BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

F I N A L D R A F T

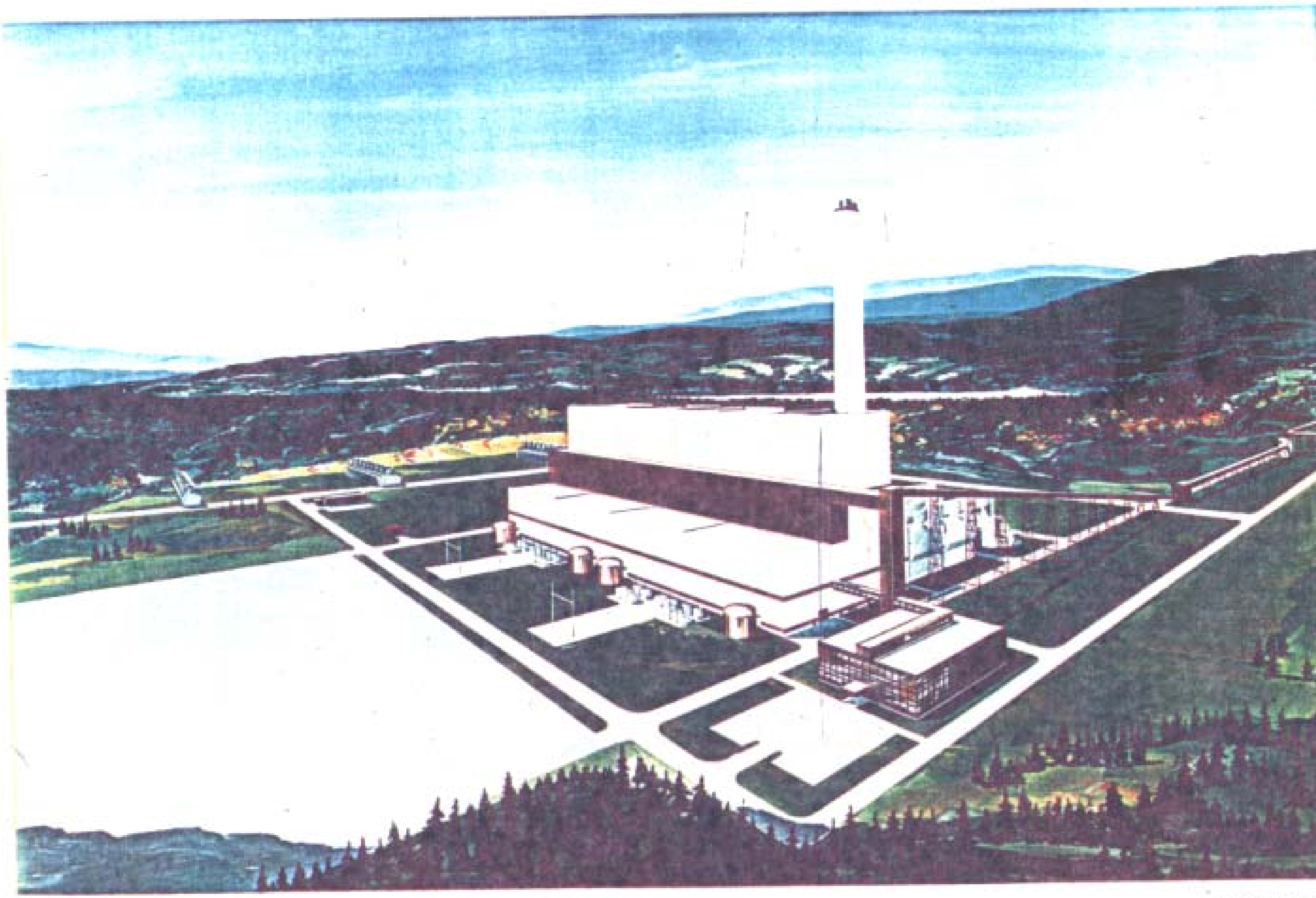
HAT CREEK PROJECT

POWER PLANT CONCEPTUAL DESIGN

REPORT

SUMMARY

JANUARY 1977



BRITISH COLUMBIA HYDRO & POWER AUTHORITY - HAT CREEK PROJECT, UNITS 1-4 NORTH-EAST VIEW

INTEG-EBASCO

SYNOPSIS

Large-scale production of low cost coal suitable for electricity generation has been shown to be practicable at Hat Creek, near Ashcroft, B.C. The studies reported or summarized in this volume have established the feasibility of economical electricity generation based on this coal. Suitable sites for the generating station have been identified, and the Harry Lake site selected as the best.

The principal characteristics of a four-unit 2000 MW generating station have been defined, and prior to detailed design and optimization can serve as a basis for planning and policy decisions. The new generating units may be required to enter service during the years 1984 - 1987.

This Summary volume of the Conceptual Design report is self-contained, but it is supported by more detailed material in three separate Appendices. Scope and contents are detailed in the Main Contents list which follows. The parallel Site Evaluation report is necessarily based on data and project concepts partly of somewhat earlier date. Consequently, some discrepancies in detail remain to be resolved in the final design and implementation stages, in the light of fuller information still accumulating. These considerations do not alter the main conclusions.

HAT CREEK PROJECT

POWER PLANT CONCEPTUAL DESIGN REPORT

MAIN CONTENTS

LIST OF ILLUSTRATIONS

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SECTION 1. INTRODUCTION

CONTENTS

1. INTRODUCTION

1.1 BACKGROUND TO THIS REPORT

1.1.1 The Hat Creek Development Project

The Hat Creek development project as currently under study consists fundamentally of the use of the Hat Creek coal deposits for large-scale electricity generation. The project proposed is a conventional-type station of approximately 2000 MW, and the coal deposits are large enough to support generating capacity of this capacity.

Although the coal will be mined at Hat Creek, the generating station could be at a considerable distance, if the inconvenience and cost of transporting the coal were offset by other factors. Consideration having been given to several possible sites ranging from mine-mouth to Howe Sound, the conclusion on environmental, technical and economic grounds was that the site should be that known as Harry Lake. This is a gently-undulating area elevated some 1600 ft. above the valley and about 3 miles from the proposed No. 1 pit, the coal source for this development.

Site selection aspects are examined and analysed in a parallel Integ-Ebasco report entitled "Hat Creek Project: Site Evaluation Study".

1.1.2 Purpose of Latest Studies and Reports

Forward planning studies by B. C. Hydro indicated that the new 2000 MW generating station may be required to enter service (unit by unit) during 1984 - 1987. In order that an adequate basis should be available for the relevant decisions to be made, and if appropriate as a starting point for timely steps towards implementation, various more detailed investigations and studies were put in hand.

This recent phase of work has included another stage in exploration, testing and analyses of the coal deposits, and studies of mining, as well as the siting studies already referred to, and numerous preliminary or supporting investigations and studies on particular aspects of these matters. Together with the conceptual design studies for the generating station itself, this work constitutes the establishment of the technical and environmental feasibility of the project, and a major step forward in the process of firm definition of the project and of its probable costs.

A considerable amount of more detailed work must obviously be done for the implementation stage, but the present level of project definition is intended to be sufficiently complete for the resolution of policy in relation to the project, and for a proper appreciation by other interested parties of its basis, nature and magnitude.

1.1.3 Scope of this Report

The main body of this report contains in section 2 a summary of the main considerations shaping the project, followed by a brief general description in section 3. Section 4 lists, and in part summarizes, other relevant reports.

An account of the bases and reasoning underlying the conceptual design, and a description of the generating station project as now proposed, is given in sections 5, 6 and 7. Sections 8 and 9 contain a summary of estimated capital costs and of principal financial and economic criteria.

Three appendix volumes contain amplifying detail:

- Appendix A: a detailed project specification, incorporating sundry schedules
- Appendix B: containing fuller discussion of particular aspects of studies made and of the conceptual design
- Appendix C: a detailed capital cost estimate

The appendices are not essential to a general reading of this report, and cross-references to appendices have been avoided.

1.2 TERMS OF REFERENCE

1.2.1 Summary Extracts

The essential nature and scope of the consultant work is set out in the initial statement in the B. C. Hydro Terms of Reference document dated May 6, 1976:

> "Provide engineering services for the conceptual design of a 2000 megawatt (net) base load conventional thermal power plant burning Hat Creek coal. The study is to include an investigation of design concepts, including an evaluation of alternatives with the selection of the group of concepts which established the optimum power plant design. Also included are site evaluation studies for the thermal power plant and associated water supply routes."

With particular reference to the conceptual design, the Terms of Reference further state:

> "The consultant shall compare viable alternatives of all major components of the thermal power plant as they relate to the plant costs, scheduling, performance and environmental impact, and produce an optimum conceptual design on this basis."

The conceptual design report is to serve, inter alia, as a basis for Government hearings and for applications for licences and permits, and as a basis for detailed design studies.

1.2.2 Specific Details

The studies were to be based on a conceptual arrangement for a generating station complex, designed for an initial 2000 MW installation of four or three machines. The relative merits of the alternative unit sizes were to be documented.

It was specified that the plant be designed to meet all existing Provincial pollution control regulations governing particulate and gaseous emissions as well as solid and liquid effluents. Space allowances and general layout implications were to be identified for possible future equipment, e.g., for flue gas desulphurization.

Among the other topics specified to be covered were numerous technical, economic and environmental aspects of the project, including:

- Capital cost of equipment
- Station heat rate and thermal cycle efficiency or net plant heat rate (NPHR)
- Auxiliary power demand
- Desirability of beneficiation of the coal
- Building space and site layout
- Maintenance
- Reliability and availability
- Lead time from assignment of conceptual design study to commercial operation
- Aesthetics
- Emissions, including water vapour and dust
- Noise control
- Ash disposal
- Waste water and leachate control.

1.2.3 Study Co-ordinator

All the work was to be under the co-ordination and direction of B. C. Hydro and Power Authority's Project Manager, and reports were to be submitted by mid-December in draft form, and towards the end of January, 1977, in final form.

1.3 REFERENCE DATA PROVIDED

1.3.1 Existing Reports

Copies of various relevant studies which had been made before, or were completed during the early stages of this conceptual design study, were made available by B. C. Hydro. These included:

- Hat Creek Coal Fired Thermal Power Plant Feasibility Report and Cost Estimate; System Design Division Report No. 104; - B. C. Hydro, July, 1975.

- Vancouver Island Thermal Generating Plant, Site Selection Inventory; - Beak Consultants Ltd., Montreal Engineering Co. Ltd., and Commonwealth Associates Inc., July, 1975.

- Preliminary Environmental Impact Study of the Proposed Hat Creek Open-Pit Mine and Thermal Generating Station; - B. C. Research and Dolmage Campbell & Associates, August, 1975.

- Preliminary Report on Hat Creek Open-Pit No. 1, PD-NCB Consultants, March, 1976.

- Proposed Hat Creek Development: Transport Study - Swan Wooster Engineering Co. Ltd., June, 1976.

1.3.2 Economic Criteria

A set of economic design criteria was prepared, in co-operation with B. C. Hydro. These are summarized in section 9.

1.3.3 B. C. Hydro Transmission System

B. C. Hydro provided data on the transmission system stability and other characteristics, as relevant to selection of unit size, and to selection or specification of generating station electrical equipment.

1.4 CONCURRENT INVESTIGATIONS, STUDIES AND REPORTS

1.4.1 Work by B. C. Hydro and its Other Consultants

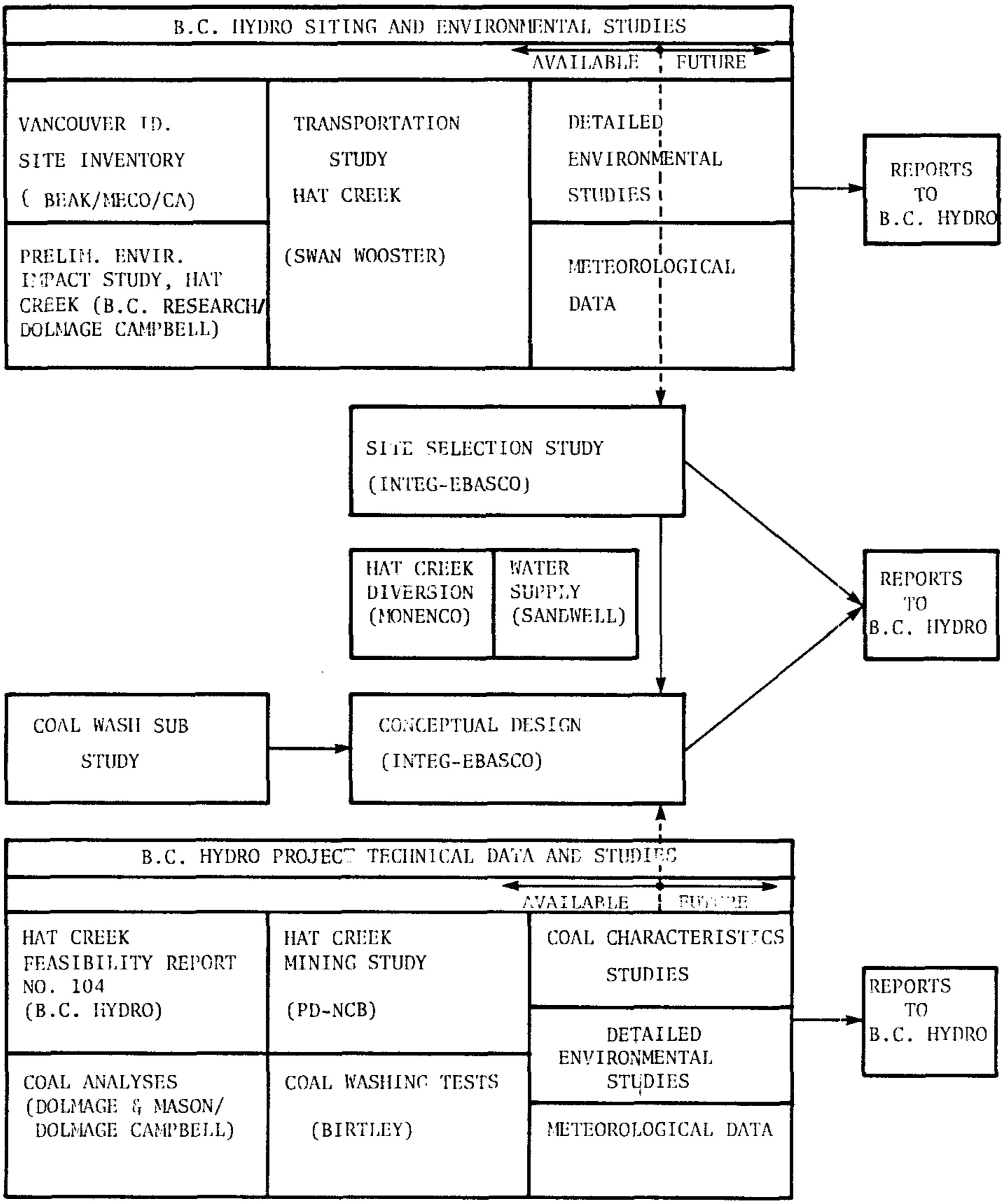
B. C. Hydro has been conducting a series of investigations and tests on the coal deposits, as well as various water analyses, meteorological observations, etc. This is part of a continuing programme. Results of the work to date have been made available to Integ-Ebasco for the purposes of its studies for B. C. Hydro.

1.4.2 Other Work by Integ-Ebasco's Nominated Sub-Consultants

Associated with the main studies, two components were assigned to nominated sub-consultants. One relates to the selection of the best means of water supply and is the subject of the report "Hat Creek Project: Water Supply Study" - Sandwell, October, 1976. The other is an investigation into ways and means for diverting the Hat Creek clear of the mine workings and other works. It is in hand by Monenco Pacific Ltd. and a report is pending.

1.4.3 Inter-relation of the Various Tasks

Figure 1.4.1 illustrates diagrammatically the information flows and relationships among the principal elements of the recent and current studies pertaining to the Hat Creek project. Some of these are outlined in section 4. Since they are in large degree concurrent and inter-dependent, most of these work areas must to some extent rely on preliminary conclusions available from the others. Among their final conclusions there may therefore be detail discrepancies, but this possibility is not a serious matter at the present stage.



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

RELATED REPORTS AND INFORMATION SOURCES

integ - ebasco

FIG. No 1.4.1

SECTION 2. SUMMARY OF PRINCIPAL CONSIDERATIONS

CONTENTS

2.1 THE PLANT SITE

The selected plant site is about 3 miles from the proposed mine, near Harry Lake at an elevation about 1,600 feet above the Hat Creek valley floor. Although a mine-mouth site would be the most economical, it has been shown to be environmentally unsuitable. All systems associated with the station are therefore based on this hilltop location, with emphasis on the preservation of surrounding amenities. The layout of the station in relation to the site is shown by the artist's impression, and the overlay and photograph, Figure 2.1.1.

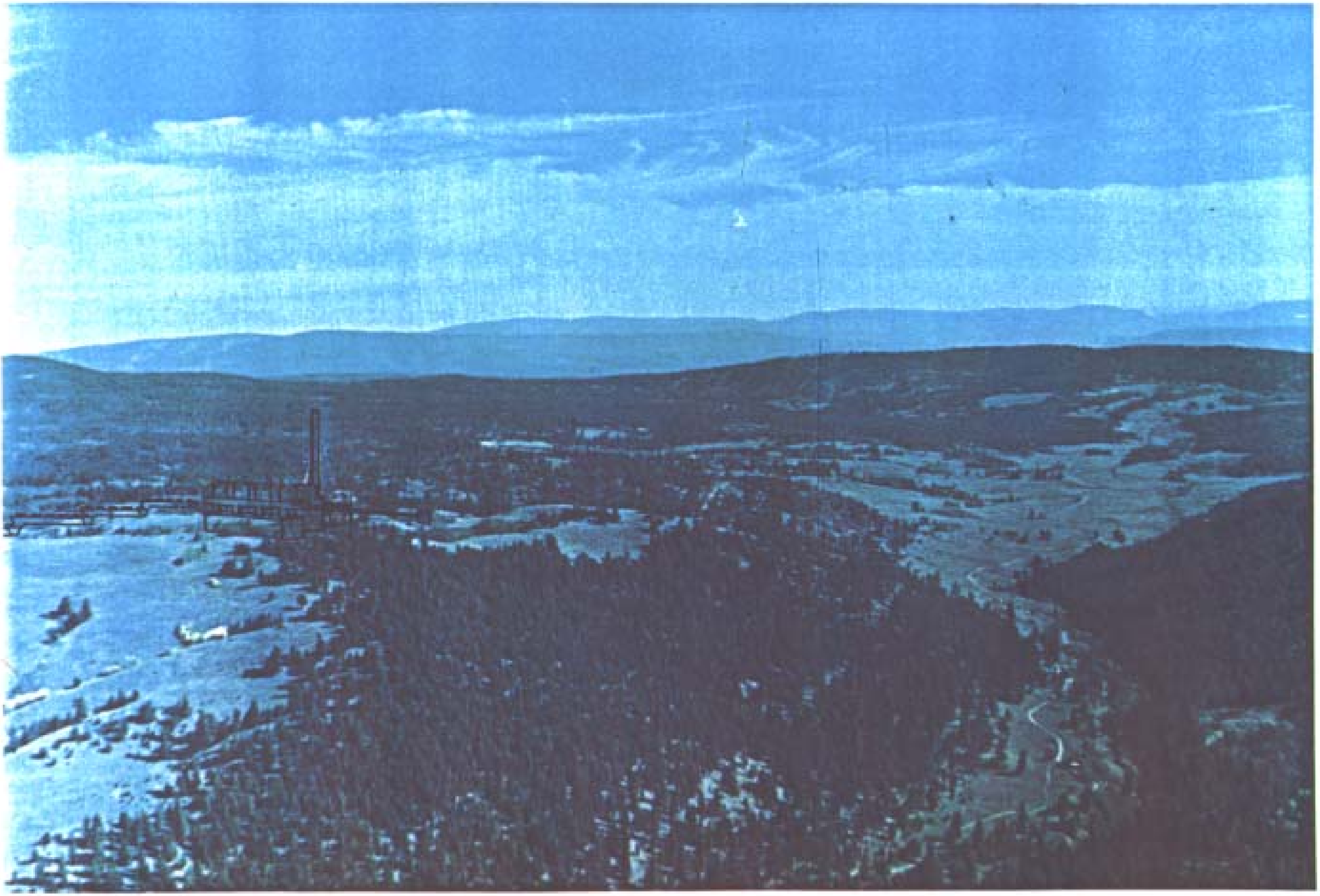
2.2 SIZE AND DUTY OF GENERATING STATION

The thermal generating station is sized to deliver approximately 2000 MW to the B.C. Hydro system electrical grid, with commissioning of the first generating unit by 1984. It is possible that the station may be extended at an undetermined future date, and in planning the site facilities, consideration is given to the requirements of future development.

The Hat Creek plant is to operate in a predominantly hydro-electric system and must meet the requirements that this imposes upon it. For this reason the plant is designed to operate in several modes: it may be expected to operate on base load for extended periods; it will probably be operated in a two shift or intermediate mode with weekend shutdowns and load cycling during later years; output may at any stage be reduced, or units shut down for extended periods, during good water years or high spring runoff periods.

