND SPEED = 10.16 MILES/HOUR



NO.	DESCRIPTION
1	CFB BOILER
2	TURBINE BUILDING
3	BAGHOUSE
4	STACK
5	FLYASH SILO
6	BED ASH SILO
7	AMMONIA STORAGE
8	MAIN POWER TRANSFORMER
9	AUX TRANSFORMER
10	WAREHOUSE & ADMIN BUILDING
11	SWITCHYARD
12	TRACK HOPPER
13	LIMESTONE CRUSHER HOUSE
14	COAL SILO
15	COAL CRUSHER HOUSE
16	COAL STORAGE PILE & RECLAIM HOPPER
17	TRANSFER TOWER
18	LIMESTONE SILO
19	WATER TREATMENT BUILDING
20	EVAPORATION POND
21	RAW WATER TANK
22	WASTE WATER TREATMENT
23	COOLING TOWER
24	CLARIFIER
25	COAL HANDLING MAINTENANCE BUILDING
26	FIRE PUMP HOUSE
27	EMERGENCY GENERATOR
28	COAL CAR THAWING SHED
29	TRANSFER TOWER

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
DECKER GENERATING STATION
SITE ARRANGEMENT

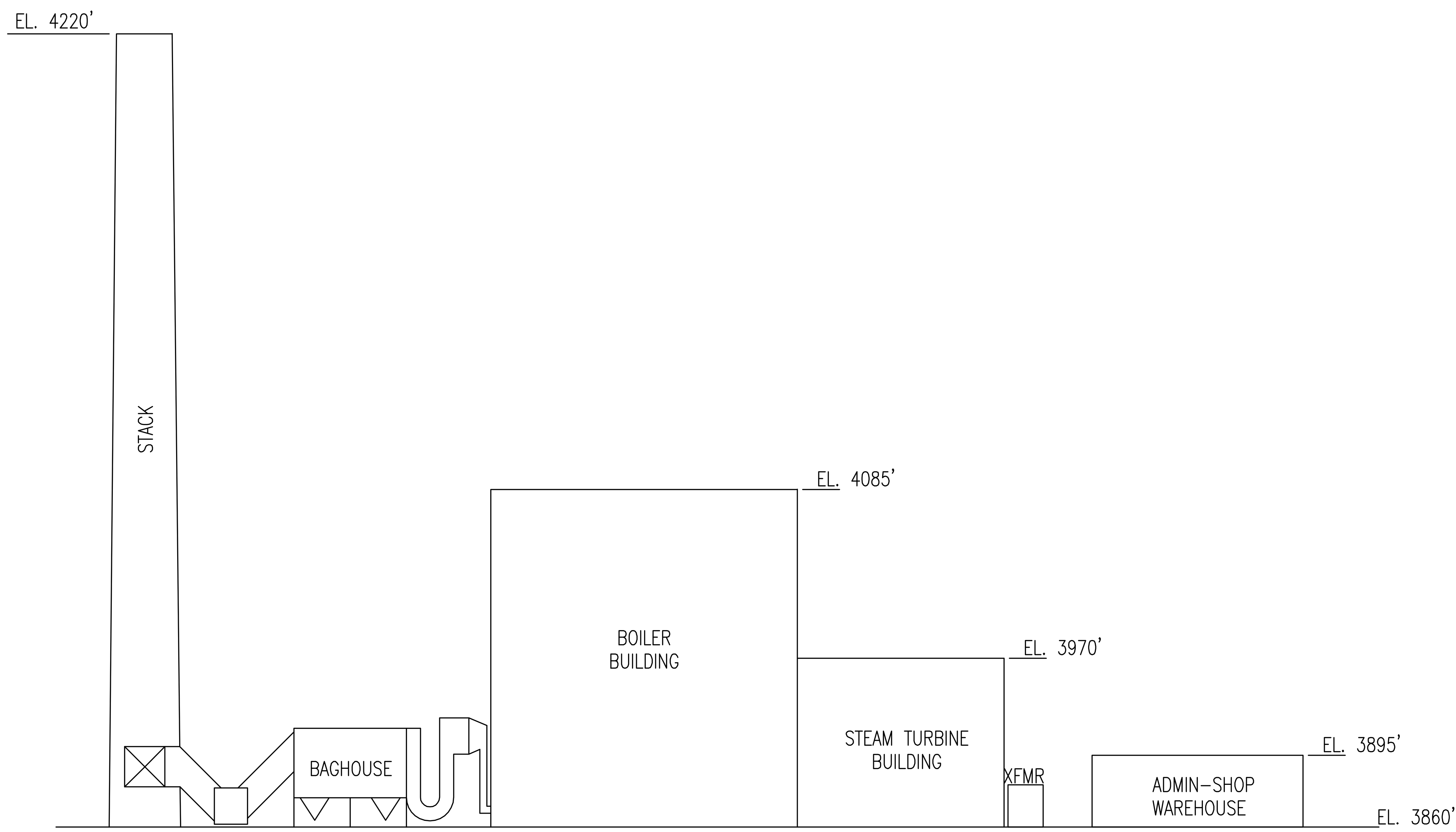
DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: AS NOTED
NO. 17180
DK-GA02
REV. A

K:\06-Studies\07-CAD\DECKER\decker_DK-GA02.dwg
CADD D1-R3

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.



PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
DECKER GENERATING STATION
SITE ARRANGEMENT ELEVATION

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: 1"=60'

NO. 17180

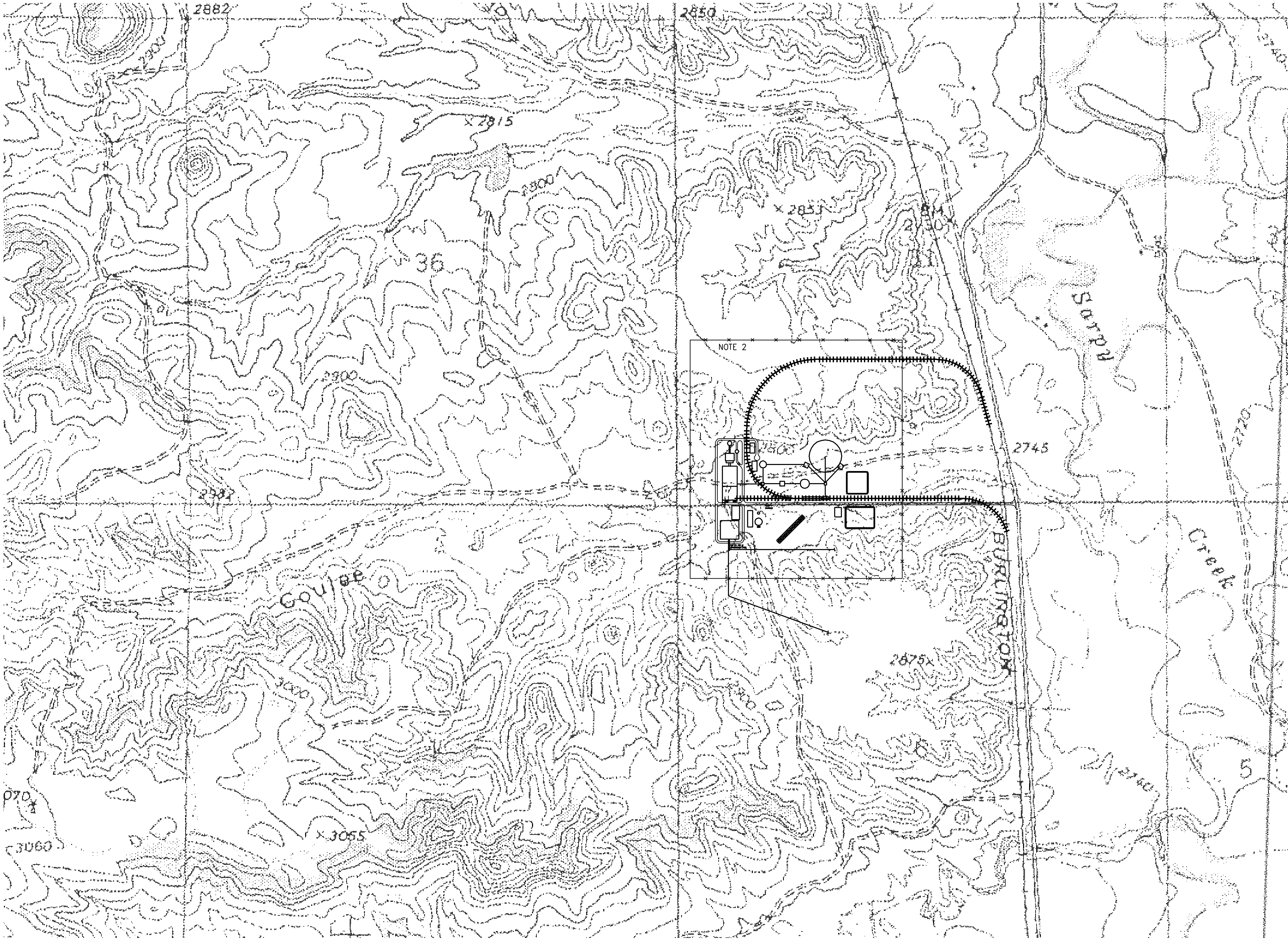
DK-GA03

REV. A

CADD 01-R3

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. FENCED SITE AREA IS 140 ACRES.



SCALE

1/4 MILE

1 MILE

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
HYSHAM GENERATING STATION
SITE AREA

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: AS NOTED

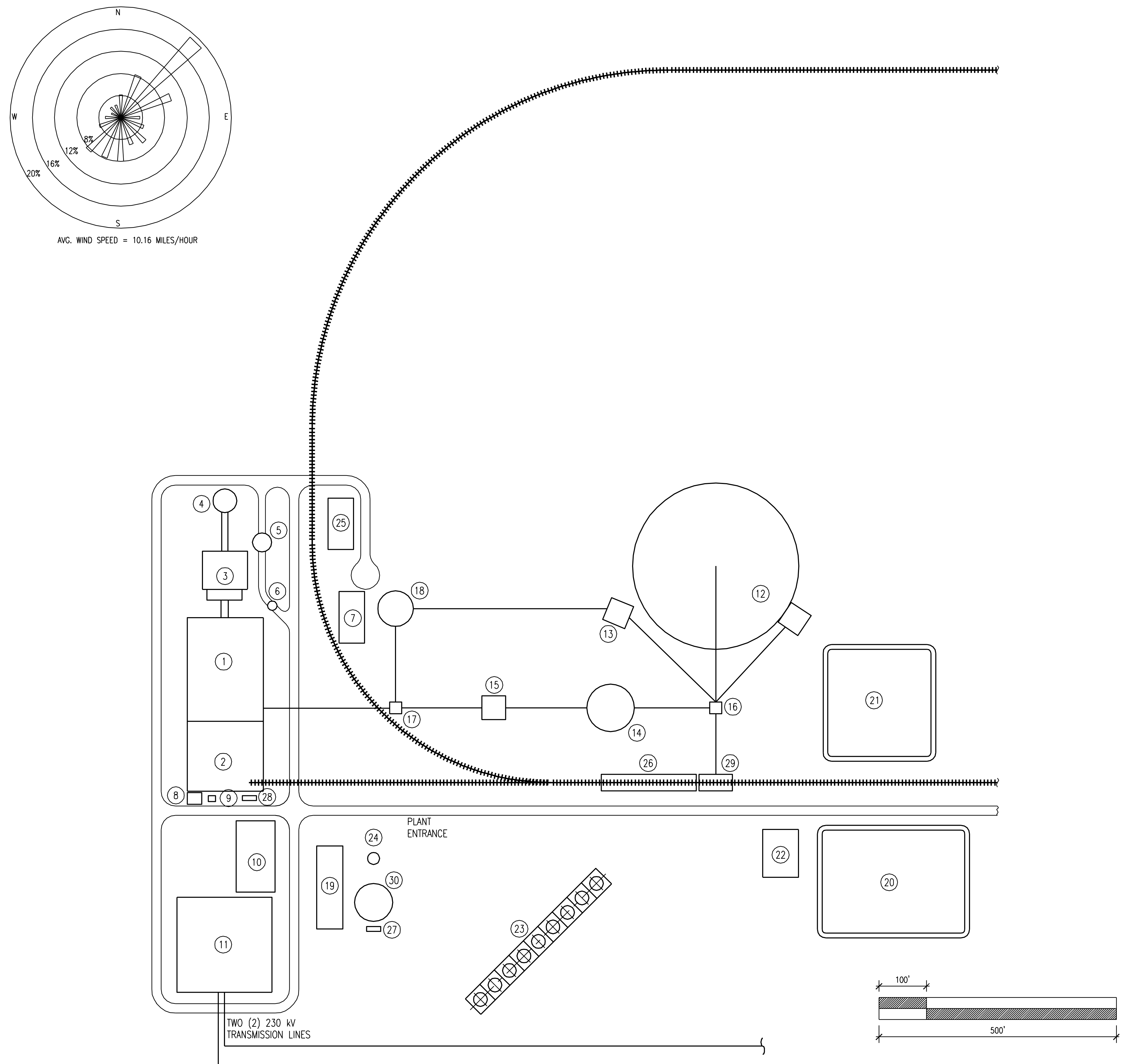
NO. 17180

REV.

H2-GA01

A

K:\06-Studies\07-CAD\hysham\hysham-GA01.dwg
CADD D1-R3



NO.	DESCRIPTION
1	CFB BOILER
2	TURBINE BUILDING
3	BAGHOUSE
4	STACK
5	FLYASH SILO
6	BED ASH SILO
7	AMMONIA STORAGE
8	MAIN POWER TRANSFORMER
9	AUX TRANSFORMER
10	WAREHOUSE & ADMIN BUILDING
11	SWITCHYARD
12	COAL PILE STORAGE & RECLAIM HOPPER
13	LIMESTONE CRUSHER HOUSE
14	COAL SILO
15	COAL CRUSHER HOUSE
16	TRANSFER TOWER
17	TRANSFER TOWER
18	LIMESTONE SILO
19	WATER TREATMENT BUILDING
20	EVAPORATION POND
21	STORM WATER RUNOFF POND
22	WASTE WATER TREATMENT
23	COOLING TOWER
24	CLARIFIER
25	COAL HANDLING MAINTENANCE BUILDING
26	COAL CAR THAWING SHED
27	FIRE PUMP HOUSE
28	EMERGENCY GENERATOR
29	TRACK HOPPER
30	RAW WATER TANK

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
HYSHAM GENERATING STATION
SITE ARRANGEMENT

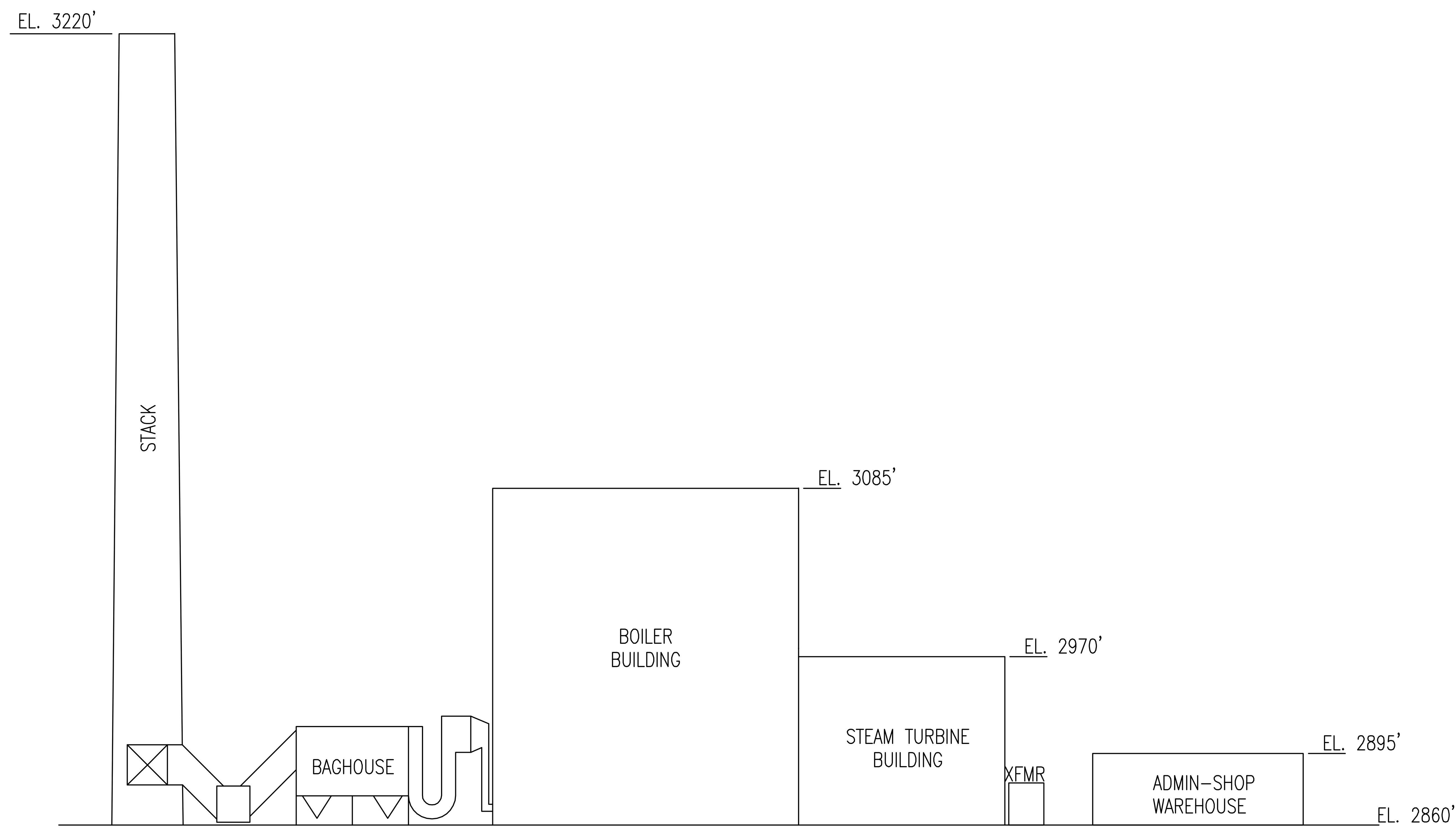
DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: 1"=60'
NO. 17180
H2-GA02
REV. A

K:\06-Studies\07-CAD\hysham\hysham-GA02.dwg
CADD D1-R3

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.



PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

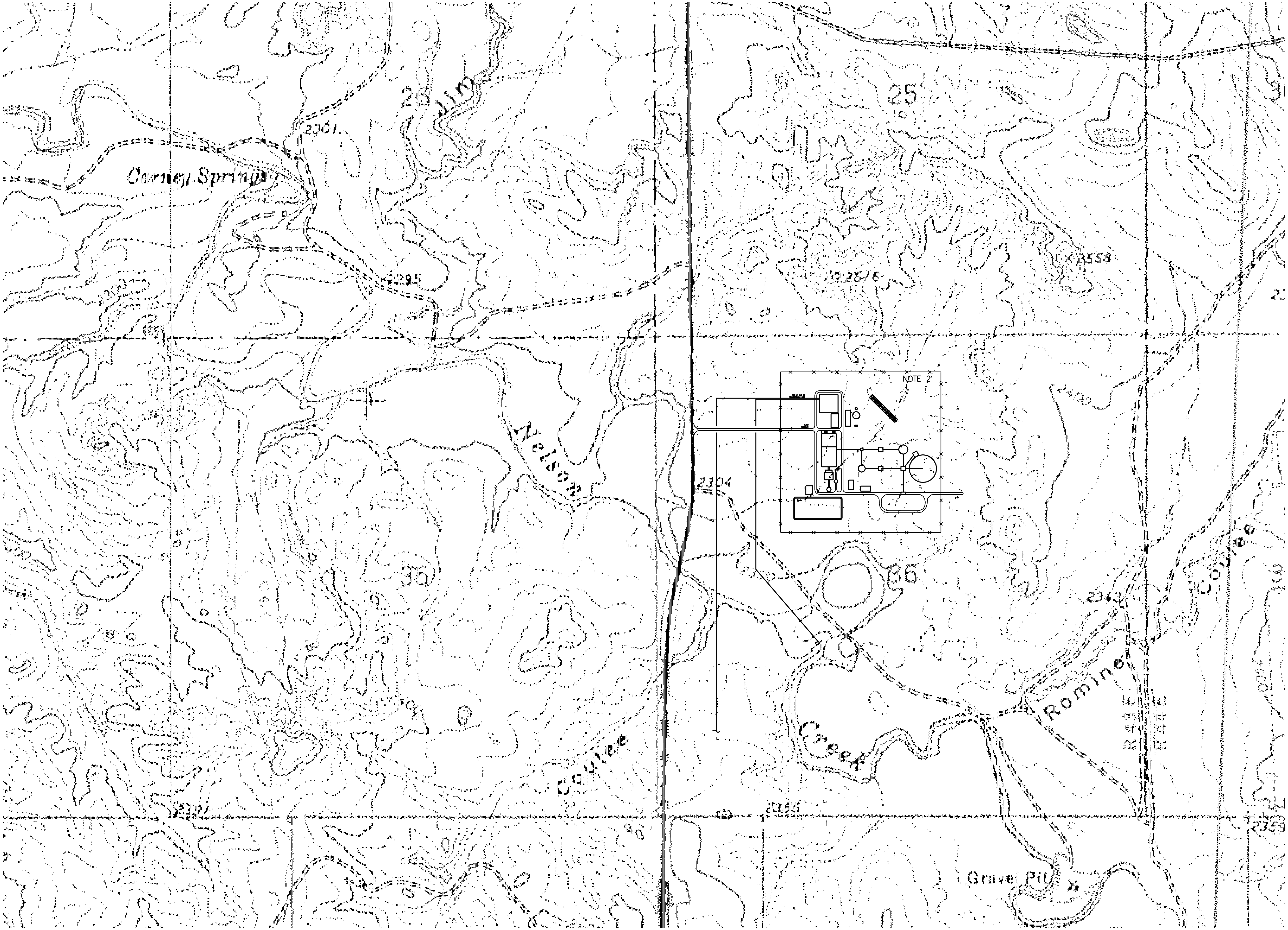
MONTANA - 43 - SOUTHERN
HYSHAM GENERATING STATION
SITE ARRANGEMENT ELEVATION

DESIGNED P. EGGERS
DRAWN P. EGGERS
CHECKED T. FREEMAN
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: 1"=60'
NO. 17180
H2-GA03
REV. A

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. FENCED SITE AREA IS 75 ACRES



SCALE

1/4 MILE

1 MILE

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
NELSON CREEK GENERATING STATION
SITE AREA

DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

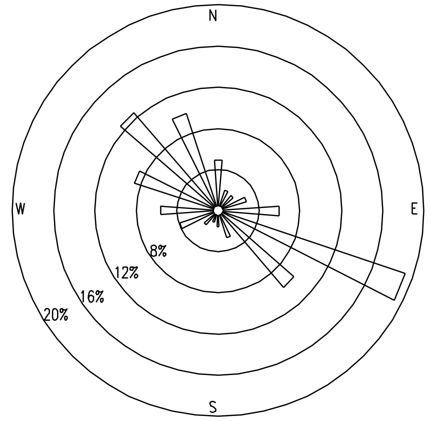
SCALE: AS NOTED

NO. 17180

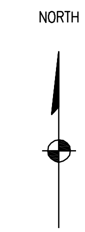
NC-GA01

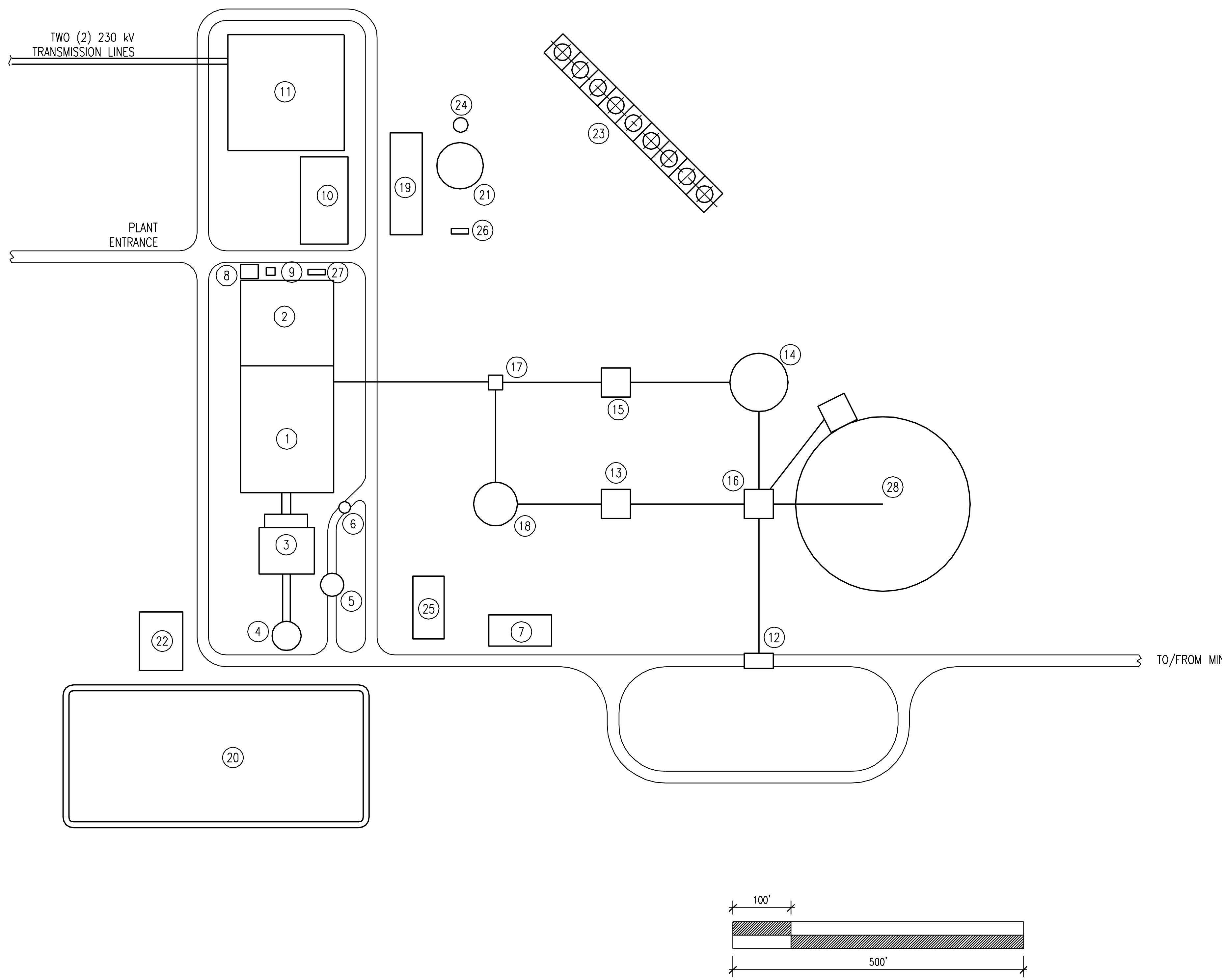
REV. A

K:\06-Studies\07-CAD\nelson_creek\NC-GA01.dwg
CADD D1-R3



AVG. WIND SPEED = 10.84 MILES/HOUR





NO.	DESCRIPTION
1	CFB BOILER
2	TURBINE BUILDING
3	BAGHOUSE
4	STACK
5	FLYASH SILO
6	BED ASH SILO
7	AMMONIA STORAGE
8	MAIN POWER TRANSFORMER
9	AUX TRANSFORMER
10	WAREHOUSE & ADMIN BUILDING
11	SWITCHYARD
12	TRUCK HOPPER
13	LIMESTONE CRUSHER HOUSE
14	COAL SILO
15	COAL CRUSHER HOUSE
16	TRANSFER TOWER
17	TRANSFER TOWER
18	LIMESTONE SILO
19	WATER TREATMENT BUILDING
20	EVAPORATION & RUNOFF POND
21	RAW WATER TANK
22	WASTE WATER TREATMENT
23	COOLING TOWER
24	CLARIFIER
25	COAL HANDLING MAINTENANCE BUILDING
26	FIRE PUMP HOUSE
27	EMERGENCY GENERATOR
28	COAL STORAGE PILE & RECLAIM HOPPER

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
NELSON CREEK GENERATING STATION
SITE ARRANGEMENT

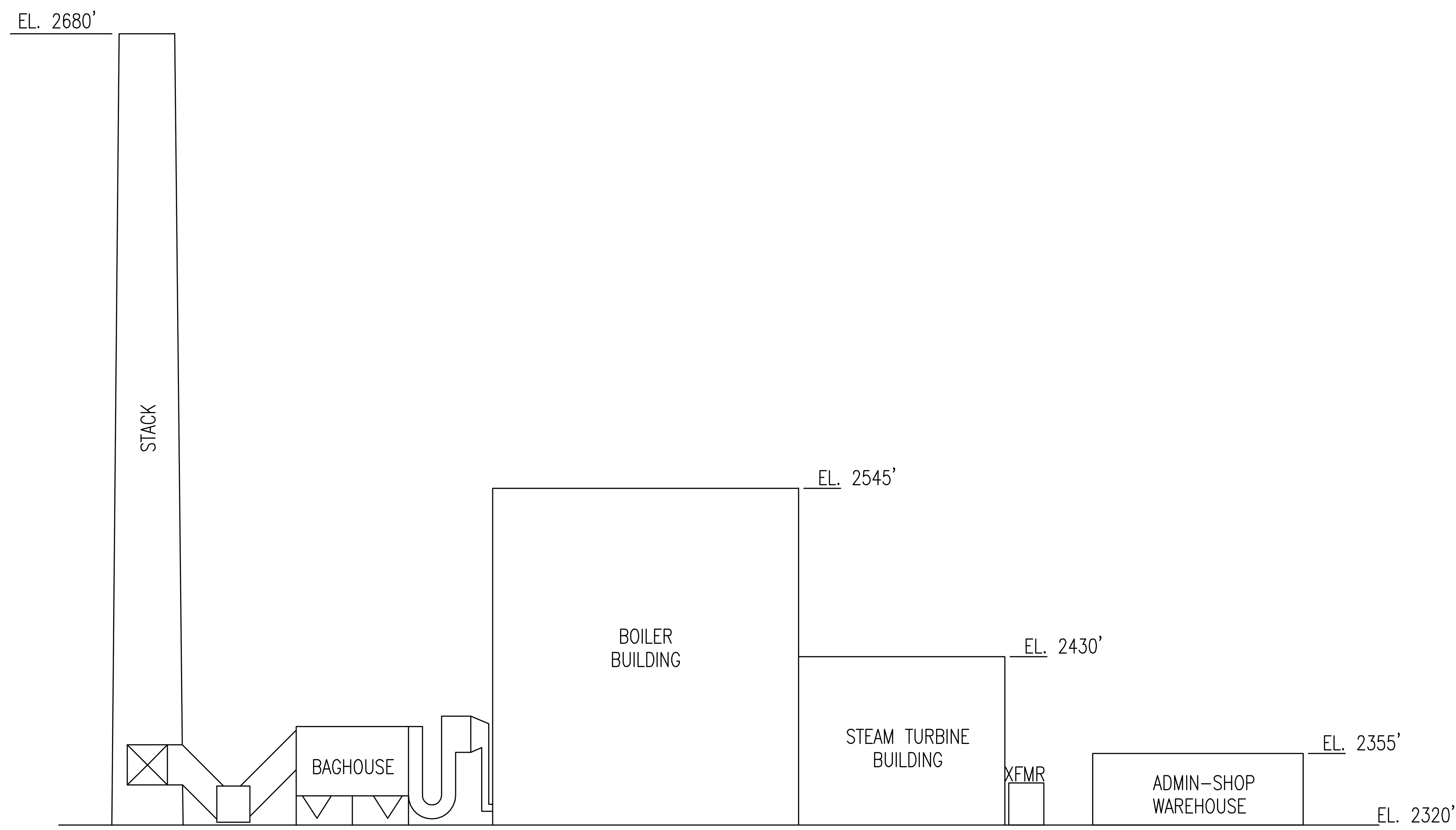
DESIGNED	P. EGGERS
DRAWN	P. EGGERS
CHECKED	T. FREEMAN
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: AS NOTED
NO. 17180
NC-GA02
REV. A

K:\06-Studies\07-CAD\nelson_creek\NC-GA02.dwg
CADD D1-R3

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.



PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
NELSON CREEK GENERATING STATION
SITE ARRANGEMENT ELEVATION

DESIGNED P. EGGERS
DRAWN P. EGGERS
CHECKED T. FREEMAN
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: 1"=60'

NO. 17180

NC-GA03

REV. A

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Q:\17180\06-Studies\07-CAD\nelson_creek\NC-GA03.dwg
CADD D1-R3

Appendix B

Preliminary Heat Balance

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251964 KW
PLANT NET HEAT RATE (HHV) 9582 BTU/KWH
FUEL FLOW 259.3 KPPH
LIMESTONE FLOW 5.776 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14
P	PSIA	2414.7	699.1	699.1	699.1	633.7	329.1	678.8	316.5	119.2	119.2	119.2	119.2	119.2	2667.5
T	°F	1000	671.1	671.1	671.1	1000	830.3	431.4	368	595.3	595.3	595.3	595.3	595.3	422.5
M	KPPH	1853.2	1800.3	1619.3	181	1619.3	99.53	180.9	280.5	160.72	81.33	79.39	6.77	1382.8	1820.6
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516.5	1436	410	341.1	1325.9	1325.9	1325.9	1325.9	1325.9	402.1

	UNITS	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2648.6	0.9875	6.193	–	–	39.77	35.29	57.58	54.87	18.76	17.87	9.838	9.283	4.603
T	°F	504.7	101.3	101.3	101.3	173.6	79.23	97.21	448.6	228.1	258.6	195.7	192.4	162.8	158.8
M	KPPH	1820.6	79.39	79.38	79.38	6.77	4288	4288	96.57	96.57	44.7	141.3	44.39	185.7	62.79
H	BTU/LB	493.2	1033.8	69.31	69.31	141.6	47.45	65.31	1258.2	196.5	1171.5	163.9	1128.1	130.8	1082.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42
P	PSIA	0.9925	4.33	234.3	5.331	11.75	252.2	252.2	234.3	234.3	210.2	187.4	167.3	12.76	50.61
T	°F	101.5	156.2	156.2	101.5	200	103.5	103.5	153.2	153.8	186.7	219	287	79.2	79.23
M	KPPH	1134.3	248.5	248.5	1145.5	1.4	1236.2	1236.2	1236.2	1484.6	1484.6	1484.6	1484.6	64425	64425
H	BTU/LB	1008.7	124.2	124.7	69.48	169	72.13	72.13	121.7	122.3	155.2	187.7	256.7	47.32	47.45

	UNITS	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	50.61	50.61	50.61	35.29	35.29	252.2	2832.6	119.2	119.2	119.2	166.2	6.509	6.509
T	°F	79.23	79.23	79.23	97.35	97.36	102.1	358.9	595.3	595.3	595.3	351.5	173.6	173.6
M	KPPH	64241	184.2	59954	59954	64241	1236.2	1857.8	1389.57	4.062	2.708	1857.8	4.062	2.708
H	BTU/LB	47.45	47.45	47.45	65.44	65.43	70.75	335.4	1325.9	1325.9	1325.9	323.5	141.6	141.6

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – MONTANA
SALEM GENERATING STATION
94° F, 27% RH, 100% BMCR

DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	B. DAHL
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: NONE
NO. 17180
S1-PF01
REV. A

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 253907 KW
PLANT NET HEAT RATE (HHV) 9509 BTU/KWH
FUEL FLOW 259.3 KPPH
LIMESTONE FLOW 5.776 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14
P	PSIA	2414.7	698.3	698.3	698.3	633	328.6	678	316	118.8	118.8	118.8	118.8	118.8	2667.3
T	°F	1000	670.8	670.8	670.8	999.2	829.4	431.2	367.8	594.2	594.2	594.2	594.2	594.2	422.3
M	KPPH	1852	1799.1	1618.1	181	1618.1	99.63	180.9	280.7	153.8	81.33	72.47	16.19	1379	1820.4
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516	1435.5	409.8	340.9	1325.4	1325.4	1325.4	1325.4	1325.4	401.9

	UNITS	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2648.3	0.4663	5.672	–	–	34.48	29.75	54.64	54.64	17.74	17.74	9.14	9.14	4.14
T	°F	504.6	77.47	77.45	77.45	204.8	56.73	72.96	444.8	227.7	255	195.1	189	161.2	154.4
M	KPPH	1820.4	72.47	72.47	72.47	16.19	4288	4288	96.68	96.68	45.23	141.9	46.08	188	70.65
H	BTU/LB	493.1	1005.7	45.55	45.55	173	24.9	41.12	1256.7	196.1	1170.1	163.2	1126.5	129.2	1079.8

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42
P	PSIA	0.7493	4.14	233.9	5.087	11.75	251.6	251.6	233.9	233.9	209.7	187	166.9	12.76	35.66
T	°F	92.27	154.4	151	92.75	200	93.14	93.14	151	151.6	185.9	218.6	286.7	56.61	56.73
M	KPPH	1120.4	258.6	258.6	1224.7	1.4	1224.7	1224.7	1224.7	1483.3	1483.3	1483.3	1483.3	38786	38786
H	BTU/LB	1004	122.4	119.5	60.78	169	61.83	61.83	119.5	120.2	154.4	187.2	256.4	24.71	24.9

	UNITS	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	35.66	35.66	35.66	29.76	29.76	251.6	2832.4	118.8	109.1	109.1	165.8	12.72	12.72
T	°F	56.73	56.73	56.73	87.89	86.24	93.14	358.7	594.2	590.9	590.9	351.2	204.8	204.8
M	KPPH	38652	133.6	34364	34364	38652	1224.7	1856.6	1395.2	9.714	6.476	1856.6	9.714	6.476
H	BTU/LB	24.9	24.9	24.9	56.04	54.39	61.83	335.2	1325.4	1324.4	1324.4	323.2	173	173

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
SALEM GENERATING STATION
45° F, 27% RH, 100% BMCR

DESIGNED	T. FREEMAN	SCALE: NONE	
DRAWN	P. EGGERS	NO. 17180	REV.
CHECKED	B. DAHL	S1-PF02	A
APPROVED	R. WALTERS		
APPROVED	K. CAVANAUGH		
DATE	06-04-04		

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251042 KW
PLANT NET HEAT RATE (HHV) 9617 BTU/KWH
FUEL FLOW 259.3 KPPH
LIMESTONE FLOW 5.776 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	696.3	696.3	696.3	631.1	327.1	676	314.3	117	117	117	117	117	2666.1	2647.2	.525	5.739	–	–	33.2	28.51	53.83	53.84	17.57	17.57	9.70	9.18	4.36
T	°F	1000	670.2	670.2	670.2	998.9	828.8	430.8	367	591.6	591.6	591.6	591.6	591.6	421.9	504.3	81.26	81.25	81.25	246.4	60.39	76.84	442.6	227.1	254	195.1	189.2	163	156.5
M	KPPH	1847.8	1795.1	1614.3	180.8	1614.3	100.1	180.6	280.8	154.54	81.05	73.49	29.57	1360.5	1815.7	1815.7	73.49	73.49	73.49	29.57	4288	4288	95.66	95.66	44.01	139.7	42.93	182.6	56.49
H	BTU/LB	1460.1	1327.5	1327.5	1327.5	1515.9	1435.3	409.3	340	1324.2	1324.2	1324.2	1324.2	1324.2	401.5	492.7	1009.8	49.35	49.35	215	28.55	45.01	1255.6	195.5	1169.7	163.2	1127.6	131	1081.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	1.123	4.36	231.9	5.461	11.75	109.2	249.8	231.9	231.9	207.9	185.3	165.3	12.76	32	32	32	32	28.52	28.52	249.8	2831.2	117	84.36	84.36	164.2	28	28
T	°F	105.7	156.5	153.8	105.6	200	107.8	109.2	153.8	154.3	186.3	218.2	285.8	60.22	60.39	60.39	60.39	60.39	101.9	98.31	107.8	357.7	591.6	584.9	584.9	350.3	246.4	246.4
M	KPPH	1121.5	124.5	124.5	1132.5	1.4	1240.1	1240.1	1240.1	1479.2	1479.2	1479.2	1479.2	30199	30199	30093	106.1	25805	25805	30093	1240.1	926.2	1390	17.742	11.828	1852.4	17.742	11.828
H	BTU/LB	1014.3	239.1	239.1	73.64	169	77.8	77.8	122.3	122.8	154.8	186.8	255.4	28.32	28.55	28.55	28.55	28.55	69.93	66.37	76.44	334.2	1324.2	1323.2	1323.2	322.3	215	215

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.
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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
SALEM GENERATING STATION
-20° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
S1-PF03
REV. A

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251544 KW
PLANT NET HEAT RATE (HHV) 9528 BTU/KWH
FUEL FLOW 251.4 KPPH
LIMESTONE FLOW 6.422 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	699.1	699.1	699.1	633.7	329.1	678.8	316.5	119.2	119.2	119.2	119.2	119.2	2667.5	2648.6	0.9875	6.193	–	–	39.77	35.29	57.58	54.87	18.76	17.87	9.838	9.283	4.603
T	°F	1000	671.1	671.1	671.1	1000	830.3	431.4	368	595.3	595.3	595.3	595.3	595.3	422.5	504.7	101.3	101.3	101.3	173.6	79.23	97.21	448.6	228.1	258.6	195.7	192.4	162.8	158.8
M	KPPH	1853.2	1800.3	1619.3	181	1619.3	99.53	180.9	280.5	160.72	81.33	79.39	6.77	1382.8	1820.6	1820.6	79.39	79.38	79.38	6.77	4288	4288	96.57	96.57	44.7	141.3	44.39	185.7	62.79
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516.5	1436	410	341.1	1325.9	1325.9	1325.9	1325.9	1325.9	402.1	493.2	1033.8	69.31	69.31	141.6	47.45	65.31	1258.2	196.5	1171.5	163.9	1128.1	130.8	1082.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	0.9925	4.33	234.3	5.331	11.75	252.2	252.2	234.3	234.3	210.2	187.4	167.3	12.76	50.61	50.61	50.61	50.61	35.29	35.29	252.2	2832.6	119.2	119.2	119.2	166.2	6.509	6.509
T	°F	101.5	156.2	156.2	101.5	200	103.5	103.5	153.2	153.8	186.7	219	287	79.2	79.23	79.23	79.23	79.23	97.35	97.36	102.1	358.9	595.3	595.3	595.3	351.5	173.6	173.6
M	KPPH	1134.3	248.5	248.5	1145.5	1.4	1236.2	1236.2	1236.2	1484.6	1484.6	1484.6	1484.6	64425	64425	64241	184.2	59954	59954	64241	1236.2	1857.8	1389.57	4.062	2.708	1857.8	4.062	2.708
H	BTU/LB	1008.7	124.2	124.7	69.48	169	72.13	72.13	121.7	122.3	155.2	187.7	256.7	47.32	47.45	47.45	47.45	47.45	65.44	65.43	70.75	335.4	1325.9	1325.9	1325.9	323.5	141.6	141.6

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – MONTANA
DECKER GENERATING STATION
94° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
DK-PF01
REV. A

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251582 KW
PLANT NET HEAT RATE (HHV) 9527 BTU/KWH
FUEL FLOW 251.4 KPPH
LIMESTONE FLOW 6.422 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	698.3	698.3	698.3	633	328.6	678	316	118.8	118.8	118.8	118.8	118.8	2667.3	2648.3	0.4663	5.672	–	–	34.48	29.75	54.64	54.64	17.74	17.74	9.14	9.14	4.14
T	°F	1000	670.8	670.8	670.8	999.2	829.4	431.2	367.8	594.2	594.2	594.2	594.2	594.2	422.3	504.6	77.47	77.45	77.45	204.8	56.73	72.96	444.8	227.7	255	195.1	189	161.2	154.4
M	KPPH	1852	1799.1	1618.1	181	1618.1	99.63	180.9	280.7	153.8	81.33	72.47	16.19	1379	1820.4	1820.4	72.47	72.47	72.47	16.19	4288	4288	96.68	96.68	45.23	141.9	46.08	188	70.65
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516	1435.5	409.8	340.9	1325.4	1325.4	1325.4	1325.4	1325.4	401.9	493.1	1005.7	45.55	45.55	173	24.9	41.12	1256.7	196.1	1170.1	163.2	1126.5	129.2	1079.8

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	0.7493	4.14	233.9	5.087	11.75	251.6	251.6	233.9	233.9	209.7	187	166.9	12.76	35.66	35.66	35.66	35.66	29.76	29.76	251.6	2832.4	118.8	109.1	109.1	165.8	12.72	12.72
T	°F	92.27	154.4	151	92.75	200	93.14	93.14	151	151.6	185.9	218.6	286.7	56.61	56.73	56.73	56.73	56.73	87.89	86.24	93.14	358.7	594.2	590.9	590.9	351.2	204.8	204.8
M	KPPH	1120.4	258.6	258.6	1224.7	1.4	1224.7	1224.7	1224.7	1483.3	1483.3	1483.3	1483.3	38786	38786	38652	133.6	34364	34364	38652	1224.7	1856.6	1395.2	9.714	6.476	1856.6	9.714	6.476
H	BTU/LB	1004	122.4	119.5	60.78	169	61.83	61.83	119.5	120.2	154.4	187.2	256.4	24.71	24.9	24.9	24.9	24.9	56.04	54.39	61.83	335.2	1325.4	1324.4	1324.4	323.2	173	173

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
DECKER GENERATING STATION
45° F, 27% RH, 100% BMCR

DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	B. DAHL
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: NONE
NO. 17180
DK-PF02
REV. A

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 250634 KW
PLANT NET HEAT RATE (HHV) 9563 BTU/KWH
FUEL FLOW 251.4 KPPH
LIMESTONE FLOW 6.422 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	696.3	696.3	696.3	631.1	327.1	676	314.3	117	117	117	117	117	2666.1	2647.2	.525	5.739	–	–	33.2	28.51	53.83	53.84	17.57	17.57	9.70	9.18	4.36
T	°F	1000	670.2	670.2	670.2	998.9	828.8	430.8	367	591.6	591.6	591.6	591.6	591.6	421.9	504.3	81.26	81.25	81.25	246.4	60.39	76.84	442.6	227.1	254	195.1	189.2	163	156.5
M	KPPH	1847.8	1795.1	1614.3	180.8	1614.3	100.1	180.6	280.8	154.54	81.05	73.49	29.57	1360.5	1815.7	1815.7	73.49	73.49	73.49	29.57	4288	4288	95.66	95.66	44.01	139.7	42.93	182.6	56.49
H	BTU/LB	1460.1	1327.5	1327.5	1327.5	1515.9	1435.3	409.3	340	1324.2	1324.2	1324.2	1324.2	1324.2	401.5	492.7	1009.8	49.35	49.35	215	28.55	45.01	1255.6	195.5	1169.7	163.2	1127.6	131	1081.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	1.123	4.36	231.9	5.461	11.75	109.2	249.8	231.9	231.9	207.9	185.3	165.3	12.76	32	32	32	32	28.52	28.52	249.8	2831.2	117	84.36	84.36	164.2	28	28
T	°F	105.7	156.5	153.8	105.6	200	107.8	109.2	153.8	154.3	186.3	218.2	285.8	60.22	60.39	60.39	60.39	60.39	101.9	98.31	107.8	357.7	591.6	584.9	584.9	350.3	246.4	246.4
M	KPPH	1121.5	124.5	124.5	1132.5	1.4	1240.1	1240.1	1240.1	1479.2	1479.2	1479.2	1479.2	30199	30199	30093	106.1	25805	25805	30093	1240.1	926.2	1390	17.742	11.828	1852.4	17.742	11.828
H	BTU/LB	1014.3	239.1	239.1	73.64	169	77.8	77.8	122.3	122.8	154.8	186.8	255.4	28.32	28.55	28.55	28.55	28.55	69.93	66.37	76.44	334.2	1324.2	1323.2	1323.2	322.3	215	215

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.
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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
DECKER GENERATING STATION
-20° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
DK-PF03
REV. A

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251578 KW
PLANT NET HEAT RATE (HHV) 9828 BTU/KWH
FUEL FLOW 280.8 KPPH
LIMESTONE FLOW 13.24 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	699.1	699.1	699.1	633.7	329.1	678.8	316.5	119.2	119.2	119.2	119.2	119.2	2667.5	2648.6	0.9875	6.193	–	–	39.77	35.29	57.58	54.87	18.76	17.87	9.838	9.283	4.603
T	°F	1000	671.1	671.1	671.1	1000	830.3	431.4	368	595.3	595.3	595.3	595.3	595.3	422.5	504.7	101.3	101.3	101.3	173.6	79.23	97.21	448.6	228.1	258.6	195.7	192.4	162.8	158.8
M	KPPH	1853.2	1800.3	1619.3	181	1619.3	99.53	180.9	280.5	160.72	81.33	79.39	6.77	1382.8	1820.6	1820.6	79.39	79.38	79.38	6.77	4288	4288	96.57	96.57	44.7	141.3	44.39	185.7	62.79
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516.5	1436	410	341.1	1325.9	1325.9	1325.9	1325.9	1325.9	402.1	493.2	1033.8	69.31	69.31	141.6	47.45	65.31	1258.2	196.5	1171.5	163.9	1128.1	130.8	1082.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	0.9925	4.33	234.3	5.331	11.75	252.2	252.2	234.3	234.3	210.2	187.4	167.3	12.76	50.61	50.61	50.61	50.61	35.29	35.29	252.2	2832.6	119.2	119.2	119.2	166.2	6.509	6.509
T	°F	101.5	156.2	156.2	101.5	200	103.5	103.5	153.2	153.8	186.7	219	287	79.2	79.23	79.23	79.23	79.23	97.35	97.36	102.1	358.9	595.3	595.3	595.3	351.5	173.6	173.6
M	KPPH	1134.3	248.5	248.5	1145.5	1.4	1236.2	1236.2	1236.2	1484.6	1484.6	1484.6	1484.6	64425	64425	64241	184.2	59954	59954	64241	1236.2	1857.8	1389.57	4.062	2.708	1857.8	4.062	2.708
H	BTU/LB	1008.7	124.2	124.7	69.48	169	72.13	72.13	121.7	122.3	155.2	187.7	256.7	47.32	47.45	47.45	47.45	47.45	65.44	65.43	70.75	335.4	1325.9	1325.9	1325.9	323.5	141.6	141.6

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – MONTANA
HYSHAM GENERATING STATION
94° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
H2-PF01
REV. A

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251686 KW
PLANT NET HEAT RATE (HHV) 9824 BTU/KWH
FUEL FLOW 280.8 KPPH
LIMESTONE FLOW 13.24 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	698.3	698.3	698.3	633	328.6	678	316	118.8	118.8	118.8	118.8	118.8	2667.3	2648.3	0.4663	5.672	–	–	34.48	29.75	54.64	54.64	17.74	17.74	9.14	9.14	4.14
T	°F	1000	670.8	670.8	670.8	999.2	829.4	431.2	367.8	594.2	594.2	594.2	594.2	594.2	422.3	504.6	77.47	77.45	77.45	204.8	56.73	72.96	444.8	227.7	255	195.1	189	161.2	154.4
M	KPPH	1852	1799.1	1618.1	181	1618.1	99.63	180.9	280.7	153.8	81.33	72.47	16.19	1379	1820.4	1820.4	72.47	72.47	72.47	16.19	4288	4288	96.68	96.68	45.23	141.9	46.08	188	70.65
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516	1435.5	409.8	340.9	1325.4	1325.4	1325.4	1325.4	1325.4	401.9	493.1	1005.7	45.55	45.55	173	24.9	41.12	1256.7	196.1	1170.1	163.2	1126.5	129.2	1079.8

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	0.7493	4.14	233.9	5.087	11.75	251.6	251.6	233.9	233.9	209.7	187	166.9	12.76	35.66	35.66	35.66	35.66	29.76	29.76	251.6	2832.4	118.8	109.1	109.1	165.8	12.72	12.72
T	°F	92.27	154.4	151	92.75	200	93.14	93.14	151	151.6	185.9	218.6	286.7	56.61	56.73	56.73	56.73	56.73	87.89	86.24	93.14	358.7	594.2	590.9	590.9	351.2	204.8	204.8
M	KPPH	1120.4	258.6	258.6	1224.7	1.4	1224.7	1224.7	1224.7	1483.3	1483.3	1483.3	1483.3	38786	38786	38652	133.6	34364	34364	38652	1224.7	1856.6	1395.2	9.714	6.476	1856.6	9.714	6.476
H	BTU/LB	1004	122.4	119.5	60.78	169	61.83	61.83	119.5	120.2	154.4	187.2	256.4	24.71	24.9	24.9	24.9	24.9	56.04	54.39	61.83	335.2	1325.4	1324.4	1324.4	323.2	173	173

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
HYSHAM GENERATING STATION
45° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
H2-PF02
REV. A

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 250788 KW
PLANT NET HEAT RATE (HHV) 9859 BTU/KWH
FUEL FLOW 280.8 KPPH
LIMESTONE FLOW 13.24 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	696.3	696.3	696.3	631.1	327.1	676	314.3	117	117	117	117	117	2666.1	2647.2	.525	5.739	–	–	33.2	28.51	53.83	53.84	17.57	17.57	9.70	9.18	4.36
T	°F	1000	670.2	670.2	670.2	998.9	828.8	430.8	367	591.6	591.6	591.6	591.6	591.6	421.9	504.3	81.26	81.25	81.25	246.4	60.39	76.84	442.6	227.1	254	195.1	189.2	163	156.5
M	KPPH	1847.8	1795.1	1614.3	180.8	1614.3	100.1	180.6	280.8	154.54	81.05	73.49	29.57	1360.5	1815.7	1815.7	73.49	73.49	73.49	29.57	4288	4288	95.66	95.66	44.01	139.7	42.93	182.6	56.49
H	BTU/LB	1460.1	1327.5	1327.5	1327.5	1515.9	1435.3	409.3	340	1324.2	1324.2	1324.2	1324.2	1324.2	401.5	492.7	1009.8	49.35	49.35	215	28.55	45.01	1255.6	195.5	1169.7	163.2	1127.6	131	1081.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	1.123	4.36	231.9	5.461	11.75	109.2	249.8	231.9	231.9	207.9	185.3	165.3	12.76	32	32	32	32	28.52	28.52	249.8	2831.2	117	84.36	84.36	164.2	28	28
T	°F	105.7	156.5	153.8	105.6	200	107.8	109.2	153.8	154.3	186.3	218.2	285.8	60.22	60.39	60.39	60.39	60.39	101.9	98.31	107.8	357.7	591.6	584.9	584.9	350.3	246.4	246.4
M	KPPH	1121.5	124.5	124.5	1132.5	1.4	1240.1	1240.1	1240.1	1479.2	1479.2	1479.2	1479.2	30199	30199	30093	106.1	25805	25805	30093	1240.1	926.2	1390	17.742	11.828	1852.4	17.742	11.828
H	BTU/LB	1014.3	239.1	239.1	73.64	169	77.8	77.8	122.3	122.8	154.8	186.8	255.4	28.32	28.55	28.55	28.55	28.55	69.93	66.37	76.44	334.2	1324.2	1323.2	1323.2	322.3	215	215

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
HYSHAM GENERATING STATION
-20° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
REV. A
H2-PF03

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251597 KW
PLANT NET HEAT RATE (HHV) 10043 BTU/KWH
FUEL FLOW 371.4 KPPH
LIMESTONE FLOW 9.731 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	699.1	699.1	699.1	633.7	329.1	678.8	316.5	119.2	119.2	119.2	119.2	119.2	2667.5	2648.6	0.9875	6.193	–	–	39.77	35.29	57.58	54.87	18.76	17.87	9.838	9.283	4.603
T	°F	1000	671.1	671.1	671.1	1000	830.3	431.4	368	595.3	595.3	595.3	595.3	595.3	422.5	504.7	101.3	101.3	101.3	173.6	79.23	97.21	448.6	228.1	258.6	195.7	192.4	162.8	158.8
M	KPPH	1853.2	1800.3	1619.3	181	1619.3	99.53	180.9	280.5	160.72	81.33	79.39	6.77	1382.8	1820.6	1820.6	79.39	79.38	79.38	6.77	4288	4288	96.57	96.57	44.7	141.3	44.39	185.7	62.79
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516.5	1436	410	341.1	1325.9	1325.9	1325.9	1325.9	1325.9	402.1	493.2	1033.8	69.31	69.31	141.6	47.45	65.31	1258.2	196.5	1171.5	163.9	1128.1	130.8	1082.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	0.9925	4.33	234.3	5.331	11.75	252.2	252.2	234.3	234.3	210.2	187.4	167.3	12.76	50.61	50.61	50.61	50.61	35.29	35.29	252.2	2832.6	119.2	119.2	119.2	166.2	6.509	6.509
T	°F	101.5	156.2	156.2	101.5	200	103.5	103.5	153.2	153.8	186.7	219	287	79.2	79.23	79.23	79.23	79.23	97.35	97.36	102.1	358.9	595.3	595.3	595.3	351.5	173.6	173.6
M	KPPH	1134.3	248.5	248.5	1145.5	1.4	1236.2	1236.2	1236.2	1484.6	1484.6	1484.6	1484.6	64425	64425	64241	184.2	59954	59954	64241	1236.2	1857.8	1389.57	4.062	2.708	1857.8	4.062	2.708
H	BTU/LB	1008.7	124.2	124.7	69.48	169	72.13	72.13	121.7	122.3	155.2	187.7	256.7	47.32	47.45	47.45	47.45	47.45	65.44	65.43	70.75	335.4	1325.9	1325.9	1325.9	323.5	141.6	141.6

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – MONTANA
NELSON CREEK GENERATING STATION
94° F, 27% RH, 100% BMCR

DESIGNED	T. FREEMAN	SCALE: NONE	
DRAWN	P. EGGERS	NO. 17180	REV.
CHECKED	B. DAHL	NC-PF01	A
APPROVED	R. WALTERS		
APPROVED	K. CAVANAUGH		
DATE	06-04-04		

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 251747 KW
PLANT NET HEAT RATE (HHV) 10037 BTU/KWH
FUEL FLOW 371.4 KPPH
LIMESTONE FLOW 9.731 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	698.3	698.3	698.3	633	328.6	678	316	118.8	118.8	118.8	118.8	118.8	2667.3	2648.3	0.4663	5.672	–	–	34.48	29.75	54.64	54.64	17.74	17.74	9.14	9.14	4.14
T	°F	1000	670.8	670.8	670.8	999.2	829.4	431.2	367.8	594.2	594.2	594.2	594.2	594.2	422.3	504.6	77.47	77.45	77.45	204.8	56.73	72.96	444.8	227.7	255	195.1	189	161.2	154.4
M	KPPH	1852	1799.1	1618.1	181	1618.1	99.63	180.9	280.7	153.8	81.33	72.47	16.19	1379	1820.4	1820.4	72.47	72.47	72.47	16.19	4288	4288	96.68	96.68	45.23	141.9	46.08	188	70.65
H	BTU/LB	1460.1	1327.8	1327.8	1327.8	1516	1435.5	409.8	340.9	1325.4	1325.4	1325.4	1325.4	1325.4	401.9	493.1	1005.7	45.55	45.55	173	24.9	41.12	1256.7	196.1	1170.1	163.2	1126.5	129.2	1079.8

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	0.7493	4.14	233.9	5.087	11.75	251.6	251.6	233.9	233.9	209.7	187	166.9	12.76	35.66	35.66	35.66	35.66	29.76	29.76	251.6	2832.4	118.8	109.1	109.1	165.8	12.72	12.72
T	°F	92.27	154.4	151	92.75	200	93.14	93.14	151	151.6	185.9	218.6	286.7	56.61	56.73	56.73	56.73	56.73	87.89	86.24	93.14	358.7	594.2	590.9	590.9	351.2	204.8	204.8
M	KPPH	1120.4	258.6	258.6	1224.7	1.4	1224.7	1224.7	1224.7	1483.3	1483.3	1483.3	1483.3	38786	38786	38652	133.6	34364	34364	38652	1224.7	1856.6	1395.2	9.714	6.476	1856.6	9.714	6.476
H	BTU/LB	1004	122.4	119.5	60.78	169	61.83	61.83	119.5	120.2	154.4	187.2	256.4	24.71	24.9	24.9	24.9	24.9	56.04	54.39	61.83	335.2	1325.4	1324.4	1324.4	323.2	173	173

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.
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www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN NELSON CREEK GENERATING STATION 45° F, 27% RH, 100% BMCR

DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	B. DAHL
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: NONE
NO. 17180
NC-PF02
REV. A

CADD D1-R3

NOTES

1. THIS DRAWING IS NOT FOR CONSTRUCTION.
2. SCAH – STEAM COIL AIR HEATER.
3. HHV = HIGHER HEATING VALUE.
4. REFER TO PROCESS FLOW DIAGRAM PF05.

PLANT NET POWER 250923 KW
PLANT NET HEAT RATE (HHV) 10070 BTU/KWH
FUEL FLOW 371.4 KPPH
LIMESTONE FLOW 9.731 KPPH

	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
P	PSIA	2414.7	696.3	696.3	696.3	631.1	327.1	676	314.3	117	117	117	117	117	2666.1	2647.2	.525	5.739	–	–	33.2	28.51	53.83	53.84	17.57	17.57	9.70	9.18	4.36
T	°F	1000	670.2	670.2	670.2	998.9	828.8	430.8	367	591.6	591.6	591.6	591.6	591.6	421.9	504.3	81.26	81.25	81.25	246.4	60.39	76.84	442.6	227.1	254	195.1	189.2	163	156.5
M	KPPH	1847.8	1795.1	1614.3	180.8	1614.3	100.1	180.6	280.8	154.54	81.05	73.49	29.57	1360.5	1815.7	1815.7	73.49	73.49	73.49	29.57	4288	4288	95.66	95.66	44.01	139.7	42.93	182.6	56.49
H	BTU/LB	1460.1	1327.5	1327.5	1327.5	1515.9	1435.3	409.3	340	1324.2	1324.2	1324.2	1324.2	1324.2	401.5	492.7	1009.8	49.35	49.35	215	28.55	45.01	1255.6	195.5	1169.7	163.2	1127.6	131	1081.2

	UNITS	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
P	PSIA	1.123	4.36	231.9	5.461	11.75	109.2	249.8	231.9	231.9	207.9	185.3	165.3	12.76	32	32	32	32	28.52	28.52	249.8	2831.2	117	84.36	84.36	164.2	28	28
T	°F	105.7	156.5	153.8	105.6	200	107.8	109.2	153.8	154.3	186.3	218.2	285.8	60.22	60.39	60.39	60.39	60.39	101.9	98.31	107.8	357.7	591.6	584.9	584.9	350.3	246.4	246.4
M	KPPH	1121.5	124.5	124.5	1132.5	1.4	1240.1	1240.1	1240.1	1479.2	1479.2	1479.2	1479.2	30199	30199	30093	106.1	25805	25805	30093	1240.1	926.2	1390	17.742	11.828	1852.4	17.742	11.828
H	BTU/LB	1014.3	239.1	239.1	73.64	169	77.8	77.8	122.3	122.8	154.8	186.8	255.4	28.32	28.55	28.55	28.55	28.55	69.93	66.37	76.44	334.2	1324.2	1323.2	1323.2	322.3	215	215

PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA – 43 – SOUTHERN
NELSON CREEK GENERATING STATION
-20° F, 27% RH, 100% BMCR

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED B. DAHL
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

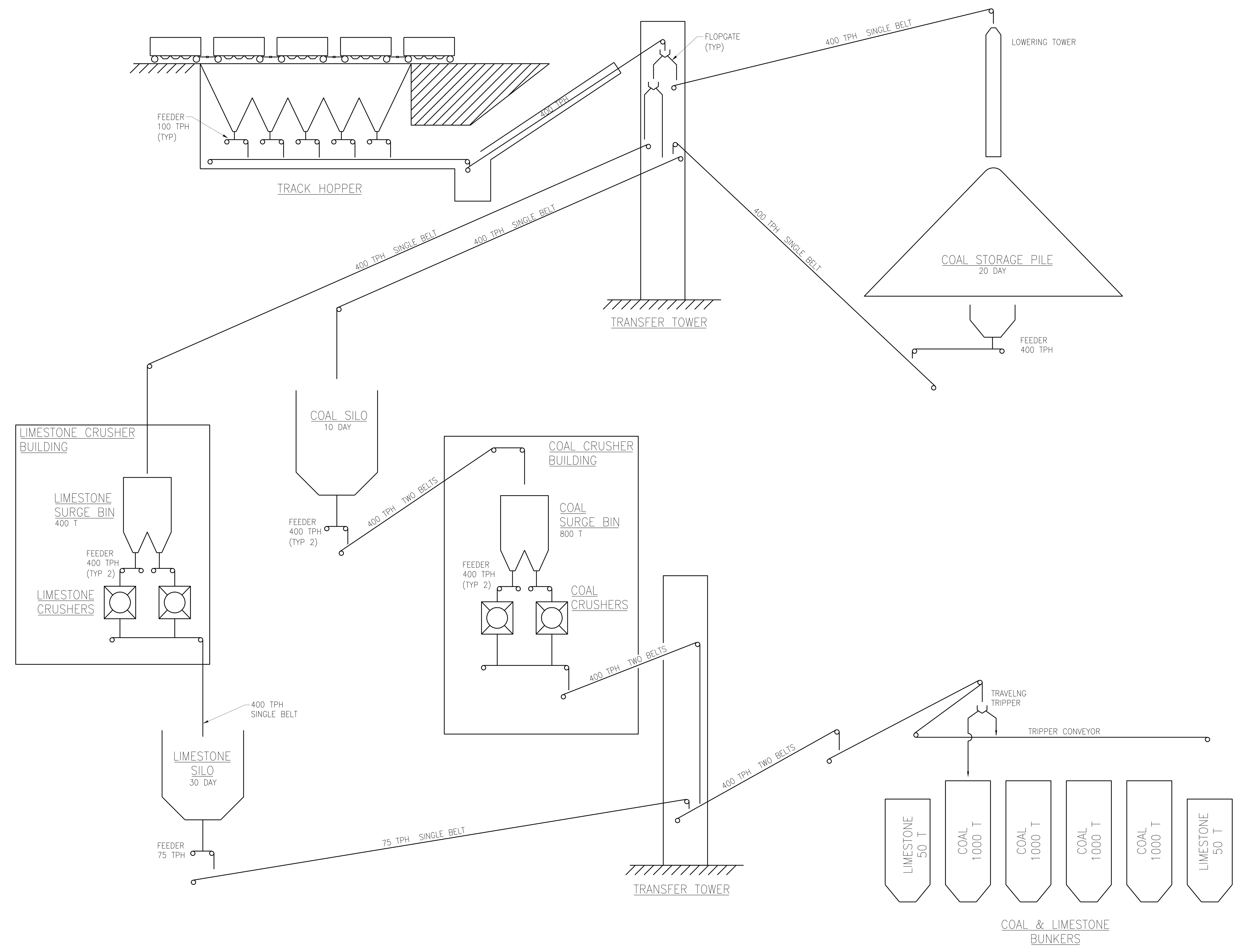
SCALE: NONE
NO. 17180
NC-PF03
REV. A

Appendix C

Material Handling Diagram

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. COAL LOADING DESIGNED FOR EIGHT(8) HOURS.
3. LIMESTONE LOADING DESIGNED FOR ONE(1) HOUR.