The design of large steam turbine generating units to suit base

VIEW OF POWER PLANT SITE FROM THE EAST



load, cycling and two shift operation requires considerable attention. In recent years manufacturers, utilities and engineers have made advances in their understanding of the factors involved for units of this size. Thus, the large modern units in the Ontario Hydro system are designed for both base load and two shift operation and plant efficiency is not seriously compromised. The applicable design requirements are discussed in more detail in section 7.

2.3 PROVINCIAL POWER GRID

The results of system steady state and transient stability studies, carried out by B.C. Hydro and also by Integ-Ebasco, are not reported in detail in this report. However, it has been verified that the conceptual design is compatible with the grid system capabilities. More detailed studies at a later stage will evaluate specific system reinforcement, load flow, and transient stability requirements.

2.4 COAL SUPPLY

Due to the geological formation of the coal deposit, the coal resource will be worked in an open pit. The pit will be of inverted conical shape, and the very steep coal seams will be worked from benches at recommended elevations. This initial mine development, designated No. 1 open pit, will extend to a depth of 600 feet below the valley floor, and in order to maintain sufficiently stable side slopes it must have a width at the surface of about two miles by the time mining to this depth is completed. The types of mining equipment recommended will have high mobility along the bench formations.

Dolmage Campbell & Associates, in a paper presented in October

1976, gave the following preliminary coal quantity estimates for the Upper Hat Creek coal deposits.

RESERVES (Long tons*)

	Proven and Probable	Possible Additional
No. 1 Deposit	625 million	100 million
No. 2 Deposit	1,000 million	1,000 million
TOTALS	1,625 million	1,100 million

It has been estimated by PD-NCB that about 450 million tons lie within the proposed 600 ft. deep No. 1 pit, which is to supply all the coal for the 2000 MW generating station.

The total potential coal resource under the valley has been estimated to be in the range 10,000 to 15,000 million tons. The total coal required by a 2000 MW plant operating for 35 years at an overall average capacity factor of 50% is about 280 million tons. It is clear that the Hat Creek deposits could easily support over 2000 MW of generating capacity.

2.5 COAL QUALITY - AVERAGE AND RANGE

An assessment has been made of the average quality for the coal which will be mined in the proposed 600 ft. deep pit. This average is

* Unless otherwise noted, tons referred to in this report are short tons.

5,950 Btu/lb. at 28% ash, 20% moisture. This average coal is used for sizing of plant other than the boilers.

The range of coal which the mine will produce depends on whether the mine operator can reject very low quality coal successfully, but it is assumed that the quality may range from 3,600 Btu/lb. to 8,000 Btu/lb. based on 20% moisture.

A review has been made of various coal preparation and blending alternatives. The viability of some of these processes remains to be proved by a testing programme, but it is judged probable that as a result of preparation and blending 95% of the coal fed to the boilers will have a heating value within 15% of the average value. This gives the range shown below, based on 20% moisture:

	95% Worst Coal	Average or Performance Coal	95% Best Coal
Heating value Btu/lb.	5,060	5,950	6,840
Ash content %	35	28	23.3
Moisture content %	20	20	20
Consumption rate (2100 MW net):			
- tons/hr at rated load	2,208	1,877	1,633
- million tons/yr at 70% capacity factor	13.5	11.5	10.0

2.6 COOLING SYSTEM

The selected cooling system employs evaporative mechanical cooling towers which have an evaporative water loss in proportion to the rejected heat load from the station. Preliminary studies of alternative cooling systems which would require less make-up showed them to be uneconomic due to the high capital cost. The cooling towers account for most of the station water consumption. The total water requirement for the initial station of 2000 MW is estimated to be approximately 20,000 U.S. gallons per minute, of which some 18,000 gallons per minute will be lost by evaporation from the cooling towers.

2.7 WATER SUPPLY

Local sources would not be adequate to supply make-up water requirements of the selected cooling tower system, and a water supply line is therefore required to bring water from the Thompson River approximately 15 miles distant. Preliminary results of the water supply study indicate that a 36 inch diameter steel pipeline is required. The intake location for this water supply system is at the confluence of the Thompson and Bonaparte Rivers. The water is pumped direct to the station reservoir.

Future studies to be carried out at the final design stage should examine the possibility of using some water from local sources to supplement the water supply from the Thompson River, with the object to reducing the large capital cost of this water supply system. It would not be intended, however, to infringe upon the Hat Creek water supply to downstream users, and this conceptual design is based on drawing all water supply from the Thompson River.

2.8 SHARING OF PROJECT FACILITIES

The conceptual design is based on the assumption that no other industrial facilities would be installed in the Hat Creek valley. The sharing of common facilities with other plants nearby might permit some reduction in the cost of water supply and other services, but resulting cost savings would probably be fairly small and the possibility is disregarded.

2.9 WASTES AND DISPOSAL

The initial plant of 2000 MW capacity produces a maximum of 13,000 [redacted] tons of ash daily, which is disposed of along with the mine spoil. Over the estimated 35 years life of the plant, the ash production is expected to reach some 76 million tons. This material is returned to the valley by conveyor, which may result in the recovery of a small portion of electrical energy. There is no open ash storage at the plant site.

The comparatively modest amount of liquid effluent from the station is neutralised and then disposed of with the boiler ash. There is zero effluent to local streams.

2.10 AIR QUALITY CONTROL

The plant is designed to minimize emissions and local pollution by undesirable contaminants, the principal items being sulphur dioxide and nitrous oxides. These gases, together with particulate matter, are subject to regulated maximum levels, under Provincial legislation. The conceptual design includes electrostatic precipitators to remove particulate matter from the flue gases. Ongoing investigations will provide necessary information on the range of sulphur contents that will be encountered in the coal deposit. At this conceptual design stage, need for a system to remove sulphur from the flue gas is not anticipated, but space is allocated to permit later installation of a suitable system should it prove to be required.

2.11 ACCESS TO SITE

The site lies within 15 road miles of the TransCanada Highway at Cache Creek, which can be considered the focal point of the highway system of British Columbia. At Cache Creek, the Province's main East-West route (TransCanada Highway 1) connects with the main North-South artery, Highway 97.

Transportation and access for all sites considered, including the Harry Lake site, were examined during a study by Swan Wooster Engineering Co. Ltd. That study dealt principally with operating requirements, especially coal transport, and is summarized in section 4 of this report.

The Swan Wooster study considered alternative ways of providing road access of acceptable quality to the mine and power plant development. The most economic and environmentally sound scheme is to upgrade Highway 12 from Carquile to the mine. About 6 miles of this highway is within the bounds of the Bonaparte Native Indian Reserve. The best alternative would be a new highway via Cornwall and Medicine Creeks, running west from the TransCanada Highway near Cache Creek, but this would cost about $8 million more.

The B.C., C.N. and C.P. railways all pass within 15 miles of the site but it would not be economic to provide a connecting spur line because of the difference in elevation involved. It is practicable to bring all necessary large equipment items by rail to local terminals, for transport to site over local roads.

The closest commercial airport is at Kamloops, about 70 miles east from the site. A feasible site for a local airstrip has been located just south of Cache Creek.

2.12 SOCIO-ECONOMIC IMPACT

The plant location is expected to bring substantial employment benefits to the communities in the area, including Ashcroft, Cache Creek and Clinton. However, the presence of the mine and generation site will not have a significant effect on the present land use pattern in these areas.

The elevation of the site makes the plant visible from Highway 12. The layout and architectural treatment of the buildings and installations should render the complex visually acceptable.

During the construction period, the labour force would be of the order of 1,000, and after commissioning of the 2000 MW plant, the steady level of employment at the station and adjacent mine would be about 700/800 altogether.

SECTION 3. OUTLINE DESCRIPTION OF PROJECT

CONTENTS

3. OUTLINE DESCRIPTION OF PROJECT

3.1 HISTORY

The Hat Creek coal deposits were first reported by Dr. G.M. Dawson of the Geological Survey of Canada in 1877. The coal was visible at a point where the creek had stripped off the overburden and was flowing on a coal bed.

In the 1920's a number of shafts were driven into the coal, and between 1933 and 1942 a few hundred tons of coal were mined each year and sold locally.

In 1957 the B. C. Electric Company Ltd. took an option on the Hat Creek property, and under the direction of Dolmage Mason Stewart the area of the exposed portion of the Hat Creek coal deposit was explored by reconnaissance diamond drilling and trenching during 1957 and 1959. This work indicated that the deposit was of sufficient size and the coal of sufficient calorific value to be of interest as a potential major source of fuel for the generation of electricity. The property, consisting of one coal crown grant and two adjoining leases, was purchased by B. C. Electric.

In 1972 an energy study was conducted by the British Columbia Energy Board, entitled "Electric Energy Resources and Future Power Supply 1972 - 1990." This study recommended that 8 x 500 MW units be installed at Hat Creek between 1986 and 1990.

In 1974 a new task force was constituted within B. C. Hydro to consider future generation sources. The task force issued a report, "Alternatives 1985-1995", which recommended that 500 MW units be installed at Hat Creek between 1983 and 1987, to be followed by larger units in the period 1988-1990.

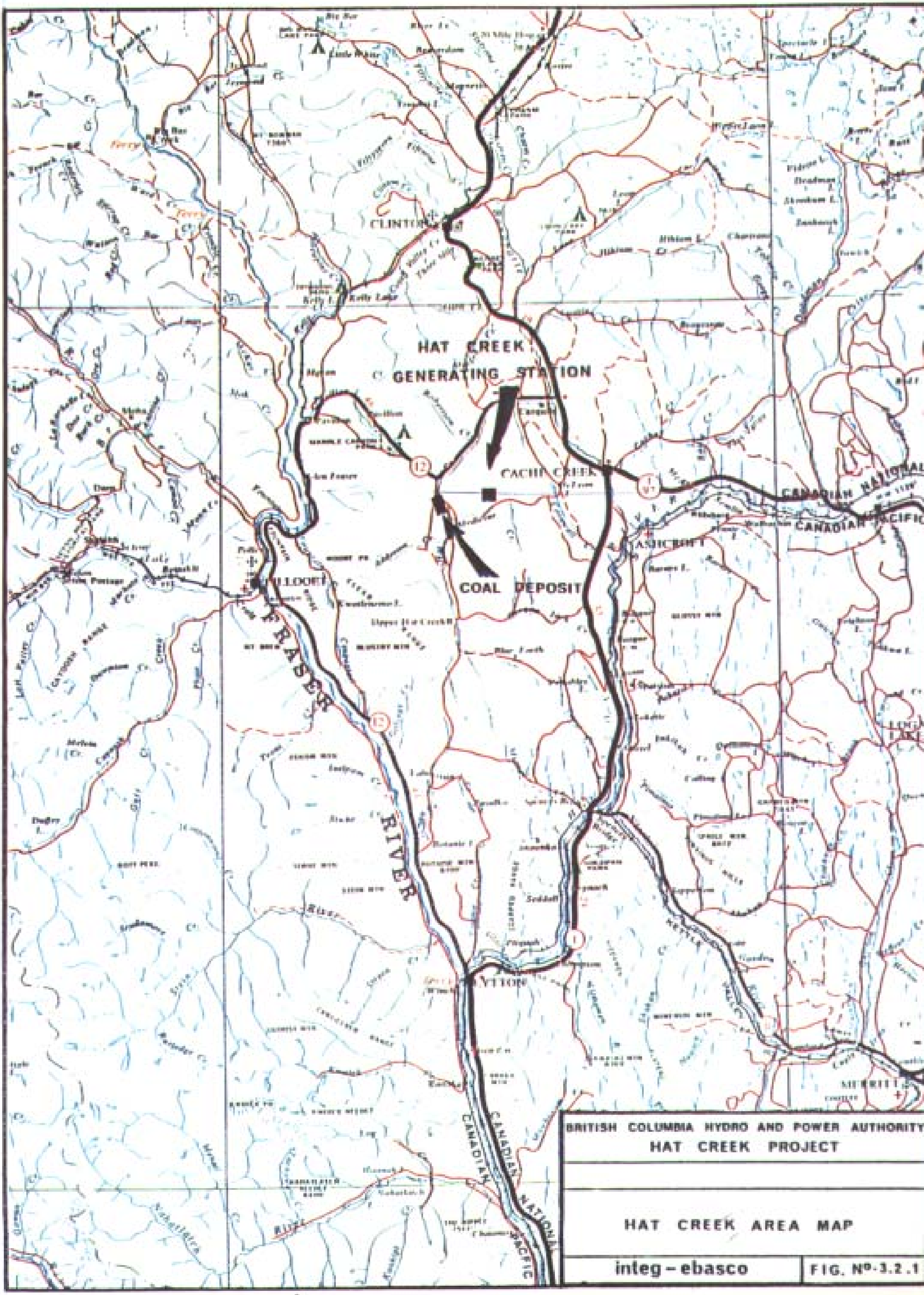
Following the publication of "Alternatives 1985-1995", Integ-Ebasco was retained in 1976 to perform a conceptual design study for a 2000 MW plant burning coal from the proposed No. 1 pit at Hat Creek. The study tasks included selection of the most suitable site, which might be beside or near the coal deposit, or at any of a number of more distant locations. From among these possible sites, that at Harry Lake near to the Hat Creek valley has been selected.

3.2 LOCATION

The Upper Hat Creek valley lies between the high rainfall coast range and the Fraser River to the west; and the arid Thompson River valley to the east. The terrain and the climate are generally similar to those of the Ashcroft-Kamloops area. However, it is almost two thousand feet higher in elevation than Ashcroft and the valley has a short growing season. Within 20 miles by road, there are four communities of reasonable size: Lillooet, Ashcroft, Cache Creek and Clinton.

This part of the valley runs generally from south to north, through the mountains between Ashcroft and Lillooet. The area is shown in Figure 3.2.1. The No. 1 coal deposit lies in the valley bottom, south of the point where the Hat Creek turns in a northeasterly direction towards Carquile, and where it is joined by the valley from Pavilion Lake running down from the northwest. Thus the proposed mine is at the south side of Highway 12 between Carquile and Pavilion, in an area where the ground surface is at about 3,000 ft. elevation.

The power plant site is located above the east side of the Hat Creek valley, close to Harry Lake in the Trachyte Hills. The high elevation site was selected primarily to facilitate adequate dispersion of



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

HAT CREEK AREA MAP

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FIG. Nº-3.2.1

the stack emissions. Furthermore, if the No. 1 coal deposit is to be mined completely, with safe side slope angles, all of the level ground in the valley bottom will be needed for the mine and associated operations.

The selected site is at an elevation of 4,600 ft., approximately 1,600 ft. above existing ground level at the proposed mine. The direct distance between the mine mouth and the power plant is about three miles. Although the elevated power plant site is obviously more exposed than a lower-level site would be, available meteorological data does not indicate that this causes any problem, and the applicable wind and snow loadings appear to be acceptable. Indeed, the climate is less severe than that at several other large thermal plants, for example those in Alberta.

The altitude of the site does not affect the efficiency of the main steam cycle although there is a small increase in auxiliary power requirement for fans. There is also a small reduction in the rating of electrical motors.

The nature of the terrain around the site is shown in Figure 3.2.2 which comprises 3 topographical sections with the vertical scale exaggerated 5 times. The Figure shows that the slopes of the surrounding mountains are relatively gentle with the exception of the sides of Medicine Creek immediately below the plant site. The Drawings at the back of this volume show the general layout of the power plant, mine and other main features of the project.

3.3 GENERATING STATION

The installation now planned has four similar steam turbine generating units of sufficient rating to meet the station auxiliary and coal mine electrical loads and provide a total net output of approximately 2000 MW to the EHV switch-yard. The conceptual design net station output of 2100 MW includes a margin for possible increases in auxiliary power consumption, e.g. for coal preparation or for eventual flue gas scrubbers, etc.

The turbine-generator building houses the four units in line end to end, and has two main cranes. It also accommodates electrical and mechanical auxiliary equipment. The administration building is attached at one end, and accommodates service and maintenance facilities, water treatment plant, storage for materials and equipment, offices and staff amenities. Adjoining the main building are the transformer bays with three single-phase main transformers per unit, and unit and station auxiliary transformers.

The four pulverised-fuel boilers have furnaces which are amply sized for the range of combustion properties of the fuel expected to be delivered from the No. 1 pit. Design for restricted flame temperature minimizes the formation of nitrogen oxides. The boilers are equipped with high-efficiency precipitators, and ash handling facilities are nearby.

All four boilers exhaust to a four-flue chimney, approximately 800 feet high. This single tall chimney gives maximum plume rise for atmospheric dispersion of the gases, and enables emissions to penetrate inversion layers when they occur. The height is subject to review in the final design stage. The individual flues have facilities for monitoring of emissions from each boiler for the purpose of combustion control and to meet regulatory requirements.

Other features of the station complex are the EHV switch-yard and banks of induced draft mechanical cooling towers. The terminal facilities for the transfer of coal from the overland conveyors to the plant conveyors are the only visible fuel handling facilities, and there is no coal pile at the generating station site.

A water storage reservoir is provided, having sufficient capacity to enable the station to operate for over a month if the make-up water supply were interrupted.

The arrangement and appearance of plant within the surrounding terrain is illustrated by the artist's impression overlay, and the photograph and Figure 2.1.1 referred to in section 2.1.

In this conceptual design, there is provision for future expansion of the plant. This would take the form of a southward extension to the station or as a new station a short distance away. If the station were extended by the addition of four or five similar machines and boilers, the main building could be duplicated, and contain similar main and auxiliary equipment including control rooms for the turbine-generators and boiler equipment. Since the administration and service building is located at the south end of the initial building, these control facilities will be centrally located to suit operation of the entire generation facility.

3.4 COAL HANDLING

Available data indicates that the coal quality is extremely variable, and that some of the coal may require treatment prior to delivery to the power plant. Preliminary proposals for the processing and transfer of coal to the station are as indicated in Figure 5.3.2, referred to in section 5.3. The necessary coal processing facilities are as yet undetermined in full detail, but sufficient space is allocated at the mine surface level, near to the coal piles for live fuel supply, reserve and blending purposes. Coal from the mine floor is delivered on multiple belt conveyors to the surface level. Following the stacking-out and reclaim and blending procedures, it is delivered by the overland multiple belt conveyor system to the boiler bunkers via a surge bin. When operating continuously at full capacity, each unit consumes daily 11,200 tons of average coal.

3.5 APPEARANCE

In the conceptual design an attempt has been made to confine dislocations of the landscape to the Hat Creek valley. The power plant itself need not detract aesthetically from its surroundings. Indeed, well designed thermal plants have simple lines which make them among the most attractive of modern industrial constructions, and architectural awards have been made for several modern plants of this type.

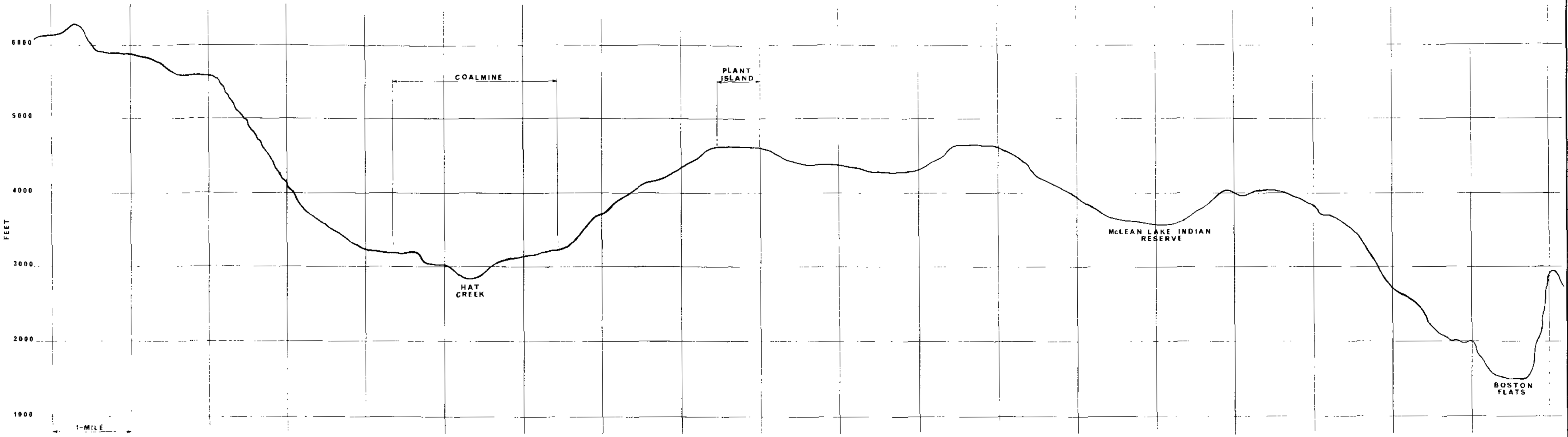
The conceptual design for the Harry Lake site has no coal or ash piles, and a single well proportioned stack. In summer there would be no visible plume from the stack, while in winter a water vapour plume would be visible, its size depending on the relative humidity.

The frontispiece of this report shows a preliminary architectural rendering of the Hat Creek station which is based on aerial photographs of the actual site. Figure 2.1.1, referred to in section 2.1, shows an artist's impression overlay and photograph.

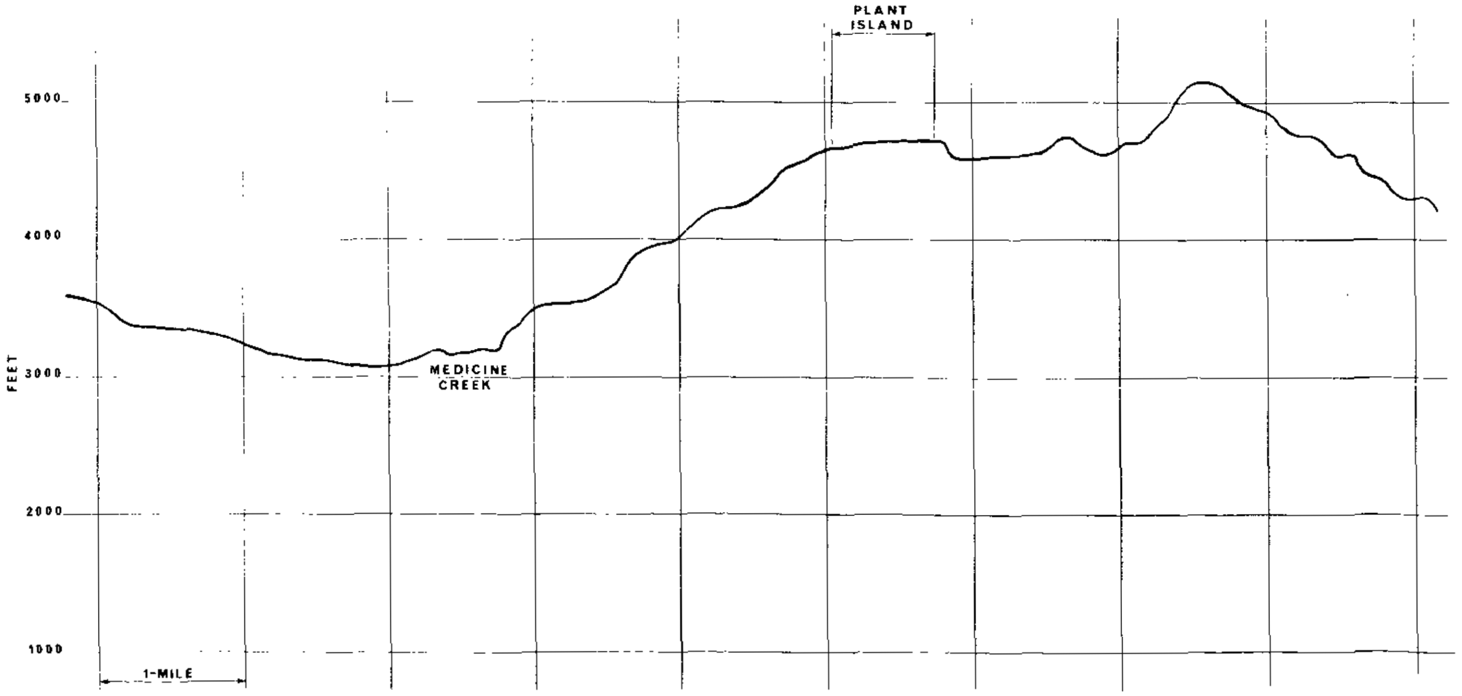
3.6 SCHEDULE AND COST

Two alternative project development schedules have been drawn up, the basic one for the first generating unit in service by January 1, 1984, and an accelerated alternative for a year earlier. These schedules are outlined in section 8.1.

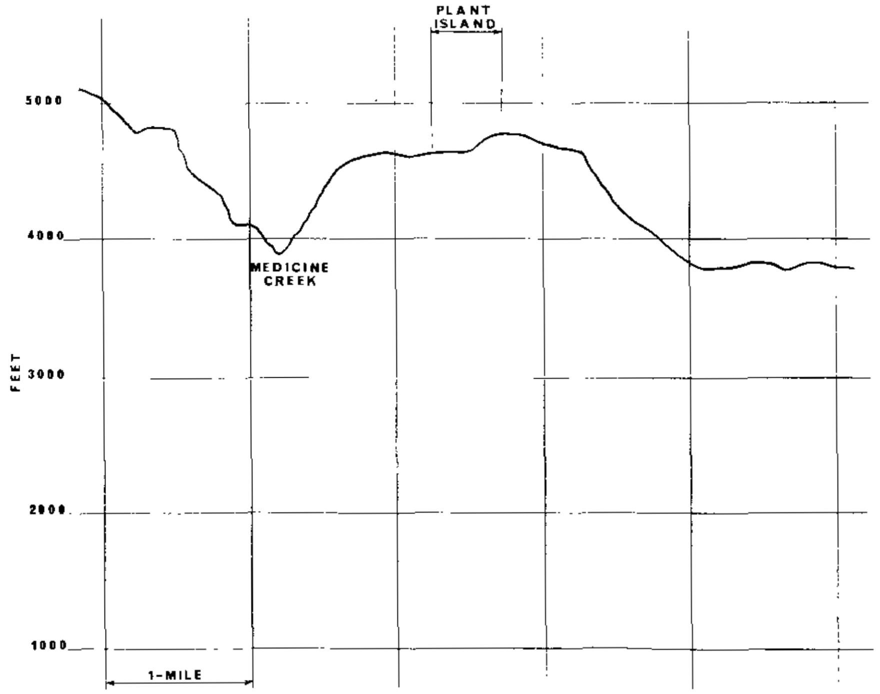
Section 8.2 gives a summary of the project capital costs. Expressed in October 1976 dollar values, total capital cost for the four-unit generating station is estimated as approximately $1016 million, excluding interest during construction costs.



SECTION LOOKING NORTH



SECTION LOOKING NORTHWEST



SECTION LOOKING WEST

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HAT CREEK PROJECT

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Vancouver Toronto

TOPOGRAPHICAL SECTIONS

SCALE 1"=2500Ft HORIZ / 1"=500Ft VERTICAL

drawing number F

FIG. No 3.2.2

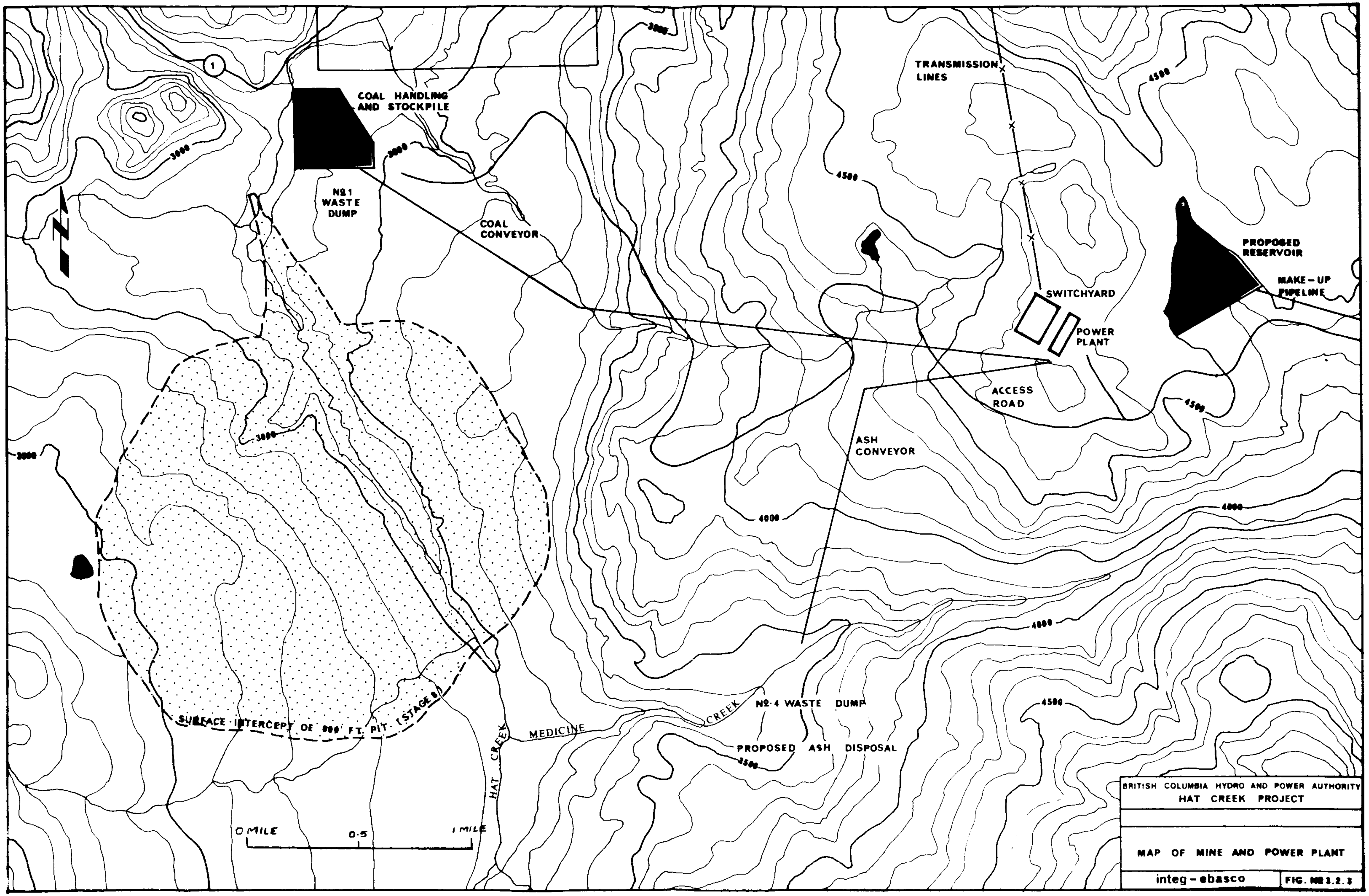
TRANSMISSION LINES
COAL HANDLING AND STOCKPILE
3000
4500
Nº1 WASTE DUMP
COAL CONVEYOR
PROPOSED RESERVOIR
MAKE-UP PIPELINE
SWITCHYARD
POWER PLANT
ACCESS ROAD
ASH CONVEYOR
4000
3500
SURFACE INTERCEPT OF 800 FT. PIT (STAGE 8)
MEDICINE CREEK
HAT CREEK
Nº 4 WASTE DUMP
PROPOSED ASH DISPOSAL
0 MILE
0.5
1 MILE
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT
MAP OF MINE AND POWER PLANT
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FIG. Nº 3.2.3

SECTION 4. SUMMARY OF RELATED REPORTS

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4. SUMMARY OF RELATED REPORTS

4.1 INTRODUCTION

The information bank available for the purpose of this study is an extensive record of previous work and could be represented by a tabulation of about 60 documents. Such a list would comprise reports, maps, drawings and data touching on most aspects of the project. However, the following list is limited to the principal documents bearing directly on the work defined by the terms of reference for this study, and summaries are given of the keys items only. The general pattern of relationships among the reference reports and the later studies now undertaken is shown in Figure 1.4.1., referred to in section 1.4. Unless otherwise noted the reports were to B.C. Hydro.

4.2 LIST OF REPORTS SUMMARIZED IN THIS SECTION

- Preliminary Report on Hat Creek Openpit No. 1
  PD-NCB Consultants Ltd. March, 1976.

- Proposed Hat Creek Development:Transportation Study
  Swan Wooster Engineering Co. Ltd. June, 1976

- Hat Creek Project, Unit Size Study
  Integ-Ebasco. June 1976

- Hat Creek Project, Water Supply Study-
  Interim Report. Sandwell & Co. Ltd. October, 1976

- Hat Creek Project - Site Evaluation Study
  Integ-Ebasco. January, 1977.

4.3 OTHER REPORTS NOT SUMMARIZED

- Preliminary Report on Underground Water Conduit Possibilities, Thompson River to Hat Creek Plant Sites. Dolmage, Campbell & Associates Ltd. 10 January, 1975

- Geology & Drill Hole Locations. Study of Hat Creek No. 1 Openpit Deposit. Dolmage Campbell & Associates Ltd. January, 1975

- Interim Report on Coal Analyses. No. 1 Openpit Deposit. Dolmage Campbell & Associates Ltd. June 27, 1975

- Vancouver Island Thermal Generating Plant, Site Selection Inventory. Beak Consultants Ltd., Montreal Engineering Co. Ltd., and Commonwealth Associates, Inc. July 1975

- Hat Creek Coal Fired Thermal Power Plant Feasibility Report & Cost Estimate. Report No. 104 B.C. Hydro. July, 1975

- Preliminary Environmental Impact Study for the Proposed Hat Creek Openpit Mine and Thermal Generating Station. B.C. Research and Dolmage Campbell & Associates Ltd. August, 1975.

- Social Aspects of the Proposed Hat Creek Development Transportation Study. Report to Swan Wooster. B.C. Research. February, 1976
  - Included in Swan Wooster Transportation Study Report.

- Environmental Aspects of a Coal Transportation Study of the Proposed Hat Creek Development. Report to Swan Wooster. TERA Environmental Resource Analysts Ltd. April, 1976
  - Included in Swan Wooster Transportation Study Report.

- Preliminary Report to Sandwell & Co. Ltd. on Thermal Generating Project - Water Supply, Geological & Geotechnical Study. Golder, Brawner & Associates Ltd. June, 1976
  - Not included in Sandwell report.

- Preliminary Hydrologic Investigation for Hat Creek Thermal Generating Station - Water Supply Study. Report to Sandwell. Northwest Hydraulic Consultants Ltd. June, 1976
  - Not included in Sandwell report.

- Hat Creek Project, Summary & Details of Government Approvals. B.C. Hydro

- Hat Creek coal characteristics: Laboratory studies by Birtley, CCRL; opinions of Dolmage Campbell; etc.

- Meteorological data and studies. B.C. Hydro. Continuing.

- Other data including coal & water analyses. Continuing.

4.4 PRELIMINARY REPORT ON HAT CREEK OPENPIT NO. 1 PD-NCB CONSULTANTS LTD. MARCH, 1976

This two-volume report dealt with the No. 1 coal deposit, and put forward a practical scheme for mining, including a selection of suitable mining equipment. The proposals were based on the general geology of the area, as understood from borehole investigations so far available.

Due to the configuration of the coal deposit, recovery of the coal necessitated an openpit working rather than a conventional strip mine operation. The general configuration of the No. 1 pit when developed to a depth of 600 ft. would be an almost conical excavation, with benches around the perimeter at selected elevations, on which the mining equipment would operate to recover the coal.

Owing to the roughly- circular shape of the pit and the hardness of the coal, draglines and bucket-wheel excavators appeared unsuitable. Furthermore, mobility of equipment was an essential requirement in conditions where the stability of the strata was suspect. However, it was possible that draglines and small bucket-wheel excavators could be used on upper benches, if it were eventually determined that boulders and concretions were not present in significant quantities.

The main pit access would be a straight incline down to the centre, where it would not be endangered by slide activity. Because of the depth of the pit, the large output and the presence of mudstone, conveyors were selected for the main haul out of the pit, both for the coal and pit waste.

It was stated that for the present the planned pit depth should be limited to 600 ft., i.e. down to elevation 2,400 ft., and that until substantial mining experience had been gained it would not be feasible to design a deeper pit or an underground mine. Although geotechnical data was largely incomplete, it was definitely stated that slope stability would be a major restriction. For the purpose of the report, a working slope angle was used which may prove pessimistic. However, there might also be some places where the slope angle would have to be reduced even further.

In regard to proposed mining equipment, the characteristics of rocks to be mined were not fully known. It could reasonably be expected that the combination of equipment finally selected would be at least as efficient and economical as that so far tentatively listed. Accordingly, the estimates of costs could be regarded as being near the upper bound of the uncertainty band. Future work on the choice of operating equipment should include a detailed optimization study.

Due to the required high rate of coal output, and the large volumes of waste material to be removed, the general scene would be characterized by a large open excavation and considerable waste dumps. It would not be possible to backfill the mine excavation until the No. 1 deposit was either worked out or abandoned as an open pit excavation.

At that stage, backfilling would become possible in parallel with the development of a new pit or an underground working to exploit deeper coal deposits.

The mine would therefore have substantial local environmental impact, and care must be taken to mitigate the undesirable features as far as practicable.

Before a further study could be recommended for the mining scheme considerable geological and geotechnical information was required and the report recommended a further two-year program of data collection. In particular, the report recommended a coal testing programme embodying extensive computer programmes to process coal quality data. A suite of computer programmes, based on block values of the whole range of data, was recommended.

Budgetary cost estimates were given in 1975 dollars. The estimates made allowance for creek diversion, box-cut and preproduction overburden stripping. The expected mine-mouth cost for run-of-mine coal was about $5.00 per ton, but a more pessimistic estimate of $5.55 per ton was derived as an "upper bound" estimate to be used for present purposes.

The second volume of the report contained plates showing the geological cross-sections of deposit No. 1, together with contours and details of the superficial deposits and overburden. Other drawings showed proposed bench arrangements, main incline conveyor and haul road, and calculations of the cumulative volumes of waste materials versus cumulative tonnage of coal. Preliminary mine development schedules were also given.

The principal data as extracted from this mining report are summarized in:

- Table 4.4.1 Schedule of Typical Mining Equipment
- Table 4.4.2 Summary of Mining Operations

Drawings reproduced as Figures 4.4.1 and 4.4.2 show stages of the proposed No. 1 pit development and the general mass of the coal deposit.

TABLE 4.4.1

SCHEDULE OF TYPICAL MINING EQUIPMENT (Main Items)

Category	Type	Manufacturer	Model	Capacity
Shovel	Electric	Bucyrus Eyrie	195	15 cu. yd.
Drills	Compressed air	Gardner Denver	3100A	4 in dia.
Compressors	Diesel	Gardner Denver	SP600	600 cfm
Off-highway trucks	Diesel	Wabco	150 C	117 tons coal
Bulldozers	Diesel	Caterpillar	D9H	-
Wheeldozers	Diesel	Caterpillar	824	-
Graders	Diesel	Caterpillar	16G	-
Scrapers	Diesel	Caterpillar	666	41 cu.yd(bank)
Compactors	Diesel	Caterpillar	825	-
Water tanker	Diesel	Caterpillar	631	10,000 US gal

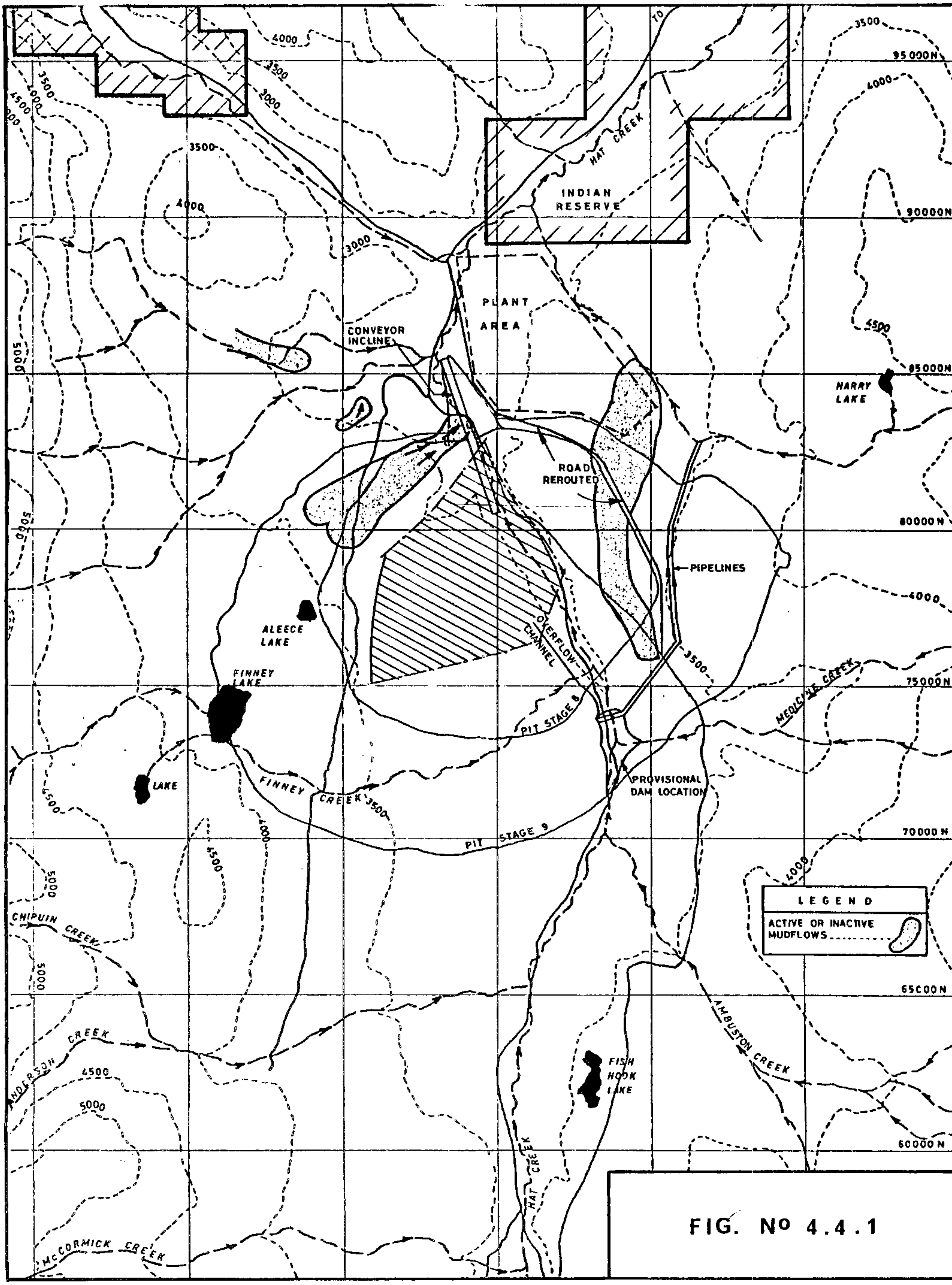
Note: The manufacturers' names and the model numbers are merely indicative.