PRELIMINARY

NO.	REVISIONS	DWN	APVD	APVD	DATE
A	PRELIMINARY REVIEW	PDE	RRW	KWC	06-04-04

Stanley Consultants INC.

9200 East Mineral Avenue, Suite 400, Englewood, Colorado 80112-3416
www.stanleyconsultants.com

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

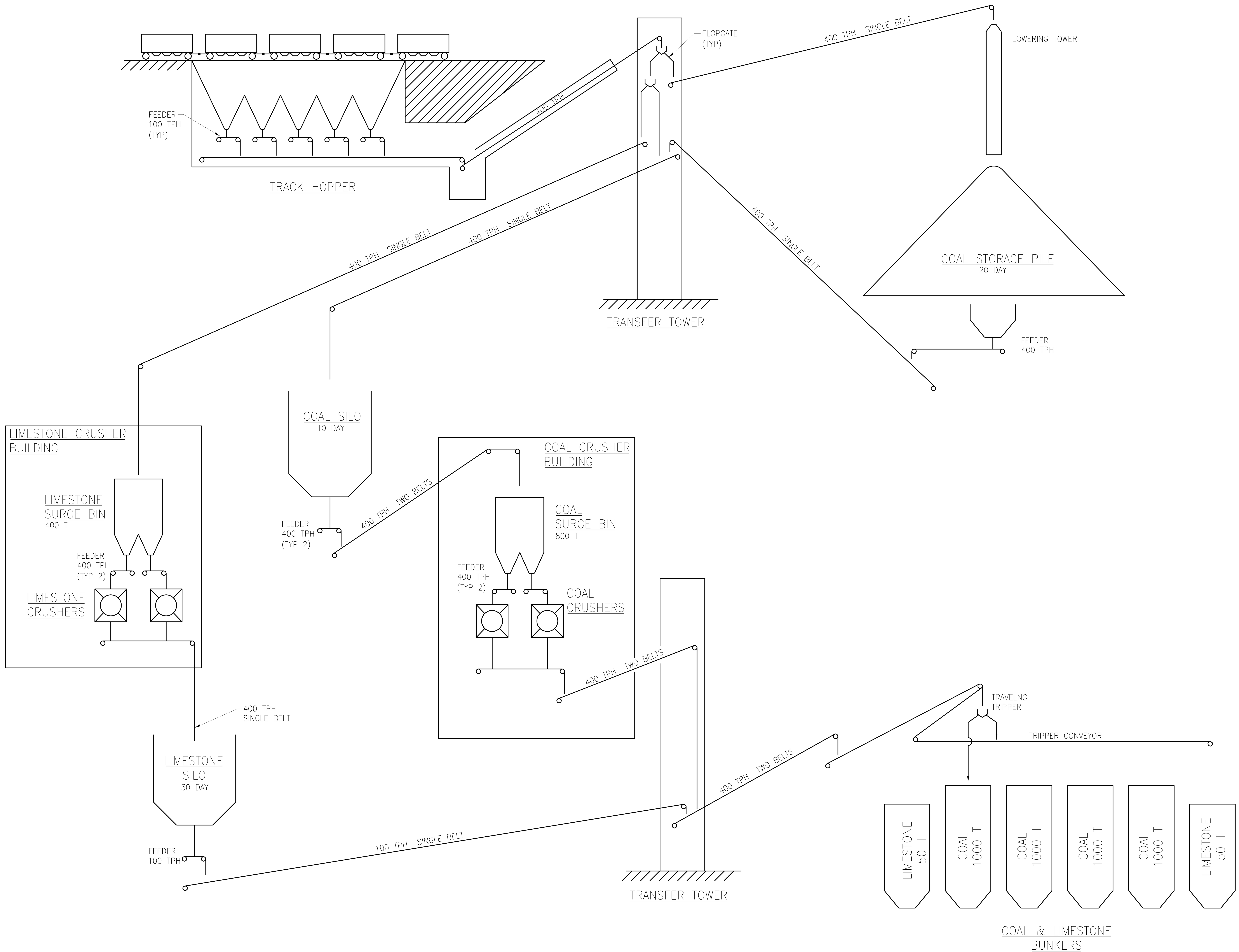
MONTANA - 43 - SOUTHERN
SALEM GENERATING STATION
COAL/LIMESTONE HANDLING

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
S1-PF04
REV. A

NOTES

1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
2. COAL LOADING DESIGNED FOR EIGHT(8) HOURS.
3. LIMESTONE LOADING DESIGNED FOR ONE(1) HOUR.



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NO.	REVISIONS	DWN	APVD	APVD	DATE
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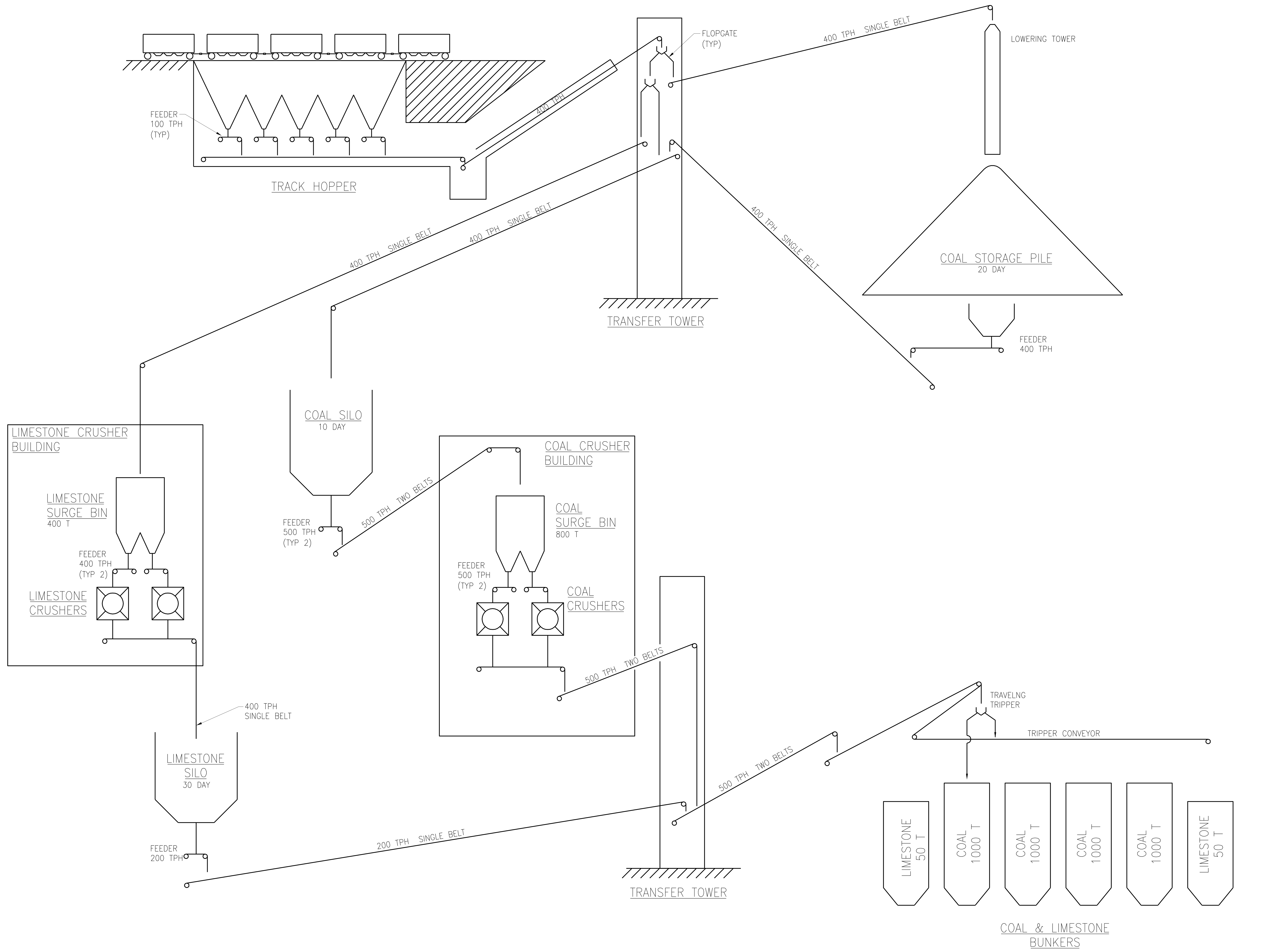
Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
DECKER GENERATING STATION
COAL/LIMESTONE HANDLING

DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: NONE
NO. 17180
DK-PF04
REV. A



NOTES

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3. LIMESTONE LOADING DESIGNED FOR ONE(1) HOUR.

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MONTANA - 43 - SOUTHERN
HYSHAM GENERATING STATION
COAL/LIMESTONE HANDLING

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
H2-PF04
REV. A

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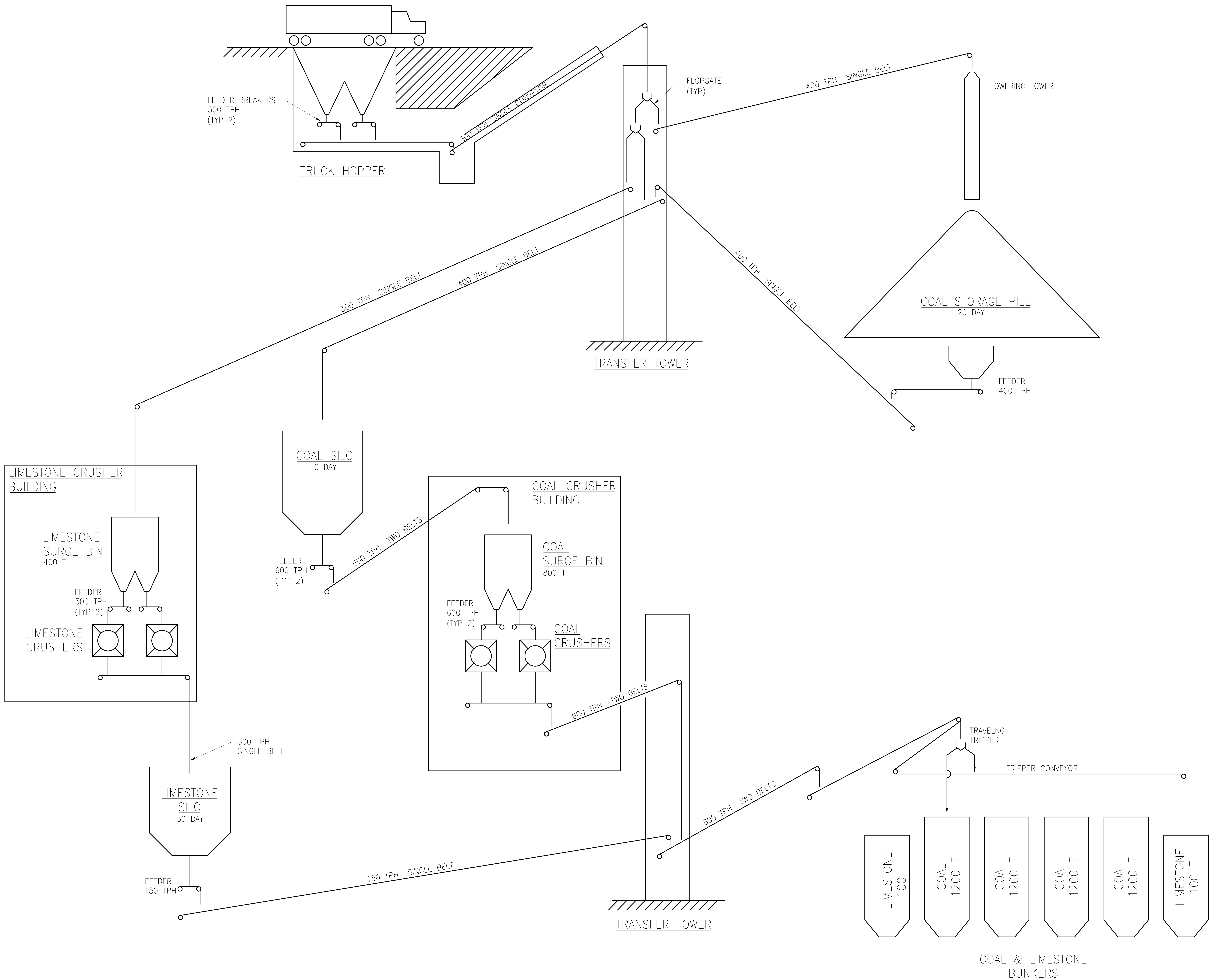

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MONTANA - 43 - SOUTHERN
NELSON CREEK GENERATING STATION
COAL/LIMESTONE HANDLING

DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

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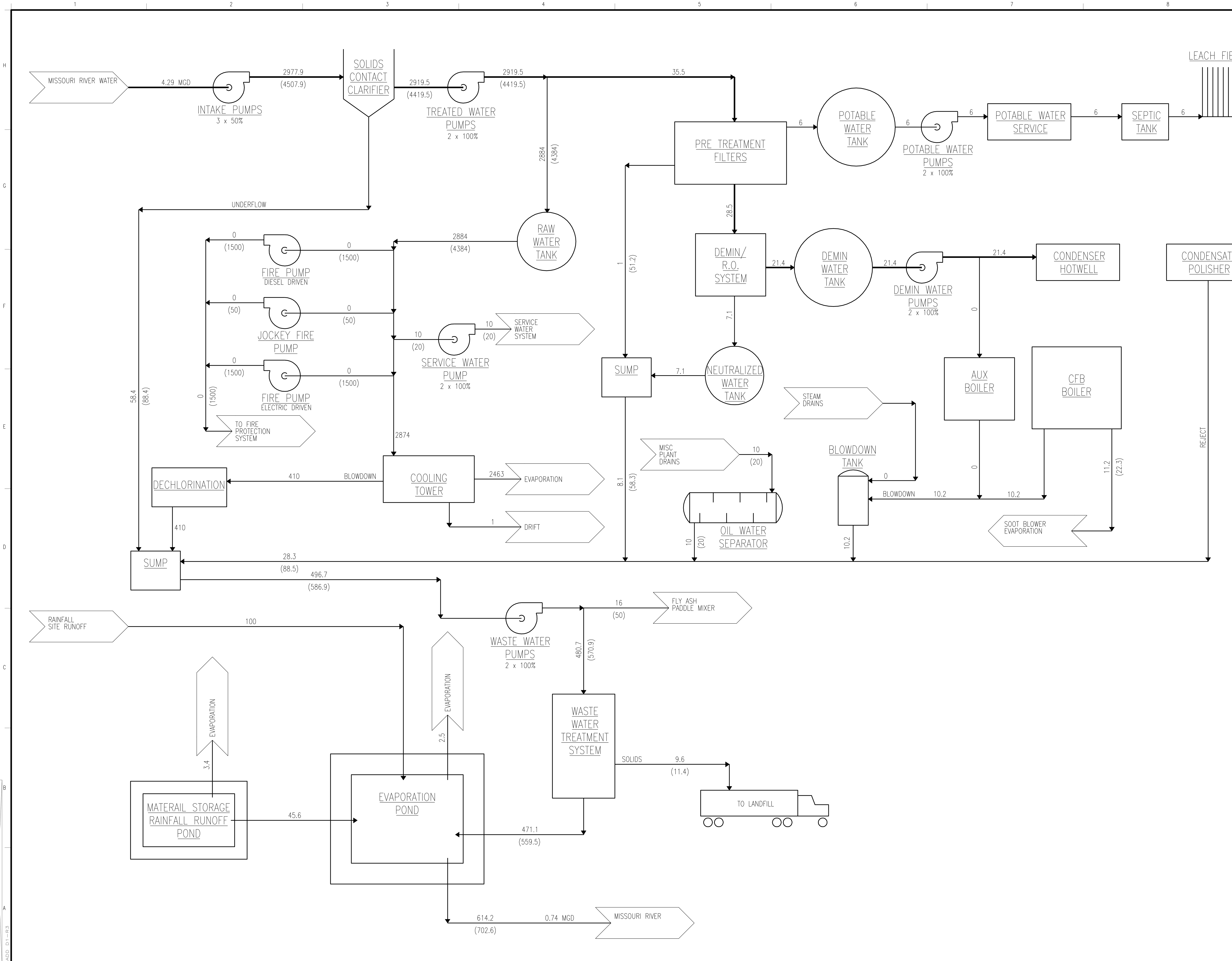
Appendix D

Preliminary Water Balance



NOTES

1. FLOW RATES ARE DAILY AVERAGE GPM.
2. FLOW RATES IN ( ) ARE MAXIMUM GPM.
3. MGD = MILLION GALLONS PER DAY.

PRELIMINARY

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MONTANA - 43 - SOUTHERN
SALEM GENERATING STATION
WATER FLOW DIAGRAM

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
S1-PF05
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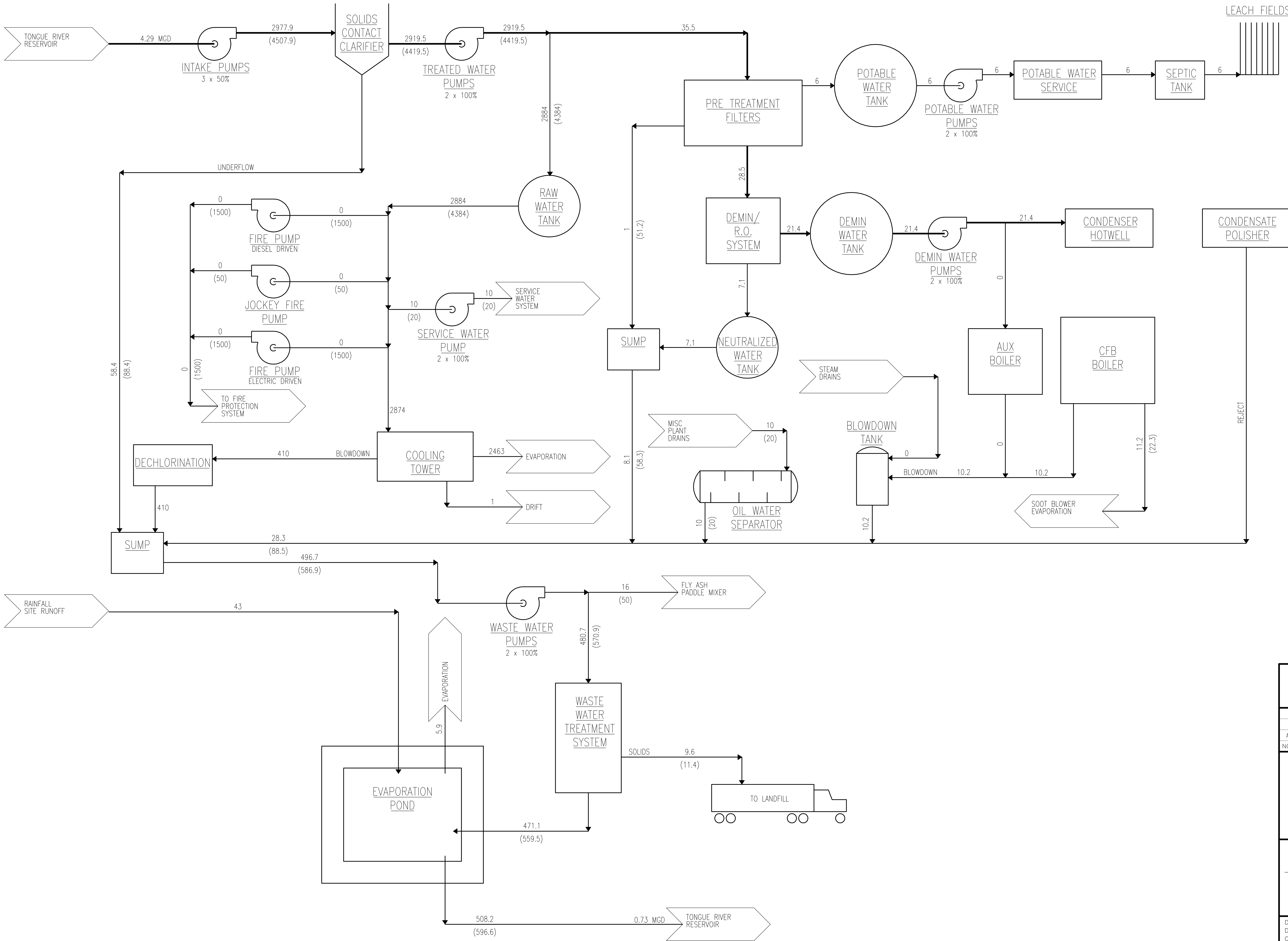

NOTES

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3. MGD = MILLION GALLONS PER DAY.

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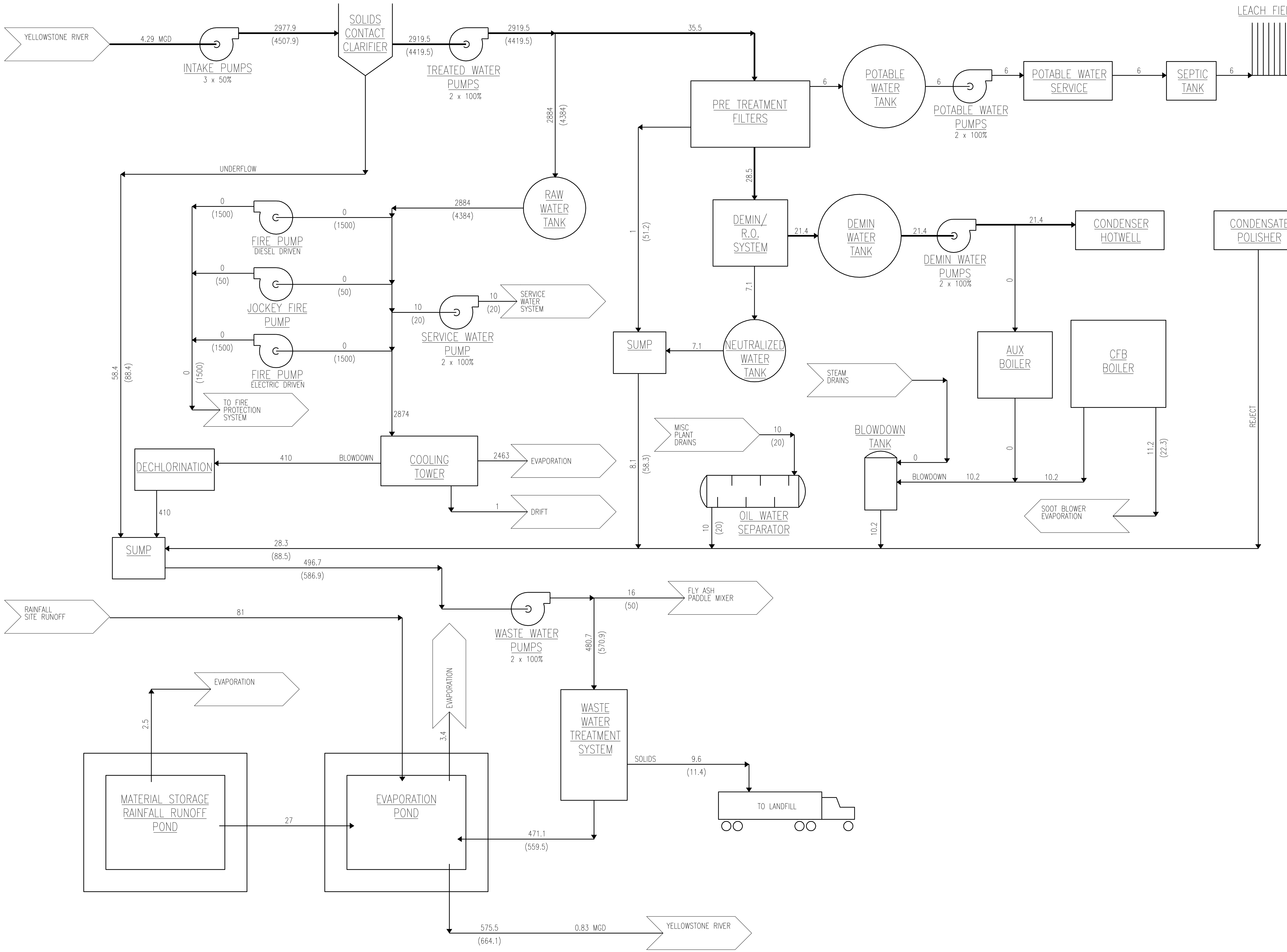
MONTANA - 43 - SOUTHERN
DECKER GENERATING STATION
WATER FLOW DIAGRAM

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
DK-PF05
REV. A



NOTES

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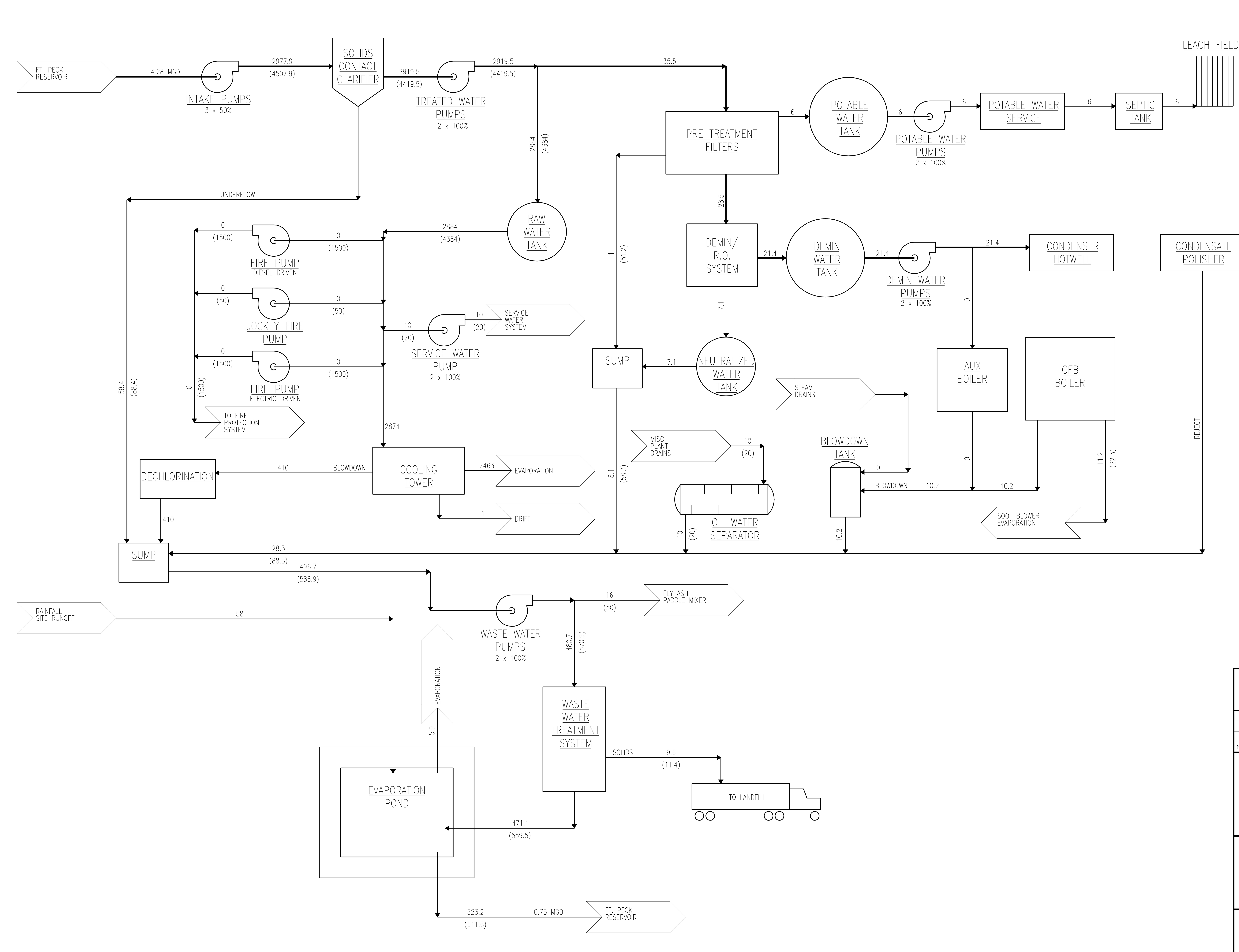
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
HYSHAM GENERATING STATION
WATER FLOW DIAGRAM

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
H2-PF05
REV. A



NOTES

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2. FLOW RATES IN ( ) ARE MAXIMUM GPM.
3. MGD = MILLION GALLONS PER DAY.