TABLE 4.4.2

SUMMARY OF MINING OPERATIONS (Openpit No. 1)

Life of deposit to 600 ft. depth	30 yrs.
In situ Coal	450,000,000 tons
Pit depth	600 ft.
Initial extraction, sampling and testing	50,000 tons
Stockpile	1,000,000 tons
Permanent pit slope, max.	25°
Working slopes	$15^{\circ}57'$
Bench slope	64°
Bench width and height	120 ft. and 50 ft.
Main incline slope	$3^{\circ}49'$
Incline width	200 ft.
Development programme basis	3 x 750 MW units
Designed output of ROM coal	13,100,000 ST/yr
Possible sustained output, ROM coal	30,000,000 ST/yr

It should be noted that the described mining scheme pre-dated selection of the site for the generating station, and definition of its conceptual design. The actual mine layout and scheme of operation will of course have regard to the proximity of the generating station at the Harry Lake site.



HAT CREEK
TO
INDIAN RESERVE
PLANT AREA
CONVEYOR INCLINE
ROAD REROUTED
PIPELINES
OVERFLOW CHANNEL
PIT STAGE 8
PIT STAGE 9
PROVISIONAL DAM LOCATION
ALEECE LAKE
FINNEY LAKE
LAKE
FINNEY CREEK
HARRY LAKE
MEDICINE CREEK
CHIPUIN CREEK
NDERSON CREEK
McCORMICK CREEK
FISH HOOK LAKE
AMBUSTON CREEK
95000N
90000N
85000N
80000N
75000N
70000N
65000N
60000N
3500
4000
4500
5000
3000
LEGEND
ACTIVE OR INACTIVE MUDFLOWS

FIG. No 4.4.1

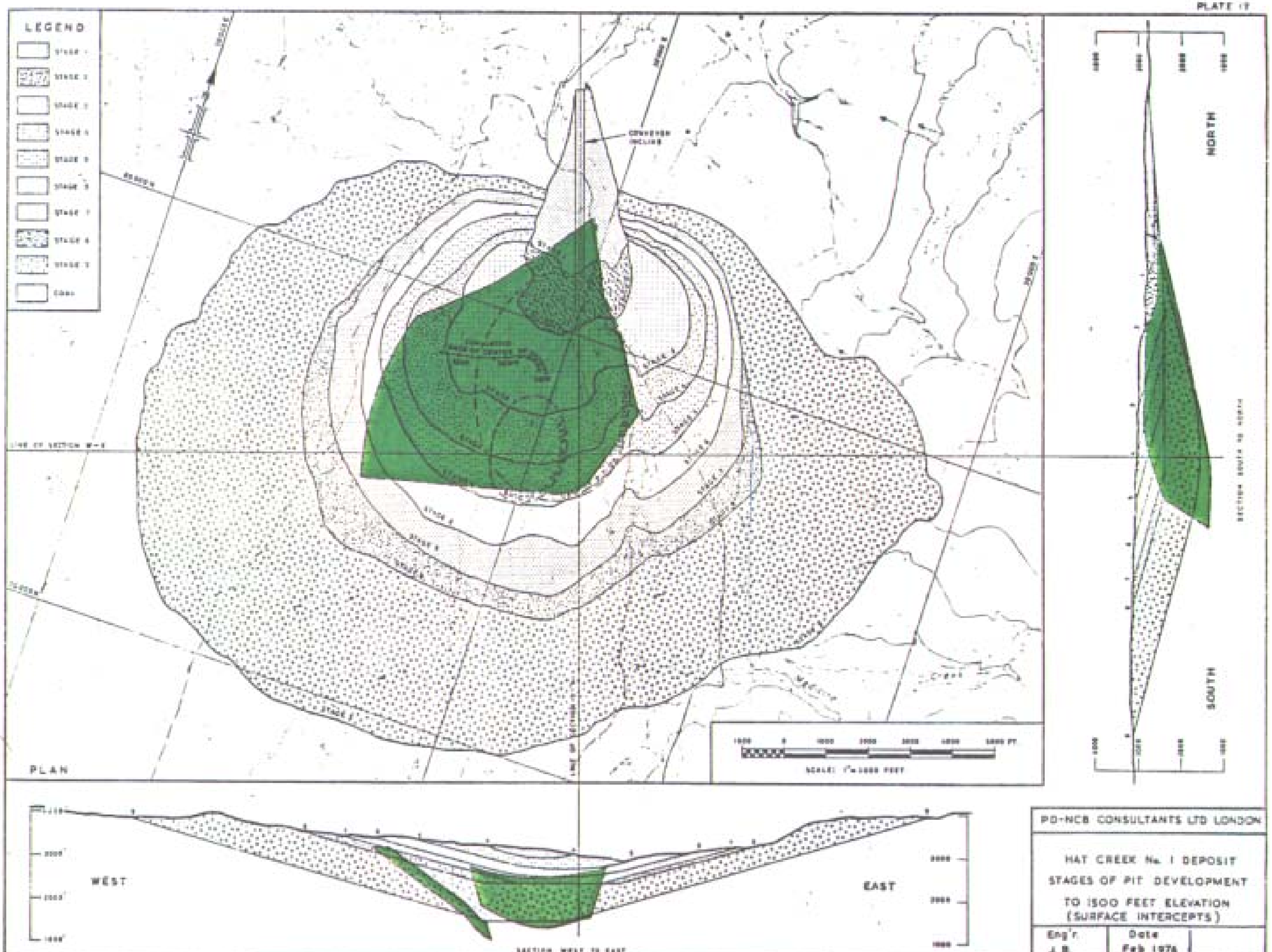


PLATE 17
LEGEND
CONVEYOR INCLINE
PLAN
NORTH
SOUTH
WEST
EAST
SECTION WEST TO EAST
PD-NCB CONSULTANTS LTD LONDON
HAT CREEK No. 1 DEPOSIT
STAGES OF PIT DEVELOPMENT
TO 1500 FEET ELEVATION
(SURFACE INTERCEPTS)
Eng'r.
J.B.
Date
Feb 1976

FIG. No 4.4.2

4.5 PROPOSED HAT CREEK DEVELOPMENT: TRANSPORTATION STUDY SWAN WOOSTER ENGINEERING CO. LTD. JUNE, 1976

This report dealt extensively with the technical and economic factors of several possible transportation systems. The influences of environmental and social factors were touched upon briefly.

The studies covered the following transportation requirements:

- Transportation of coal from the mine to plant sites.
- Access roads to the mine and plant sites for supplies and employees, etc.
- Transportation of ash from plant to mine.
- Air strip.
- Transportation of coal for the "test burn".

All known systems for bulk transportation of commodities were examined and a preliminary assessment of the value of each mode of transportation given. In general, railway and conveyor systems were preferred for this application. The report examined transportation routes and systems for seven possible plant sites, including Roberts Bank and Squamish. For each plant site, at least one route was considered that avoided native Indian lands.

The Swan Wooster report identified the optimum system of transportation of coal for each plant location, giving a relative ranking of both environmental and social impacts for each case. The capital and operating cost estimates were based on material movements applicable to a 2000 MW installation at each plant site, were considered briefly. All costs given in the report related to price levels at the beginning of January, 1976. The costs and environmental rankings are summarized in Table 4.5.1 Estimated Costs and Impacts.

The report concluded that for the selected routes as defined, railway unit trains generally provided the most economic system of coal transportation from mine to each of the plant sites. Overland conveyors would be the preferred alternative for short routes where gradients were too steep for railway operation.

TABLE 4.5.1

	ESTIMATED COSTS & IMPACTS							
	COAL TRANSPORTATION				HIGHWAY ACCESS			
PLANT SITE	Mode	Cost $/Ton	Environ-mental Rank	Social Rank	Roadway Route	Capital Cost ($million)	Environ-mental Rank	Social Rank
					Highway 12	5	1	4
Mine Mouth	Extension of mine system	-	-	-	Medicine/ Cornwall Creek	12	2	3
Harry Lake	Conveyor	0.33	1	5	Highway 12	4.5*	1	5
					Medicine/ Cornwall Creek	1*	2	2
Big Bar Creek	Rail Conveyor/Rail	2.07 3.20	8 9	6 4	North from Clinton	20	3	6
Ashcroft	Rail Rail/Conveyor	1.12 1.47	7 2	8 2	Connect with Highway #1	0.5	Nominal	1
Squamish	Rail Conveyor/Rail	6.84 6.74	4 6	9 3	Existing	-	Nominal	7
Britannia	Rail Conveyor/Rail	6.84 6.74	4 6	9 3	Existing	-	Nominal	7
Roberts Bank	Rail Rail/Conveyor	7.09 8.07	5 3	7 1	Existing	-	Nominal	8

Notes: 1) Transportation services from the mine to the mine mouth are considered to be part of the mine operation and are not examined in this report.
2) The conveyor and rail combination systems shown for Big Bar Creek, Ashcroft, Squamish, Britannia and Roberts Bank are alternatives which avoid the use of native Indian land.
3) A ranking of 9 is least attractive environmentally and/or socially.

* These amounts must be added to the cost of mine mouth access; i.e. the total cost of the Medicine Creek/Cornwall Creek route, including 1 mile spur to the plant, is 13 million.

4.6 HAT CREEK PROJECT. UNIT SIZE STUDY INTEG-EBASCO. JUNE, 1976

This study recommended that 4 x 500 MW nominal (net) units be the basis of the Hat Creek conceptual design study. This conclusion followed consideration of the following nominal (net) unit sizes:

4 x 500 MW
3 x 667 MW
3 x 667 MW with 2 boilers per unit

It was determined that all the unit sizes were acceptable in the context of system stability. Hence the choice of unit size would depend upon economics and the potential problems of building large boilers to burn Hat Creek coal.

An economic analysis of investment and production costs, including costs of reserve capacity, was made for each of the alternatives. On the basis of U.S. statistics (Edison Electric Institute) for forced outage rates of the various sizes of equipment, it showed that the 4 x 500 MW alternative would be the most attractive. However, there was some evidence that the statistics available to date excessively penalized the larger, newer units. The analysis therefore also included the 667 MW units on the alternative assumption that they would have the same forced outage rate as 500 MW units. The results of the comparison are shown in Table 4.6.1 Cost Differentials for Alternative Unit Sizes.

TABLE 4.6.1

COST DIFFERENTIALS FOR ALTERNATIVE UNIT SIZES

Unit Size	4 x 500 MW	3 x 667 MW	3 x 667 MW	3 x 667 with 2 boilers per unit
Assumed Forced Outage Rate	EEI Statistics	EEI Statistics	As 500 MW units	EEI Statistics
Cost Differential,$: PW(5% discount rate) PW(10% discount rate	 Base Base	 +88 million +22 million	 -34 million -27 million	 +76 million +46 million

In view of the uncertain nature of the Hat Creek coal, and the different ways in which it may eventually be blended or upgraded, it was judged unwise at this time to recommend single boilers for 667 MW (net) units. This opinion was largely shared by the Canadian boiler manufacturers. Accordingly, the four-unit alternative was adopted.

A decision on unit size could be reviewed up to the time of equipment purchase, having regard to latest conclusions as to the quality of coal and the desirability and practicability of up-grading it.

4.7 HAT CREEK PROJECT, WATER SUPPLY STUDY SANDWELL & CO. LTD. OCTOBER, 1976

This report presented the results of a comparative feasibility study of six potential plant sites identified by B.C. Hydro. The interior sites were at Ashcroft, Harry Lake, Mine Mouth, and Big Bar Creek, and the tidewater sites were at Britannia Beach and Dunsmuir (Vancouver Island). Potential sites at Squamish, Roberts Bank, Soda Creek, and Stave Lake were not included.

The work dealt with complete water supply systems, including preliminary designs for the water intakes, pumping stations and conduits, and with due regard to the electrical power requirements of the pumping stations.

For the interior sites, a total of 67 water intake locations along the Fraser and Thompson Rivers were appraised. For this purpose, some 70 miles of river were surveyed by helicopter reconnaissance during May, 1976. Eleven intake positions were deemed to be acceptable.

The preliminary estimate of required water supply quantities was taken as 30,000 USgpm for interior sites, and 3,500 USgpm for tidewater sites, in each case for a generating capacity of 2000 MW.

Consideration was given to pipelines and other forms of water conduits. In particular, the design of a pipeline was well defined. The report did not attempt to optimize the design of the pipeline in terms of diameter, wall thickness and other characteristics, but adopted a reasonable diameter of 36 in., giving a water velocity of 9.7 ft./sec. for a flow rate of 30,000 USgpm.

If, however, a tunnel were adopted, the minimum size from the point of view of construction would be 72 in., and this would be adequate for the ultimate water requirement. The water flow rate in a conduit of this size when related to an installed capacity of 2000 MW would be 3.6 ft./sec.

For water supply to both the mine mouth and Harry Lake sites, consideration was given to drawing water from the Fraser River as an alternative to the selected Thompson River source. Tunnels and pipelines were considered for both these sites.

It was concluded that the best source of water supply for these two sites was the Thompson River, employing a buried pipeline to the power plant complex. The pipeline alignment is shown as route G on Figure 4.7.1; the pump station would be upstream of the confluence of the Bonaparte and Thompson Rivers.

The report also outlined and discussed feasible water supply schemes for the other plant sites.

It was recommended that site visits should be made to selected water intake locations during low water conditions, i.e. between November and March. Observations should be made and selected data collected, including ice conditions, water levels, and low water configurations, and a programme of water sampling should commence to determine the extent of need for water treatment.

The report made reference to information received from Golder Brawner & Associates Ltd. relating to geological and geotechnical studies, and from Northwest Hydraulic Consultants Ltd. on a preliminary hydrologic investigation, but these reports were not included. Another reference listed was a preliminary report by Dolmage Campbell & Associates Ltd., on underground water conduit possibilities. That report was submitted directly to B.C. Hydro and was not a part of the Sandwell report.

Table 4.7.1 Cost Estimate Summary lists the capital and operating costs for the alternative water supply systems for each site location, and Table 4.7.2 Summary of Technical Particulars gives the leading parameters for the supply pipeline for the Harry Lake site.

TABLE 4.7.1

COST ESTIMATE SUMMARY

Site	Feasible Water Source	Route - Designation	Capital Cost ($ '000)	Operating Cost ($ '000/ yr)
Ashcroft	Thompson R.	Pipeline - R	10,700	985
Harry Lake	Thompson R.	Pipeline - G	47,800	4,650
	Fraser R.	Pipeline - L	82,000	7,360
	Thompson R.	Tunnel - T1	87,600	6,200
	Fraser R.	Tunnel - T3	81,000	6,370
Mine Mouth	Thompson R.	Pipeline - C	49,700	5,110
	Fraser R.	Pipeline F	82,500	7,360
	Thompson R.	Tunnel - T2	82,500	4,060
	Fraser R.	Tunnel - T4	75,400	4,280
Big Bar Creek	Fraser R.	Pipeline - 0	35,200	4,980
Britannia Beach	Stawamus R. or Mamquam R.	Pipeline - S	14,400	180
Dunsmuir	Little Qualicum R.	Pipeline - V	10,200	182

These cost estimates relate to mid-1976 price levels, and exclude I.D.C.

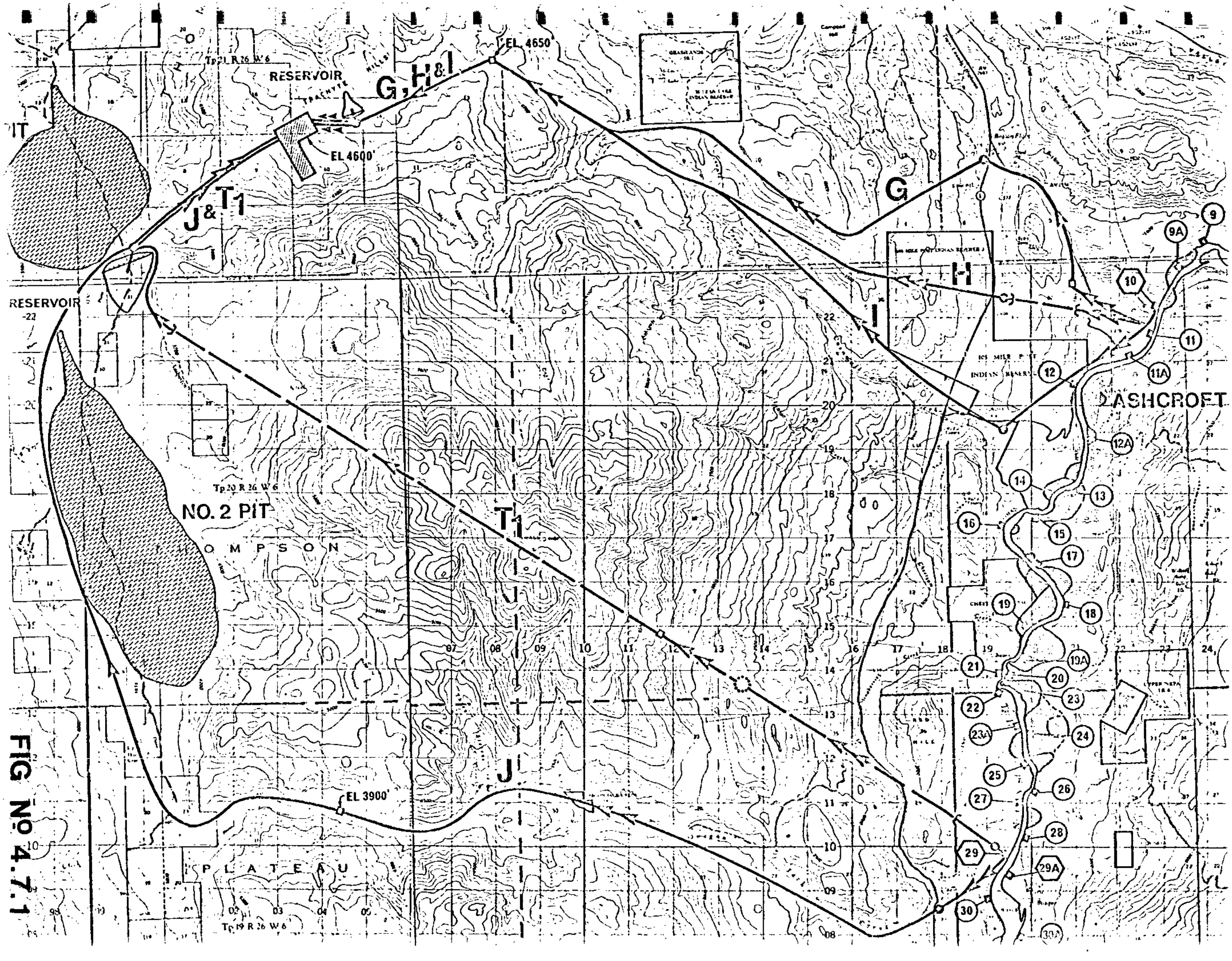
TABLE 4.7.2

SUMMARY OF TECHNICAL PARTICULARS*

(Harry Lake Pipeline Scheme)

Total Capital Cost	$47,800,000	(55,000,000)
Route Length	15.3 Miles	(13 approx.)
Electric Power Requirement	29.3 MW	(25 MW approx.)
Pipe Diameter	36 in.	
No. of Pump Stations	4	(1 low pressure) (1 high pressure)
Capacity	30,000 USgpm	(25,000 USgpm)
Weight of Pipework	5045 tons	

* Modified in Sandwell and Company draft final report December, 1976. Modified figures are shown in brackets.



EL 4650'
RESERVOIR
G, H & I
EL 4600'
G
H
I
J & T1
PIT
RESERVOIR
ASHCROFT
105 MILE POST INDIAN RESERVE
Tp 21 R 26 W 6
Tp 20 R 26 W 6
Tp 19 R 26 W 6
NO. 2 PIT
THOMPSON
T1
J
EL 3900'
PLATEAU
9
9A
10
11
11A
12
12A
13
14
15
16
17
18
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19A
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21
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23A
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29A
30
30A

FIG Nº 4.7.1

4.8 HAT CREEK PROJECT. SITE EVALUATION STUDY INTEG-EBASCO SEPTEMBER 1976

This report brought together the results of several contributing studies of the environmental factors, engineering criteria and economics for all identified potential plant sites, having due regard to political and social guidelines contained in the terms of reference for the work.

The report necessarily relied on the results of the independent studies carried out by specialist consulting engineers and scientists, among which some of the main items are listed in sections 4.2 and 4.3, and/or represented in Figure 1.4.1 referred to in section 1.4.

By means of a complex process of evaluation described in detail in the report, a preferred station site was identified, together with two acceptable sites. A total of ten possible plant sites were evaluated, including three sites situated on tide water. Three of the sites, namely Stave Lake, Dunsmuir and Soda Creek were identified and incorporated during the process of the work.

In each case, the study utilized a conceptual layout for the plant comprising 4 units of 500 MW nominal (net) capacity. The power plant complex included the chinmey with air quality control equipment, material handling systems including coal and ash movement, ash disposal, terminal equipment for the coal transportation system, make up water supply systems and the electrical power transmission switchyards for each of the site locations.

A preliminary qualitative analysis justified the elimination of two sites, at Squamish and Roberts Bank, as it was clearly evident that both sites were totally unacceptable from environmental and ecological points of view.

The mine mouth site appeared to be the most economic development, but very significant environmental impacts, particularly those related to air quality, rendered the site unacceptable. On balance, the Harry Lake site offered the most favourable conditions for the establishment of this major thermal generating station.

The two second-ranked alternative sites are those at Big Bar Creek and Soda Creek. However, these would be significantly more costly to develop and would be dependent upon the construction of the Ashcroft-Clinton rail connector, together with a spur line through the Hat Creek valley.

The summary evaluations of the several plant sites took into account differences in prospective costs, environmental suitability, and any uncertainties still attaching to any of the site-dependent technical aspects. Table 4.8.1 Summary Site Evaluation presents the relative rankings in respect of costs and environmental acceptability.

TABLE 4.8.1

SUMMARY SITE EVALUATION

Site	Environmental Impact Index (Percent)	Costs Differential ($ million) Interest rate 5%	10%
Dunsmuir	65.8	746	215
Britannia Beach	100.0	623	241
Stave Lake	88.9	615	225
Ashcroft	37.8	78	28
Mine Mouth	47.6	0 (base)	0
Harry Lake	26.2	40	20
Big Bar Creek	27.9	360	163
Soda Creek	29.9	697	314

SECTION 5: CONCEPTUAL DESIGN

CONTENTS

5.1 BASIS AND SCOPE OF CONCEPTUAL DESIGN

5.1.1 General

This section reviews the conceptual design of the major equipment and systems of the proposed Hat Creek generating station.

The process of conceptual design consists of:

- An evaluation of alternative approaches from an engineering and economic viewpoint, and
- An examination, in broad terms, of the project design and operational requirements appropriate to the selected approach.

This process has been applied to all major plant items and systems throughout the generating station project.

In general, the plant equipment and systems proposed are of conventional design, and essentially similar to installations in a large number of coal fired generating stations, with capacity of 2000 MW or more, in Canada and elsewhere. More detailed evaluations in respect of some alternatives relating to the coal and water were necessary in view of the design constraints in these areas.

Detailed studies were made of the coal handling and preparation system, the ash handling and disposal system, the water supply system and the boiler plant design. A number of economic and design studies were carried out:

- Preliminary consideration of coal blending and/or benefici-tion, with implications for the size and reliability of the coal handling plant, boiler and precipitator.

- Optimization of the turbine cycle, condenser, and cooling towers system, taking account of water supply factors.

- Design and location of coal handling plant.

- Method of ash removal and selection of disposal area.

No 'value' judgements are made with respect to environmental, socio-economic or other similar factors, but provisions for meeting specified or postulated requirements are incorporated in the project.

5.1.2 Special Considerations

The following paragraphs list those design considerations peculiar to the Hat Creek project, to which special attention has been given in this conceptual design study.

a) Coal Quality

The Hat Creek coal has several unusual features:

- Average heating value is low, although coal of lower average heating values is being burned in Europe and Australia.

- The quality varies widely throughout the deposit, the worst 10% having a higher heating value (HHV) of less than 3,550 Btu/lb, while the best 10% has an HHV of over 8,000 Btu/lb - both figures based on 20% moisture. This variation is unusually high.

- The uneven, highly fractured seam structure of the Hat Creek deposit will necessitate extensive drilling in order to assess fully the coal quality throughout the field, and to develop a detailed mine production plan.

- The shape of the coal deposit limits the mining contractor's ability to mine the coal selectively. Thus the quality of coal being mined will vary as the mine develops, and there will be a corresponding variation in the quality delivered to the plant.

- The coal contains montmorillonite, or bentonitic clays. Such clays have caused serious problems at Centralia G.S. of Pacific Power & Light in the State of Washington, and are well known for the largely unsolved problems they present in ore and tar-sand mining.

- The coal tends to dry out quickly in the Hat Creek climate. The average moisture content of as-mined coal is about 24%, while the average air dried moisture level indicated by laboratory tests is 10-14%.

- The ash fusion temperature of the as-mined coal varies widely but the range is above that for most Western Canadian sub-bituminous coals.

- The ash content of the as-mined coal is higher than that of any coal which is now being burned in a station of this size, although plants of similar size are being designed for higher ash coals.

b) Cost of Coal

The coal cost quoted by the mining consultant is low by present-day standards. On an energy basis, its cost is about 25% of current world oil and natural gas prices.

c) Ash Disposal

The generating station will produce approximately 3.3 million tons of ash per year, when operating at 70% capacity factor and burning average coal.

Mining of low-grade coals for power generation is normally done using strip mining methods. It is common practice to dispose of the ash, along with mine spoil, in the worked-out part of the mine. However, the Hat Creek No. 1 pit will be worked by progressively deepening the pit, and neither mine spoil nor ash can be disposed of in the pit until the end of coal extraction.

d) Water Supply

The two nearest large sources of water are the Fraser and Thompson Rivers. The Thompson River has been selected as the more economical source of water, supplying the site via a 15-mile pipeline requiring up to 30 MW of pumping power. Water will consequently be relatively expensive at the site.

e) Water Disposal

The low minimum flows of the local rivers and the sensitivity of fishing interests make it desirable that the plant complex be designed for zero discharge.

f) Local and Regional Topography

The mountainous topography does not offer convenient locations for an adequate cooling pond. For the present, tower cooling is proposed.

It is difficult to ensure that there will not be occasional impingement of the chimney fumes upon higher land.

g) Proven Design

An important design restriction is that no unproven type of equipment should be incorporated in the conceptual design.

h) Sulphur Dioxide Emissions

The B.C. Pollution Control Board objectives for sulphur dioxide emissions are unusually stringent, by comparison with the stipulations of the regulatory bodies of other provinces and other countries.

5.2 CHARACTERISTICS OF HAT CREEK COAL

5.2.1 Historical

a) 1957-1975 Work

The first serious drilling of the Hat Creek deposit was conducted under the management of Dolmage Mason & Associates in 1957-59. A more extensive programme commenced in 1974 under the control of Dolmage Cambell & Associates and continued through 1975.

This programme was directed to determining the extent of the deposit, rather than its quality. Proximate analyses were made of all samples, but complete ultimate, ash fusion and other analyses were only performed on a limited number of composite samples prepared by mixing coal samples which appeared to be similar in quality but which had been obtained from different depths.

Testing such samples has a limited value from the standpoint of the boiler design. Up to the end of 1975 ultimate analyses had been made of about 50 composite samples.

In the mid-1975 Dolmage Campbell produced a computer summary of proximate analysis data from all the 1957-59 and 1974-75 drill holes. At that time, they concluded that the range of coal quality coming from the mine would depend primarily on the degree of selective mining employed.

For the purpose of showing the effect of possible selective mining, an arbitrary cut-off was chosen at 44% ash and 20% moisture. In their sampling procedure Dolmage Campbell considered any sample which had more than 75% ash, on a dry basis, to be waste.

Twenty percent in-situ moisture was used by Dolmage Campbell as a reasonably representative estimate. It was however their opinion that the coal would dry out in the atmosphere to a lower moisture content.

The weighted mean of all samples below 44% ash was taken as representing the best average coal obtainable by selective mining, employing excavators of moderate size. The weighted mean of all samples, including those with more than 44% ash, would yield a grade approaching the poorest to be expected employing excavators of moderate size but selectively discarding the major waste beds only.

If large bucket wheel or dragline excavators were employed the average quality would be even lower due to the effects of dilution by additional waste material, but such equipment is not, at present, proposed.

The average coal qualities suggested by Dolmage Campbell on the basis of these assumptions are shown in Table 5.2.1, Average Coal Qualities.

TABLE 5.2.1

AVERAGE COAL QUALITIES (Estimated July 1975)

	Average of all samples below 44% ash	Average of all samples including those above 44% ash
Analysis, percent:		
Moisture	20	20
Fixed Carbon	27.2	24.2
Ash	25	31
Incombustible Volatiles	6.7	6.0
Combustible Volatiles	21.1	18.8
Sulphur	0.37	0.37
HHV, Btu/lb	6400	5438

The analyses of samples were weighted for sample length.

Dolmage Campbell noted that the results of the 1957-59 work did not fully correlate with later work, and that the 1957-59 results did not appear to be completely reliable.

b) Mining Report by PD-NCB

The Coal Mining reports, which were produced in two stages by PD-NCB in 1975 and 1976, concluded that the amount of coal data available at the time would not justify a sophisticated attempt to calculate the average coal quality which the mine would produce. PD-NCB reviewed Dolmage Campbell's earlier conclusions and adopted a slightly more conservative approach. In essence they stated that it would not be practicable for the mine operator to remove the coal without some dilution by waste material, whether from overburden, sidewall or waste bands.

Based on the average coal heating value of 6,000 Btu/lb, 20% moisture, 28% ash which Dolmage Campbell had postulated in March 1975, PD-NCB added a dilution of about 7% waste to derive an average mined coal of 5500 Btu/lb, 20% moisture, 32% ash. In calculating the effect of this dilution the moisture content was maintained at a fixed 20%. PD-NCB stated that their assumptions on dilution were based on Dolmage Campbell's earlier estimate that 22% of the total deposit comprised waste material.

c) Selective Mining to Reject Partings

It was Dolmage Campbell's original assumption that partings of more than 5 ft. can be rejected by a competent shovel operator. They recognized the complications of this assumption - namely that many of the beds lie at an incline, and that it might not always be possible to differentiate visually between some waste beds with coal particles embedded in them, and coal itself. Furthermore the thicknesses of waste bands have so far only been measured along the line of drill holes which may give a misleading impression.

Following discussions with PD-NCB in 1976, the sampling programme was modified so that waste beds of more than 3 ft. thickness, contained within a coal seam were neglected on the assumption that they could be rejected by the shovel operator. PD-NCB believed that 3 ft. would be a reasonable limit for the minimum bed thickness which could be rejected in a producing mine operation, and it was Dolmage Campbell's opinion that it might be economical to reject partings of 3 ft. down to as little as 1 ft. thickness if they were known to be bentonitic.

5.2.2 Assessment of Average Coal Quality

An assessment of average coal quality is required for some aspects of the design of the coal and ash handling facilities, but the boiler cannot be designed around average qualities. It must be capable of handling the full range of coals it is likely to receive, without loss of reliability.

Without a firm mine plan, it is not possible to translate geological data into an estimate of average mined coal quality without making assumptions about the competence and operating philosophy of the mine operator. As a mining plan was not scheduled for completion in 1976, it was necessary, initially, to base the Integ-Ebasco conceptual design study on PD-NCB's estimate of average mined coal quality of 5,500 Btu/lb. However, in October 1976 the data from special drill holes 135 and 136, which were sampled at 5 ft. intervals, became available. These data, together with the sample results from other 1976 holes, provided a much better base for assessments of average coal quality. Holes 135 and 136 were drilled to evaluate how rapidly the coal qualities changed with depth and to develop statistical data on the validity of different sample lengths. The locations of these special holes were chosen so that they would cut the four major zones of the deposit which had been identified by Dolmage Campbell.

Using data from holes 135 and 136, and weighted to allow for the sizes of the different coal strata, Dolmage Campbell's preliminary conclusions were:

- About 10% of the field is waste material, which contains more than 75% ash on a dry basis and was excluded from the sampling as it occurs in partings more than 5 ft. thick. This amount represents less than half of the 22% upon which PD-NCB based their estimate of average coal quality.
- A further 16% of the deposit is coal of more than 44% ash content, at 20% moisture.
- The average heating value of the remaining coal is about 6300 Btu/lb at 20% moisture, corresponding to about 26.5% ash. The average heating value of all the coal, including the 16% with more than 44% ash, is about 6,000 Btu/lb.

With B.C. Hydro's agreement, Integ-Ebasco have used the data from holes 135 and 136, together with other 1974-1976 drilling programme data, to establish average coal quality values.

Account has been taken of the depth of the mine. Existing data shows that the proposed 600 ft. pit will yield coal with a slightly lower average heating value and a higher sulphur content than the overall deposit. Assuming that all coal with heating value less than 3600 Btu/lb at 20% moisture can be rejected (this corresponds to slightly over 44% ash and is therefore similar to Dolmage Campbell's assumptions), the average coal quality for a 600 ft. deep pit is estimated to be:

5950 Btu/lb	28% ash	20% moisture

This average coal has been used as the basis for the conceptual design other than for the boiler.

5.2.3 Coal Properties

The mean values referred to previously are averaged from the wide range of coals in the Hat Creek deposit. While the concept of an average coal is useful in determine gross energy available from the deposit, it may lead to misunderstanding of the actual coals in the field unless the variability of the individual properties and the way those properties coexist in actual coals is understood.

a) Burning

The coal analyses reviewed to date and the two Burning Profiles obtained suggest that the Hat Creek coal will burn well in power plant furnaces, in both raw and prepared forms. Additional tests in a laboratory furnace have been conducted recently by Canadian Combustion Research Laboratory in Ottawa but the report will not be available until 1977. Correlation between the CCRL report and the coal properties should then be made.

b) Representative Sample Availability

Integ-Ebasco has used only those samples with essentially full analyses. These are largely derived from the 1976 programme.

Dolmage Campbell has advised that the coals in the various geological strata will have similar variation regardless of the depth below the surface. Consequently, until additional analyses are completed for all strata above elevation 2400 ft. (i.e. the floor of the conceptual mine), analyses from all depths are used. It is recognized that some properties will be different in the near-surface coal, but while important to plant operation, these differences are not considered to be significant for the conceptual design.

c) Heating Value Variability

There is a wide range of heating values in the Hat Creek coal. Figure 5.2.1 shows the frequency of occurrences of raw coals of different heating values (shown at 25% moisture).

In general this report quotes coal properties on either a dry or a 20% moisture basis, because Dolmage Campbell, PD-NCB and B.C. Hydro have, in the past used these bases. Much of Integ-Ebasco's computer analysis has been based on 25% moisture because this is closer to the estimated as-mined moisture content.

Note: All heating values are weighted by the number of vertical feet in the sample. The median value is that value relative to which 50% of the coals represented have higher heating values and 50% have lower values.

In this section of the report the term "range" includes 99.7% of the coal.

The median value is 5825 Btu/lb at 25% moisture or 6225 Btu/lb at 20% moisture. This corresponds closely to Dolmage Campbell's estimate for the whole deposit (paragraph 5.2.2). As stated in that paragraph, the estimated average heating value for the proposed 600 ft. deep pit is slightly lower.

The range of heating values for raw Hat Creek coals is from 3200 Btu/lb dry to 8700 Btu/lb dry. This is ±50% of the mean or about 10 times the variation normally experienced from a single mine seam.

A sufficient number of samples of "pure" coal are not yet available to have a comparable statistical value for the variability of the "pure" coal. The limited quantities available of "pure" coal samples show a median value of 8700 Btu/lb and a range of 8230 to 9350 Btu/lb at 25% moisture. The "pure" coal has a ±6.5% variation which approaches the variation found in normal coals (about ±4.5% on a constant moisture basis).

In the above discussion, "pure" coal is that portion of the "raw" coal whose specific gravity is 1.3 or less as determined by a laboratory sink-float test. This consists of the hydrocarbons themselves with that ash that remains intimately associated with the hydrocarbons after removal of the external minerals.

Various degrees of coal preparation will produce results intermediate between the raw and "pure" extremes. The economic choice will be determined after completion of the proposed beneficiation program.

d) Volatile, Fixed Carbon and Mineral Matter

The laboratory analyses report the median value of the volatile component of the proximate analysis is equal to the median fixed carbon component. When preliminary corrections are applied to deduct for the portion of the reported volatile matter that does not burn, the corrected median value of combustible volatiles on a dry basis is 28% with a range from 9% to 40%. The corresponding fixed carbon median is 32% with a range from 7% to 54%, and the mineral matter median is 40% with a range from 10% to 70%.

e) Moisture as Mined

Figure 5.2.2 shows the frequency with which different percentages of moisture occur. The median value is 23% and the range is from 14% to 32%. The above moistures are percentages of the moist coal "as received" at the laboratory - not on the dry basis used generally in this sub-section. It is expected that the "as fired" moisture content would be somewhat higher for coal prepared using wet processes. Stockpiling before use might produce a somewhat lower figure.

f) Grindability

Grindability determinations to date have been by the Hardgrove method. The results show significant variation in the grindability of the same coal with different moistures and some "caking" in the test equipment. Figure 5.2.3 shows the frequency distributions of the Hardgrove Grindability Index (HGI) for samples taken throughout 1974-76, since only 15 are currently available for 1976. There is a difference between the results reported in 1974-75 and those reported in 1976, with the earlier reports showing the coals harder to grind. These differences require further investigation. The median HGI value is 46 with a range from 27 to 70. This would represent approximately a 3 to 1 variation in mill throughput.

The frequency distribution for the HGI of the "pure" coals has yet to be determined.

5.2.4 Quantity and Character of Ash

a) Amount of Ash

Figure 5.2.4 shows the frequency distribution of various percentages of ash for the raw coal. Since the sample base has been restricted to samples "selectively mined" to less than 55% ash, this distribution has been truncated above that value. For the remaining samples, the median ash content is 34% and the range is from 8% to 55%. All these values are on a dry basis.

The limited number of samples of "pure" coal show a median ash content of 7%, and a range from 3% to 10%. Various degrees of cleaning will result in values between those for the raw coal and the "pure" coal, and the degree will be determined by the economic choice previously referred to.

For the range of the ash in the raw coal, there will be from 7 to 150 pounds of ash for a million Btu of heating value, while in "pure" coal, there would be from 3 to 9 pounds of ash per million Btu.