PRELIMINARY

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MONTANA - 43 - SOUTHERN
NELSON CREEK GENERATING STATION
WATER FLOW DIAGRAM

DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04

SCALE: NONE
NO. 17180
NC-PF05
REV. A

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Appendix E

Ash Handling System

NOTES

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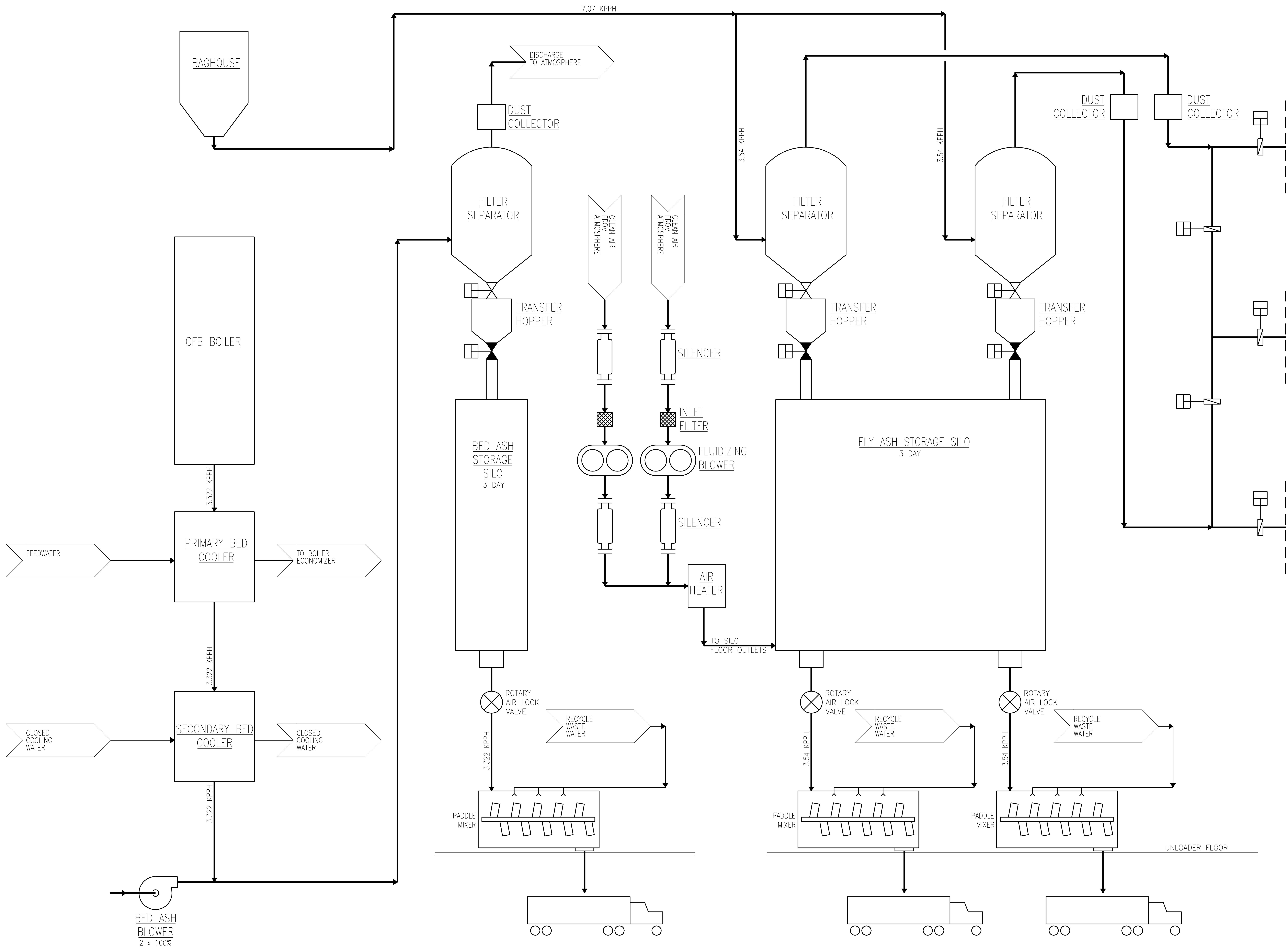

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MONTANA – 43 – SOUTHERN
SALEM GENERATING STATION
FLY ASH HANDLING SYSTEM

DESIGNED	T. FREEMAN	SCALE: NONE	
DRAWN	P. EGGERS	NO. 17180	REV.
CHECKED		S1-PF06	A
APPROVED	R. WALTERS		
APPROVED	K. CAVANAUGH		
DATE	06-04-04		


NOTES
1. THIS DRAWING IS FOR PRELIMINARY REVIEW ONLY.
6.89 KPPH
BAGHOUSE
DISCHARGE TO ATMOSPHERE
DUST COLLECTOR
FILTER SEPARATOR
3.45 KPPH
3.45 KPPH
CLEAN AIR FROM ATMOSPHERE
CLEAN AIR FROM ATMOSPHERE
TRANSFER HOPPER
SILENCER
INLET FILTER
FLUIDIZING BLOWER
SILENCER
AIR HEATER
TO SILO FLOOR OUTLETS
CFB BOILER
3.42 KPPH
FEEDWATER
PRIMARY BED COOLER
TO BOILER ECONOMIZER
3.42 KPPH
CLOSED COOLING WATER
SECONDARY BED COOLER
CLOSED COOLING WATER
3.42 KPPH
BED ASH BLOWER
2 x 100%
BED ASH STORAGE SILO
3 DAY
FLY ASH STORAGE SILO
3 DAY
ROTARY AIR LOCK VALVE
RECYCLE WASTE WATER
3.42 KPPH
3.45 KPPH
3.45 KPPH
PADDLE MIXER
UNLOADER FLOOR
MECHANICAL EXHAUSTER
ACOUSTICAL ENCLOSURE (TYP)
PRELIMINARY
A | PRELIMINARY REVIEW | PDE | RRW | KWC | 06-04-04
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MONTANA - 43 - SOUTHERN
DECKER GENERATING STATION
FLY ASH HANDLING SYSTEM
DESIGNED T. FREEMAN
DRAWN P. EGGERS
CHECKED
APPROVED R. WALTERS
APPROVED K. CAVANAUGH
DATE 06-04-04
SCALE: NONE
NO. 17180
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DK-PF06
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MONTANA – 43 – SOUTHERN
HYSHAM GENERATING STATION
FLY ASH HANDLING SYSTEM

DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: NONE
NO. 17180
H2-PF06
REV. A

NOTES

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MONTANA - 43 - SOUTHERN
NELSON CREEK GENERATING STATION
FLY ASH HANDLING SYSTEM

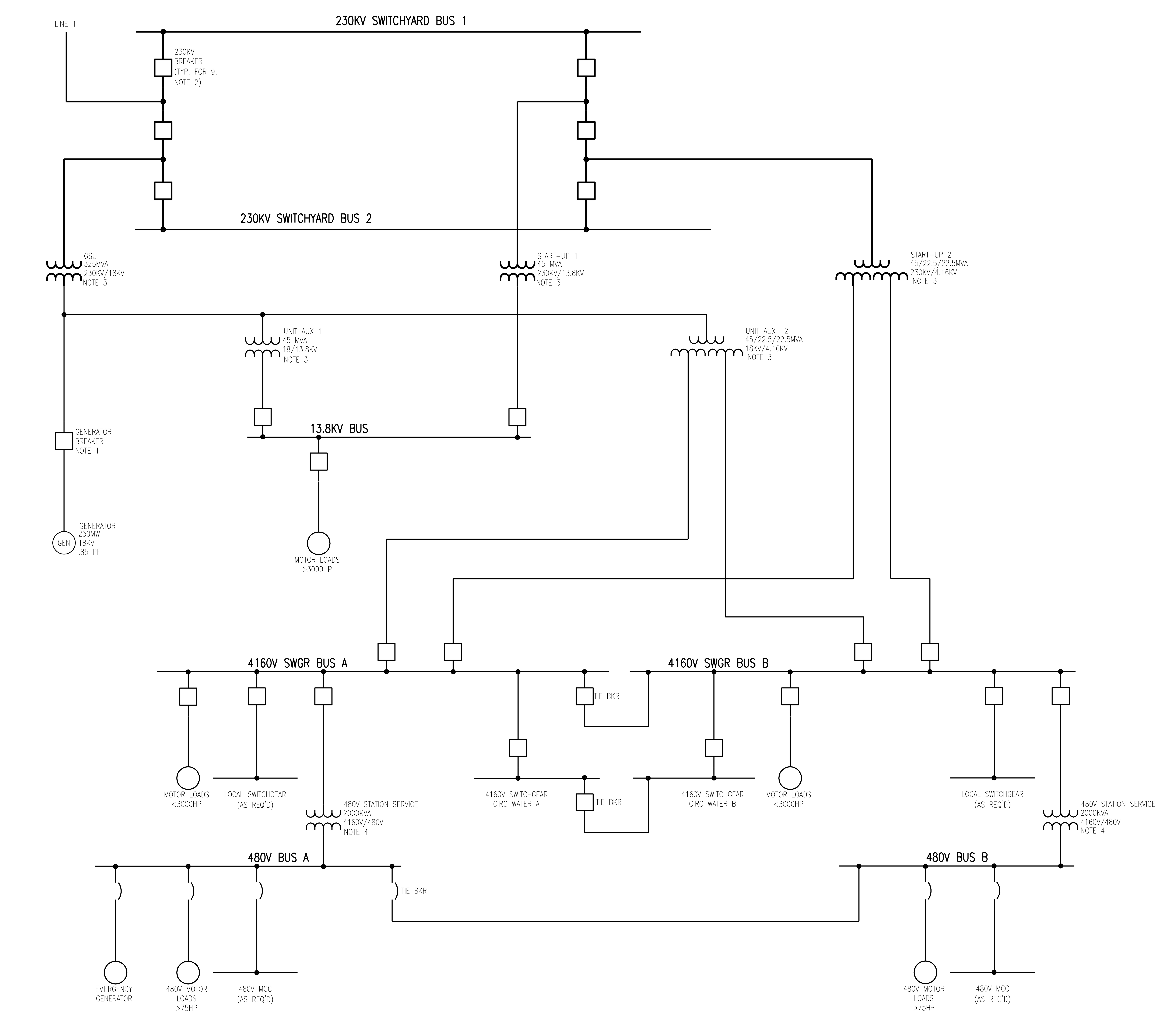
DESIGNED	T. FREEMAN
DRAWN	P. EGGERS
CHECKED	
APPROVED	R. WALTERS
APPROVED	K. CAVANAUGH
DATE	06-04-04

SCALE: NONE

NO. 17180 — NC-PF06 — REV. A

Appendix F

One Line Diagrams



NOTES:

1. GENERATOR BREAKER OPTIONAL WITH USE OF START-UP TRANSFORMERS.
2. SWITCHYARD CONFIGURATION TO BE DETERMINED.
3. TOP MVA RATING SHOWN FOR TRANSFORMERS- SIZES ARE PRELIMINARY.
4. 480V TRANSFORMERS AND SWITCHGEAR AS REQUIRED BY SITE LAYOUT- TYPICAL SHOWN.

SUBMITTAL FOR REVIEW
NOT FOR CONSTRUCTION 09/02/04

NO.	REVISIONS	DWN	APVD	APVD	DATE
B	ISSUED FOR DESIGN CRITERIA REVIEW	LFP	LRJ	RW	09/02/04
A	ISSUED FOR REVIEW	LFP	LRJ		RW

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Southern Montana Electric
Generation & Transmission Cooperative, Inc.

MONTANA - 43 - SOUTHERN
HIGHWOOD STATION UNIT 1
OVERALL ONE LINE DIAGRAM

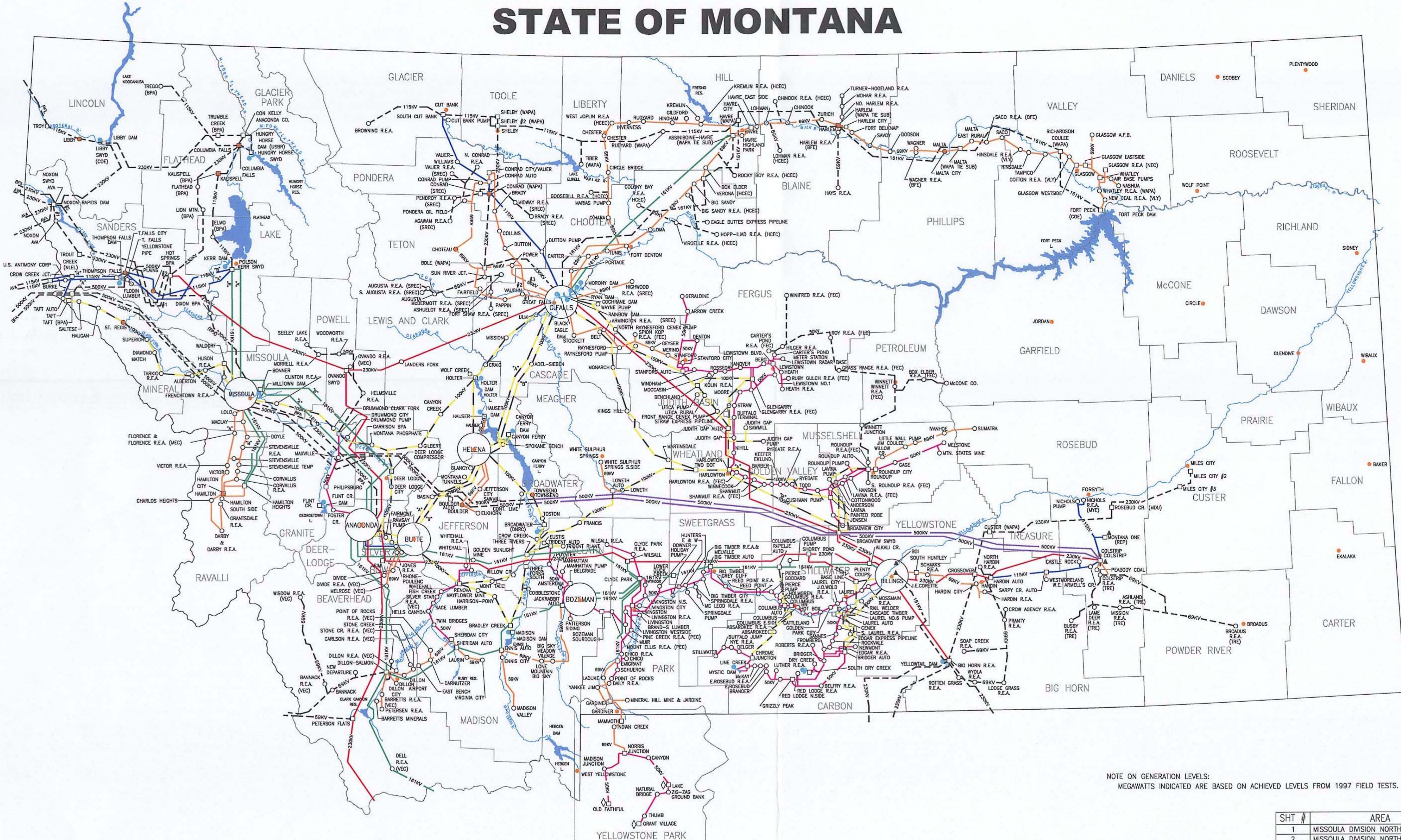
DESIGNED
DRAWN
CHECKED
APPROVED
APPROVED
DATE

SCALE: NONE
NO. 17453
REV.
EE01
B

Appendix G

Transmission Maps

STATE OF MONTANA



NOTE ON GENERATION LEVELS:
MEGAWATTS INDICATED ARE BASED ON ACHIEVED LEVELS FROM 1997 FIELD TESTS.

LEGEND

- PCB NORMALLY CLOSED
- PCB NORMALLY OPEN
- VACUUM CIRCUIT BREAKER
- AIR BLAST CIRCUIT BREAKER
- CIRCUIT SWITCHER
- *
- ABSW NORMALLY CLOSED
- ABSW NORMALLY OPEN
- ABSW W/GROUNDING
- ABSW/W INTERLOCKING GROUND SWITCH
- ABSW FUSED

S–SUPERVISORY M–MOTORIZED
A–AUTOMATIC V–VACUUM
R–RELAY I–INTERRUPTER
■GENERATION POINT OF RECEIPT

- CURRENT TRANSFORMER\ TIE–LINE METERING
- DISC. CLOSED
- DISC. OPEN
- HOOK GROUND SWITCH
- HI SPEED GND. SWITCH
- SHUNT CAPACITOR
- SERIES CAPACITOR
- REACTOR
- FUSED DISC.
- REGULATOR
- GENERATING PLANT
- HOT LINE LOOPS
- AUTO TRANSFORMER
- (LTC) LOAD TAPE CHANGER
- DIST.TRANSFORMER
- POT. TRANSFORMER
- R RUSTRAK / M METROSONICS / P PAPER CHART — RECORDING VOLTMETERS
- 2.4 MILEAGE BETWEEN POINTS
- PHASE ANGLE REGULATOR

PP&L OWNERSHIP
PP&L
50KV
69KV
100KV
115KV
161KV
230KV
500KV

ABBREVIATIONS

UTILITIES
- AVA – AVISTA
- IPC – IDAHO POWER COMPANY
- MDU – MONTANA–DAKOTA UTILITIES
- NWE – NORTHWESTERN ENERGY
- PAC – PACIFICORP
- PPL – PENNSYLVANIA POWER & LIGHT GLOBAL

GOVERNMENT AGENCIES
- BPA – BONNEVILLE POWER ADMINISTRATION
- COE – US ARMY CORPS OF ENGINEERS
- DNRC – DEPARTMENT OF NATURAL RESOURCES & CONSERVATION
- USAF – UNITED STATES AIR FORCE
- USBR – UNITED STATES BUREAU OF RECLAMATION
- WAPA – WESTERN AREA POWER ADMINISTRATION

INDEPENDENT POWER PRODUCERS/COGENERATION
- REP – ROSEBUD ENERGY PARTNERS
- YELP – YELLOWSTONE ENERGY LIMITED PARTNERSHIP

R.E.A.'S/COOPERATIVES
- BEC – BEARTOOTH ELECTRIC
- BFE – BIG FLAT ELECTRIC
- BHE – BIGHORN ELECTRIC
- FEC – FERGUS ELECTRIC
- GEC – GLACIER ELECTRIC
- HCEC – HILL COUNTY ELECTRIC
- MEC – MISSOULA ELECTRIC
- MRE – MARIAS RIVER ELECTRIC
- MVE – MISSION VALLEY ELECTRIC
- MYE – MID–YELLOWSTONE ELECTRIC
- NEC – NORTHERN ELECTRIC
- NLEL – NORTHERN LIGHTS ELECTRIC
- PEC – PARK ELECTRIC
- REC – RAVALLI ELECTRIC
- SREC – SUN RIVER ELECTRIC
- TRE – TONGUE RIVER ELECTRIC
- VEC – VIGILANTE ELECTRIC
- YVE – YELLOWSTONE VALLEY ELECTRIC
- VLY – VALLEY ELECTRIC

LEGEND

- □ MAJOR SWITCHING OR SUBSTATION
- ○ ELECTRIC DISTRIBUTION POINT
- HYDROELECTRIC PLANT
- ▲ THERMOELECTRIC PLANT
- ◇ DIESEL GENERATOR
- –69KV– – OTHER OWNERSHIP
- COUNTY SEAT

SHT #	AREA
1	MISSOULA DIVISION NORTHWEST
2	MISSOULA DIVISION NORTH
3	MISSOULA DIVISION SOUTH
4	BUTTE DIVISION WEST
5	GREAT FALLS DIVISION NORTHWEST
6	HELENA DIVISION
7	BUTTE DIVISION EAST
8	BUTTE DIVISION SOUTH
9	GREAT FALLS DIVISION NORTH
10	GREAT FALLS DIVISION
11	BOZEMAN DIVISION NORTH
12	BOZEMAN DIVISION SOUTH
13	HAVRE DISTRICT CENTRAL
14	BILLINGS DIVISION NORTHWEST
15	BILLINGS DIVISION CITY AREA
16	BILLINGS DIVISION SOUTHWEST
17	HAVRE DISTRICT EAST
18	BILLINGS DIVISION NORTHEAST
19	BILLINGS DIVISION EAST
20	BILLINGS DIVISION SOUTHEAST

REVISION	DATE
2003 REVISIONS	JAN–04

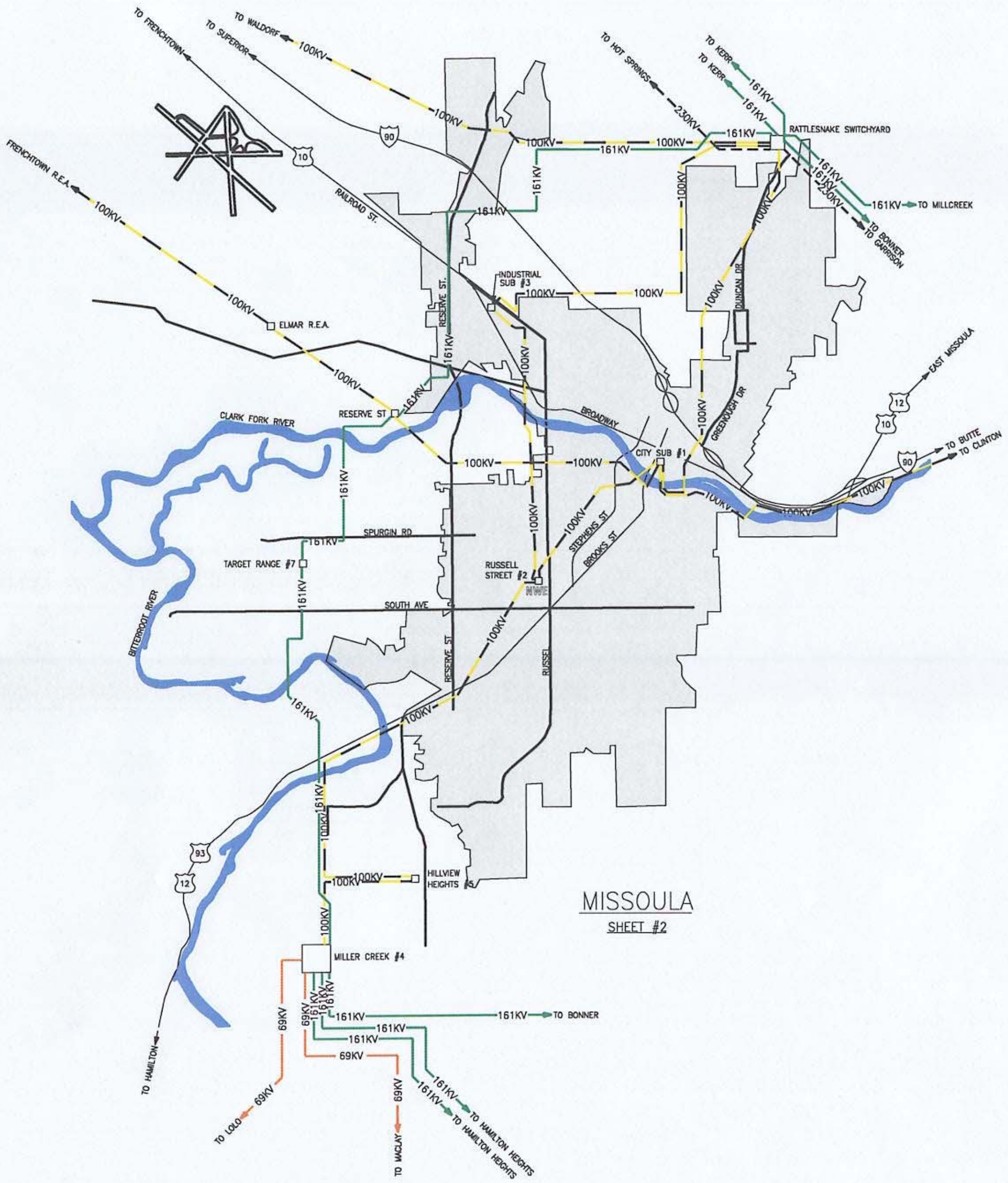
NorthWestern Energy

INFORMATION SHEET
ELECTRIC TRANSMISSION SYSTEM
ONE LINE DIAGRAM

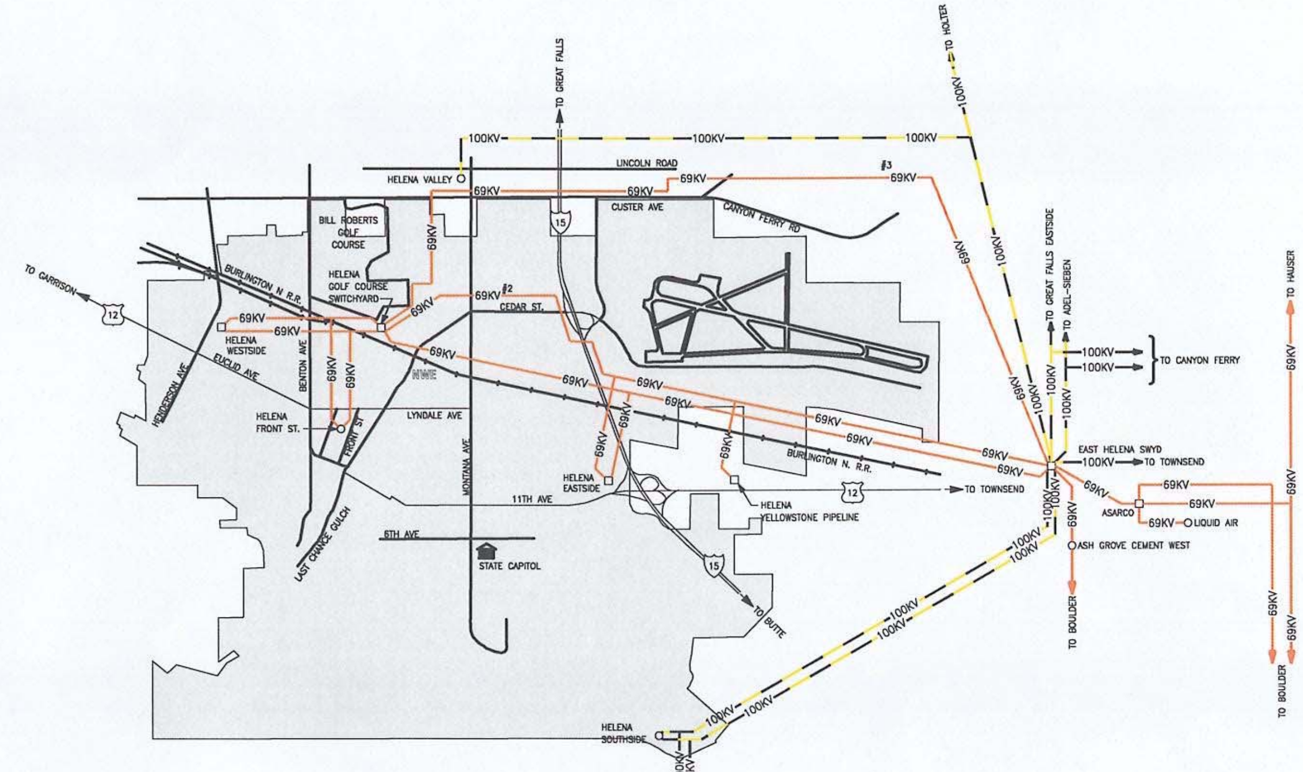
DRAWING NUMBER 41735–C2 REV 17

SHEET 1A ACAD2004

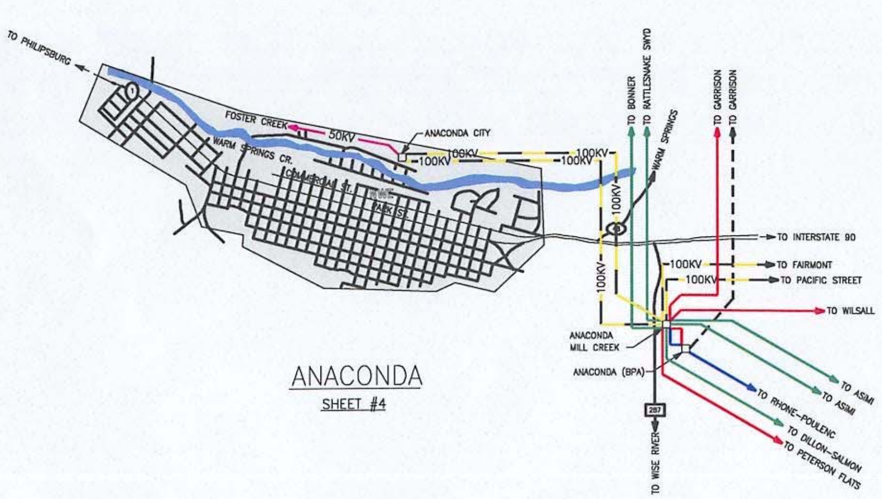
41735–C2–1A–17



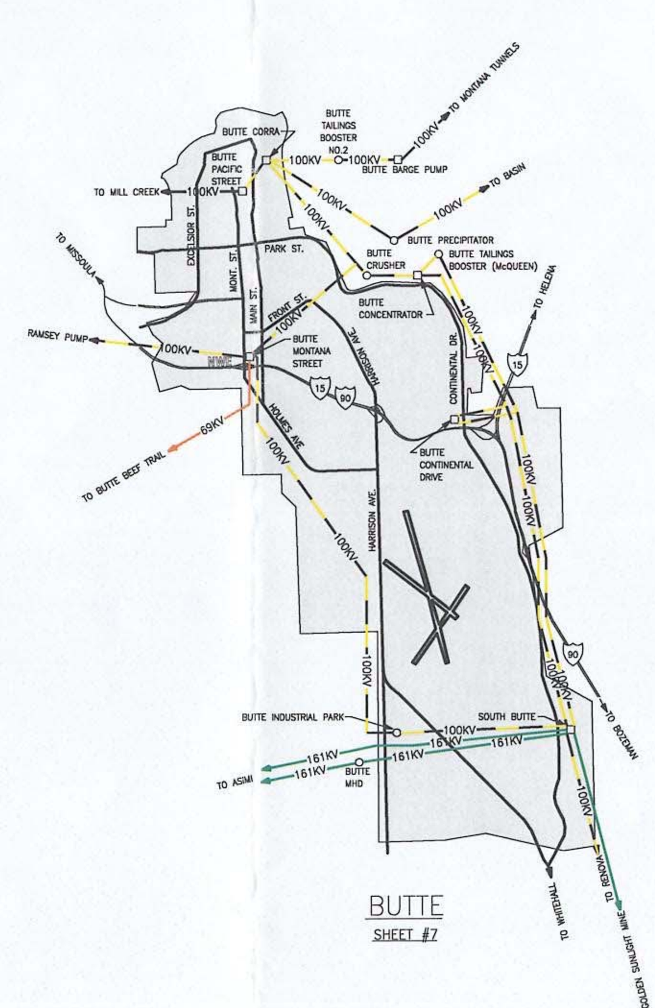
MISSOULA
SHEET #2



HELENA
SHEET #6



ANACONDA
SHEET #4



BUTTE
SHEET #7

REVISION	DATE
2003 REVISIONS	JAN-04

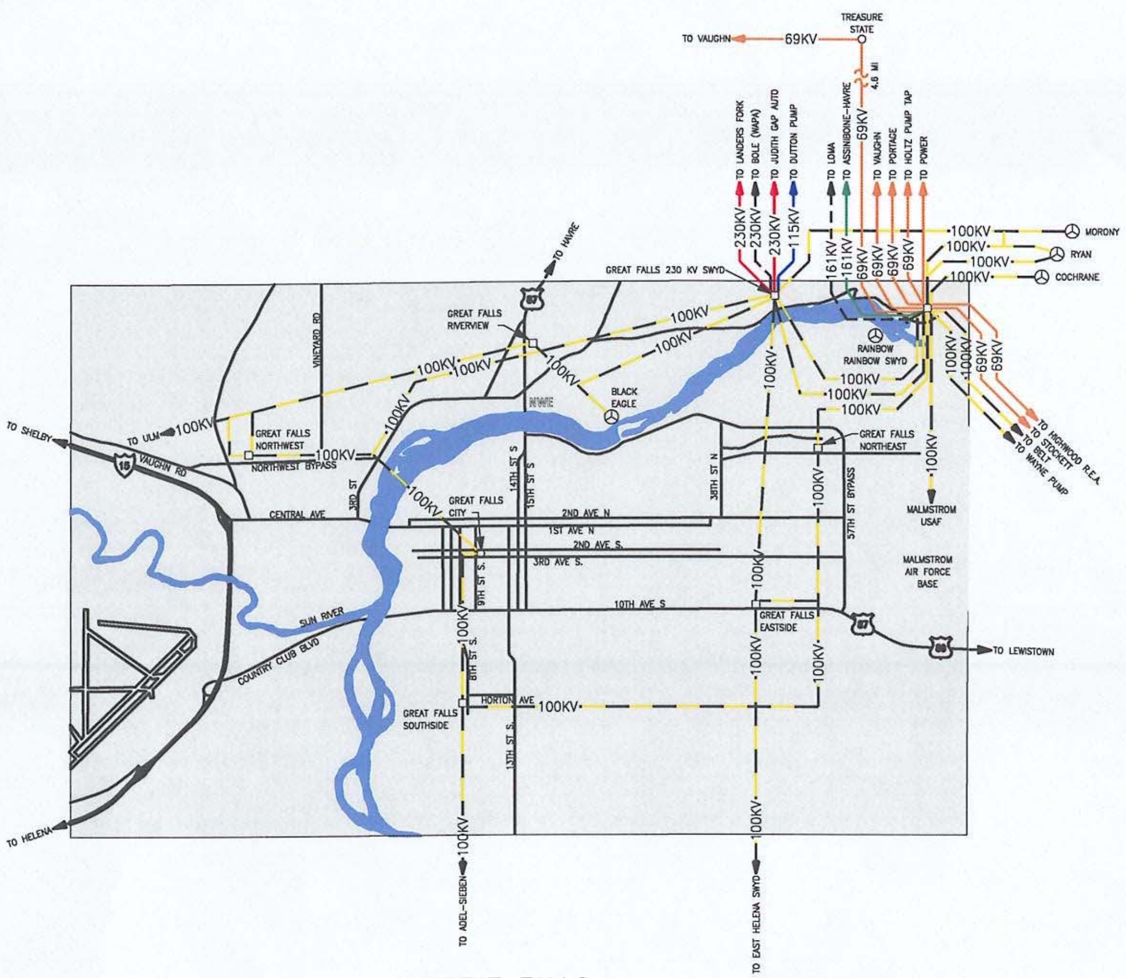
NorthWestern Energy

INFORMATION SHEET
ELECTRIC TRANSMISSION SYSTEM
ONE LINE DIAGRAM

DRAWING NUMBER 41735-C2 REV 17

SHEET 1B ACAD2004

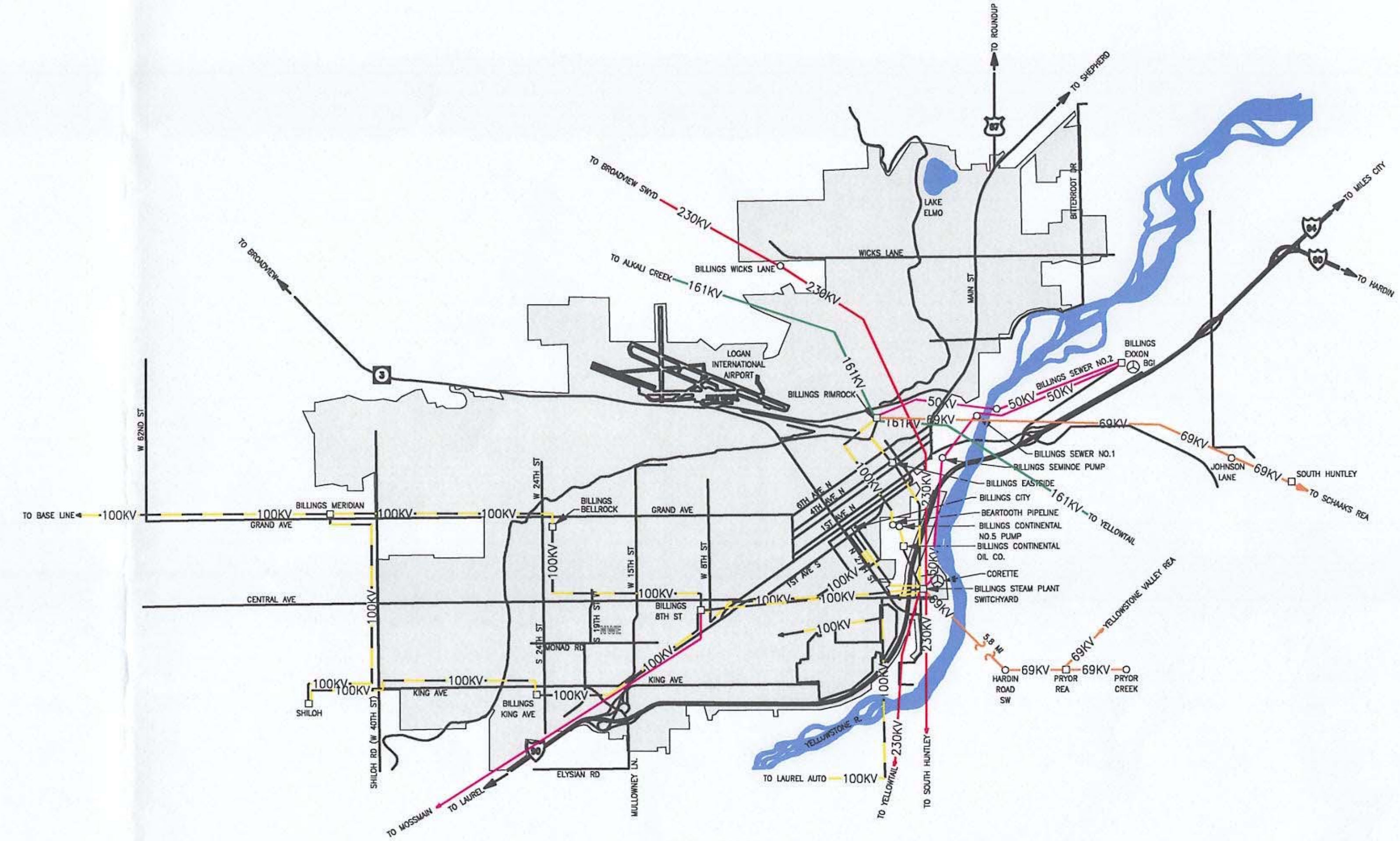
41735-C2-1B-17



GREAT FALLS

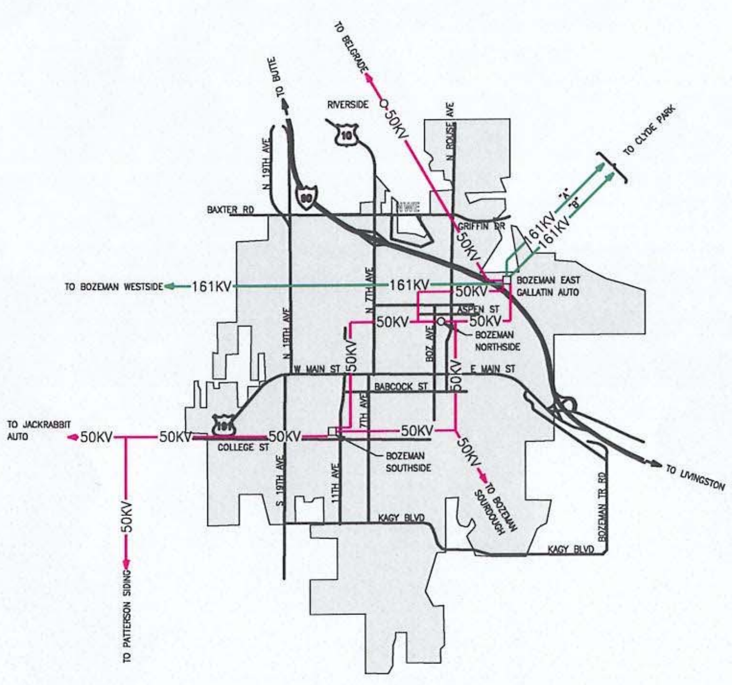
SHEET #10

For Pam



BILLINGS

SHEET #15



BOZEMAN

SHEET #11

REVISION	DATE
2003 REVISIONS	JAN-04

NorthWestern Energy

INFORMATION SHEET
ELECTRIC TRANSMISSION SYSTEM
ONE LINE DIAGRAM

DRAWING NUMBER 41735-C2 REV 17

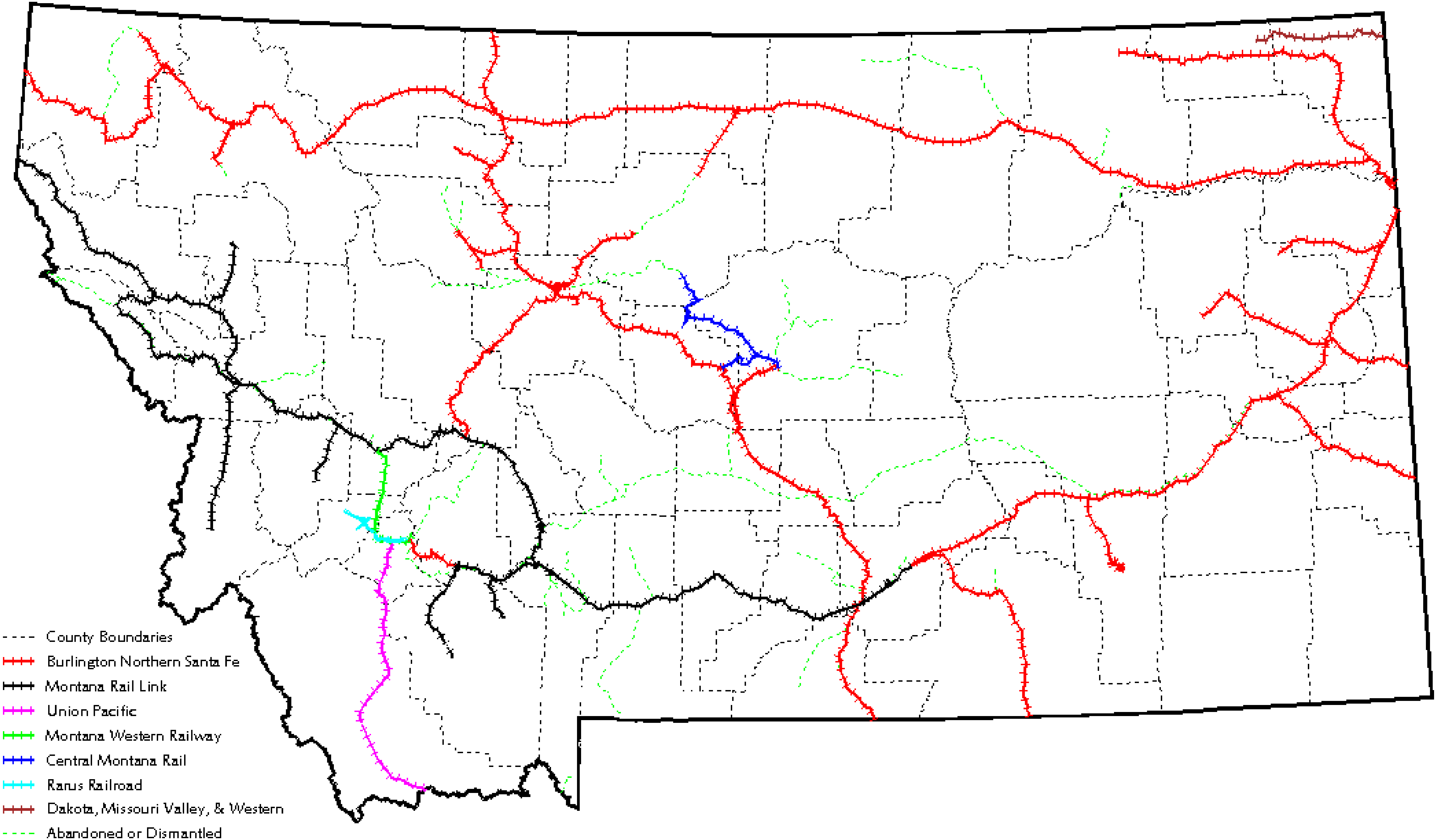
SHEET 1C ACAD2004

41735-C2-1C-17

Appendix H

Transportation Maps

Railroads



County Boundaries
Burlington Northern Santa Fe
Montana Rail Link
Union Pacific
Montana Western Railway
Central Montana Rail
Rarus Railroad
Dakota, Missouri Valley, & Western
Abandoned or Dismantled

Appendix J

Cost Estimate/Economic Analysis

Spring Creek 94°F DB, 100% Load (SALEM)

Project Cost Summary	Reference Cost	Estimated Cost	
I Specialized Equipment	115,673,800	122,885,700	USD
II Other Equipment	32,869,102	40,474,481	USD
III Civil	10,871,394	13,632,060	USD
IV Mechanical	57,750,635	76,761,788	USD
V Electrical	6,348,183	8,402,813	USD
VI Buildings & Structures	6,682,260	8,077,182	USD
VII Engineering & Plant Startup	16,659,593	16,659,593	USD
Subtotal - Contractor's Internal Cost	246,854,966	286,893,617	USD
VIII Contractor's Soft & Miscellaneous Costs	54,547,909	68,425,130	USD
Contractor's Price	301,402,876	355,318,747	USD
IX Owner's Soft & Miscellaneous Costs	18,070,144	20,765,937	USD
Total - Owner's Cost	319,473,019	376,084,685	USD
Net Plant Output	250.0	250.0	MW
Cost per kW - Contractor's	1,206	1,421	USD per kW
Cost per kW - Owner's	1,278	1,504	USD per kW

Total Plant (Reference Basis):	Reference Cost	Hours
Commodities	24,135,505	
Labor	72,306,490	2,502,307

Effective Labor Rates:	Cost per Hour
Civil Account	25.01
Mechanical Account	29.00
Electrical Account	30.00

Buildings	% of Total Cost	Estimated Cost	Hours
Labor	50	3,341,130	
Material	50	3,341,130	
Labor Hours			126,540

Note: Totals may not tally due to round-off.

	Item Cost	Unit Cost	Quantity	Ref. Cost	Est. Cost
I Specialized Equipment				115,673,800	122,885,700
1. Boiler		71,292,000	1	71,292,000	76,574,000
Furnace & Cyclones (incl. drum, radiant platens & circ. pumps)	41,769,000				
Convective Elements (incl. interconnecting piping)	12,684,000				
Additional Waterwall	549,600				
Soot Blowers	2,113,000				
Desuperheaters and Controls	3,055,000				
Air and Flue Gas Ducts	2,311,000				
Coal Feeders	4,192,000				
FD Fan, PA Fan, ID Fan	1,522,000				
Structural Steel, Ladders, Walkways	1,061,000				
Steam Air Heater	121,050				
Rotary Air Heaters	1,913,000				
Transportation to Site					
2. Steam Turbine Package		25,765,000	1	25,765,000	25,700,000
Turbine					
Generator	0				
Exhaust System					
Electrical/Control/Instrumentation Package					
Lube Oil Package w/ main, auxiliary & emergency pump					
High Voltage Generator					
Transportation to Site					
3. Feedwater Heaters			7	1,873,600	1,873,600
Feedwater Heater 1-P	213,250		1		
Feedwater Heater 2	180,800		1		
Feedwater Heater 3	170,250		1		
Feedwater Heater 4	199,000		1		
Feedwater Heater 5-DA	300,450		1		
Feedwater Heater 6	380,850		1		
Feedwater Heater 7	429,000		1		
Feedwater Heater 8					
Feedwater Heater 9					
Feedwater Heater 10					
Feedwater Heater 11					
Feedwater Heater 12					
4. Water-cooled Condensers			2	2,066,900	1,960,000
Water-cooled Condenser 1	1,771,000		1		
Water-cooled Condenser 2					
Water-cooled Condenser 3					
Water-cooled Condenser 4					
Water-cooled Condenser 5					
Water-cooled Condenser 6					
Feed Pump Turbine Water-cooled Condenser	295,900		1		
5. Air-cooled Condense				0	0
Tube Bundles					
Fans, Gears, and Motors					
Steam Duct & Condenser					
Turbine Exhaust Transition					
Steam Jet Air Ejector					
Condensate Receiver Tank					
Support Structures					
Transportation to Site					
6. Particulate Contro		5,726,000	1	5,726,000	5,726,000
Fabric Filter					
Bags					
Ductwork					
Instruments & Controls					
Transportation to Site					
7. Flue Gas Desulfurizatio				0	0
Reagent Feed System					
Absorber Tower					
Auxiliary Equipment of Absorber Tower					
Slurry Pumps					
Flue Gas Handling System					
Flue Gas Reheater					
Waste/Byproduct Handling System					
Support Equipment					
8. Nitrogen Oxide Contro				0	0
9. Stack		3,432,000	1	3,432,000	3,432,000
10. Continuous Emissions Monitoring Syste		221,100	1	221,100	221,100
Enclosures					
Electronics, Display Units, Printers & Sensors					
11. Distributed Control Syster		627,200	1	627,200	750,000
Enclosures					
Electronics, Display Units, Printers & Sensors					
Transportation to Site					
12. Transmission Voltage Equipmen		2,121,000	1	2,121,000	4,100,000
Transformers	1,793,000				
Circuit Breakers	907,000				
Miscellaneous Equipment	101,000				
Transportation to Site					
13. Generating Voltage Equipmen		2,549,000	1	2,549,000	2,549,000
Generator Buswork	1,549,000				
Circuit Breakers	879,000				
Current Limiting Reactors					
Miscellaneous Equipment	121,400				
Transportation to Site					
14. User-definec				0	0

Note: Totals may not tally due to round-off.

	Unit Cost	Quantity	Ref. Cost	Est. Cost
II Other Equipment			32,869,102	40,474,481
1. Pumps			5,434,950	5,434,930
Boiler Feed Pump (turbine included)	1,780,000	2	3,560,000	3,560,000
Boiler Feed Booster Pump	34,360	2	68,720	68,700
Condenser C.W. Pump	400,400	3	1,201,200	1,201,200
Condensate Forwarding Pump	60,600	2	121,200	121,200
Condenser Vacuum Pump	59,500	2	119,000	119,000
Fuel Oil Unloading Pump			0	0
Fuel Oil Forwarding Pump			0	0
Aux Cooling Water Pump (closed loop)	7,500	2	15,000	15,000
Treated Water Pump	3,700	1	3,700	3,700
Diesel Fire Pump	42,980	1	42,980	42,980
Electric Fire Pump	31,020	1	31,020	31,020
Jockey Fire Pump	2,580	1	2,580	2,580
ST+Generator Lube Oil Coolant Pump			0	0
ST Generator Coolant Pump			0	0
Demin Water Pump	3,590	2	7,180	7,180
Raw Water Pump 1	23,990	1	23,990	23,990
Raw Water Pump 2	23,990	1	23,990	23,990
Raw Water Pump 3	23,990	1	23,990	23,990
District Heating Pump			0	0
Aux Cooling Water Pump (open loop)	7,500	2	15,000	15,000
FGD Slurry Pump			0	0
Startup Boiler Feed Pump	175,400	1	175,400	175,400
2. Tanks		9	1,293,660	1,293,660
Fuel Oil			0	0
Hydrous Ammonia	50,850	1	50,850	50,850
Demineralized Water	70,800	1	70,800	70,800
Raw Water	215,250	5	1,076,250	1,076,250
Neutralized Water	57,300	1	57,300	57,300
Acid Storage	19,230	1	19,230	19,230
Caustic Storage	19,230	1	19,230	19,230
Waste Water			0	0
Dedicated Fire Protection Water Storage			0	0
3. Cooling Tower	2,090,000	1	2,090,000	2,500,000
4. Auxiliary Heat Exchangers			44,180	44,180
Auxiliary Cooling Water Heat Exchanger	44,180	1	44,180	44,180
Auxiliary Cooling Tower			0	0
Primary Air Fan Fin Fan Cooler			0	0
Induced Draft Fan Fin Fan Cooler			0	0
Miscellaneous Heat Exchangers			0	0
5. District Heaters			0	0
District Heater 1			0	0
District Heater 2			0	0
6. Auxiliary Boiler	619,100	1	619,100	619,100
7. Makeup Water Treatment System	1,169,000	1	1,169,000	1,169,000
8. Waste Water Treatment System	82,900	1	82,900	82,900
9. Bridge Crane(s)	372,250	1	372,250	372,250
Steam Turbine Crane				
10. Station/Instrument Air Compressors	99,100	2	198,200	198,200
11. Reciprocating Engine Genset(s)		2	92,400	92,400
Emergency Generator	92,400	1	92,400	92,400
Black Start Generator	0	0	0	0
12. General Plant Instrumentation	161,700	1	161,700	161,700
13. Medium Voltage Equipment	1,697,600	1	1,697,600	1,697,600
Transformers	248,750			
Circuit Breakers	71,000			
Switchgear	551,800			
Motor Control Centers	745,200			
Miscellaneous	80,850			
14. Low Voltage Equipment	390,490	1	390,490	390,490
Transformers	173,200			
Circuit Breakers	82,250			
Switchgear				
Motor Control Centers	116,450			
Miscellaneous	18,590			
15. Coal Handling Equipment	14,881,000	1	14,881,000	14,881,000
16. Ash Handling Equipment	2,086,000	1	2,086,000	2,086,000
17. Miscellaneous Equipment	1,530,672		1,530,672	1,551,171
18. User-defined - Condensate Polisher	362,500	2	725,000	725,000
19. Extra Material Handling Equipment	7,174,900	1	7,174,900	7,174,900

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
III Civil	**4,709,110**	**261,830**	**25**			**10,871,394**	**13,632,060**
1. Site Work	**2,646,000**	**81,750**	**25.00**			**4,689,750**	**5,543,016**
Site Clearing							
Demolition							
Culverts & Drainage							
Erosion Control							
Fencing, Controlled Access Gates							
Finish Grading							
Finish Landscaping							
Material (Dirt, Sand, Stone)							
Waste Material Removal							
Obstacles R&R							
Miscellaneous							
2. Excavation & Backfill	**269,387**	**7,468**	**25.00**	**9.87**	**46,192**	**456,084**	**534,029**
Steam Turbine	5.63	0.16	25.00	9.62	7,570	72,860	85,489
Boiler	5.46	0.15	25.00	9.12	22,540	205,600	240,044
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	8.57	0.27	25.00	15.37	706	10,850	12,854
Cooling Tower	6.10	0.15	25.00	9.81	4,320	42,360	49,040
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Feedwater Heaters	10.46	0.36	25.00	19.37	1,560	30,210	36,013
District Heater(s)	0.00	0.00		0.00		0	0
Underground Piping	5.72	0.17	25.00	9.94	5,230	51,965	61,160
Switchyard	7.95	0.16	25.00	12.04	66	799	912
Miscellaneous	5.83	0.16	25.00	9.87	4,200	41,440	48,517
3. Concrete	**1,627,793**	**170,532**	**25.00**	**309.58**	**17,786**	**5,506,230**	**7,313,390**
Steam Turbine	89.18	11.89	25.00	386.34	2,910	1,124,250	1,485,283
Laydown pads:	67.17	9.40	25.00	302.16	53	16,105	21,334
Boiler	64.85	9.00	25.00	289.88	8,410	2,437,900	3,228,019
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	65.75	9.06	25.00	292.33	459	134,180	177,600
Cooling Tower	64.67	8.98	25.00	289.12	1,810	523,300	692,909
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Underground Piping:	73.48	9.35	25.00	307.33	56	17,315	22,816
Makeup Water Treatment System	58.81	8.98	25.00	283.39	118	33,440	44,504
Auxiliary Boiler	5,310.00	6.76	25.00	5,479.00	74	22,220	29,270
Electrical Power Equipment	70.04	10.60	25.00	335.04	450	150,770	200,557
Feedwater Heaters	66.01	9.00	25.00	291.10	843	245,400	324,621
Pumps	83.22	10.60	25.00	348.25	183	63,730	83,979
Auxiliary Heat Exchangers	0.00	0.00		0.00		0	0
District Heater(s)	0.00	0.00		0.00		0	0
Station/Instrument Air Compressors	73.47	10.29	25.00	330.71	44	14,495	19,202
Bridge Crane(s)	0.00	0.00		0.00		0	0
Reciprocating Engine Genset(s)	58.86	9.00	25.00	283.95	271	76,950	102,418
Tanks:	66.45	9.30	25.00	298.93	428	127,940	194,903
Switchyard	65.73	9.21	25.00	296.02	66	19,635	26,012
Miscellaneous	69.63	9.60	25.00	309.69	1,610	498,600	659,964
4. Roads, Parking, Walkways	**165,930**	**2,080**	**25.67**	**52.46**	**4,181**	**219,330**	**241,625**
Pavement, Curbing, Striping	31.44	0.43	25.00	42.20	4,180	176,400	195,188
Lighting	40,532.93	328.68	30.00	50,393.24	1	42,930	46,437
5. User-defined						**0**	**0**

NOTE: Individual items listed in III.2-4 are per unit quantity.

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
IV Mechanical	17,353,353	2,054,607	29.00			57,750,635	76,761,788
1. On-Site Transportation & Rigging	2,628,000					2,628,000	3,176,595
2. Equipment Erection & Assembly	3,494,193	1,343,584	29.00			42,458,129	58,725,572
Steam Turbine Package	71,400	27,970	29.00	882,530	1	882,530	1,221,177
Boiler	1,857,000	727,700	29.00	22,960,300	1	22,960,300	31,770,928
Feedwater Heaters	9,670	3,790	29.00	119,580		119,580	165,467
Condenser(s)	17,550	6,880	29.00	217,070		217,070	300,370
Cooling Tower				0		0	0
Particulate Control	277,650	108,800	29.00	3,432,850	1	3,432,850	4,750,146
Flue Gas Desulfurization				0		0	0
Nitrogen Oxide Control				0		0	0
Coal Handling System	549,800	215,450	29.00	6,797,850		6,797,850	9,406,411
Ash Handling System	326,750	128,050	29.00	4,040,200		4,040,200	5,590,565
Makeup Water Treatment System	58,300	7,800	29.00	284,500		284,500	378,939
Auxiliary Boiler	513	201	29.00	6,342		6,342	8,776
Electrical Power Equipment	46,190	18,100	29.00	571,090		571,090	790,236
Pumps	9,720	3,810	29.00	120,210		120,210	166,340
Auxiliary Heat Exchangers	158	62	29.00	1,956		1,956	2,707
District Heater(s)				0		0	0
Station/Instrument Air Compressors	713	279	29.00	8,804		8,804	12,182
Bridge Crane(s)	1,840	722	29.00	22,778		22,778	31,520
Reciprocating Engine Genset(s)	689	270	29.00	8,519		8,519	11,788
Miscellaneous	266,250	93,700	29.00	2,983,550		2,983,550	4,118,023
3. Piping	10,902,360	705,043	29.00	187.78	64,769	12,162,286	14,284,998
High Pressure Steam	1,808.82	19.85	29.00	2,384.45	465	1,108,770	1,220,522
Cold Reheat Steam	207.48	7.40	29.00	422.13	762	321,660	389,946
Hot Reheat Steam	929.12	16.99	29.00	1,421.83	1,020	1,450,270	1,660,093
FWH Heating Steam	502.24	7.59	29.00	722.41	760	549,030	618,890
Other Steam & Heating	56.62	3.36	29.00	153.96	429	66,050	83,485
Feedwater	802.34	9.95	29.00	1,090.98	1,280	1,396,460	1,550,710
Circulating Water	413.21	14.00	29.00	819.21	935	765,960	924,447
Auxiliary Cooling Water	52.50	2.61	29.00	128.32	2,360	302,830	377,533
Other Water	11.61	1.11	29.00	43.68	898	39,227	51,250
Raw Water	385.62	6.14	29.00	563.66	2,010	1,132,960	1,282,367
Service Water	20.73	1.33	29.00	59.41	6,050	359,430	457,137
Fuel Gas	0.00	0.00		0.00		0	0
Fuel Oil	0.00	0.00		0.00		0	0
Service Air	9.87	1.02	29.00	39.51	4,540	179,360	235,539
Vacuum Air	144.30	5.09	29.00	291.83	230	67,120	81,286
Ammonia	3,480.00	482.00	29.00	15.89	1,100	17,479	23,280
Boiler & Equipment Drain	15.37	1.08	29.00	46.77	28,210	1,319,450	1,689,334
Boiler Blowdown	18.94	1.27	29.00	55.70	3,030	168,760	215,253
Steam Blowoff	816.15	14.18	29.00	1,227.28	960	1,178,190	1,342,973
Fire Protection	80.78	3.03	29.00	168.61	5,290	891,930	1,085,892
Miscellaneous	111.16	2.75	29.00	190.84	4,440	847,350	995,062
4. Steel	328,800	5,980	29.00	2,523.72	199	502,220	574,623
Racks, Supports, Ladders, Walkways, Platforms	1,652.26	30.05	29.00	2,523.72	199	502,220	574,623
5. User-defined						0	0

NOTE: Individual items listed in IV.2-4 are per unit quantity.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
V Electrical	**1,663,092**	**156,170**	**30.00**			**6,348,183**	**8,402,813**
1. Controls	**89,012**	**93,279**	**30.00**			**2,887,373**	**4,154,293**
Steam Turbine Package	4,700	4,940	30.00	152,900.00	1	152,900	214,774
Boiler	60,250	63,250	30.00	1,957,750.00	1	1,957,750	2,749,956
Feedwater Heaters						0	0
Condenser(s)	345	362	30.00			11,205	15,739
Cooling Tower						0	0
Particulate Control	5,450	5,730	30.00	177,350.00	1	177,350	249,118
Flue Gas Desulfurization						0	0
Nitrogen Oxide Control						0	0
Coal Handling System	10,790	11,340	30.00			350,990	591,628
Ash Handling System	6,420	6,740	30.00			208,620	293,039
Makeup Water Treatment System	391	411	30.00			12,721	17,869
Auxiliary Boiler						0	0
Electrical Power Equipment						0	0
Pumps	403	423	30.00			13,093	18,391
Auxiliary Heat Exchangers						0	0
District Heater(s)						0	0
Station/Instrument Air Compressors	47	15	30.00			488	672
Bridge Crane(s)	121	38	30.00			1,261	1,737
Reciprocating Engine Genset(s)	95	30	30.00			995	1,371
2. Assembly & Wiring	**1,574,080**	**62,891**	**30.00**			**3,460,810**	**4,248,520**
Switchgear	2,758	262	30.00	10,618.00	5	53,090	69,498
Motor Control Centers	468	41	30.00	1,687.83	46	77,640	101,062
Feeders	8,338	360	30.00	19,129.41	102	1,951,200	2,410,742
Medium/Low Voltage Cable Bus	6,578	169	30.00	11,650.00	53	617,450	729,674
Cable Tray	142,000	4,220	30.00	268,600.00	1	268,600	321,456
General Plant Instrumentation	309	4	30.00	431.89	227	98,040	109,726
Generator to Step-up Transformer Bus	6,050	318	30.00	15,590.00	1	15,590	19,573
Transformers	3,627	572	30.00	20,776.67	6	124,660	167,621
Circuit Breakers	2,461	259	30.00	10,223.75	8	81,790	107,717
Miscellaneous	80,050	3,090	30.00	172,750.00	1	172,750	211,452
3. User-defined						**0**	**0**

NOTE: Individual items listed in V.1-2 are per unit quantity.