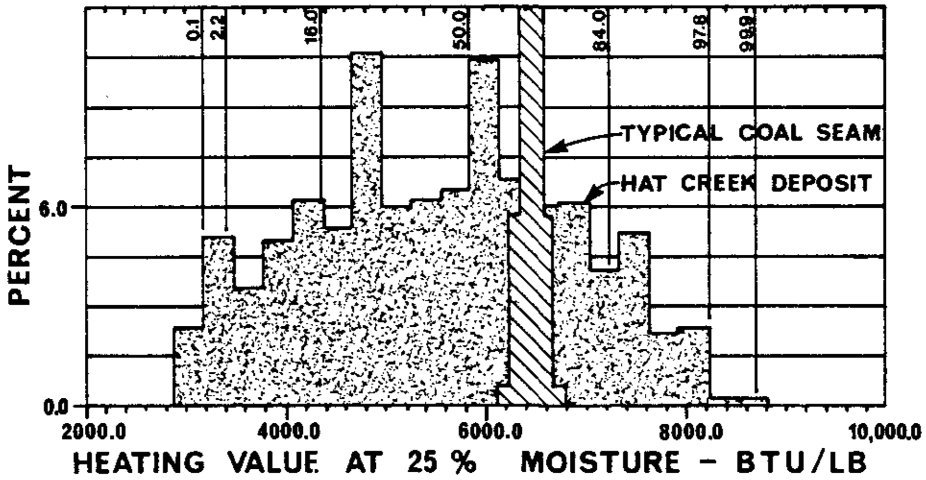

FIG. Nº 5.2.1

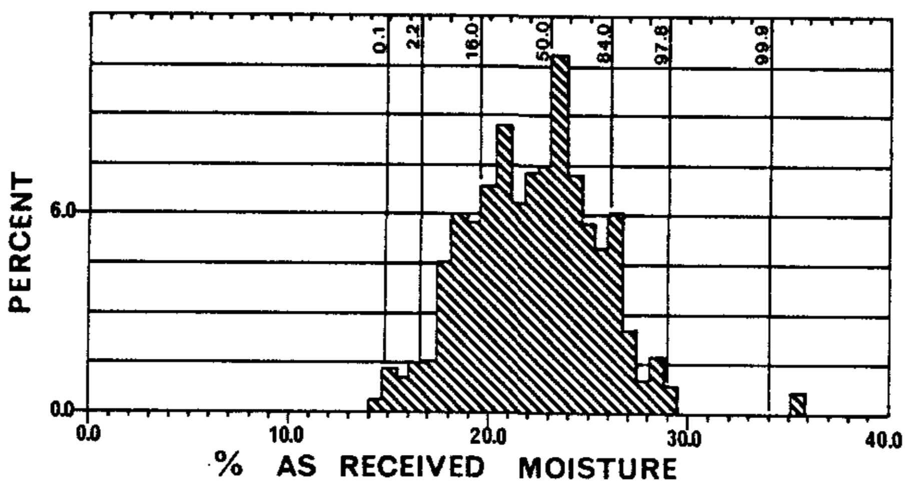

FIG. Nº. 5.2.2

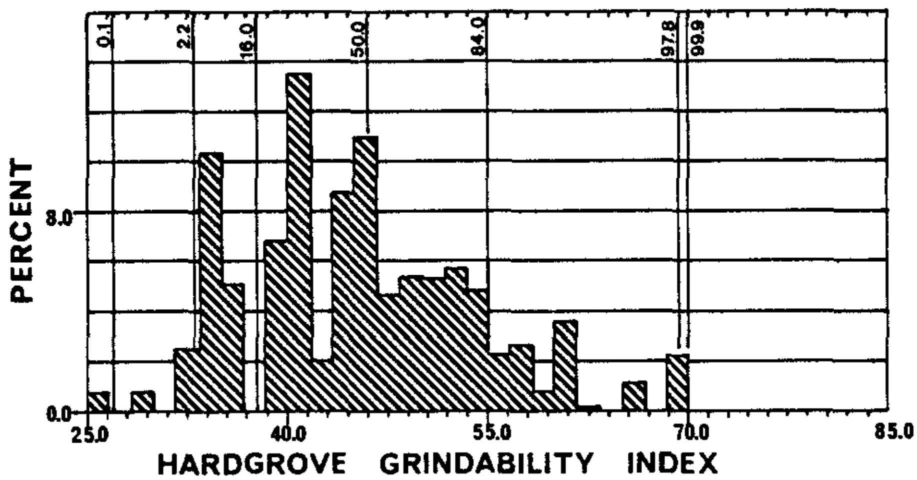

FIG. Nº 5.2.3

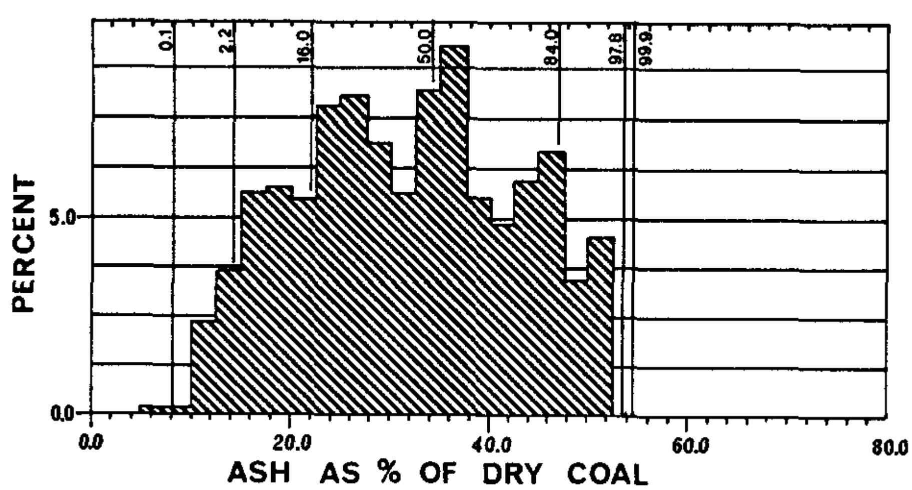

FIG. Nº 5.2.4

b) Type of Ash

There is a wide variation in the character of the ash as well as the quantity. Based upon laboratory chemical analysis, the ashes from Hat Creek coals range from those similar to Eastern North American coals through to those similar to Western North American coals.

One characteristic of the ash is indicated by the temperatures at which it initially softens and at which it becomes fluid, and the changes in its viscosity through this temperature range. It is preferable to examine this aspect through high temperature viscosity observation, but it is normal initially to investigate the ash fusion properties by observing the fusion of small ash pellets, with subsequent examination of selected samples in the high temperature viscometer. This latter work has yet to be started.

A second characteristic of the ash relates to the minerals that make up the ash in the coal, and the form of their occurrence (i.e., whether they are separate nodules, or whether they are intimately associated with the hydrocarbon itself). It is customary first to examine the metallic elements that remain after the coal samples have been incinerated. Based on this chemical analysis of the ash, other samples can be selected for more detailed mineral analysis. The degree of variation of ash analysis with different fractions of the Hat Creek coal can be determined by the conventional float-sink tests and much of this work remains for the future. Preliminary work has been completed on about 11 samples, and these results are taken into account in this report. Significantly more samples need to be examined in this manner before final design conclusions can be drawn.

Possibly the easiest way to picture the relationship between ash elements and the fusion temperatures is to examine a plot of the initial temperature at which the ash deforms against the amount of base elements, as shown in Figure 5.2.5. (Base elements are considered to be iron, calcium, magnesium, sodium, and potassium). The use of mole percent compensates for molecular weight thus putting all elements on an equivalent chemical basis. Such a curve is U-shaped; the deformation temperature decreases until approximately one-third to one-half of the ash is "basic"; the temperature then rises again as the amount of base increases further. This indicates low fusion temperatures for most ashes whose base mole percent lies between 25% and 75%. Other mineral constituents, particularly the ratio of sand to clay and the amount of lime, shift the U-curve up and down, and slightly from side to side. Because of the U-shape of the curve, mixing two coals, one with a low base percentage and one with a high base percentage, each of which by itself has a high fusion temperature, can thus produce a mixture that has a much lower fusion temperature. The samples to date have shown a preponderance of base percentages below 30%. Because of the property shown in this U-shaped curve, most of the "pure" coals at Hat Creek have lower fusion temperatures than most of the raw coals.

The frequency distribution of the initial deformation temperature under reducing conditions (usually the most stringent condition) is shown in Figure 5.2.6. For the raw coal, more than 10% has ash with initial deformation below 2300^{o}F. Theoretically the ash deformation temperature from the as-mined coal would be below 2050^{o}F for an aggregate of 200 hours per year.

This distribution shows that for about 4% of the time (about 350 hours a year) the fusion temperature index of slagging would classify the slagging potential as "high"*. No data is yet available.

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*G.F. Moore, R.J. Gray; ASME Winter Meeting, November 1974.

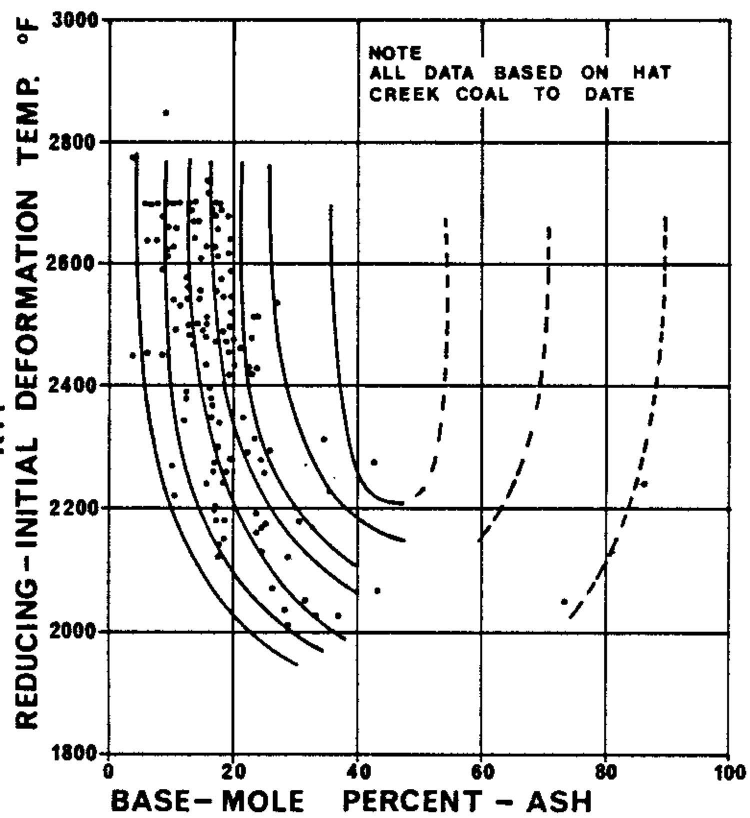

NOTE
ALL DATA BASED ON HAT CREEK COAL TO DATE
3000
2800
2600
2400
2200
2000
1800
0
20
40
60
80
100
-'RIT'-
REDUCING - INITIAL DEFORMATION TEMP. °F
BASE - MOLE PERCENT - ASH

FIG. Nº 5.2.5

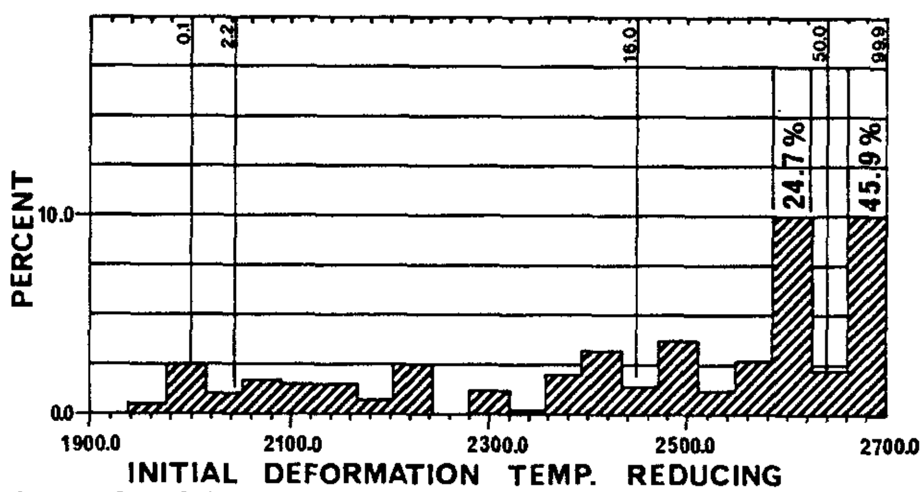

0.1
2.2
16.0
50.0
99.9
24.7 %
45.9 %
PERCENT
10.0
0.0
1900.0
2100.0
2300.0
2500.0
2700.0
INITIAL DEFORMATION TEMP. REDUCING

FIG. № 5.2.6

on slag viscosity.

All coals have some tendency to foul the boiler heating surfaces.

The strength of fouling deposits on the high temperature heat absorption surface can vary widely, resulting in varying degrees of difficulty in removing the deposits, even for ashes having the same fusion temperatures. In general, there is a relationship between the alkali (sodium and potassium) content of the coal and the strength of the deposit such that the higher the alkali, the stronger the deposit, and the more severe the fouling. Although the sodium and potassium content of the ash is not high on a percentage of ash basis, the absolute amounts of sodium and potassium are high, when expressed in pounds per million Btu, owing to the modest heating value and high ash content for the raw coal. The alkali per million Btu at Hat Creek shows levels that are similar to some of the Decker coals; some Hat Creek coals are higher and some are lower. Decker coal is considered a "severe" fouling coal. The higher sodium content in the "pure" coal ash analyses at Hat Creek indicates that much of the alkali is intimately associated with the hydrocarbons. Thus the actual volatilization of the alkali may well be higher than the raw coal analysis would initially suggest.

Work to date indicates that the much smaller quantity of ash in "pure" coal corresponds to considerably less total alkali per million Btu, and is a greatly reduced potential for fouling. This area needs further work to determine the range of fouling potential for different degrees of coal purity.

5.2.5 Sulphur

Figure 5.2.7 shows the sulphur content on a dry basis with a mean of 0.6% and a range from 0.1% to 2%, but with only a very small proportion of samples exhibiting more than 1% sulphur. Other studies show that the very low-sulphur coal occurs in the bottom strata. Figure 5.2.8 shows the frequency distribution for the organic sulphur which is inherent with the coal molecule, and as such, not readily removable by coal separation or milling. This shows a mean organic sulphur content of 0.45% and a range of 0.06 to 1.8%, on a dry basis.

Figure 5.2.9 shows the frequency distribution for total sulphur minus pyritic sulphur and as such is an approximation to the sulphur that might be present in the furnace. This shows a mean value of 0.6% and a range from 0.1% to 2.5%. Of this range 84% is below 0.8% sulphur and 98% below 1.3% sulphur (all values on dry basis).

Figure 5.2.10 is a comparable distribution for the limited set of "pure" coal samples. This shows a mean of 0.6% and a range from 0.2% to 0.7%. This probably represents the best treatment possible, and might not be attainable continuously in a large scale plant.

5.2.6 Clays

During the work with the coal it was determined that in addition to the normal kaolinitic clays there were variable quantities of montmorillonite or bentonitic clays. This latter group has extreme swelling characteristics when exposed to water and produces a sticky, semi-plastic material, very difficult to handle. Such material has caused significant operating problems in a northwestern United States

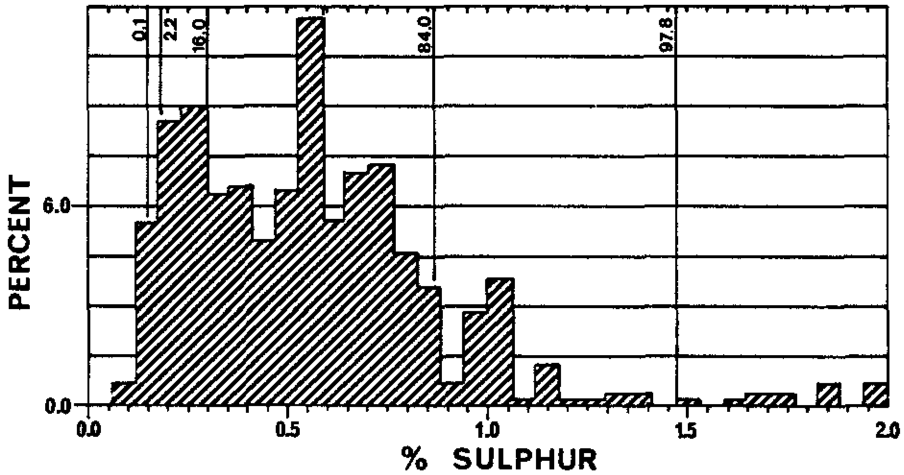


FIG. Nº 5.2.7

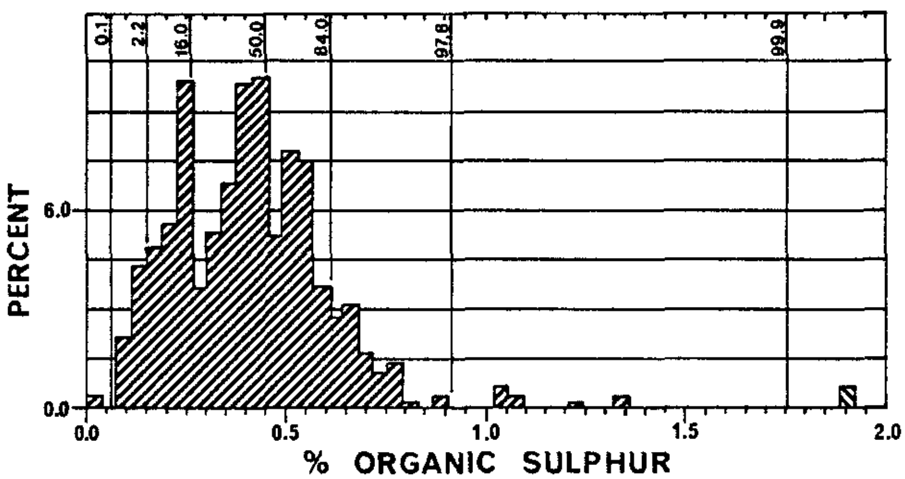


FIG. Nº 5.2.8

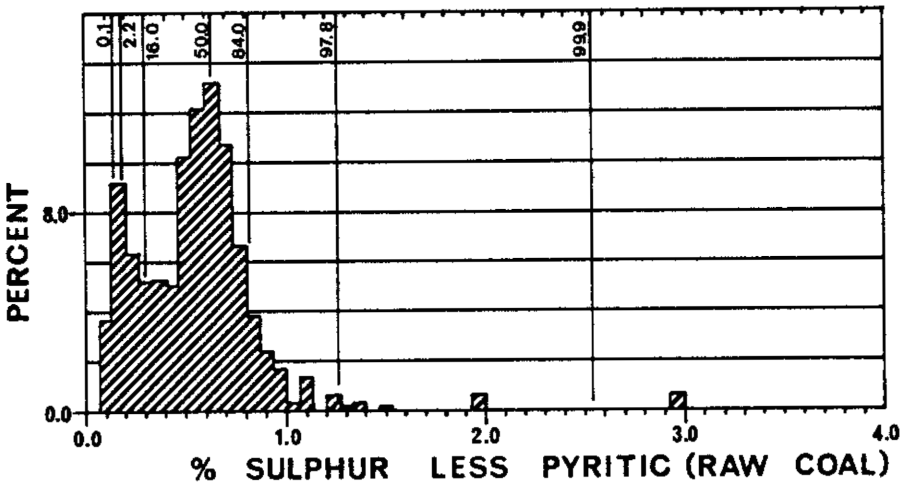


FIG. Nº 5.2.9

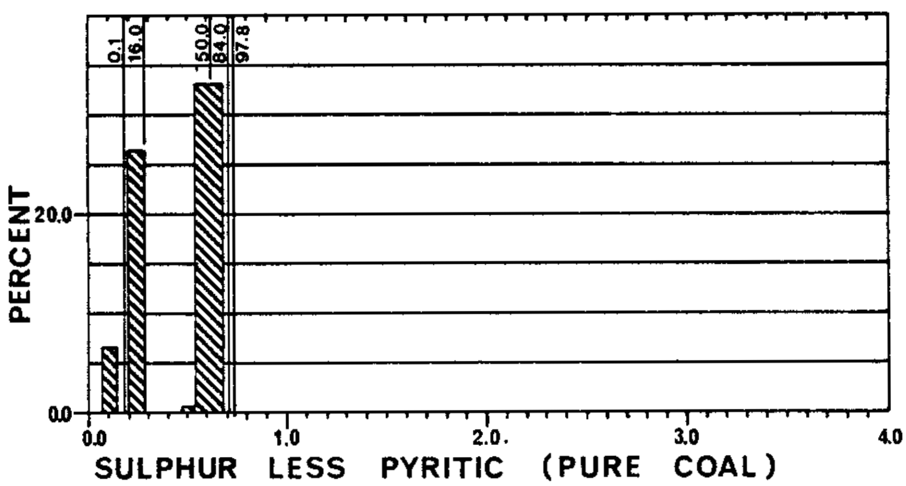
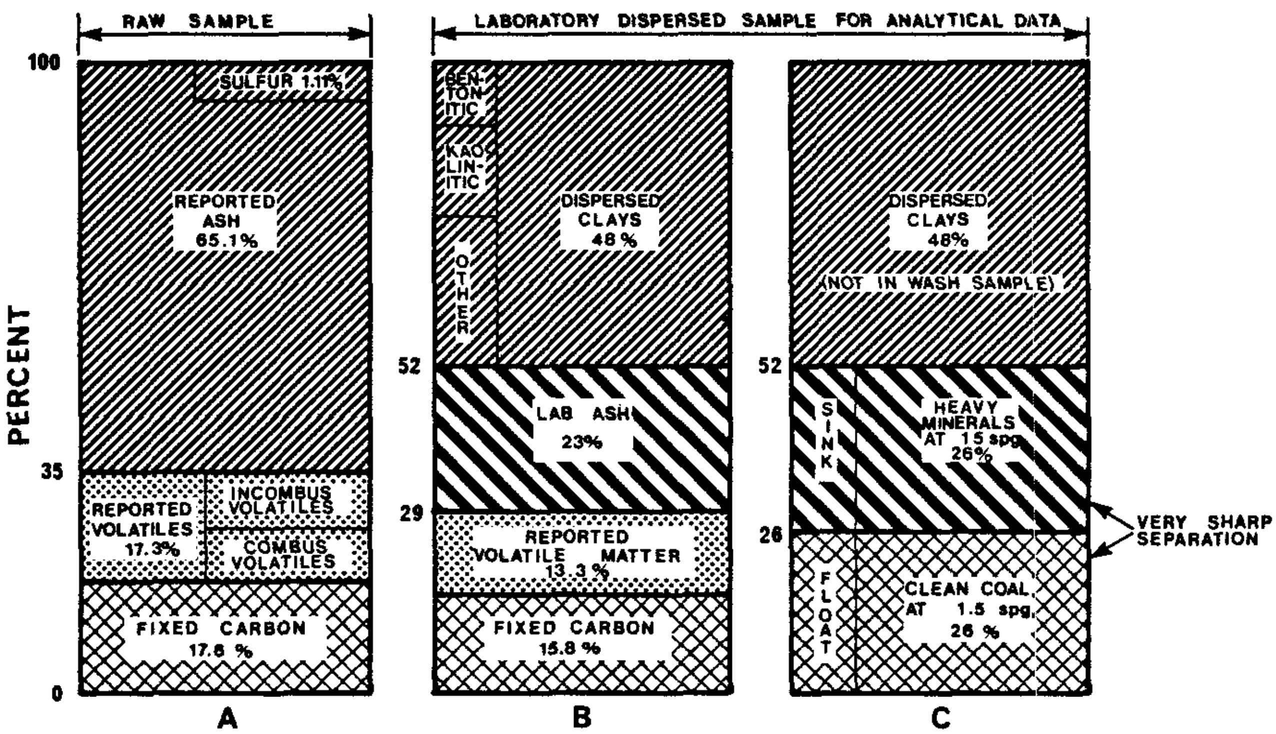


FIG. Nº 5.2.10

power plant, and that experience shows the desirability of removing it or otherwise ameliorating its effects. Integ-Ebasco has recommended a programme designed to arrive at the most economic and feasible way of dealing with this problem. Because of the swelling characteristics this material greatly decreases in density after absorbing water. Consequently, wet coal preparation schemes based on density would not separate clay from the good coal.