	Area	Cost/Unit Area	Ref. Cost	Est. Cost
VI Buildings			6,682,260	8,077,182
1. Boiler House and Turbine Hall	57,650.0	101.00	5,822,650	7,038,128
2. Administration, Control Room, Machine Shop / Warehouse	12,700.0	61.18	776,986	939,182
3. Water Treatment System	1,140.0	61.66	70,292	84,966
4. Guard House	200.0	61.66	12,332	14,906
5. User-defined			0	0

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
VII Engineering & Startup	409,950	29,700	50.19			16,659,593	16,659,593
1. Engineering						14,759,000	14,759,000
2. Start-Up	409,950	29,700	50.19	1,900,593		1,900,593	1,900,593
3. User-defined						0	0

	Ref. Cost	Est. Cost
VIII Soft & Miscellaneous Costs	**72,618,053**	**89,191,068**
1. Contractor's Soft Costs	**54,547,909**	**68,425,130**
Contingency:	28,041,314	34,051,236
Profit:	16,632,396	22,898,150
Permits, Licenses, Fees, Miscellaneous	0	0
Bonds and Insurance	2,468,550	2,868,936
Spare Parts & Materials	0	0
Contractor's Fee	7,405,649	8,606,809
2. Owner's Soft Costs	**18,070,144**	**20,765,937**
Permits, Licenses, Fees, Miscellaneous	6,028,058	7,106,375
Land Cost	0	0
Utility Connection Cost	0	0
Legal & Financial Costs	6,028,058	7,106,375
Escalation	0	0
Spare Parts & Materials	3,000,000	3,000,000
Project Administration & Developer's Fee	3,014,029	3,553,187
3. Total User-defined Costs	**0**	**0**

	Multiplier
Labor Rate	1.4175
Specialized Equipment	1.0000
1. Boiler	1.0000
2. Steam Turbine Package	1.0000
3. Feedwater Heater	1.0000
4. Water-cooled Condenser	1.0000
5. Air-cooled Condenser	1.0000
6. Electrostatic Precipitator	1.0000
7. Flue Gas Desulfurization	1.0000
8. Nitogen Oxide Control	1.0000
9. Stack	1.0000
10. Continuous Emissions Monotoring System	1.0000
11. Distributed Control System	1.0000
12. Transmission Voltage Equipment	1.0000
13. Generating Voltage Equipment	1.0000
Other Equipment	1.0000
1. Pumps	1.0000
2. Tanks	1.0000
3. Cooling Tower	1.0000
4. Auxiliary Heat Exchangers	1.0000
5. District Heaters	1.0000
6. Auxiliary Boiler	1.0000
7. Makeup Water Treatment System	1.0000
8. Waste Water Treatment System	1.0000
9. Bridge Crane(s)	1.0000
10. Station/Instrument Air Compressor	1.0000
11. Recip Engine Genset(s)	1.0000
12. General Plant Instrumentation	1.0000
13. Medium Voltage Equipment	1.0000
14. Low Voltage Equipment	1.0000
15. Coal Handling Equipment	1.0000
16. Ash Handling Equipment	1.0000
17. Miscellaneous Equipment	1.0000
Commodity	1.0000

Contractor's Soft Costs	Percentage, %	+ Fixed Amount
1. Contingency		
Labor	15.0	0
Specialized Equipment	10.0	0
Other Equipment	10.0	0
Commodities	10.0	0
2. Profit		
Labor	20.0	0
Specialized Equipment	0.0	0
Other Equipment	3.0	0
Commodities	5.0	0
3. Permits, Licenses, Fees & Miscellaneous	0.0	0
4. Bonds and Insurance	1.0	0
5. Spare Parts and Materials	0.0	0

6. Contractor's Fee	3.0	0
Owner's Soft Costs		
1. Permits, Licenses, Fees & Miscellaneous	2.0	0
2. Land Cost	0.0	0
3. Utility Connection Cost	0.0	0
4. Legal and Financial Costs	2.0	0
5. Escalation	0.0	0
6. Spare Parts and Materials	0.0	3,000,000
7. Project Administration and Developer's Fee	1.0	0

Decker 94°F DB, 100% Load

Project Cost Summary	Reference Cost	Estimated Cost	
I Specialized Equipment	114,960,350	122,861,050	USD
II Other Equipment	32,128,150	39,039,650	USD
III Civil	10,800,579	13,541,357	USD
IV Mechanical	57,498,514	76,423,212	USD
V Electrical	6,377,399	8,435,980	USD
VI Buildings & Structures	6,616,610	7,997,828	USD
VII Engineering & Plant Startup	16,663,245	16,663,245	USD
Subtotal - Contractor's Internal Cost	245,044,848	284,962,321	USD
VIII Contractor's Soft & Miscellaneous Costs	54,265,911	68,037,073	USD
Contractor's Price	299,310,759	352,999,394	USD
IX Owner's Soft & Miscellaneous Costs	17,965,538	20,649,970	USD
Total - Owner's Cost	317,276,297	373,649,364	USD
Net Plant Output	251.0	251.0	MW
Cost per kW - Contractor's	1,192	1,406	USD per kW
Cost per kW - Owner's	1,264	1,489	USD per kW

Total Plant (Reference Basis):	Reference Cost	Hours
Commodities	24,065,008	
Labor	72,082,276	2,494,289

Effective Labor Rates:	Cost per Hour
Civil Account	25.01
Mechanical Account	29.00
Electrical Account	30.00

Buildings	% of Total Cost	Estimated Cost	Hours
Labor	50	3,308,305	
Material	50	3,308,305	
Labor Hours			125,297

Note: Totals may not tally due to round-off.

	Item Cost	Unit Cost	Quantity	Ref. Cost	Est. Cost
I Specialized Equipment				114,960,350	122,861,050
1. Boiler		70,656,000	1	70,656,000	76,651,000
Furnace & Cyclones (incl. drum, radiant platens & circ. pumps)	41,683,000				
Convective Elements (incl. interconnecting piping)	12,342,000				
Additional Waterwall	539,700				
Soot Blowers	2,099,000				
Desuperheaters and Controls	3,054,000				
Air and Flue Gas Ducts	2,284,000				
Coal Feeders	4,083,000				
FD Fan, PA Fan, ID Fan	1,503,000				
Structural Steel, Ladders, Walkways	1,050,000				
Steam Air Heater	120,100				
Rotary Air Heaters	1,898,000				
Transportation to Site					
2. Steam Turbine Package		25,791,000	1	25,791,000	25,700,000
Turbine					
Generator	0				
Exhaust System					
Electrical/Control/Instrumentation Package					
Lube Oil Package w/ main, auxiliary & emergency pump					
High Voltage Generator					
Transportation to Site					
3. Feedwater Heaters			7	1,865,950	1,865,950
Feedwater Heater 1-P	213,050		1		
Feedwater Heater 2	180,400		1		
Feedwater Heater 3	169,850		1		
Feedwater Heater 4	192,400		1		
Feedwater Heater 5-DA	300,400		1		
Feedwater Heater 6	380,900		1		
Feedwater Heater 7	428,950		1		
Feedwater Heater 8					
Feedwater Heater 9					
Feedwater Heater 10					
Feedwater Heater 11					
Feedwater Heater 12					
4. Water-cooled Condensers			2	2,065,000	1,960,000
Water-cooled Condenser 1	1,775,000		1		
Water-cooled Condenser 2					
Water-cooled Condenser 3					
Water-cooled Condenser 4					
Water-cooled Condenser 5					
Water-cooled Condenser 6					
Feed Pump Turbine Water-cooled Condenser	290,000		1		
5. Air-cooled Condense				0	0
Tube Bundles					
Fans, Gears, and Motors					
Steam Duct & Condenser					
Turbine Exhaust Transition					
Steam Jet Air Ejector					
Condensate Receiver Tank					
Support Structures					
Transportation to Site					
6. Particulate Contro		5,649,000	1	5,649,000	5,649,000
Fabric Filter					
Bags					
Ductwork					
Instruments & Controls					
Transportation to Site					
7. Flue Gas Desulfurizatio				0	0
Reagent Feed System					
Absorber Tower					
Auxiliary Equipment of Absorber Tower					
Slurry Pumps					
Flue Gas Handling System					
Flue Gas Reheater					
Waste/Byproduct Handling System					
Support Equipment					
8. Nitrogen Oxide Contro				0	0
9. Stack		3,414,000	1	3,414,000	3,414,000
10. Continuous Emissions Monitoring Syste		221,100	1	221,100	221,100
Enclosures					
Electronics, Display Units, Printers & Sensors					
11. Distributed Control Syster		627,300	1	627,300	750,000
Enclosures					
Electronics, Display Units, Printers & Sensors					
Transportation to Site					
12. Transmission Voltage Equipmen		2,121,000	1	2,121,000	4,100,000
Transformers	1,793,000				
Circuit Breakers	906,800				
Miscellaneous Equipment	101,000				
Transportation to Site					
13. Generating Voltage Equipmen		2,550,000	1	2,550,000	2,550,000
Generator Buswork	1,549,000				
Circuit Breakers	879,500				
Current Limiting Reactors					
Miscellaneous Equipment	121,450				
Transportation to Site					
14. User-definec				0	0

Note: Totals may not tally due to round-off.

	Unit Cost	Quantity	Ref. Cost	Est. Cost
II Other Equipment			32,128,150	39,039,650
1. Pumps			5,321,390	5,321,390
Boiler Feed Pump (turbine included)	1,723,000	2	3,446,000	3,446,000
Boiler Feed Booster Pump	34,360	2	68,720	68,720
Condenser C.W. Pump	400,500	3	1,201,500	1,201,500
Condensate Forwarding Pump	60,700	2	121,400	121,400
Condenser Vacuum Pump	59,500	2	119,000	119,000
Fuel Oil Unloading Pump			0	0
Fuel Oil Forwarding Pump			0	0
Aux Cooling Water Pump (closed loop)	7,500	2	15,000	15,000
Treated Water Pump	3,690	1	3,690	3,690
Diesel Fire Pump	42,980	1	42,980	42,980
Electric Fire Pump	31,020	1	31,020	31,020
Jockey Fire Pump	2,580	1	2,580	2,580
ST+Generator Lube Oil Coolant Pump			0	0
ST Generator Coolant Pump			0	0
Demin Water Pump	3,580	2	7,160	7,160
Raw Water Pump 1	23,980	1	23,980	23,980
Raw Water Pump 2	23,980	1	23,980	23,980
Raw Water Pump 3	23,980	1	23,980	23,980
District Heating Pump			0	0
Aux Cooling Water Pump (open loop)	7,500	2	15,000	15,000
FGD Slurry Pump			0	0
Startup Boiler Feed Pump	175,400	1	175,400	175,400
2. Tanks		9	1,292,530	1,292,530
Fuel Oil			0	0
Hydrous Ammonia	50,850	1	50,850	50,850
Demineralized Water	70,400	1	70,400	70,400
Raw Water	215,250	5	1,076,250	1,076,250
Neutralized Water	57,050	1	57,050	57,050
Acid Storage	18,990	1	18,990	18,990
Caustic Storage	18,990	1	18,990	18,990
Waste Water			0	0
Dedicated Fire Protection Water Storage			0	0
3. Cooling Tower	2,090,000	1	2,090,000	2,090,000
4. Auxiliary Heat Exchangers			44,190	44,190
Auxiliary Cooling Water Heat Exchanger	44,190	1	44,190	44,190
Auxiliary Cooling Tower			0	0
Primary Air Fan Fin Fan Cooler			0	0
Induced Draft Fan Fin Fan Cooler			0	0
Miscellaneous Heat Exchangers			0	0
5. District Heaters			0	0
District Heater 1			0	0
District Heater 2			0	0
6. Auxiliary Boiler	619,100	1	619,100	619,100
7. Makeup Water Treatment System	1,158,000	1	1,158,000	1,158,000
8. Waste Water Treatment System	82,150	1	82,150	82,150
9. Bridge Crane(s)	372,250	1	372,250	372,250
Steam Turbine Crane				
10. Station/Instrument Air Compressors	99,100	2	198,200	198,200
11. Reciprocating Engine Genset(s)		2	92,400	92,400
Emergency Generator	92,400	1	92,400	92,400
Black Start Generator				
12. General Plant Instrumentation	161,750	1	161,750	161,750
13. Medium Voltage Equipment	1,712,550	1	1,712,550	1,712,550
Transformers	250,200			
Circuit Breakers	71,900			
Switchgear	553,300			
Motor Control Centers	755,600			
Miscellaneous	81,550			
14. Low Voltage Equipment	390,490	1	390,490	390,490
Transformers	173,200			
Circuit Breakers	82,250			
Switchgear				
Motor Control Centers	116,450			
Miscellaneous	18,590			
15. Coal Handling Equipment	14,650,000	1	14,650,000	14,650,000
16. Ash Handling Equipment	2,068,000	1	2,068,000	2,068,000
17. Miscellaneous Equipment	1,512,650		1,512,650	1,512,650
18. User-defined - Condensate Polisher	362,500	2	362,500	725,000
18. Exra Material Handling Equipment	6,549,000	1	6,549,000	6,549,000

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
III Civil	**4,684,327**	**259,923**	**25**			**10,800,579**	**13,541,357**
1. Site Work	**2,638,000**	**81,550**	**25.00**			**4,676,750**	**5,527,928**
Site Clearing							
Demolition							
Culverts & Drainage							
Erosion Control							
Fencing, Controlled Access Gates							
Finish Grading							
Finish Landscaping							
Material (Dirt, Sand, Stone)							
Waste Material Removal							
Obstacles R&R							
Miscellaneous							
2. Excavation & Backfill	**266,607**	**7,392**	**25.00**	**9.88**	**45,673**	**451,404**	**528,556**
Steam Turbine	5.63	0.16	25.00	9.63	7,570	72,870	85,499
Boiler	5.46	0.15	25.00	9.13	22,060	201,300	235,013
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	8.54	0.27	25.00	15.33	707	10,840	12,844
Cooling Tower	6.10	0.15	25.00	9.80	4,320	42,350	49,030
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Feedwater Heaters	10.39	0.35	25.00	19.24	1,570	30,210	36,013
District Heater(s)	0.00	0.00		0.00		0	0
Underground Piping	5.73	0.17	25.00	9.94	5,230	51,995	61,190
Switchyard	7.94	0.16	25.00	12.03	66	799	912
Miscellaneous	5.84	0.16	25.00	9.89	4,150	41,040	48,054
3. Concrete	**1,614,090**	**168,901**	**25.00**	**310.00**	**17,592**	**5,453,395**	**7,243,548**
Steam Turbine	89.24	11.90	25.00	386.67	2,910	1,125,200	1,486,547
Laydown pads:	67.10	9.41	25.00	302.34	53	16,130	21,370
Boiler	64.84	9.00	25.00	289.93	8,230	2,386,100	3,159,519
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	65.63	9.07	25.00	292.26	460	134,440	177,964
Cooling Tower	64.67	8.98	25.00	289.12	1,810	523,300	692,909
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Underground Piping:	73.48	9.35	25.00	307.33	56	17,315	22,816
Makeup Water Treatment System	58.89	8.97	25.00	283.25	117	33,140	44,099
Auxiliary Boiler	5,310.00	6.76	25.00	5,479.00	74	22,220	29,270
Electrical Power Equipment	70.16	10.62	25.00	335.68	451	151,390	201,386
Feedwater Heaters	66.05	9.00	25.00	291.17	844	245,750	325,075
Pumps	83.80	10.70	25.00	351.18	187	65,670	86,545
Auxiliary Heat Exchangers	0.00	0.00		0.00		0	0
District Heater(s)	0.00	0.00		0.00		0	0
Station/Instrument Air Compressors	73.47	10.29	25.00	330.71	44	14,495	19,202
Bridge Crane(s)	0.00	0.00		0.00		0	0
Reciprocating Engine Genset(s)	58.86	9.00	25.00	283.95	271	76,950	102,418
Tanks:	66.38	9.30	25.00	298.86	428	127,910	194,869
Switchyard	65.71	9.21	25.00	295.93	66	19,635	26,012
Miscellaneous	69.81	9.63	25.00	310.53	1,590	493,750	653,548
4. Roads, Parking, Walkways	**165,630**	**2,080**	**25.67**	**52.51**	**4,171**	**219,030**	**241,325**
Pavement, Curbing, Striping	31.44	0.43	25.00	42.23	4,170	176,100	194,888
Lighting	40,532.93	328.68	30.00	50,393.24	1	42,930	46,437
5. User-defined						**0**	**0**

NOTE: Individual items listed in III.2-4 are per unit quantity.

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
IV Mechanical	17,292,313	2,048,018	29.00			57,498,514	76,423,212
1. On-Site Transportation & Rigging	2,596,000					2,596,000	3,137,915
2. Equipment Erection & Assembly	3,478,573	1,337,604	29.00			42,269,089	58,464,129
Steam Turbine Package	71,450	27,990	29.00	883,160	1	883,160	1,222,049
Boiler	1,859,000	728,500	29.00	22,985,500	1	22,985,500	31,805,814
Feedwater Heaters	9,690	3,800	29.00	119,890		119,890	165,899
Condenser(s)	17,530	6,870	29.00	216,760		216,760	299,939
Cooling Tower				0		0	0
Particulate Control	273,900	107,300	29.00	3,385,600	1	3,385,600	4,684,735
Flue Gas Desulfurization				0		0	0
Nitrogen Oxide Control				0		0	0
Coal Handling System	539,400	211,350	29.00	6,668,550		6,668,550	9,227,470
Ash Handling System	323,850	126,900	29.00	4,003,950		4,003,950	5,540,392
Makeup Water Treatment System	57,750	7,730	29.00	281,920		281,920	375,511
Auxiliary Boiler	513	201	29.00	6,342		6,342	8,776
Electrical Power Equipment	46,780	18,330	29.00	578,350		578,350	800,280
Pumps	10,210	4,000	29.00	126,210		126,210	174,640
Auxiliary Heat Exchangers	158	62	29.00	1,956		1,956	2,707
District Heater(s)				0		0	0
Station/Instrument Air Compressors	713	279	29.00	8,804		8,804	12,182
Bridge Crane(s)	1,840	722	29.00	22,778		22,778	31,520
Reciprocating Engine Genset(s)	689	270	29.00	8,519		8,519	11,788
Miscellaneous	265,100	93,300	29.00	2,970,800		2,970,800	4,100,430
3. Piping	10,888,790	704,434	29.00	187.69	64,632	12,131,055	14,246,394
High Pressure Steam	1,807.51	19.83	29.00	2,382.53	466	1,110,260	1,222,133
Cold Reheat Steam	207.48	7.40	29.00	422.13	762	321,660	389,946
Hot Reheat Steam	930.29	16.99	29.00	1,423.01	1,020	1,451,470	1,661,293
FWH Heating Steam	486.35	7.41	29.00	701.36	758	531,630	599,674
Other Steam & Heating	50.94	3.12	29.00	141.48	426	60,270	76,373
Feedwater	802.34	9.91	29.00	1,089.85	1,280	1,395,010	1,548,654
Circulating Water	413.09	13.99	29.00	818.65	936	766,260	924,747
Auxiliary Cooling Water	52.46	2.61	29.00	128.28	2,360	302,730	377,433
Other Water	9.45	0.94	29.00	36.85	872	32,136	42,113
Raw Water	385.52	6.14	29.00	563.56	2,010	1,132,760	1,282,167
Service Water	20.75	1.33	29.00	59.45	6,040	359,090	456,676
Fuel Gas	0.00	0.00		0.00		0	0
Fuel Oil	0.00	0.00		0.00		0	0
Service Air	9.79	1.02	29.00	39.30	4,530	178,050	233,866
Vacuum Air	144.30	5.09	29.00	291.83	230	67,120	81,286
Ammonia	3,480.00	482.00	29.00	15.89	1,100	17,479	23,280
Boiler & Equipment Drain	15.38	1.08	29.00	46.83	28,140	1,317,930	1,687,451
Boiler Blowdown	18.97	1.27	29.00	55.75	3,020	168,370	214,742
Steam Blowoff	810.49	14.02	29.00	1,217.15	972	1,183,070	1,348,095
Fire Protection	80.88	3.03	29.00	168.65	5,280	890,470	1,083,948
Miscellaneous	111.21	2.74	29.00	190.81	4,430	845,290	992,517
4. Steel	328,950	5,980	29.00	2,524.47	199	502,370	574,773
Racks, Supports, Ladders, Walkways, Platforms	1,653.02	30.05	29.00	2,524.47	199	502,370	574,773
5. User-defined						0	0

NOTE: Individual items listed in IV.2-4 are per unit quantity.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
V Electrical	1,678,268	156,638	30.00			6,377,399	8,435,980
1. Controls	88,748	93,037	30.00			2,879,849	4,141,827
Steam Turbine Package	4,700	4,940	30.00	152,900.00	1	152,900	214,774
Boiler	60,300	63,350	30.00	1,960,800.00	1	1,960,800	2,754,259
Feedwater Heaters						0	0
Condenser(s)	344	362	30.00			11,204	15,738
Cooling Tower						0	0
Particulate Control	5,380	5,650	30.00	174,880.00	1	174,880	245,646
Flue Gas Desulfurization						0	0
Nitrogen Oxide Control						0	0
Coal Handling System	10,590	11,120	30.00			344,190	580,162
Ash Handling System	6,360	6,680	30.00			206,760	290,427
Makeup Water Treatment System	388	407	30.00			12,598	17,696
Auxiliary Boiler						0	0
Electrical Power Equipment						0	0
Pumps	423	445	30.00			13,773	19,347
Auxiliary Heat Exchangers						0	0
District Heater(s)						0	0
Station/Instrument Air Compressors	47	15	30.00			488	672
Bridge Crane(s)	121	38	30.00			1,261	1,737
Reciprocating Engine Genset(s)	95	30	30.00			995	1,371
2. Assembly & Wiring	1,589,520	63,601	30.00			3,497,550	4,294,153
Switchgear	2,766	264	30.00	10,686.00	5	53,430	69,963
Motor Control Centers	464	41	30.00	1,682.98	47	79,100	103,023
Feeders	8,277	358	30.00	19,004.81	104	1,976,500	2,442,305
Medium/Low Voltage Cable Bus	6,484	167	30.00	11,489.82	54	620,450	733,300
Cable Tray	144,500	4,290	30.00	273,200.00	1	273,200	326,932
General Plant Instrumentation	309	4	30.00	431.89	227	98,040	109,726
Generator to Step-up Transformer Bus	6,050	318	30.00	15,590.00	1	15,590	19,573
Transformers	3,628	572	30.00	20,778.33	6	124,670	167,631
Circuit Breakers	2,465	259	30.00	10,227.50	8	81,820	107,747
Miscellaneous	80,850	3,130	30.00	174,750.00	1	174,750	213,953
3. User-defined						0	0

NOTE: Individual items listed in V.1-2 are per unit quantity.

Note: Totals may not tally due to round-off.

	Area	Cost/Unit Area	Ref. Cost	Est. Cost
VI Buildings			6,616,610	7,997,828
1. Boiler House and Turbine Hall	57,000.0	101.00	5,757,000	6,958,774
2. Administration, Control Room, Machine Shop / Warehouse	12,700.0	61.18	776,986	939,182
3. Water Treatment System	1,140.0	61.66	70,292	84,966
4. Guard House	200.0	61.66	12,332	14,906
5. User-defined			0	0

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
VII Engineering & Startup	410,100	29,710	50.19			16,663,245	16,663,245
1. Engineering						14,762,000	14,762,000
2. Start-Up	410,100	29,710	50.19	1,901,245		1,901,245	1,901,245
3. User-defined						0	0

Note: Totals may not tally due to round-off.

	Ref. Cost	Est. Cost
VIII Soft & Miscellaneous Costs	**72,231,449**	**88,687,042**
1. Contractor's Soft Costs	**54,265,911**	**68,037,073**
Contingency:	27,891,442	33,850,565
Profit:	16,572,675	22,788,015
Permits, Licenses, Fees, Miscellaneous	0	0
Bonds and Insurance	2,450,448	2,849,623
Spare Parts & Materials	0	0
Contractor's Fee	7,351,345	8,548,870
2. Owner's Soft Costs	**17,965,538**	**20,649,970**
Permits, Licenses, Fees, Miscellaneous	5,986,215	7,059,988
Land Cost	0	0
Utility Connection Cost	0	0
Legal & Financial Costs	5,986,215	7,059,988
Escalation	0	0
Spare Parts & Materials	3,000,000	3,000,000
Project Administration & Developer's Fee	2,993,108	3,529,994
3. Total User-defined Costs	**0**	**0**

Note: Totals may not tally due to round-off.

	Multiplier
Labor Rate	1.4175
Specialized Equipment	1.0000
1. Boiler	1.0000
2. Steam Turbine Package	1.0000
3. Feedwater Heater	1.0000
4. Water-cooled Condenser	1.0000
5. Air-cooled Condenser	1.0000
6. Electrostatic Precipitator	1.0000
7. Flue Gas Desulfurization	1.0000
8. Nitogen Oxide Control	1.0000
9. Stack	1.0000
10. Continuous Emissions Monotoring System	1.0000
11. Distributed Control System	1.0000
12. Transmission Voltage Equipment	1.0000
13. Generating Voltage Equipment	1.0000
Other Equipment	1.0000
1. Pumps	1.0000
2. Tanks	1.0000
3. Cooling Tower	1.0000
4. Auxiliary Heat Exchangers	1.0000
5. District Heaters	1.0000
6. Auxiliary Boiler	1.0000
7. Makeup Water Treatment System	1.0000
8. Waste Water Treatment System	1.0000
9. Bridge Crane(s)	1.0000
10. Station/Instrument Air Compressor	1.0000
11. Recip Engine Genset(s)	1.0000
12. General Plant Instrumentation	1.0000
13. Medium Voltage Equipment	1.0000
14. Low Voltage Equipment	1.0000
15. Coal Handling Equipment	1.0000
16. Ash Handling Equipment	1.0000
17. Miscellaneous Equipment	1.0000
Commodity	1.0000

Contractor's Soft Costs	Percentage, %	+ Fixed Amount
1. Contingency		
Labor	15.0	0
Specialized Equipment	10.0	0
Other Equipment	10.0	0
Commodities	10.0	0
2. Profit		
Labor	20.0	0
Specialized Equipment	0.0	0
Other Equipment	3.0	0
Commodities	5.0	0
3. Permits, Licenses, Fees & Miscellaneous	0.0	0
4. Bonds and Insurance	1.0	0
5. Spare Parts and Materials	0.0	0

6. Contractor's Fee	3.0	0
Owner's Soft Costs		
1. Permits, Licenses, Fees & Miscellaneous	2.0	0
2. Land Cost	0.0	0
3. Utility Connection Cost	0.0	0
4. Legal and Financial Costs	2.0	0
5. Escalation	0.0	0
6. Spare Parts and Materials	0.0	3,000,000
7. Project Administration and Developer's Fee	1.0	0

Absaloka, 94°F DB, 100% Load (HYSHAM)

Project Cost Summary	Reference Cost	Estimated Cost	
I Specialized Equipment	116,681,250	122,910,450	USD
II Other Equipment	37,002,374	45,197,574	USD
III Civil	11,031,339	13,838,132	USD
IV Mechanical	65,056,146	86,860,287	USD
V Electrical	6,771,250	8,987,375	USD
VI Buildings & Structures	6,813,560	8,235,891	USD
VII Engineering & Plant Startup	16,685,454	16,685,454	USD
Subtotal - Contractor's Internal Cost	260,041,373	302,715,163	USD
VIII Contractor's Soft & Miscellaneous Costs	58,328,738	73,335,801	USD
Contractor's Price	318,370,112	376,050,964	USD
IX Owner's Soft & Miscellaneous Costs	18,918,506	21,802,548	USD
Total - Owner's Cost	337,288,617	397,853,512	USD
Net Plant Output	251.0	251.0	MW
Cost per kW - Contractor's	1,268	1,498	USD per kW
Cost per kW - Owner's	1,344	1,585	USD per kW

Total Plant (Reference Basis):	Reference Cost	Hours
Commodities	24,867,789	
Labor	79,464,947	2,749,285

Effective Labor Rates:	Cost per Hour
Civil Account	25.01
Mechanical Account	29.00
Electrical Account	30.00

Buildings	% of Total Cost	Estimated Cost	Hours
Labor	50	3,406,780	
Material	50	3,406,780	
Labor Hours			129,027

Note: Totals may not tally due to round-off.

	Item Cost	Unit Cost	Quantity	Ref. Cost	Est. Cost
I Specialized Equipment				116,681,250	122,910,450
1. Boiler		72,162,000	1	72,162,000	76,501,000
Furnace & Cyclones (incl. drum, radiant platens & circ. pumps)	41,907,000				
Convective Elements (incl. interconnecting piping)	13,025,000				
Additional Waterwall	557,000				
Soot Blowers	2,130,000				
Desuperheaters and Controls	3,062,000				
Air and Flue Gas Ducts	2,317,000				
Coal Feeders	4,485,000				
FD Fan, PA Fan, ID Fan	1,555,000				
Structural Steel, Ladders, Walkways	1,073,000				
Steam Air Heater	121,150				
Rotary Air Heaters	1,930,000				
Transportation to Site					
2. Steam Turbine Package		25,797,000	1	25,797,000	25,700,000
Turbine					
Generator	0				
Exhaust System					
Electrical/Control/Instrumentation Package					
Lube Oil Package w/ main, auxiliary & emergency pump					
High Voltage Generator					
Transportation to Site					
3. Feedwater Heaters			7	1,875,350	1,875,350
Feedwater Heater 1-P	213,550		1		
Feedwater Heater 2	179,650		1		
Feedwater Heater 3	170,400		1		
Feedwater Heater 4	199,300		1		
Feedwater Heater 5-DA	300,900		1		
Feedwater Heater 6	381,650		1		
Feedwater Heater 7	429,900		1		
Feedwater Heater 8					
Feedwater Heater 9					
Feedwater Heater 10					
Feedwater Heater 11					
Feedwater Heater 12					
4. Water-cooled Condensers			2	2,071,000	1,960,000
Water-cooled Condenser 1	1,775,000		1		
Water-cooled Condenser 2					
Water-cooled Condenser 3					
Water-cooled Condenser 4					
Water-cooled Condenser 5					
Water-cooled Condenser 6					
Feed Pump Turbine Water-cooled Condenser	296,000		1		
5. Air-cooled Condense				0	0
Tube Bundles					
Fans, Gears, and Motors					
Steam Duct & Condenser					
Turbine Exhaust Transition					
Steam Jet Air Ejector					
Condensate Receiver Tank					
Support Structures					
Transportation to Site					
6. Particulate Contro		5,799,000	1	5,799,000	5,799,000
Fabric Filter					
Bags					
Ductwork					
Instruments & Controls					
Transportation to Site					
7. Flue Gas Desulfurizatio				0	0
Reagent Feed System					
Absorber Tower					
Auxiliary Equipment of Absorber Tower					
Slurry Pumps					
Flue Gas Handling System					
Flue Gas Reheater					
Waste/Byproduct Handling System					
Support Equipment					
8. Nitrogen Oxide Contro				0	0
9. Stack		3,448,000	1	3,448,000	3,448,000
10. Continuous Emissions Monitoring Syste		221,100	1	221,100	221,100
Enclosures					
Electronics, Display Units, Printers & Sensors					
11. Distributed Control Syster		627,800	1	627,800	750,000
Enclosures					
Electronics, Display Units, Printers & Sensors					
Transportation to Site					
12. Transmission Voltage Equipmen		2,124,000	1	2,124,000	4,100,000
Transformers	1,796,000				
Circuit Breakers	906,600				
Miscellaneous Equipment	101,150				
Transportation to Site					
13. Generating Voltage Equipmen		2,556,000	1	2,556,000	2,556,000
Generator Buswork	1,553,000				
Circuit Breakers	882,000				
Current Limiting Reactors					
Miscellaneous Equipment	121,750				
Transportation to Site					
14. User-definec				0	0

Note: Totals may not tally due to round-off.

	Unit Cost	Quantity	Ref. Cost	Est. Cost
II Other Equipment			37,002,374	45,197,574
1. Pumps			5,402,870	5,402,870
Boiler Feed Pump (turbine included)	1,782,000	2	3,564,000	3,564,000
Boiler Feed Booster Pump	34,360	2	68,720	68,720
Condenser C.W. Pump	401,800	3	1,205,400	1,205,400
Condensate Forwarding Pump	60,750	2	121,500	121,500
Condenser Vacuum Pump	59,600	2	119,200	119,200
Fuel Oil Unloading Pump			0	0
Fuel Oil Forwarding Pump			0	0
Aux Cooling Water Pump (closed loop)	7,510	2	15,020	15,020
Treated Water Pump	3,710	1	3,710	3,710
Diesel Fire Pump	42,980	1	42,980	42,980
Electric Fire Pump	31,020	1	31,020	31,020
Jockey Fire Pump	2,580	1	2,580	2,580
ST+Generator Lube Oil Coolant Pump			0	0
ST Generator Coolant Pump			0	0
Demin Water Pump	3,610	2	7,220	7,220
Raw Water Pump 1	24,050	1	24,050	24,050
Raw Water Pump 2	24,050	1	24,050	24,050
Raw Water Pump 3	24,050	1	24,050	24,050
District Heating Pump			0	0
Aux Cooling Water Pump (open loop)	7,510	2	15,020	15,020
FGD Slurry Pump			0	0
Startup Boiler Feed Pump	134,350	1	134,350	134,350
2. Tanks		9	1,294,930	1,294,930
Fuel Oil			0	0
Hydrous Ammonia	50,850	1	50,850	50,850
Demineralized Water	71,300	1	71,300	71,300
Raw Water	215,250	5	1,076,250	1,076,250
Neutralized Water	57,550	1	57,550	57,550
Acid Storage	19,490	1	19,490	19,490
Caustic Storage	19,490	1	19,490	19,490
Waste Water			0	0
Dedicated Fire Protection Water Storage			0	0
3. Cooling Tower	2,093,000	1	2,093,000	2,093,000
4. Auxiliary Heat Exchangers			44,290	44,290
Auxiliary Cooling Water Heat Exchanger	44,290	1	44,290	44,290
Auxiliary Cooling Tower			0	0
Primary Air Fan Fin Fan Cooler			0	0
Induced Draft Fan Fin Fan Cooler			0	0
Miscellaneous Heat Exchangers			0	0
5. District Heaters			0	0
District Heater 1			0	0
District Heater 2			0	0
6. Auxiliary Boiler	619,100	1	619,100	619,100
7. Makeup Water Treatment System	1,190,000	1	1,190,000	1,190,000
8. Waste Water Treatment System	84,400	1	84,400	84,400
9. Bridge Crane(s)	372,250	1	372,250	372,250
Steam Turbine Crane				
10. Station/Instrument Air Compressors	99,100	2	198,200	198,200
11. Reciprocating Engine Genset(s)		2	92,400	92,400
Emergency Generator	92,400	1	92,400	92,400
Black Start Generator		0	0	0
12. General Plant Instrumentation	161,900	1	161,900	161,900
13. Medium Voltage Equipment	1,762,000	1	1,762,000	1,762,000
Transformers	255,050			
Circuit Breakers	74,950			
Switchgear	558,200			
Motor Control Centers	789,900			
Miscellaneous	83,900			
14. Low Voltage Equipment	392,540	1	392,540	392,540
Transformers	173,700			
Circuit Breakers	82,800			
Switchgear				
Motor Control Centers	117,350			
Miscellaneous	18,690			
15. Coal Handling Equipment	15,507,000	1	15,507,000	15,507,000
16. Ash Handling Equipment	5,335,000	1	5,335,000	5,335,000
17. Miscellaneous Equipment	1,727,494		1,727,494	1,727,494
18. User-defined - Condensate Polisher	362,500	2	725,000	725,000
19. Extra Material Handling Equipment	8,195,200	1	8,195,200	8,195,200

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
III Civil	4,756,987	266,247	25			11,031,339	13,838,132
1. Site Work	2,661,000	82,250	25.00			4,717,250	5,575,734
Site Clearing							
Demolition							
Culverts & Drainage							
Erosion Control							
Fencing, Controlled Access Gates							
Finish Grading							
Finish Landscaping							
Material (Dirt, Sand, Stone)							
Waste Material Removal							
Obstacles R&R							
Miscellaneous							
2. Excavation & Backfill	276,467	7,656	25.00	9.84	47,524	467,864	547,772
Steam Turbine	5.63	0.16	25.00	9.61	7,590	72,960	85,589
Boiler	5.46	0.15	25.00	9.11	23,720	216,150	252,368
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	8.56	0.27	25.00	15.34	708	10,860	12,864
Cooling Tower	6.10	0.15	25.00	9.80	4,330	42,435	49,125
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Feedwater Heaters	10.44	0.36	25.00	19.34	1,560	30,165	35,958
District Heater(s)	0.00	0.00		0.00		0	0
Underground Piping	5.72	0.17	25.00	9.94	5,230	51,965	61,160
Switchyard	7.93	0.16	25.00	12.02	66	799	912
Miscellaneous	5.82	0.16	25.00	9.84	4,320	42,530	49,794
3. Concrete	1,652,990	174,261	25.00	309.09	18,203	5,626,295	7,472,401
Steam Turbine	89.09	11.87	25.00	385.92	2,920	1,126,900	1,488,768
Laydown pads:	67.24	9.40	25.00	302.30	53	16,140	21,380
Boiler	64.81	9.00	25.00	289.73	8,770	2,540,900	3,364,419
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	65.64	9.07	25.00	292.32	461	134,760	178,389
Cooling Tower	64.81	9.00	25.00	289.81	1,810	524,550	694,577
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Underground Piping:	73.48	9.35	25.00	307.33	56	17,315	22,816
Makeup Water Treatment System	58.75	9.00	25.00	283.75	120	34,050	45,323
Auxiliary Boiler	5,310.00	6.76	25.00	5,479.00	74	22,220	29,270
Electrical Power Equipment	70.00	10.60	25.00	334.90	453	151,710	201,810
Feedwater Heaters	66.09	9.00	25.00	291.15	842	245,150	324,266
Pumps	82.88	10.60	25.00	347.83	184	64,000	84,353
Auxiliary Heat Exchangers	0.00	0.00		0.00		0	0
District Heater(s)	0.00	0.00		0.00		0	0
Station/Instrument Air Compressors	73.47	10.29	25.00	330.71	44	14,495	19,202
Bridge Crane(s)	0.00	0.00		0.00		0	0
Reciprocating Engine Genset(s)	58.86	9.00	25.00	283.95	271	76,950	102,418
Tanks:	66.50	9.30	25.00	298.97	428	127,960	194,926
Switchyard	65.76	9.19	25.00	295.64	66	19,645	26,022
Miscellaneous	69.42	9.58	25.00	308.82	1,650	509,550	674,463
4. Roads, Parking, Walkways	166,530	2,080	25.67	52.35	4,201	219,930	242,224
Pavement, Curbing, Striping	31.43	0.43	25.00	42.14	4,200	177,000	195,787
Lighting	40,532.93	328.68	30.00	50,393.24	1	42,930	46,437
5. User-defined						0	0

NOTE: Individual items listed in III.2-4 are per unit quantity.

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
IV Mechanical	17,988,573	2,284,617	29.00			65,056,146	86,860,287
1. On-Site Transportation & Rigging	2,667,000					2,667,000	3,223,736
2. Equipment Erection & Assembly	4,086,453	1,573,554	29.00			49,719,519	68,771,324
Steam Turbine Package	71,550	28,030	29.00	884,420	1	884,420	1,223,793
Boiler	1,862,000	729,500	29.00	23,017,500	1	23,017,500	31,849,921
Feedwater Heaters	9,670	3,790	29.00	119,580		119,580	165,467
Condenser(s)	17,590	6,890	29.00	217,400		217,400	300,821
Cooling Tower				0		0	0
Particulate Control	281,200	110,200	29.00	3,477,000	1	3,477,000	4,811,247
Flue Gas Desulfurization				0		0	0
Nitrogen Oxide Control				0		0	0
Coal Handling System	578,100	226,550	29.00	7,148,050		7,148,050	9,891,004
Ash Handling System	835,600	327,400	29.00	10,330,200		10,330,200	14,294,196
Makeup Water Treatment System	59,400	7,940	29.00	289,660		289,660	385,794
Auxiliary Boiler	513	201	29.00	6,342		6,342	8,776
Electrical Power Equipment	46,350	18,160	29.00	572,990		572,990	792,862
Pumps	9,730	3,810	29.00	120,220		120,220	166,350
Auxiliary Heat Exchangers	158	62	29.00	1,956		1,956	2,707
District Heater(s)				0		0	0
Station/Instrument Air Compressors	713	279	29.00	8,804		8,804	12,182
Bridge Crane(s)	1,840	722	29.00	22,778		22,778	31,520
Reciprocating Engine Genset(s)	689	270	29.00	8,519		8,519	11,788
Miscellaneous	311,350	109,750	29.00	3,494,100		3,494,100	4,822,898
3. Piping	10,905,370	705,063	29.00	187.85	64,763	12,165,877	14,288,831
High Pressure Steam	1,807.51	19.83	29.00	2,382.53	466	1,110,260	1,222,133
Cold Reheat Steam	207.48	7.40	29.00	422.13	762	321,660	389,946
Hot Reheat Steam	929.12	16.99	29.00	1,421.83	1,020	1,450,270	1,660,093
FWH Heating Steam	499.93	7.55	29.00	718.95	764	549,280	619,140
Other Steam & Heating	56.47	3.34	29.00	153.36	431	66,100	83,535
Feedwater	796.90	9.88	29.00	1,083.53	1,290	1,397,750	1,552,121
Circulating Water	413.21	14.00	29.00	819.21	935	765,960	924,447
Auxiliary Cooling Water	52.56	2.62	29.00	128.63	2,360	303,560	378,505
Other Water	12.86	1.15	29.00	46.33	739	34,237	44,565
Raw Water	385.72	6.14	29.00	563.76	2,010	1,133,160	1,282,567
Service Water	20.86	1.34	29.00	59.60	6,070	361,790	459,982
Fuel Gas	0.00	0.00		0.00		0	0
Fuel Oil	0.00	0.00		0.00		0	0
Service Air	9.85	1.02	29.00	39.43	4,550	179,400	235,579
Vacuum Air	144.30	5.09	29.00	291.83	230	67,120	81,286
Ammonia	3,480.00	482.00	29.00	15.89	1,100	17,479	23,280
Boiler & Equipment Drain	15.35	1.08	29.00	46.70	28,290	1,321,260	1,691,629
Boiler Blowdown	18.91	1.26	29.00	55.55	3,040	168,860	215,353
Steam Blowoff	817.99	14.23	29.00	1,230.54	956	1,176,400	1,341,062
Fire Protection	80.56	3.03	29.00	168.32	5,310	893,780	1,088,347
Miscellaneous	111.21	2.75	29.00	190.89	4,440	847,550	995,262
4. Steel	329,750	6,000	29.00	2,518.75	200	503,750	576,395
Racks, Supports, Ladders, Walkways, Platforms	1,648.75	30.00	29.00	2,518.75	200	503,750	576,395
5. User-defined						0	0

NOTE: Individual items listed in IV.2-4 are per unit quantity.

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
V Electrical	1,711,429	168,661	30.00			6,771,250	8,987,375
1. Controls	99,789	104,638	30.00			3,238,920	4,653,157
Steam Turbine Package	4,710	4,950	30.00	153,210.00	1	153,210	215,209
Boiler	60,400	63,450	30.00	1,963,900.00	1	1,963,900	2,758,611
Feedwater Heaters						0	0
Condenser(s)	345	363	30.00			11,235	15,782
Cooling Tower						0	0
Particulate Control	5,520	5,800	30.00	179,520.00	1	179,520	252,165
Flue Gas Desulfurization						0	0
Nitrogen Oxide Control						0	0
Coal Handling System	11,350	11,920	30.00			368,950	621,898
Ash Handling System	16,400	17,230	30.00			533,300	749,106
Makeup Water Treatment System	398	418	30.00			12,938	18,173
Auxiliary Boiler						0	0
Electrical Power Equipment						0	0
Pumps	403	424	30.00			13,123	18,434
Auxiliary Heat Exchangers						0	0
District Heater(s)						0	0
Station/Instrument Air Compressors	47	15	30.00			488	672
Bridge Crane(s)	121	38	30.00			1,261	1,737
Reciprocating Engine Genset(s)	95	30	30.00			995	1,371
2. Assembly & Wiring	1,611,640	64,023	30.00			3,532,330	4,334,218
Switchgear	2,792	270	30.00	10,892.00	5	54,460	71,369
Motor Control Centers	493	41	30.00	1,725.65	46	79,380	103,052
Feeders	8,554	367	30.00	19,553.92	102	1,994,500	2,462,935
Medium/Low Voltage Cable Bus	6,799	174	30.00	12,023.58	53	637,250	752,856
Cable Tray	142,300	4,230	30.00	269,200.00	1	269,200	322,181
General Plant Instrumentation	309	4	30.00	432.82	227	98,250	109,961
Generator to Step-up Transformer Bus	6,060	318	30.00	15,600.00	1	15,600	19,583
Transformers	3,640	573	30.00	20,840.00	6	125,040	168,126
Circuit Breakers	2,475	260	30.00	10,275.00	8	82,200	108,252
Miscellaneous	81,950	3,150	30.00	176,450.00	1	176,450	215,904
3. User-defined						0	0

NOTE: Individual items listed in V.1-2 are per unit quantity.

Note: Totals may not tally due to round-off.

	Area	Cost/Unit Area	Ref. Cost	Est. Cost
VI Buildings			6,813,560	8,235,891
1. Boiler House and Turbine Hall	58,950.0	101.00	5,953,950	7,196,837
2. Administration, Control Room, Machine Shop / Warehouse	12,700.0	61.18	776,986	939,182
3. Water Treatment System	1,140.0	61.66	70,292	84,966
4. Guard House	200.0	61.66	12,332	14,906
5. User-defined			0	0

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
VII Engineering & Startup	410,800	29,760	50.19			16,685,454	16,685,454
1. Engineering						14,781,000	14,781,000
2. Start-Up	410,800	29,760	50.19	1,904,454		1,904,454	1,904,454
3. User-defined						0	0

Note: Totals may not tally due to round-off.

	Ref. Cost	Est. Cost
VIII Soft & Miscellaneous Costs	**77,247,244**	**95,138,349**
1. Contractor's Soft Costs	**58,328,738**	**73,335,801**
Contingency:	29,702,383	36,121,316
Profit:	18,224,700	25,105,879
Permits, Licenses, Fees, Miscellaneous	0	0
Bonds and Insurance	2,600,414	3,027,152
Spare Parts & Materials	0	0
Contractor's Fee	7,801,241	9,081,455
2. Owner's Soft Costs	**18,918,506**	**21,802,548**
Permits, Licenses, Fees, Miscellaneous	6,367,402	7,521,019
Land Cost	0	0
Utility Connection Cost	0	0
Legal & Financial Costs	6,367,402	7,521,019
Escalation	0	0
Spare Parts & Materials	3,000,000	3,000,000
Project Administration & Developer's Fee	3,183,701	3,760,510
3. Total User-defined Costs	**0**	**0**

Note: Totals may not tally due to round-off.

	Multiplier
Labor Rate	1.4175
Specialized Equipment	1.0000
1. Boiler	1.0000
2. Steam Turbine Package	1.0000
3. Feedwater Heater	1.0000
4. Water-cooled Condenser	1.0000
5. Air-cooled Condenser	1.0000
6. Electrostatic Precipitator	1.0000
7. Flue Gas Desulfurization	1.0000
8. Nitogen Oxide Control	1.0000
9. Stack	1.0000
10. Continuous Emissions Monotoring System	1.0000
11. Distributed Control System	1.0000
12. Transmission Voltage Equipment	1.0000
13. Generating Voltage Equipment	1.0000
Other Equipment	1.0000
1. Pumps	1.0000
2. Tanks	1.0000
3. Cooling Tower	1.0000
4. Auxiliary Heat Exchangers	1.0000
5. District Heaters	1.0000
6. Auxiliary Boiler	1.0000
7. Makeup Water Treatment System	1.0000
8. Waste Water Treatment System	1.0000
9. Bridge Crane(s)	1.0000
10. Station/Instrument Air Compressor	1.0000
11. Recip Engine Genset(s)	1.0000
12. General Plant Instrumentation	1.0000
13. Medium Voltage Equipment	1.0000
14. Low Voltage Equipment	1.0000
15. Coal Handling Equipment	1.0000
16. Ash Handling Equipment	1.0000
17. Miscellaneous Equipment	1.0000
Commodity	1.0000

Contractor's Soft Costs	Percentage, %	+ Fixed Amount
1. Contingency		
Labor	15.0	0
Specialized Equipment	10.0	0
Other Equipment	10.0	0
Commodities	10.0	0
2. Profit		
Labor	20.0	0
Specialized Equipment	0.0	0
Other Equipment	3.0	0
Commodities	5.0	0
3. Permits, Licenses, Fees & Miscellaneous	0.0	0
4. Bonds and Insurance	1.0	0
5. Spare Parts and Materials	0.0	0

6. Contractor's Fee	3.0	0
Owner's Soft Costs		
1. Permits, Licenses, Fees & Miscellaneous	2.0	0
2. Land Cost	0.0	0
3. Utility Connection Cost	0.0	0
4. Legal and Financial Costs	2.0	0
5. Escalation	0.0	0
6. Spare Parts and Materials	0.0	3,000,000
7. Project Administration and Developer's Fee	1.0	0

Nelson Creek 94°F DB, 100% Load

Project Cost Summary	Reference Cost	Estimated Cost	
I Specialized Equipment	119,852,850	125,273,000	USD
II Other Equipment	43,034,131	52,888,303	USD
III Civil	12,076,250	15,139,235	USD
IV Mechanical	68,569,418	91,680,866	USD
V Electrical	6,774,419	9,058,622	USD
VI Buildings & Structures	7,326,077	8,855,395	USD
VII Engineering & Plant Startup	16,704,614	16,704,614	USD
Subtotal - Contractor's Internal Cost	274,337,759	319,600,035	USD
IX Contractor's Soft & Miscellaneous Costs	61,437,833	77,232,097	USD
Contractor's Price	335,775,592	396,832,132	USD
X Owner's Soft & Miscellaneous Costs	19,788,780	22,841,607	USD
Total - Owner's Cost	355,564,372	419,673,739	USD
Net Plant Output	250.0	250.0	MW
Cost per kW - Contractor's	1,343	1,587	USD per kW
Cost per kW - Owner's	1,422	1,679	USD per kW

Total Plant (Reference Basis):	Reference Cost	Hours
Commodities	25,675,929	
Labor	83,221,319	2,882,065

Effective Labor Rates:	Cost per Hour
Civil Account	25.00
Mechanical Account	29.00
Electrical Account	30.00

Buildings	% of Total Cost	Estimated Cost	Hours
Labor	50	3,663,038	
Material	50	3,663,038	
Labor Hours			138,734

Note: Totals may not tally due to round-off.

	Item Cost	Unit Cost	Quantity	Ref. Cost	Est. Cost
I Specialized Equipment				119,852,850	125,273,000
1. Boiler		75,003,000	1	75,003,000	78,563,000
Furnace & Cyclones (incl. drum, radiant platens & circ. pumps)	41,807,000				
Convective Elements (incl. interconnecting piping)	14,427,000				
Additional Waterwall	585,800				
Soot Blowers	2,180,000				
Desuperheaters and Controls	3,067,000				
Air and Flue Gas Ducts	2,416,000				
Coal Feeders	5,679,000				
FD Fan, PA Fan, ID Fan	1,612,000				
Structural Steel, Ladders, Walkways	1,117,000				
Steam Air Heater	123,250				
Rotary Air Heaters	1,987,000				
Transportation to Site					
2. Steam Turbine Package		25,821,000	1	25,821,000	25,700,000
Turbine					
Generator	0				
Exhaust System					
Electrical/Control/Instrumentation Package					
Lube Oil Package w/ main, auxiliary & emergency pump					
High Voltage Generator					
Transportation to Site					
3. Feedwater Heaters			7	1,877,900	1,877,900
Feedwater Heater 1-P	213,750		1		
Feedwater Heater 2	179,800		1		
Feedwater Heater 3	170,550		1		
Feedwater Heater 4	199,500		1		
Feedwater Heater 5-DA	301,250		1		
Feedwater Heater 6	382,450		1		
Feedwater Heater 7	430,600		1		
Feedwater Heater 8					
Feedwater Heater 9					
Feedwater Heater 10					
Feedwater Heater 11					
Feedwater Heater 12					
4. Water-cooled Condensers			2	2,073,550	1,960,000
Water-cooled Condenser 1	1,778,000		1		
Water-cooled Condenser 2					
Water-cooled Condenser 3					
Water-cooled Condenser 4					
Water-cooled Condenser 5					
Water-cooled Condenser 6					
Feed Pump Turbine Water-cooled Condenser	295,550		1		
5. Air-cooled Condense				0	0
Tube Bundles					
Fans, Gears, and Motors					
Steam Duct & Condenser					
Turbine Exhaust Transition					
Steam Jet Air Ejector					
Condensate Receiver Tank					
Support Structures					
Transportation to Site					
6. Particulate Contro		6,037,000	1	6,037,000	6,037,000
Fabric Filter					
Bags					
Ductwork					
Instruments & Controls					
Transportation to Site					
7. Flue Gas Desulfurizatio				0	0
Reagent Feed System					
Absorber Tower					
Auxiliary Equipment of Absorber Tower					
Slurry Pumps					
Flue Gas Handling System					
Flue Gas Reheater					
Waste/Byproduct Handling System					
Support Equipment					
8. Nitrogen Oxide Contro				0	0
9. Stack		3,502,000	1	3,502,000	3,502,000
10. Continuous Emissions Monitoring Syste		221,100	1	221,100	221,100
Enclosures					
Electronics, Display Units, Printers & Sensors					
11. Distributed Control Syster		628,300	1	628,300	750,000
Enclosures					
Electronics, Display Units, Printers & Sensors					
Transportation to Site					
12. Transmission Voltage Equipmen		2,127,000	1	2,127,000	4,100,000
Transformers	1,799,000				
Circuit Breakers	906,800				
Miscellaneous Equipment	101,300				
Transportation to Site					
13. Generating Voltage Equipmen		2,562,000	1	2,562,000	2,562,000
Generator Buswork	1,556,000				
Circuit Breakers	884,200				
Current Limiting Reactors					
Miscellaneous Equipment	122,000				
Transportation to Site					
14. User-definec				0	0

Note: Totals may not tally due to round-off.

	Unit Cost	Quantity	Ref. Cost	Est. Cost
II Other Equipment			43,034,131	52,888,303
1. Pumps			5,439,330	5,439,330
Boiler Feed Pump (turbine included)	1,778,000	2	3,556,000	3,556,000
Boiler Feed Booster Pump	34,360	2	68,720	68,720
Condenser C.W. Pump	402,700	3	1,208,100	1,208,100
Condensate Forwarding Pump	60,850	2	121,700	121,700
Condenser Vacuum Pump	59,650	2	119,300	119,300
Fuel Oil Unloading Pump			0	0
Fuel Oil Forwarding Pump			0	0
Aux Cooling Water Pump (closed loop)	7,530	2	15,060	15,060
Treated Water Pump	3,750	1	3,750	3,750
Diesel Fire Pump	42,980	1	42,980	42,980
Electric Fire Pump	31,020	1	31,020	31,020
Jockey Fire Pump	2,580	1	2,580	2,580
ST+Generator Lube Oil Coolant Pump			0	0
ST Generator Coolant Pump			0	0
Demin Water Pump	3,650	2	7,300	7,300
Raw Water Pump 1	24,120	1	24,120	24,120
Raw Water Pump 2	24,120	1	24,120	24,120
Raw Water Pump 3	24,120	1	24,120	24,120
District Heating Pump			0	0
Aux Cooling Water Pump (open loop)	7,530	2	15,060	15,060
FGD Slurry Pump			0	0
Startup Boiler Feed Pump	175,400	1	175,400	175,400
2. Tanks		9	1,249,240	1,249,240
Fuel Oil			0	0
Hydrous Ammonia			0	0
Demineralized Water	73,400	1	73,400	73,400
Raw Water	215,250	5	1,076,250	1,076,250
Neutralized Water	58,550	1	58,550	58,550
Acid Storage	20,520	1	20,520	20,520
Caustic Storage	20,520	1	20,520	20,520
Waste Water			0	0
Dedicated Fire Protection Water Storage			0	0
3. Cooling Tower	2,095,000	1	2,095,000	2,095,000
4. Auxiliary Heat Exchangers			44,380	44,380
Auxiliary Cooling Water Heat Exchanger	44,380	1	44,380	44,380
Auxiliary Cooling Tower			0	0
Primary Air Fan Fin Fan Cooler			0	0
Induced Draft Fan Fin Fan Cooler			0	0
Miscellaneous Heat Exchangers			0	0
5. District Heaters			0	0
District Heater 1			0	0
District Heater 2			0	0
6. Auxiliary Boiler	619,100	1	619,100	619,100
7. Makeup Water Treatment System	1,243,000	1	1,243,000	1,243,000
8. Waste Water Treatment System	88,150	1	88,150	88,150
9. Bridge Crane(s)	372,250	1	372,250	372,250
Steam Turbine Crane				
10. Station/Instrument Air Compressors	99,100	2	198,200	198,200
11. Reciprocating Engine Genset(s)		2	92,400	92,400
Emergency Generator	92,400	1	92,400	92,400
Black Start Generator		0	0	0
12. General Plant Instrumentation	162,000	1	162,000	162,000
13. Medium Voltage Equipment	1,919,100	1	1,919,100	1,919,100
Transformers	260,350			
Circuit Breakers	86,850			
Switchgear	652,300			
Motor Control Centers	828,200			
Miscellaneous	91,400			
14. Low Voltage Equipment	360,260	1	360,260	360,260
Transformers	127,750			
Circuit Breakers	122,400			
Switchgear				
Motor Control Centers	92,950			
Miscellaneous	17,160			
15. Coal Handling Equipment	20,787,000	1	20,787,000	20,787,000
16. Ash Handling Equipment	5,625,000	1	5,625,000	5,625,000
17. Miscellaneous Equipment	2,014,721		2,014,721	2,014,721
18. User-defined - Condensate Polisher	362,500	2	725,000	725,000
19. Extra Material Handling Equipment	9,854,172	1	9,854,172	9,854,172

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
III Civil	5,188,398	290,787	25			12,076,250	15,139,235
1. Site Work	2,949,000	91,150	25.00			5,227,750	6,179,128
Site Clearing							
Demolition							
Culverts & Drainage							
Erosion Control							
Fencing, Controlled Access Gates							
Finish Grading							
Finish Landscaping							
Material (Dirt, Sand, Stone)							
Waste Material Removal							
Obstacles R&R							
Miscellaneous							
2. Excavation & Backfill	306,248	8,464	25.00	9.75	53,127	517,845	606,186
Steam Turbine	5.63	0.16	25.00	9.61	7,600	73,030	85,659
Boiler	5.43	0.15	25.00	9.08	28,840	261,850	305,792
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	8.55	0.27	25.00	15.31	710	10,870	12,874
Cooling Tower	6.09	0.15	25.00	9.79	4,340	42,500	49,201
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Feedwater Heaters	10.46	0.36	25.00	19.37	1,560	30,210	36,013
District Heater(s)	0.00	0.00		0.00		0	0
Underground Piping	5.73	0.17	25.00	9.94	5,180	51,495	60,607
Switchyard	7.94	0.16	25.00	12.02	67	800	913
Miscellaneous	5.76	0.16	25.00	9.75	4,830	47,090	55,127
3. Concrete	1,759,220	189,053	25.00	307.70	19,832	6,102,325	8,102,878
Steam Turbine	89.26	11.90	25.00	386.70	2,920	1,129,150	1,491,749
Laydown pads:	67.15	9.41	25.00	302.38	53	16,165	21,415
Boiler	64.83	9.00	25.00	289.93	10,240	2,968,900	3,931,237
Stack	0.00	0.00		0.00		0	0
Water Cooled Condenser(s)	65.63	9.05	25.00	291.82	462	134,820	178,449
Cooling Tower	64.92	9.01	25.00	290.19	1,810	525,250	695,486
Air Cooled Condenser	0.00	0.00		0.00		0	0
Particulate Control	0.00	0.00	25.00	0.00	0	0	0
Flue Gas Desulfurization	0.00	0.00		0.00		0	0
Nitrogen Oxide Control	0.00	0.00		0.00		0	0
Underground Piping:	73.48	9.35	25.00	307.33	56	17,315	22,816
Makeup Water Treatment System	59.03	9.03	25.00	284.84	124	35,320	47,010
Auxiliary Boiler	5,310.00	6.76	25.00	5,479.00	74	22,220	29,270
Electrical Power Equipment	69.67	10.55	25.00	333.41	455	151,700	201,800
Feedwater Heaters	66.07	9.00	25.00	291.16	843	245,450	324,671
Pumps	82.83	10.60	25.00	347.77	184	63,990	84,343
Auxiliary Heat Exchangers	0.00	0.00		0.00		0	0
District Heater(s)	0.00	0.00		0.00		0	0
Station/Instrument Air Compressors	73.47	10.29	25.00	330.71	44	14,495	19,202
Bridge Crane(s)	0.00	0.00		0.00		0	0
Reciprocating Engine Genset(s)	58.86	9.00	25.00	283.95	271	76,950	102,418
Tanks:	66.39	9.30	25.00	298.90	429	128,230	195,357
Switchyard	65.67	9.20	25.00	295.61	67	19,670	26,058
Miscellaneous	69.00	9.52	25.00	307.06	1,800	552,700	731,599
4. Roads, Parking, Walkways	173,930	2,120	25.66	51.30	4,451	228,330	251,042
Pavement, Curbing, Striping	31.33	0.41	25.00	41.66	4,450	185,400	204,605
Lighting	40,532.93	328.68	30.00	50,393.24	1	42,930	46,437
5. User-defined						0	0

NOTE: Individual items listed in III.2-4 are per unit quantity.

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
IV Mechanical	18,447,073	2,389,954	29.00			68,569,418	91,680,866
1. On-Site Transportation & Rigging	2,820,000					2,820,000	3,408,675
2. Equipment Erection & Assembly	4,349,353	1,675,114	29.00			52,927,659	73,209,102
Steam Turbine Package	71,650	28,070	29.00	885,680	1	885,680	1,225,538
Boiler	1,864,000	730,300	29.00	23,042,700	1	23,042,700	31,884,807
Feedwater Heaters	9,680	3,790	29.00	119,590		119,590	165,477
Condenser(s)	17,610	6,900	29.00	217,710		217,710	301,252
Cooling Tower				0		0	0
Particulate Control	292,700	114,700	29.00	3,619,000	1	3,619,000	5,007,730
Flue Gas Desulfurization				0		0	0
Nitrogen Oxide Control				0		0	0
Coal Handling System	758,200	297,100	29.00	9,374,100		9,374,100	12,971,238
Ash Handling System	881,000	345,200	29.00	10,891,800		10,891,800	15,071,309
Makeup Water Treatment System	62,100	8,290	29.00	302,510		302,510	402,881
Auxiliary Boiler	513	201	29.00	6,342		6,342	8,776
Electrical Power Equipment	47,360	18,560	29.00	585,600		585,600	810,315
Pumps	9,740	3,820	29.00	120,520		120,520	166,771
Auxiliary Heat Exchangers	158	62	29.00	1,956		1,956	2,707
District Heater(s)				0		0	0
Station/Instrument Air Compressors	713	279	29.00	8,804		8,804	12,182
Bridge Crane(s)	1,840	722	29.00	22,778		22,778	31,520
Reciprocating Engine Genset(s)	689	270	29.00	8,519		8,519	11,788
Miscellaneous	331,400	116,850	29.00	3,720,050		3,720,050	5,134,811
3. Piping	10,947,220	708,830	29.00	181.62	67,816	12,316,969	14,485,533
High Pressure Steam	1,806.42	19.79	29.00	2,380.21	467	1,111,560	1,223,433
Cold Reheat Steam	207.48	7.40	29.00	422.13	762	321,660	389,946
Hot Reheat Steam	931.47	17.00	29.00	1,424.47	1,020	1,452,960	1,662,904
FWH Heating Steam	491.91	7.51	29.00	709.69	779	552,850	623,679
Other Steam & Heating	56.02	3.34	29.00	152.91	437	66,820	84,497
Feedwater	780.30	9.72	29.00	1,062.17	1,320	1,402,070	1,557,409
Circulating Water	414.15	14.10	29.00	823.15	926	762,240	920,364
Auxiliary Cooling Water	51.65	2.60	29.00	127.17	2,450	311,570	388,816
Other Water	11.25	1.09	29.00	43.00	959	41,240	53,953
Raw Water	378.98	6.13	29.00	556.64	2,060	1,146,680	1,299,477
Service Water	20.70	1.33	29.00	59.37	6,390	379,380	482,536
Fuel Gas	0.00	0.00		0.00		0	0
Fuel Oil	0.00	0.00		0.00		0	0
Service Air	9.80	1.02	29.00	39.35	4,790	188,480	247,565
Vacuum Air	144.30	5.09	29.00	291.83	230	67,120	81,286
Ammonia	3,480.00	482.00	29.00	15.89	1,100	17,479	23,280
Boiler & Equipment Drain	15.06	1.08	29.00	46.27	29,750	1,376,530	1,764,213
Boiler Blowdown	18.55	1.26	29.00	54.98	3,200	175,930	224,602
Steam Blowoff	827.78	14.20	29.00	1,239.54	936	1,160,210	1,321,119
Fire Protection	78.17	3.01	29.00	165.32	5,590	924,150	1,127,556
Miscellaneous	106.82	2.68	29.00	184.52	4,650	858,040	1,008,899
4. Steel	330,500	6,010	29.00	2,523.95	200	504,790	577,556
Racks, Supports, Ladders, Walkways, Platforms	1,652.50	30.05	29.00	2,523.95	200	504,790	577,556
5. User-defined						0	0

NOTE: Individual items listed in IV.2-4 are per unit quantity.