A preliminary laboratory technique has been devised that will disperse the clay-bearing material and permit reasonable estimation of the total amount of clay, and roughly, the division between the bentonitic type and others. By dispersing the clays the difficulty in separating the "pure" coal from the raw sample is eliminated and a very sharp, easy laboratory separation is then possible.

Figure 5.2.11 shows in graphical form the results from the analysis of one sample using this technique. The left hand bar (A) shows the conventional, proximate analysis. Most of the reported "ash" in bar (A) is actually clay, as shown in bars (B) and (C). Some of the reported volatiles in (A) are water of hydration associated with the clay (B and C) and some are heavy minerals, as shown on bar (C). In bars (B) and (C) the clays are dispersed, taking a small amount of the fixed carbon with them. Bar (B) shows a conventional proximate analysis for the non-dispersed segment. Bar (C) shows the separation of heavy minerals and "pure" coal from the non-dispersed segment. For this high ash sample, approximately half the sample was clay and one-quarter heavy minerals. Similar clay separation should be carried out on a full range of Hat Creek coal. All further coal analysis should include the clay separation procedure.



EFFECT OF CLAYS IN COAL

FIG Nº 5.2.11

5.2.7 Abrasion and Wear

No laboratory tests to measure the abrasiveness of the Hat Creek coal or ashes have been completed. These should be undertaken. The clay dispersion test previously mentioned did show that small and very hard particles were released when the clay was removed. However, in this one sample these particles were easily and sharply separated from the coal by gravity.

5.2.8 Typical Coal Analysės

Table A shows analyses for two Hat Creek coals whose values all fall in a middle region for each of the properties; thus they could be considered in the middle region for all Hat Creek coals.

Table B shows analyses for 11 Hat Creek coals, and how their analyses differ as between the "pure" coal and the raw sample.

Table C shows the analyses for 11 Hat Creek coals which were selected (based on present knowledge) to be representative of the range of hydrocarbons in the proposed Pit No. 1.

Table D shows ash analyses, indicative of the range of ash constituents present.

5.2.9 Summary

In summary, based on data available to date, Integ-Ebasco believes that:

- Hat Creek coal is usable for power production.

- Variations in coal properties are due to the existence of a number of somewhat different pure coals, diluted in varying degrees by normal and bentonitic type clays and other minerals.

- Variations in the coal, while unusually large, can be satisfactorily dealt with by proper fuel preparation and appropriate power plant and system design.

- Reasonable environmental protection requirements can be met.

- Further study of coal fractions, ash minerals, clay properties, clay removal and possible preparation methods should be undertaken before the design specifications are released.

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TABLE A
INTERIM MID-RANGE SAMPLES - DEPOSIT 1

COR % = APPRX CORRECTION FOR CO2

HOLE,ZONE - SAMPLE	135B -158	136B -135
TOP ELEVATION FT MSL	1874	2153
FEET (VERTICAL) OF SAMPLE	5.0	10.0
WASH SPECIFIC GRAVITY	RAW	RAW
WASH SP. GR. WT %	100.0	100.0
MOISTURE % AS RECD COAL	20.62	25.06
BTU/# STD MOIST=25%	5641	6366
H.H.V. BTU/LB DRY COAL	7521	8488
ASH % DRY COAL UNCOR	36.29	29.65
FIX CARB % DRY COAL UNCOR	33.51	38.01
VOL MATT % DRY COAL UNCOR	30.20	32.34
TOT. S % DRY COAL	0.72	0.74
S PYRITIC % COAL	0.19	0.17
S SULFATE % COAL	0.00	0.01
S ORGANIC % COAL	0.53	0.56
CO2 % DRY COAL	1.06	0.92
CARB ULT COR % DRY COAL	43.53	49.83
HYDR ULT % DRY COAL	3.66	3.97
NITR ULT % DRY COAL	0.97	1.01
CLOR ULT % DRY COAL	0.02	0.07
S ULT % DRY COAL	0.72	0.74
ASH ULT COR % DRY COAL	37.35	30.57
OXY ULT COR % DRY COAL	14.67	15.91
UNDET.+ERR COR % DRY COAL	-0.92	-2.10
OXY (DIFF) COR % DRY COAL	13.75	13.81
INIT DEF'F REDUCE & OXID	2700+ 2700+	2700+ 2700+
H=W 'F REDUCE & OXID	2700+ 2700+	2700+ 2700+
H=W/2 'F REDUCE & OXID	2700+ 2700+	2700+ 2700+
FLUID 'F REDUCE & OXID	2700+ 2700+	2700+ 2700+
SIO2 % DRY ASH - MOLE %	54.15 66.34	51.63 63.15
AL2O3 % DRY ASH - MOLE %	33.64 24.28	36.07 25.99
TIO2 % DRY ASH - MOLE %	0.83 0.76	0.70 0.64
FE2O3 % DRY ASH - MOLE %	4.95 2.31	4.61 2.15
CAO % DRY ASH - MOLE %	2.29 3.00	1.72 2.25
MGO % DRY ASH - MOLE %	0.31 0.57	1.40 2.55
NA2O % DRY ASH - MOLE %	1.24 1.47	1.37 1.62
K2O % DRY ASH - MOLE %	0.70 0.55	0.67 0.52
MN3O4 % DRY ASH - MOLE %	0.01 0.00	0.01 0.00
V2O5 % DRY ASH - MOLE %	0.05 0.02	0.07 0.03
P2O5 % DRY ASH - MOLE %	0.10 0.05	0.06 0.03
SO3 % DRY ASH - MOLE %	0.69 0.63	1.15 1.06
UNDET.+ERROR % DRY ASH	1.04	0.54
HARDGROVE GRIND INDEX	MISSING	MISSING
PSEUDO EQUILIB MOISTURE	24.2	24.9
FIELD COAL SP. GR.	1.35	1.47
ASH % DRY COAL	15.4	19.3
CARBONATE #/MBTU	1.92	1.48
S TOT. IN COAL #/MBTU	0.96	0.87
S (TOT-PYR) #/MBTU	0.70	0.67

TABLE B - PART 1

ACTUAL COAL ANALYSES - PURE COAL AND ASSOCIATED RAW SAMPLE - DEPOSIT 1

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COR % = APPRX CORRECTION FOR CO2								
HOLE,ZONE - SAMPLE	135A - 33	135A - 33	135A - 63	135A - 63	135A - 79	135A - 79	135A - 95	135A - 95
TOP ELEVATION FT MSL	2529	2529	2379	2379	2299	2299	2219	2219
FEET (VERTICAL) OF SAMPLE	10.0	10.0	10.0	10.0	10.0	10.0	5.0	5.0
WASH SPECIFIC GRAVITY	PURE COAL	RAW COAL	PURE COAL	RAW COAL	PURE COAL	RAW COAL	PURE COAL	RAW COAL
WASH SP. GR. WT %	2.6	100.0	3.7	100.0	2.5	100.0	4.9	100.0
MOISTURE % AS RECD COAL	MISS	28.37	MISS	22.36	MISS	23.92	MISS	24.16
BTU/# STD MOIST=25%	8388	6368	8494	5686	8625	5332	8949	7873
H.H.V. BTU/LB DRY COAL	11184	8491	11325	7582	11500	7110	11932	10497
ASH % DRY COAL UNCOR	8.28	29.05	8.33	31.61	8.23	39.50	6.21	15.85
FIX CARB % DRY COAL UNCOR	52.51	37.36	52.40	33.12	52.16	30.47	52.94	43.76
VOL MATT % DRY COAL UNCOR	39.21	33.59	39.27	35.27	39.61	30.03	40.85	40.39
TOT. S % DRY COAL	0.69	0.63	0.83	0.58	0.83	0.61	0.76	0.75
S PYRITIC % COAL	MISS	0.09	MISS	0.07	MISS	0.05	MISS	0.05
S SULFATE % COAL	MISS	0.00	MISS	0.00	MISS	0.01	MISS	0.00
S ORGANIC % COAL	MISS	0.54	MISS	0.51	MISS	0.55	MISS	0.70
CO2 % DRY COAL	0.02	0.36	0.04	2.35	0.02	0.70	0.02	0.13
CARB ULT COR % DRY COAL	65.53	48.47	65.72	43.54	66.37	40.31	69.36	58.19
HYDR ULT % DRY COAL	4.89	4.15	4.89	4.06	4.95	3.73	5.24	5.63
NITR ULT % DRY COAL	1.23	1.02	1.18	1.17	1.13	1.16	1.13	1.11
CLOR ULT % DRY COAL	0.07	0.01	0.20	0.10	0.10	0.11	0.10	0.09
S ULT % DRY COAL	0.69	0.63	0.83	0.58	0.83	0.61	0.76	0.75
ASH ULT COR % DRY COAL	8.30	29.41	8.37	33.96	8.25	40.20	6.23	15.98
OXY ULT COR % DRY COAL	0.00	17.29	0.00	14.05	0.00	14.01	0.00	17.65
UNDET.+ERR COR % DRY COAL	0.00	-0.98	0.00	2.54	0.00	-0.13	0.00	0.60
OXY (DIFF) COR % DRY COAL	19.29	16.31	18.81	16.59	18.37	13.88	17.18	18.25
INIT DEF'F REDUCE & OXID	2220 2320	2700+ 2700+	2200 2260	2520 2645	2380 2450	2700+ 2700+	2190 2260	2490 2560
H=W 'F REDUCE & OXID	2230 2330	2700+ 2700+	2220 2280	2570 2700+	2400 2480	2700+ 2700+	2200 2280	2555 2625
H=W/2 'F REDUCE & OXID	2240 2340	2700+ 2700+	2230 2300	2610 2700+	2420 2510	2700+ 2700+	2210 2300	2580 2675
FLUID 'F REDUCE & OXID	2250 2350	2700+ 2700+	2240 2320	2640 2700+	2440 2530	2700+ 2700+	2220 2320	2610 2700
SIO2 % DRY ASH - MOLE %	40.37 48.28	50.77 62.65	42.33 51.12	53.18 64.82	48.96 57.71	60.16 71.16	46.45 54.57	50.60 63.43
AL2O3 % DRY ASH - MOLE %	34.78 24.51	35.13 25.54	28.34 20.16	24.10 17.31	28.68 19.92	25.48 17.76	29.09 20.13	30.22 22.32
TIO2 % DRY ASH - MOLE %	2.03 1.82	1.28 1.19	2.47 2.24	1.18 1.08	1.33 1.18	1.17 1.04	1.24 1.09	1.32 1.24
FE2O3 % DRY ASH - MOLE %	3.45 1.57	4.73 2.22	7.90 3.63	10.42 4.84	3.88 1.74	5.55 2.50	4.78 2.14	9.62 4.59
CAO % DRY ASH - MOLE %	8.07 10.34	1.80 2.38	6.43 8.32	4.46 5.82	5.25 6.63	1.47 1.86	5.55 6.98	1.39 1.87
MGO % DRY ASH - MOLE %	3.30 5.88	1.46 2.68	3.02 5.43	1.89 3.43	2.36 4.14	1.45 2.55	3.27 5.72	1.38 2.58
NA2O % DRY ASH - MOLE %	3.28 3.80	1.00 1.20	2.91 3.40	0.76 0.90	3.80 4.34	0.76 0.87	5.22 5.94	1.05 1.28
K2O % DRY ASH - MOLE %	0.79 0.60	0.41 0.32	0.83 0.64	0.37 0.29	0.94 0.71	0.85 0.64	1.04 0.78	0.63 0.50
MN3O4 % DRY ASH - MOLE %	0.05 0.02	0.02 0.01	0.04 0.01	0.15 0.05	0.04 0.01	0.11 0.03	0.03 0.01	0.01 0.00
V2O5 % DRY ASH - MOLE %	0.30 0.12	0.07 0.03	0.53 0.21	0.05 0.02	0.22 0.09	0.04 0.02	0.17 0.07	0.07 0.03
P2O5 % DRY ASH - MOLE %	0.47 0.24	0.46 0.24	0.15 0.08	0.30 0.15	0.20 0.10	0.21 0.11	0.29 0.14	0.32 0.17
SO3 % DRY ASH - MOLE %	3.15 2.83	1.66 1.54	5.24 4.75	1.42 1.30	3.88 3.43	1.64 1.46	2.75 2.42	2.11 1.98
UNDET.+ERROR % DRY ASH	-0.04	1.20	-0.19	1.72	0.46	1.11	0.12	1.28
CARBONATE #/MBTU	0.02	0.58	0.05	4.23	0.02	1.34	0.02	0.17
S TOT. IN COAL #/MBTU	0.62	0.74	0.73	0.76	0.72	0.86	0.64	0.71
S (TOT-PYR) #/MBTU	0.62	0.64	0.73	0.67	0.72	0.79	0.64	0.67
NA2O+K2O AS NA2O% IN ASH	3.81	1.27	3.46	1.01	4.43	1.33	5.91	1.47
NA2O+K2O AS NA2O% IN COAL	0.32	0.37	0.29	0.32	0.36	0.52	0.37	0.23
NA2O+K2O AS NA2O #/MBTU	0.28	0.44	0.25	0.42	0.32	0.74	0.31	0.22
ASH BASE MOLE %	24.12	10.93	25.35	19.37	19.64	10.78	23.78	14.95
MOLE RATIO SIO2/AL2O3	1.97	2.45	2.54	3.75	2.90	4.01	2.71	2.84

TABLE B - PART 2 19 NOV 76

ACTUAL COAL ANALYSES - PURE COAL AND ASSOCIATED RAW SAMPLE - DEPOSIT 1

COR % = APPRX CORRECTION FOR CO2

HOLE,ZONE - SAMPLE	135B -158	135B -158	135C -203	135C -203	135D -223	135D -223	135D -251	135D -251
TOP ELEVATION FT MSL	1874	1874	1594	1594	1494	1494	1354	1354
FEET (VERTICAL) OF SAMPLE	5.0	5.0	10.0	10.0	10.0	10.0	5.0	5.0
WASH SPECIFIC GRAVITY	PURE COAL	RAW COAL	PURE COAL	RAW COAL	PURE COAL	RAW COAL	PURE COAL	RAW COAL
WASH SP. GR. WT %	1.6	100.0	1.7	100.0	1.3	100.0	2.8	100.0
MOISTURE % AS RECD COAL	MISS	20.62	MISS	19.44	MISS	19.93	MISS	23.40
BTU/# STD MOIST=25%	8782	5641	9369	5107	9260	6346	9184	7684
H.H.V. BTU/LB DRY COAL	11709	7521	12492	6809	12347	8461	12245	10245
ASH % DRY COAL UNCOR	7.88	36.29	3.56	40.48	4.49	30.73	5.61	20.02
FIX CARB % DRY COAL UNCOR	52.17	33.51	56.65	30.93	57.83	39.16	55.58	45.89
VOL MATT % DRY COAL UNCOR	39.95	30.20	39.79	28.59	37.68	30.11	38.81	34.09
TOT. S % DRY COAL	0.82	0.72	0.81	0.43	0.40	0.24	0.22	0.24
S PYRITIC % COAL	MISS	0.19	MISS	0.04	MISS	0.02	MISS	0.01
S SULFATE % COAL	MISS	0.00	MISS	0.03	MISS	0.01	MISS	0.01
S ORGANIC % COAL	MISS	0.53	MISS	0.36	MISS	0.21	MISS	0.22
CO2 % DRY COAL	0.01	1.06	0.01	1.53	0.02	0.01	0.02	0.42
CARB ULT COR % DRY COAL	68.14	43.53	72.47	41.09	71.40	49.70	71.34	59.95
HYDR ULT % DRY COAL	4.89	3.66	5.16	3.40	5.19	3.85	5.05	4.47
NITR ULT % DRY COAL	1.04	0.97	1.12	1.05	1.04	0.93	1.14	1.96
CLOR ULT % DRY COAL	0.00	0.02	0.09	0.00	0.08	0.00	0.10	0.02
S ULT % DRY COAL	0.82	0.72	0.81	0.43	0.40	0.24	0.22	0.24
ASH ULT COR % DRY COAL	7.89	37.35	3.57	42.01	4.51	30.74	5.63	20.44
OXY ULT COR % DRY COAL	0.00	14.67	0.00	13.95	0.00	16.21	0.00	15.89
UNDET.+ERR COR % DRY COAL	0.00	-0.92	0.00	-1.93	0.00	-1.67	0.00	-1.97
OXY (DIFF) COR % DRY COAL	17.22	13.75	16.78	12.02	17.38	14.54	16.52	13.92
INIT DEF 'F REDUCE & OXID	2340 2450	2700+ 2700+	2180 2210	2700+ 2700+	2200 2240	2700+ 2700+	2400 2420	2700+ 2700+
H=W 'F REDUCE & OXID	2370 2500	2700+ 2700+	2190 2220	2700+ 2700+	2210 2250	2700+ 2700+	2420 2440	2700+ 2700+
H=W/2 'F REDUCE & OXID	2470 2560	2700+ 2700+	2210 2230	2700+ 2700+	2220 2260	2700+ 2700+	2430 2460	2700+ 2700+
FLUID 'F REDUCE & OXID	2560 2640	2700+ 2700+	2220 2240	2700+ 2700+	2230 2270	2700+ 2700+	2440 2480	2700+ 2700+
SIO2 % DRY ASH - MOLE %	50.03 59.05	54.15 66.34	34.59 42.72	54.25 66.16	43.32 51.73	50.97 62.92	44.41 53.71	50.84 62.41
AL2O3 % DRY ASH - MOLE %	30.49 21.20	33.64 24.28	30.83 22.44	32.53 23.37	31.34 22.05	37.98 27.62	33.92 24.17	39.14 28.31
TIO2 % DRY ASH - MOLE %	2.44 2.16	0.83 0.76	5.45 5.06	0.73 0.67	3.25 2.92	0.82 0.76	1.65 1.50	0.89 0.82
FE2O3 % DRY ASH - MOLE %	3.54 1.59	4.95 2.31	4.57 2.15	5.44 2.53	3.61 1.64	3.95 1.86	3.27 1.51	3.23 1.51
CAO % DRY ASH - MOLE %	3.13 3.96	2.29 3.00	8.08 10.69	1.75 2.29	4.41 5.64	1.53 2.02	5.22 6.76	2.20 2.89
MGO % DRY ASH - MOLE %	1.76 3.09	0.31 0.57	0.32 0.59	0.95 1.73	1.90 3.38	0.94 1.73	1.41 2.54	0.95 1.74
NA2O % DRY ASH - MOLE %	6.29 7.19	1.24 1.47	11.54 13.81	1.12 1.32	8.64 10.00	1.50 1.79	5.60 6.56	1.69 2.01
K2O % DRY ASH - MOLE %	0.90 0.68	0.70 0.55	1.45 1.14	0.98 0.76	1.03 0.78	0.66 0.52	0.55 0.42	0.22 0.17
MN3O4 % DRY ASH - MOLE %	0.03 0.01	0.01 0.00	0.03 0.01	0.04 0.01	0.04 0.01	0.03 0.01	0.05 0.02	0.02 0.01
V2O5 % DRY ASH - MOLE %	0.42 0.16	0.05 0.02	1.05 0.43	0.05 0.02	0.56 0.22	0.04 0.02	0.32 0.13	0.07 0.03
P2O5 % DRY ASH - MOLE %	0.16 0.08	0.10 0.05	0.53 0.28	0.21 0.11	0.33 0.17	0.26 0.14	0.17 0.09	0.07 0.04
SO3 % DRY ASH - MOLE %	0.92 0.81	0.69 0.63	0.74 0.69	1.13 1.03	1.64 1.47	0.67 0.62	2.87 2.60	0.08 0.07
UNDET.+ERROR % DRY ASH	-0.11	1.04	0.82	0.82	-0.07	0.65	0.56	0.60
CARBONATE #/MBTU	0.01	1.92	0.01	3.06	0.02	0.02	0.02	0.56
S TOT. IN COAL #/MBTU	0.70	0.96	0.65	0.63	0.32	0.28	0.18	0.23
S (TOT-PYR) #/MBTU	0.70	0.70	0.65	0.57	0.32	0.26	0.18	0.22
NA2O+K2O AS NA2O% IN ASH	6.89	1.71	12.51	1.77	9.33	1.94	5.97	1.84
NA2O+K2O AS NA2O% IN COAL	0.54	0.62	0.45	0.72	0.42	0.60	0.33	0.37
NA2O+K2O AS NA2O #/MBTU	0.46	0.82	0.36	1.05	0.34	0.70	0.27	0.36
ASH BASE MOLE %	17.98	10.00	30.26	10.95	23.10	9.63	19.53	9.67
MOLE RATIO SIO2/AL2O3	2.79	2.73	1.90	2.83	2.35	2.28	2.22	2.20