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
V Electrical	1,629,008	171,514	30.00			6,774,419	9,058,622
1. Controls	104,528	109,606	30.00			3,392,699	4,901,504
Steam Turbine Package	4,720	4,950	30.00	153,220.00	1	153,220	215,219
Boiler	60,450	63,500	30.00	1,965,450.00	1	1,965,450	2,760,788
Feedwater Heaters						0	0
Condenser(s)	346	363	30.00			11,236	15,783
Cooling Tower						0	0
Particulate Control	5,750	6,040	30.00	186,950.00	1	186,950	262,601
Flue Gas Desulfurization						0	0
Nitrogen Oxide Control						0	0
Coal Handling System	14,880	15,640	30.00			484,080	815,965
Ash Handling System	17,300	18,170	30.00			562,400	789,979
Makeup Water Treatment System	415	436	30.00			13,495	18,956
Auxiliary Boiler						0	0
Electrical Power Equipment						0	0
Pumps	404	424	30.00			13,124	18,435
Auxiliary Heat Exchangers						0	0
District Heater(s)						0	0
Station/Instrument Air Compressors	47	15	30.00			488	672
Bridge Crane(s)	121	38	30.00			1,261	1,737
Reciprocating Engine Genset(s)	95	30	30.00			995	1,371
2. Assembly & Wiring	1,524,480	61,908	30.00			3,381,720	4,157,118
Switchgear	2,718	253	30.00	10,318.33	6	61,910	80,948
Motor Control Centers	501	42	30.00	1,746.30	46	80,330	104,253
Feeders	8,037	351	30.00	18,563.73	102	1,893,500	2,341,770
Medium/Low Voltage Cable Bus	5,967	162	30.00	10,816.67	54	584,100	693,443
Cable Tray	148,550	4,410	30.00	280,850.00	1	280,850	336,085
General Plant Instrumentation	317	4	30.00	443.92	227	100,770	112,781
Generator to Step-up Transformer Bus	6,060	319	30.00	15,630.00	1	15,630	19,625
Transformers	4,262	672	30.00	24,422.00	5	122,110	164,194
Circuit Breakers	2,539	267	30.00	10,552.86	7	73,870	97,292
Miscellaneous	77,450	3,040	30.00	168,650.00	1	168,650	206,726
3. User-defined						0	0

NOTE: Individual items listed in V.1-2 are per unit quantity.

	Area	Cost/Unit Area	Ref. Cost	Est. Cost
VI Buildings			7,326,077	8,855,395
1. Boiler House and Turbine Hall	64,000.0	101.00	6,464,000	7,813,360
2. Administration, Control Room, Machine Shop / Warehouse	12,700.0	61.18	776,986	939,182
3. Water Treatment System	1,180.0	61.66	72,759	87,947
4. Guard House	200.0	61.66	12,332	14,906
5. User-defined			0	0

Note: Totals may not tally due to round-off.

	Material	Labor Hours	Labor Rate	Unit Cost	Quantity	Ref. Cost	Est. Cost
VII Engineering & Startup	411,450	29,810	50.19			16,704,614	16,704,614
1. Engineering						14,797,000	14,797,000
2. Start-Up	411,450	29,810	50.19	1,907,614		1,907,614	1,907,614
3. User-defined						0	0

	Ref. Cost	Est. Cost
IX Soft & Miscellaneous Costs	**81,226,613**	**100,073,704**
1. Contractor's Soft Costs	**61,437,833**	**77,232,097**
Contingency:	31,266,989	38,006,156
Profit:	19,197,334	26,441,940
Permits, Licenses, Fees, Miscellaneous	0	0
Bonds and Insurance	2,743,378	3,196,000
Spare Parts & Materials	0	0
Contractor's Fee	8,230,133	9,588,001
2. Owner's Soft Costs	**19,788,780**	**22,841,607**
Permits, Licenses, Fees, Miscellaneous	6,715,512	7,936,643
Land Cost	0	0
Utility Connection Cost	0	0
Legal & Financial Costs	6,715,512	7,936,643
Escalation	0	0
Spare Parts & Materials	3,000,000	3,000,000
Project Administration & Developer's Fee	3,357,756	3,968,321
3. Total User-defined Costs	**0**	**0**

	Multiplier
Labor Rate	1.4175
Specialized Equipment	1.0000
1. Boiler	1.0000
2. Steam Turbine Package	1.0000
3. Feedwater Heater	1.0000
4. Water-cooled Condenser	1.0000
5. Air-cooled Condenser	1.0000
6. Electrostatic Precipitator	1.0000
7. Flue Gas Desulfurization	1.0000
8. Nitogen Oxide Control	1.0000
9. Stack	1.0000
10. Continuous Emissions Monotoring System	1.0000
11. Distributed Control System	1.0000
12. Transmission Voltage Equipment	1.0000
13. Generating Voltage Equipment	1.0000
Other Equipment	1.0000
1. Pumps	1.0000
2. Tanks	1.0000
3. Cooling Tower	1.0000
4. Auxiliary Heat Exchangers	1.0000
5. District Heaters	1.0000
6. Auxiliary Boiler	1.0000
7. Makeup Water Treatment System	1.0000
8. Waste Water Treatment System	1.0000
9. Bridge Crane(s)	1.0000
10. Station/Instrument Air Compressor	1.0000
11. Recip Engine Genset(s)	1.0000
12. General Plant Instrumentation	1.0000
13. Medium Voltage Equipment	1.0000
14. Low Voltage Equipment	1.0000
15. Coal Handling Equipment	1.0000
16. Ash Handling Equipment	1.0000
17. Miscellaneous Equipment	1.0000
Commodity	1.0000

Contractor's Soft Costs	Percentage, %	+ Fixed Amount
1. Contingency		
Labor	15.0	0
Specialized Equipment	10.0	0
Other Equipment	10.0	0
Commodities	10.0	0
2. Profit		
Labor	20.0	0
Specialized Equipment	0.0	0
Other Equipment	3.0	0
Commodities	5.0	0
3. Permits, Licenses, Fees & Miscellaneous	0.0	0
4. Bonds and Insurance	1.0	0
5. Spare Parts and Materials	0.0	0
6. Contractor's Fee	3.0	0
Owner's Soft Costs		
1. Permits, Licenses, Fees & Miscellaneous	2.0	0
2. Land Cost	0.0	0
3. Utility Connection Cost	0.0	0
4. Legal and Financial Costs	2.0	0
5. Escalation	0.0	0
6. Spare Parts and Materials	0.0	3,000,000
7. Project Administration and Developer's Fee	1.0	0

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1	5/23/05 2:02 PM		Southern Montana EC Site Selection Study							Salem, Salem Industrial, Decker and Hysham Run						INPUT WORKSHEET				Page 1 of 17	
2																					
3	COMMON INPUTS																				
4						Escalation Rates:						Capacity Factors:									
5	Financial Parameters:					Fuel			[redacted]	/year		CF_1	[redacted]								
6	Interest Rate		[redacted]			Fixed O&M			[redacted]	/year		CF_2	[redacted]								
7	Capital Recovery Factor-20 yrs		[redacted]			Variable O&M			[redacted]	/year		CF_3	[redacted]								
8	Capital Recovery Factor-30 yrs		[redacted]			Property Insurance			[redacted]	/year		CF_4	(See Noncommon Inputs by alternate.)								
9	Property Taxes and Insurance		[redacted]	/total investment		Administrative & General			[redacted]	/year											
10	Replacement Tax		[redacted]	¢/kWh		Replacement Tax			[redacted]	/year		SO_2 Emission Allowance Costs:									
11	Debt Service Coverage Ratio		[redacted]			Transmission O&M			[redacted]	/year		[redacted]	/Ton (2009-2015)								
12	Project Reserve		[redacted]			Transmission Tax			[redacted]	/year		[redacted]	/Ton (2016-2038)								
13	Transmission O&M		[redacted]	/transmission investment		SO_2 Emission Impact (2009-2015)			[redacted]	/year		[redacted]	/Ton of Emissions (up to 4,000 Tons)								
14						SO_2 Emission Impact (2017-2038)			[redacted]	/year											
15																					
16	NONCOMMON INPUTS- SALEM 1 SITE														CF_4						
17				Alt.	Net		Installed Cost		Generation Plant O&M		Heat			Administrative	Capacity			Annual Energy Output		Transmission	SO_2
18				No.	Capacity	Generation	Transmission	Total	Fixed	Variable	Rate	Fuel Cost		& General	Factors	CF_1	CF_2	CF_3	CF_4	Taxes	Emissions
19					(MW)	($1000)	($1000)	($1000)	($/kW/yr)	(¢/kWh)	(Btu/kWh)	(¢/10^6 Btu)	(¢/kWh)	($1000)	(%)	(MWh)	(MWh)	(MWh)	(MWh)	($1000)	(lbs/10^6 Btu)
20																					
21	Unit Fully Loaded @ System Peak			1	250	[redacted]															
23																					
24																					
25	Unit 80% Loaded @ System Peak			2	200	[redacted]															
26																					
30																					
46																					
47	NONCOMMON INPUTS- DECKER SITE														CF_4						
48				Alt.	Net		Installed Cost		Generation Plant O&M		Heat			Administrative	Capacity			Annual Energy Output		Transmission	SO_2
49				No.	Capacity	Generation	Transmission	Total	Fixed	Variable	Rate	Fuel Cost		& General	Factors	CF_1	CF_2	CF_3	CF_4	Taxes	Emissions
50					(MW)	($1000)	($1000)	($1000)	($/kW/yr)	(¢/kWh)	(Btu/kWh)	(¢/MMBtu)	(¢/kWh)	($1000)	(%)	(MWh)	(MWh)	(MWh)	(MWh)	($1000)	(lbs/MMBtu)
54																					
55	Unit Fully Loaded @ System Peak			1	250	[redacted]															
56																					
57																					
58	Unit 80% Loaded @ System Peak			2	200	[redacted]															
60																					
61																					
79																					
80	NONCOMMON INPUTS- HYSHAM 2 SITE														CF_4						
81				Alt.	Net		Installed Cost		Generation Plant O&M		Heat			Administrative	Capacity			Annual Energy Output		Transmission	SO_2
82				No.	Capacity	Generation	Transmission	Total	Fixed	Variable	Rate	Fuel Cost		& General	Factors	CF_1	CF_2	CF_3	CF_4	Taxes	Emissions
83					(MW)	($1000)	($1000)	($1000)	($/kW/yr)	(¢/kWh)	(Btu/kWh)	(¢/10^6 Btu)	(¢/kWh)	($1000)	(%)	(MWh)	(MWh)	(MWh)	(MWh)	($1000)	(lbs/MMBtu)
87																					
88	Unit Fully Loaded @ System Peak			1	250	[redacted]															
89																					
90																					
91	Unit 80% Loaded @ System Peak			2	200	[redacted]															
92																					
94																					
95																					
96	NONCOMMON INPUTS- SALEM INDUSTRIAL SITE														CF_4						
97				Alt.	Net		Installed Cost		Generation Plant O&M		Heat			Administrative	Capacity			Annual Energy Output		Transmission	SO_2
98				No.	Capacity	Generation	Transmission	Total	Fixed	Variable	Rate	Fuel Cost		& General	Factors	CF_1	CF_2	CF_3	CF_4	Taxes	Emissions
99					(MW)	($1000)	($1000)	($1000)	($/kW/yr)	(¢/kWh)	(Btu/kWh)	(¢/MMBtu)	(¢/kWh)	($1000)	(%)	(MWh)	(MWh)	(MWh)	(MWh)	($1000)	(lbs/MMBtu)
103																					
104	Unit Fully Loaded @ System Peak			1	250	[redacted]															
105																					
106																					
107	Unit 80% Loaded @ System Peak			2	200	[redacted]															
108																					
110																					

Interest Expense [redacted]
Interest Received
Percent of Yr Interest Earned [redacted]

	2004	2005	2006	2007	2008	Total

Schedule for Interest Paid During Construction

Generation Construction Cost (Total Plant):
Percent Borrowed
Cumulative Percent
[redacted]

Transmission Construction Cost:
Percent Borrowed
Cumulative Percent
[redacted]

Schedule for Interest Received During Construction

Generation Construction Cost (Total Plant):
Percent Paid Out
Cumulative Percent
[redacted]

Transmission Construction Cost:
Percent Paid Out
Cumulative Percent
[redacted]

Salem 1 Site

Generation Installed Cost = [redacted] ($1000)
Transmission Installed Cost = [redacted] ($1000)

Interest Paid During Construction

Generation Construction Cost (Total Plant)
Amount Borrowed
Interest Expense
[redacted]
Transmission Construction Cost
Amount Borrowed
Interest Expense
[redacted]

Interest Received During Construction

Generation Construction Cost (Total Plant)
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]
Transmission Construction Cost [redacted]
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]

Net Interest Paid/(Received) During Construction

Generation Construction Cost (Total Plant)
Transmission Construction Cost
[redacted]

Decker Site

Generation Installed Cost = [redacted] ($1000)
Transmission Installed Cost = [redacted] ($1000)

Interest Paid During Construction

Generation Construction Cost (Total Plant)
Amount Borrowed
Interest Expense
[redacted]
Transmission Construction Cost
Amount Borrowed
Interest Expense
[redacted]

Interest Received During Construction

Generation Construction Cost (Total Plant)
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
Transmission Construction Cost
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]

Net Interest Paid/(Received) During Construction

Generation Construction Cost (Total Plant)
Transmission Construction Cost
[redacted]

Hysham 2 Site

Generation Installed Cost = [redacted] ($1000)
Transmission Installed Cost = [redacted] ($1000)

[redacted]

Generation Construction Cost (Total Plant)
Amount Borrowed
Interest Expense
[redacted]
Transmission Construction Cost [redacted]
Amount Borrowed
Interest Expense
[redacted]

Interest Received During Construction

Generation Construction Cost (Total Plant)
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]
Transmission Construction Cost
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]

Net Interest Paid/(Received) During Construction

Generation Construction Cost (Total Plant)
Transmission Construction Cost
[redacted]

Salem Industrial Site

Generation Installed Cost = [redacted] ($1000)
Transmission Installed Cost = [redacted] ($1000)

Interest Paid During Construction

Generation Construction Cost (Total Plant)
Amount Borrowed
Interest Expense
[redacted]
Transmission Construction Cost
Amount Borrowed
Interest Expense
[redacted]

Interest Received During Construction

Generation Construction Cost (Total Plant)
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]
Transmission Construction Cost
Paid to Contractors
Cumulative
Unpaid Amount
Interest Income
[redacted]

Net Interest Paid/(Received) During Construction

Generation Construction Cost (Total Plant)
Transmission Construction Cost
[redacted]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 1 - SALEM 1 SITE		**Unit Fully Loaded @ System Peak**																														
Non-Energy Related Costs - $1000																																
Fixed Plant O&M	[redacted]																															
Transmission O&M																																
Transmission Taxes																																
Property Taxes and Insurance																																
Administrative & General																																
Subtotal - w/o Debt Service																																
Debt Service Payment-20 Yrs w/o DSC																																
Debt Service Payment-30 Yrs w/o DSC																																
Debt Service Payment-20 Yrs w/DSC																																
Debt Service Payment-30 Yrs w/DSC																																
Subtotal - 20 Yr DS w/o DSC																																
Subtotal - 30 Yr DS w/o DSC																																
Subtotal - 20 Yr DS w/DSC																																
Subtotal - 30 Yr DS w/DSC																																
TOTAL BUSBAR COSTS -		**ALTERNATE 1 - SALEM 1 SITE**																														
Energy Related Costs - CF1 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
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Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Cumulative Present Value																																
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Cumulative Present Value																																
30 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														
Energy Related Costs - CF2 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
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TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														

5/23/05 2:02 PM	IOWA ENERGY PROJECT				BASE CASE			ALTERNATE 1 - SALEM 1 SITE							Unit Fully Loaded @ System Peak																Page 3 of 17	
																															20 Year	30 Year
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total	Total
TOTAL BUSBAR COSTS -		**ALTERNATE 1 - SALEM 1 SITE**			**(CONTINUED)**																											
Energy Related Costs - CF3 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Cumulative Present Value																																
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Present Value (2007 Level)																																
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30 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														
Energy Related Costs - CF4 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
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Present Value (2007 Level)																																
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TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 2 - SALEM 1 SITE		**Unit 80% Loaded @ System Peak**																														
Non-Energy Related Costs - $1000																																
Fixed Plant O&M	[redacted]																															
Transmission O&M																																
Transmission Taxes																																
Property Taxes and Insurance																																
Administrative & General																																
Subtotal - w/o Debt Service																																
Debt Service Payment-20 Yrs w/o DSC																																
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Subtotal - 20 Yr DS w/o DSC																																
Subtotal - 30 Yr DS w/o DSC																																
Subtotal - 20 Yr DS w/DSC																																
Subtotal - 30 Yr DS w/DSC																																
TOTAL BUSBAR COSTS -		**ALTERNATE 2 - SALEM 1 SITE**																														
Energy Related Costs - CF1 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
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20 Years w/o Debt Service Coverage:																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														
Energy Related Costs - CF2 - $1000																																
Fuel Costs	[redacted]																															
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SO_2 Emission Allowance Cost																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														

5/23/05 2:02 PM	**IOWA ENERGY PROJECT**				**BASE CASE**			**ALTERNATE 2 - SALEM 1 SITE**							**Unit 80% Loaded @ System Peak**																Page 5 of 17	
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
TOTAL BUSBAR COSTS -		**ALTERNATE 2 - SALEM 1 SITE**			**(CONTINUED)**																											
Energy Related Costs - CF3 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
Energy Related Costs - CF4 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 1 - DECKER SITE		**Unit Fully Loaded @ System Peak**																														
Non-Energy Related Costs - $1000																																
Fixed Plant O&M	[redacted]																															
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Energy Related Costs - CF2 - $1000																																
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5/23/05 2:02 PM	IOWA ENERGY PROJECT				BASE CASE			ALTERNATE 1 - DECKER SITE							Unit Fully Loaded @ System Peak																Page 7 of 17	
																															20 Year	30 Year
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total	Total
TOTAL BUSBAR COSTS -		**ALTERNATE 1 - DECKER SITE**			**(CONTINUED)**																											
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Fuel Costs	[redacted]																															
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20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														
Energy Related Costs - CF4 - $1000																																
Fuel Costs	[redacted]																															
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SO_2 Emission Allowance Cost																																
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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 2 - DECKER SITE		Unit 80% Loaded @ System Peak																														
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Energy Related Costs - CF1 - $1000																																
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5/23/05 2:02 PM		IOWA ENERGY PROJECT				BASE CASE			ALTERNATE 2 - DECKER SITE							Unit 80% Loaded @ System Peak																Page 9 of 17	
																																20 Year	30 Year
		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total	Total
TOTAL BUSBAR COSTS -			**ALTERNATE 2 - DECKER SITE**			**(CONTINUED)**																											
Energy Related Costs - CF3 - $1000																																	
Fuel Costs		[redacted]																															
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Energy Related Costs - CF4 - $1000																																	
Fuel Costs		[redacted]																															
Variable Plant O&M		[redacted]																															
SO_2 Emission Allowance Cost		[redacted]																															
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ALTERNATE 1 - HYSHAM 2 SITE		**Unit Fully Loaded @ System Peak**																														
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Fixed Plant O&M	[redacted]																															
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Energy Related Costs - CF1 - $1000																																
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Energy Related Costs - CF2 - $1000																																
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TOTAL BUSBAR COSTS -		**ALTERNATE 1 - HYSHAM 2 SITE**			**(CONTINUED)**																											
Energy Related Costs - CF3 - $1000																																
Fuel Costs	[redacted]																															
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Energy Related Costs - CF4 - $1000																																
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Variable Plant O&M	[redacted]																															
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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 2 - HYSHAM 2 SITE		**Unit 80% Loaded @ System Peak**
Non-Energy Related Costs - $1000	
Fixed Plant O&M	[redacted]
Transmission O&M	[redacted]
Transmission Taxes	[redacted]
Property Taxes and Insurance	[redacted]
Administrative & General	[redacted]
Subtotal - w/o Debt Service	[redacted]
Debt Service Payment-20 Yrs w/o DSC	[redacted]
Debt Service Payment-30 Yrs w/o DSC	[redacted]
Debt Service Payment-20 Yrs w/DSC	[redacted]
Debt Service Payment-30 Yrs w/DSC	[redacted]
Subtotal - 20 Yr DS w/o DSC	[redacted]
Subtotal - 30 Yr DS w/o DSC	[redacted]
Subtotal - 20 Yr DS w/DSC	[redacted]
Subtotal - 30 Yr DS w/DSC	[redacted]
TOTAL BUSBAR COSTS -		**ALTERNATE 2 - HYSHAM 2 SITE**
Energy Related Costs - CF1 - $1000	
Fuel Costs	[redacted]
Variable Plant O&M	[redacted]
SO_2 Emission Allowance Cost	[redacted]
Title V Permitting	[redacted]
Replacment Tax	[redacted]
Subtotal	[redacted]
Project Reserve	[redacted]
20 Years w/o Debt Service Coverage:	
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
30 Years w/o Debt Service Coverage:	[redacted]
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
20 Years with Debt Service Coverage:	[redacted]
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
30 Years with Debt Service Coverage:	[redacted]
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
20 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**
30 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**
20 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**
30 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**
Energy Related Costs - CF2 - $1000	
Fuel Costs	[redacted]
Variable Plant O&M	[redacted]
SO_2 Emission Allowance Cost	[redacted]
Title V Permitting	[redacted]
Replacment Tax	[redacted]
Subtotal	[redacted]
Project Reserve	[redacted]
20 Years w/o Debt Service Coverage:	
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
30 Years w/o Debt Service Coverage:	[redacted]
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
20 Years with Debt Service Coverage:	[redacted]
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
30 Years with Debt Service Coverage:	[redacted]
TOTAL BUSBAR COSTS	[redacted]
¢/kWh	[redacted]
Present Value (2007 Level)	[redacted]
Cumulative Present Value	[redacted]
20 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**
30 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**
20 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**
30 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
TOTAL BUSBAR COSTS -		**ALTERNATE 2 - HYSHAM 2 SITE**			**(CONTINUED)**																											
Energy Related Costs - CF3 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
Energy Related Costs - CF4 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 1 - SALEM INDUSTRIAL SITE		**Unit Fully Loaded @ System Peak**																														
Non-Energy Related Costs - $1000																																
Fixed Plant O&M	[redacted]																															
Transmission O&M																																
Transmission Taxes																																
Property Taxes and Insurance																																
Administrative & General																																
Subtotal - w/o Debt Service																																
Debt Service Payment-20 Yrs w/o DSC																																
Debt Service Payment-30 Yrs w/o DSC																																
Debt Service Payment-20 Yrs w/DSC																																
Debt Service Payment-30 Yrs w/DSC																																
Subtotal - 20 Yr DS w/o DSC																																
Subtotal - 30 Yr DS w/o DSC																																
Subtotal - 20 Yr DS w/DSC																																
Subtotal - 30 Yr DS w/DSC																																
TOTAL BUSBAR COSTS -		**ALTERNATE 1 - SALEM INDUSTRIAL SITE**																														
Energy Related Costs - CF1 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
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Present Value (2007 Level)																																
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30 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
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Cumulative Present Value																																
30 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														
Energy Related Costs - CF2 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
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Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
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TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
TOTAL BUSBAR COSTS -		**ALTERNATE 1 - SALEM INDUSTRIAL SITE**				**(CONTINUED)**																										
Energy Related Costs - CF3 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
Energy Related Costs - CF4 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**c/kWh**																														

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20 Year Total	30 Year Total
ALTERNATE 2 - SALEM INDUSTRIAL SITE		**Unit 80% Loaded @ System Peak**																														
Non-Energy Related Costs - $1000																																
Fixed Plant O&M	[redacted]																															
Transmission O&M																																
Transmission Taxes																																
Property Taxes and Insurance																																
Administrative & General																																
Subtotal - w/o Debt Service																																
Debt Service Payment-20 Yrs w/o DSC																																
Debt Service Payment-30 Yrs w/o DSC																																
Debt Service Payment-20 Yrs w/DSC																																
Debt Service Payment-30 Yrs w/DSC																																
Subtotal - 20 Yr DS w/o DSC																																
Subtotal - 30 Yr DS w/o DSC																																
Subtotal - 20 Yr DS w/DSC																																
Subtotal - 30 Yr DS w/DSC																																
TOTAL BUSBAR COSTS -		**ALTERNATE 2 - SALEM INDUSTRIAL SITE**																														
Energy Related Costs - CF1 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														
Energy Related Costs - CF2 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M																																
SO_2 Emission Allowance Cost																																
Title V Permitting																																
Replacment Tax																																
Subtotal																																
Project Reserve																																
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
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Present Value (2007 Level)																																
Cumulative Present Value																																
30 Years with Debt Service Coverage:																																
TOTAL BUSBAR COSTS																																
c/kWh																																
Present Value (2007 Level)																																
Cumulative Present Value																																
20 Year Levelized Costs - w/o DSC	[redacted]	**c/kWh**																														
30 Year Levelized Costs - w/o DSC		**c/kWh**																														
20 Year Levelized Costs - w/DSC		**c/kWh**																														
30 Year Levelized Costs - w/DSC		**c/kWh**																														

5/23/05 2:02 PM	IOWA ENERGY PROJECT				BASE CASE			ALTERNATE 2 - SALEM INDUSTRIAL SITE							Unit 80% Loaded @ System Peak																Page 17 of 17	
																															20 Year	30 Year
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total	Total
TOTAL BUSBAR COSTS -		**ALTERNATE 2 - SALEM INDUSTRIAL SITE**				**(CONTINUED)**																										
Energy Related Costs - CF3 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**																														
Energy Related Costs - CF4 - $1000																																
Fuel Costs	[redacted]																															
Variable Plant O&M	[redacted]																															
SO_2 Emission Allowance Cost	[redacted]																															
Title V Permitting	[redacted]																															
Replacment Tax	[redacted]																															
Subtotal	[redacted]																															
Project Reserve	[redacted]																															
20 Years w/o Debt Service Coverage:																																
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years w/o Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
30 Years with Debt Service Coverage:	[redacted]																															
TOTAL BUSBAR COSTS	[redacted]																															
¢/kWh	[redacted]																															
Present Value (2007 Level)	[redacted]																															
Cumulative Present Value	[redacted]																															
20 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**																														
30 Year Levelized Costs - w/o DSC	[redacted]	**¢/kWh**																														
20 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**																														
30 Year Levelized Costs - w/DSC	[redacted]	**¢/kWh**																														

ALTERNATE 1 - SALEM 1 SITE - BUSBAR COSTS ($1000)

Unit Fully Loaded @ System Peak
90% Capacity Factor - 30 Years Financing
Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M	[redacted]									
Variable Plant O&M	[redacted]									
Debt Service Payment	[redacted]									
Administrative & General	[redacted]									
Transmission O&M	[redacted]									
Transmission Taxes	[redacted]									
Replacment Tax	[redacted]									
SO2 Emission Allowance Cost	[redacted]									
Title V Permitting	[redacted]									
Property Taxes and Insurance	[redacted]									
Project Reserve	[redacted]									
TOTAL BUSBAR COSTS	[redacted]									
¢/kWh	[redacted]									

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 2 - SALEM 1 SITE - BUSBAR COSTS ($1000)

Unit 80% Loaded @ System Peak
65% Capacity Factor - 30 Years Financing
Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M	[redacted]									
Variable Plant O&M	[redacted]									
Debt Service Payment	[redacted]									
Administrative & General	[redacted]									
Transmission O&M	[redacted]									
Transmission Taxes	[redacted]									
Replacment Tax	[redacted]									
SO2 Emission Allowance Cost	[redacted]									
Title V Permitting	[redacted]									
Property Taxes and Insurance	[redacted]									
Project Reserve	[redacted]									
TOTAL BUSBAR COSTS	[redacted]									
¢/kWh	[redacted]									

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 1 - DECKER SITE - BUSBAR COSTS ($1000)

Unit Fully Loaded @ System Peak
90% Capacity Factor - 30 Years Financing
Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M										
Variable Plant O&M										
Debt Service Payment										
Administrative & General										
Transmission O&M										
Transmission Taxes										
Replacment Tax										
SO2 Emission Allowance Cost										
Title V Permitting										
Property Taxes and Insurance										
Project Reserve										
TOTAL BUSBAR COSTS										
¢/kWh										

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 2 - DECKER SITE - BUSBAR COSTS ($1000)

Unit 80% Loaded @ System Peak
65% Capacity Factor - 30 Years Financing
Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M										
Variable Plant O&M										
Debt Service Payment										
Administrative & General										
Transmission O&M										
Transmission Taxes										
Replacment Tax										
SO2 Emission Allowance Cost										
Title V Permitting										
Property Taxes and Insurance										
Project Reserve										
TOTAL BUSBAR COSTS										
¢/kWh										

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 1 - HYSHAM 2 SITE - BUSBAR COSTS ($1000)

Unit Fully Loaded @ System Peak

90% Capacity Factor - 30 Years Financing

Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M										
Variable Plant O&M										
Debt Service Payment										
Administrative & General										
Transmission O&M										
Transmission Taxes										
Replacment Tax										
SO2 Emission Allowance Cost										
Title V Permitting										
Property Taxes and Insurance										
Project Reserve										
TOTAL BUSBAR COSTS										
¢/kWh										

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 2 - HYSHAM 2 SITE - BUSBAR COSTS ($1000)

Unit 80% Loaded @ System Peak

65% Capacity Factor - 30 Years Financing

Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M										
Variable Plant O&M										
Debt Service Payment										
Administrative & General										
Transmission O&M										
Transmission Taxes										
Replacment Tax										
SO2 Emission Allowance Cost										
Title V Permitting										
Property Taxes and Insurance										
Project Reserve										
TOTAL BUSBAR COSTS										
¢/kWh										

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 1 - SALEM INDUSTRIAL SITE - BUSBAR COSTS ($1000)
Unit Fully Loaded @ System Peak
90% Capacity Factor - 30 Years Financing
Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M										
Variable Plant O&M										
Debt Service Payment										
Administrative & General										
Transmission O&M										
Transmission Taxes										
Replacment Tax										
SO2 Emission Allowance Cost										
Title V Permitting										
Property Taxes and Insurance										
Project Reserve										
TOTAL BUSBAR COSTS										
¢/kWh										

30 Year Levelized Costs [redacted] **¢/kWh**

ALTERNATE 2 - SALEM INDUSTRIAL SITE - BUSBAR COSTS ($1000)
Unit 80% Loaded @ System Peak
65% Capacity Factor - 30 Years Financing
Salem, Salem Industrial, Decker and Hysham Run

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Fuel Costs	[redacted]									
Fixed Plant O&M										
Variable Plant O&M										
Debt Service Payment										
Administrative & General										
Transmission O&M										
Transmission Taxes										
Replacment Tax										
SO2 Emission Allowance Cost										
Title V Permitting										
Property Taxes and Insurance										
Project Reserve										
TOTAL BUSBAR COSTS										
¢/kWh										

30 Year Levelized Costs [redacted] **¢/kWh**

Case Description: **<u>Salem, Salem Industrial, Decker and Hysham Run</u>**

TOTAL BUSBAR COSTS (¢/kWh)

ALTERNATE 1

Unit Fully Loaded @ System Peak

90% Capacity Factor - 30 Years Financing

Year	Salem 1	Decker	Hysham 2	Salem Industrial
30 Year Levelized Cost:	[redacted]			
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				

Case Description: <u>Salem, Salem Industrial, Decker and Hysham Run</u>

TOTAL BUSBAR COSTS (¢/kWh)
ALTERNATE 2
Unit 80% Loaded @ System Peak
65% Capacity Factor - 30 Years Financing

Year	Salem 1	Decker	Hysham 2	Salem Industrial
30 Year Levelized Cost:	[redacted]			
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				