TABLE B - PART 3

ACTUAL COAL ANALYSES - PURE COAL AND ASSOCIATED RAW SAMPLE - DEPOSIT I

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COR % = APPRX CORRECTION FOR CO2

HOLE,ZONE - SAMPLE	135D -264	135D -264	136D -233	136D -233	511 -130	511 -200
TOP ELEVATION FT MSL	1289	1289	1664	1664	3145	3145
FEET (VERTICAL) OF SAMPLE	5.0	5.0	5.0	5.0	0.5	0.5
WASH SPECIFIC GRAVITY	PURE COAL	RAW COAL	PURE COAL	RAW COAL	PURE COAL	RAW COAL
WASH SP. GR. WT %	6.0	100.0	6.0	100.0	2.8	100.0
MOISTURE % AS RECD COAL	MISS	18.74	MISS	22.62	MISS	MISS
BTU/# STD MOIST=25%	9301	8557	8625	7822	8230	6187
H.H.V. BTU/LB DRY COAL	12401	11410	11500	10430	10974	8250
ASH % DRY COAL UNCOR	5.22	11.28	10.18	18.58	10.75	29.76
FIX CARB % DRY COAL UNCOR	57.37	53.57	49.84	43.98	48.89	36.91
VOL MATT % DRY COAL UNCOR	37.41	35.15	39.98	37.44	39.36	33.91
TOT. S % DRY COAL	0.34	0.30	0.34	0.34	0.95	1.42
S PYRITIC % COAL	MISS	0.03	MISS	0.01	0.32	0.88
S SULFATE % COAL	MISS	0.00	MISS	0.00	0.01	0.03
S ORGANIC % COAL	MISS	0.27	MISS	0.33	0.62	0.51
CO2 % DRY COAL	0.01	1.35	0.02	0.27	0.00	0.00
CARB ULT COR % DRY COAL	72.60	65.69	67.44	60.15	63.67	48.23
HYDR ULT % DRY COAL	5.07	4.75	4.94	4.68	4.68	3.71
NITR ULT % DRY COAL	1.07	1.19	1.06	1.01	0.95	0.51
CLOR ULT % DRY COAL	0.06	0.02	0.19	0.06	0.08	0.04
S ULT % DRY COAL	0.34	0.30	0.34	0.34	0.95	1.42
ASH ULT COR % DRY COAL	5.23	12.63	10.20	18.85	10.75	29.76
OXY ULT COR % DRY COAL	0.00	16.41	0.00	16.22	0.00	0.00
UNDET.+ERR COR % DRY COAL	0.00	-0.99	0.00	-1.31	0.00	0.00
OXY (DIFF) COR % DRY COAL	15.63	15.42	15.83	14.91	18.91	16.33
INIT DEF 'F REDUCE & OXID	2260 2315	2255 2350	2700+ 2700+	2700+ 2700+	2230 2290	2610 2660
H=W 'F REDUCE & OXID	2270 2340	2260 2355	2700+ 2700+	2700+ 2700+	2245 2300	2620 2680
H=W/2 'F REDUCE & OXID	2280 2350	2265 2370	2700+ 2700+	2700+ 2700+	2250 2310	2630 2700
FLUID 'F REDUCE & OXID	2290 2360	2270 2380	2700+ 2700+	2700+ 2700+	2260 2340	2640 2700+
SIO2 % DRY ASH - MOLE %	46.69 56.59	46.83 56.03	49.48 59.41	50.87 61.92	44.26 53.23	52.50 63.81
AL2O3 % DRY ASH - MOLE %	28.78 20.55	25.60 18.05	35.93 25.42	40.19 28.82	26.29 18.63	29.97 21.46
TIO2 % DRY ASH - MOLE %	1.02 0.93	0.85 0.76	1.31 1.18	1.24 1.13	1.72 1.56	0.85 0.78
FE2O3 % DRY ASH - MOLE %	6.32 2.92	8.15 3.71	1.99 0.91	2.02 0.94	7.71 3.53	8.84 4.09
CAO % DRY ASH - MOLE %	5.69 7.39	8.46 10.84	4.34 5.58	2.13 2.78	7.64 9.84	3.19 4.15
MGO % DRY ASH - MOLE %	0.63 1.14	2.16 3.85	0.94 1.68	0.81 1.47	2.55 4.57	1.82 3.30
NA2O % DRY ASH - MOLE %	6.16 7.23	2.63 3.05	3.70 4.30	2.16 2.55	1.07 1.25	0.60 0.71
K2O % DRY ASH - MOLE %	0.51 0.39	0.30 0.23	0.42 0.32	0.31 0.24	0.89 0.68	1.19 0.92
MN3O4 % DRY ASH - MOLE %	0.21 0.07	0.51 0.16	0.02 0.01	0.01 0.00	0.00 0.00	0.00 0.00
V2O5 % DRY ASH - MOLE %	0.13 0.05	0.06 0.02	0.13 0.05	0.06 0.02	0.00 0.00	0.00 0.00
P2O5 % DRY ASH - MOLE %	0.22 0.11	0.03 0.02	0.14 0.07	0.16 0.08	0.19 0.10	0.09 0.05
SO3 % DRY ASH - MOLE %	2.89 2.63	3.65 3.28	1.18 1.06	0.04 0.04	7.33 6.61	0.81 0.74
UNDET.+ERROR % DRY ASH	0.75	0.77	0.42	0.00	0.35	0.14
CARBONATE #/MBTU	0.01	1.61	0.02	0.35	0.00	0.00
S TOT. IN COAL #/MBTU	0.27	0.26	0.30	0.33	0.87	1.72
S (TOT-PYR) #/MBTU	0.27	0.24	0.30	0.32	0.57	0.65
NA2O+K2O AS NA2O% IN ASH	6.50	2.83	3.98	2.37	1.66	1.39
NA2O+K2O AS NA2O% IN COAL	0.34	0.32	0.41	0.44	0.18	0.41
NA2O+K2O AS NA2O #/MBTU	0.27	0.28	0.35	0.42	0.16	0.50
ASH BASE MOLE %	21.92	25.27	13.73	8.82	24.10	16.62
MOLE RATIO SIO2/AL2O3	2.75	3.10	2.34	2.15	2.86	2.97

TABLE C - PART 1 19 NOV 76

ACTUAL COAL ANALYSES OVER A RANGE OF HEATING VALUE INDICES - DEPOSIT 1

COR % = APPRX CORRECTION FOR CO2

HOLE,ZONE - SAMPLE	38A -402	120C - 59	135A - 95	135B -157	135C -221	135D -240	135D -243	135D -264
TOP ELEVATION FT MSL	2706	1565	2219	1879	1504	1409	1394	1289
FEET (VERTICAL) OF SAMPLE	34.6	20.0	5.0	5.0	10.0	5.0	10.0	5.0
WASH SPECIFIC GRAVITY	RAW	RAW	RAW	RAW	RAW	RAW	RAW	RAW
WASH SP. GR. WT %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MOISTURE % AS RECD COAL	MISSING	18.86	24.16	20.03	19.62	21.41	19.41	18.74
BTU/# STD MOIST=25%	*5161*	5295	7873	4335	4006	7280	5962	8557
H.H.V. BTU/LB DRY COAL	6881	7060	10497	5780	5342	9707	7949	11410
ASH % DRY COAL UNCOR	39.17	39.91	15.85	47.55	46.45	23.30	34.38	11.28
FIX CARB % DRY COAL UNCOR	28.41	25.78	43.76	26.08	18.76	43.31	35.03	53.57
VOL MATT % DRY COAL UNCOR	32.42	34.31	40.39	26.37	34.79	33.39	30.59	35.15
TOT. S % DRY COAL	1.13	0.35	0.75	0.71	0.25	0.18	0.18	0.30
S PYRITIC % COAL	0.38	0.07	0.05	0.34	0.09	0.02	0.02	0.03
S SULFATE % COAL	0.05	0.00	0.00	0.00	0.01	0.00	0.02	0.00
S ORGANIC % COAL	0.70	0.28	0.70	0.37	0.15	0.16	0.14	0.27
CO2 % DRY COAL	MISSING	2.19	0.13	1.11	10.97	0.27	0.45	1.35
CARB ULT COR % DRY COAL	40.36	40.68	58.19	34.91	34.44	56.28	46.48	65.69
HYDR ULT % DRY COAL	3.31	3.12	5.63	3.31	1.60	4.38	3.94	4.75
NITR ULT % DRY COAL	1.40	0.92	1.11	0.69	0.86	1.01	0.79	1.19
CLOR ULT % DRY COAL	0.04	0.01	0.09	0.00	0.00	0.01	0.01	0.02
S ULT % DRY COAL	1.13	0.35	0.75	0.71	0.25	0.18	0.18	0.30
ASH ULT COR % DRY COAL	39.17	42.10	15.98	48.66	57.42	23.57	34.83	12.63
OXY ULT COR % DRY COAL	MISSING	MISSING	17.65	13.44	12.85	16.95	13.95	16.41
UNDET.+ERR COR % DRY COAL	MISSING	MISSING	0.60	-1.72	-7.42	-2.38	-0.18	-0.99
OXY (DIFF) COR % DRY COAL	14.59	12.82	18.25	11.72	5.43	14.57	13.77	15.42
INIT DEF'F REDUCE & OXID	2670 2700+	2640+ MSSNG	2490 2560	2700+ 2700+	2070 2280	2700+ 2700+	2700+ 2700+	2255 2350
H=W 'F REDUCE & OXID	2700+ 2700+	2640+ MSSNG	2555 2625	2700+ 2700+	2080 2290	2700+ 2700+	2700+ 2700+	2260 2355
H=W/2 'F REDUCE & OXID	2700+ 2700+	2640+ MSSNG	2580 2675	2700+ 2700+	2090 2300	2700+ 2700+	2700+ 2700+	2265 2370
FLUID 'F REDUCE & OXID	2700+ 2700+	2640+ MSSNG	2610 2700	2700+ 2700+	2100 2310	2700+ 2700+	2700+ 2700+	2270 2380
SIO2 % DRY ASH - MOLE %	53.73 65.53	54.26 66.80	50.60 63.43	51.88 63.78	32.43 45.04	53.17 64.65	55.17 66.81	46.83 56.03
AL2O3 % DRY ASH - MOLE %	28.20 20.26	28.92 20.98	30.22 22.32	36.62 26.53	22.19 18.16	38.37 27.49	37.34 26.64	25.60 18.05
TIO2 % DRY ASH - MOLE %	0.89 0.82	1.01 0.93	1.32 1.24	1.09 1.01	0.39 0.41	0.72 0.66	0.71 0.65	0.83 0.76
FE2O3 % DRY ASH - MOLE %	8.07 3.75	7.15 3.35	9.62 4.59	4.31 2.02	28.44 15.04	2.52 1.17	2.40 1.11	8.15 3.71
CAO % DRY ASH - MOLE %	2.24 2.93	2.10 2.77	1.39 1.87	1.93 2.54	7.02 10.44	1.54 2.01	1.19 1.54	8.46 10.84
MGO % DRY ASH - MOLE %	1.61 2.93	0.99 1.82	1.38 2.58	1.08 1.98	3.29 6.81	0.72 1.30	0.63 1.14	2.16 3.85
NA2O % DRY ASH - MOLE %	0.85 1.00	1.05 1.25	1.05 1.28	0.90 1.07	0.80 1.08	1.64 1.93	1.17 1.37	2.63 3.05
K2O % DRY ASH - MOLE %	0.81 0.63	0.70 0.55	0.63 0.50	0.60 0.47	0.71 0.63	0.35 0.27	0.21 0.16	0.30 0.23
MN3O4 % DRY ASH - MOLE %	0.00 0.00	0.19 0.06	0.01 0.00	0.01 0.00	0.98 0.36	0.04 0.01	0.03 0.01	0.51 0.16
V2O5 % DRY ASH - MOLE %	0.00 0.00	0.05 0.02	0.07 0.03	0.06 0.02	0.03 0.01	0.05 0.02	0.05 0.02	0.06 0.02
P2O5 % DRY ASH - MOLE %	0.16 0.08	0.20 0.10	0.32 0.17	0.10 0.05	0.76 0.45	0.11 0.06	0.15 0.08	0.03 0.02
SO3 % DRY ASH - MOLE %	2.26 2.07	1.47 1.36	2.11 1.98	0.57 0.53	1.51 1.57	0.48 0.44	0.52 0.47	3.65 3.28
UNDET.+ERROR % DRY ASH	1.18	1.91	1.28	0.85	1.45	0.29	0.33	0.77
HARDGROVE GRIND INDEX	52	MISSING	MISSING	MISSING	MISSING	MISSING	MISSING	MISSING
PSEUDO EQUILIB MOISTURE	MISSING	MISSING	28.3	22.9	18.0	18.6	19.5	20.4
FIELD COAL SP. GR.	MISSING	MISSING	1.32	1.46	1.59	1.45	1.50	1.37
ASH % DRY COAL	MISSING	MISSING	16.3	27.7	50.4	31.3	34.0	23.9
CARBONATE #/MBTU	MISSING	4.23	0.17	2.62	28.00	0.38	0.77	1.61
S TOT. IN COAL #/MBTU	1.64	0.50	0.71	1.23	0.47	0.19	0.23	0.26
S (TOT-PYR) #/MBTU	1.09	0.40	0.67	0.64	0.30	0.16	0.20	0.24

TABLE C - PART 2

ACTUAL COAL ANALYSES OVER A RANGE OF HEATING VALUE INDICES - DEPOSIT 1

COR % = APPRX CORRECTION FOR CO2

HOLE,ZONE - SAMPLE	136A - 75		136B -119		136B -138		136C -200	
TOP ELEVATION FT MSL	2453		2233		2138		1829	
FEET (VERTICAL) OF SAMPLE	10.0		5.0		5.0		10.0	
WASH SPECIFIC GRAVITY	RAW		RAW		RAW		RAW	
WASH SP. GR. WT %	100.0		100.0		100.0		100.0	
MOISTURE % AS RECD COAL	23.37		23.55		23.21		15.80	
BTU/# STD MOIST=25%	3538		6884		5905		3201	
H.H.V. BTU/LB DRY COAL	4717		9179		7874		4268	
ASH % DRY COAL UNCOR	54.56		24.48		32.91		54.20	
FIX CARB % DRY COAL UNCOR	19.98		40.48		35.31		14.96	
VOL MATT % DRY COAL UNCOR	25.46		35.04		31.78		30.84	
TOT. S % DRY COAL	0.45		0.94		0.48		0.24	
S PYRITIC % COAL	0.16		0.33		0.05		0.07	
S SULFATE % COAL	0.00		0.00		0.01		0.00	
S ORGANIC % COAL	0.29		0.61		0.42		0.17	
CO2 % DRY COAL	1.56		0.61		1.06		9.40	
CARB ULT COR % DRY COAL	28.50		53.81		46.29		25.01	
HYDR ULT % DRY COAL	2.96		4.26		3.90		2.42	
NITR ULT % DRY COAL	0.60		1.00		1.04		0.64	
CLOR ULT % DRY COAL	0.06		0.06		0.04		0.05	
S ULT % DRY COAL	0.45		0.94		0.48		0.24	
ASH ULT COR % DRY COAL	56.12		25.09		33.97		63.60	
OXY ULT COR % DRY COAL	13.49		16.68		17.14		10.25	
UNDET.+ERR COR % DRY COAL	-2.18		-1.84		-2.86		-2.21	
OXY (DIFF) COR % DRY COAL	11.31		14.84		14.28		8.04	
INIT DEF 'F REDUCE & OXID	2700+	2700+	2700+	2700+	2700+	2700+	2050	2150
H=W 'F REDUCE & OXID	2700+	2700+	2700+	2700+	2700+	2700+	2060	2160
H=W/2 'F REDUCE & OXID	2700+	2700+	2700+	2700+	2700+	2700+	2080	2170
FLUID 'F REDUCE & OXID	2700+	2700+	2700+	2700+	2700+	2700+	2100	2180
SIO2 % DRY ASH - MOLE %	54.21	66.51	53.84	65.90	53.77	63.06	40.34	52.01
AL2O3 % DRY ASH - MOLE %	33.35	24.11	31.19	22.49	30.39	21.00	27.44	20.84
TIO2 % DRY ASH - MOLE %	0.80	0.74	0.98	0.90	0.75	0.66	0.60	0.58
FE2O3 % DRY ASH - MOLE %	3.49	1.63	6.07	2.83	4.70	2.19	19.20	9.43
CAO % DRY ASH - MOLE %	1.80	2.37	2.02	2.65	4.60	5.78	5.94	8.20
MGO % DRY ASH - MOLE %	1.13	2.07	1.29	2.35	2.26	3.95	3.31	6.36
NA2O % DRY ASH - MOLE %	0.43	0.51	1.48	1.76	1.21	1.37	0.61	0.76
K2O % DRY ASH - MOLE %	0.68	0.53	0.60	0.47	0.52	0.39	0.52	0.43
MN3O4 % DRY ASH - MOLE %	0.02	0.01	0.22	0.07	0.01	0.00	0.30	0.10
V2O5 % DRY ASH - MOLE %	0.05	0.02	0.05	0.02	0.04	0.02	0.04	0.02
P2O5 % DRY ASH - MOLE %	1.10	0.57	0.14	0.07	0.06	0.03	0.41	0.22
SO3 % DRY ASH - MOLE %	1.02	0.94	0.54	0.50	1.87	1.64	1.08	1.04
UNDET.+ERROR % DRY ASH	1.92		1.58		-0.18		0.21	
HARDGROVE GRIND INDEX	MISSING		MISSING		MISSING		MISSING	
PSEUDO EQUILIB MOISTURE	18.1		25.5		27.6		17.7	
FIELD COAL SP. GR.	1.72		1.32		1.38		1.73	
ASH % DRY COAL	61.9		15.8		21.2		56.0	
CARBONATE #/MBTU	4.51		0.91		1.84		30.03	
S TOT. IN COAL #/MBTU	0.95		1.02		0.61		0.56	
S (TOT-PYR) #/MBTU	0.61		0.66		0.55		0.40	

TABLE D

ACTUAL ASH ANALYSES OVER A RANGE OF FUSION TEMPERATURES - DEPOSIT 1

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HOLE,ZONE - SAMPLE	120A- 9	128A- 18	133D- 22	135A- 89	135D-223	135D-234	135D-273	136A- 23	136B-157	140A- 1
WASH SPECIFIC GRAVITY	RAW	RAW	RAW	RAW	RAW	RAW	RAW	RAW	RAW	RAW
INIT DEF'F REDUCE	2048	2478	1950	2340	2700+	2000	2400	2700+	2220	2263
H=W 'F REDUCE	2078	2507	2080	2380	2700+	2010	2500	2700+	2240	2302
H=W/2 'F REDUCE	2097	2526	2180	2410	2700+	2020	2600	2700+	2260	2331
FLUID 'F REDUCE	2380	2634	2320	2435	2700+	2025	2690	2700+	2275	2380
INIT DEF'F OXID	MISSING	MISSING	MISSING	2500	2700+	2270	2575	2700+	2260	MISSING
H=W 'F OXID	MISSING	MISSING	MISSING	2550	2700+	2280	2630	2700+	2280	MISSING
H=W/2 'F OXID	MISSING	MISSING	MISSING	2620	2700+	2290	2685	2700+	2300	MISSING
FLUID 'F OXID	MISSING	MISSING	MISSING	2700+	2700+	2300	2700+	2700+	2320	MISSING
SIO2 % DRY ASH	17.76	22.52	45.39	59.40	50.97	35.30	62.90	51.60	52.86	32.72
AL2O3 % DRY ASH	5.02	9.26	18.48	24.37	37.98	23.96	23.40	32.80	35.37	17.20
TIO2 % DRY ASH	0.22	0.34	0.31	0.99	0.82	0.53	0.85	1.06	0.89	0.75
FE2O3 % DRY ASH	64.05	12.15	18.39	7.99	3.95	24.21	6.74	6.96	4.51	3.67
CAO % DRY ASH	4.25	47.08	4.20	1.64	1.53	7.29	1.73	1.31	2.36	36.38
MGO % DRY ASH	3.07	1.74	2.63	1.20	0.94	3.06	0.47	1.29	1.45	2.07
NA2O % DRY ASH	0.60	1.59	0.87	0.45	1.50	1.67	1.51	0.93	0.54	2.97
K2O % DRY ASH	0.10	0.14	0.07	0.56	0.66	0.46	0.10	1.68	0.60	0.33
MN3O4 % DRY ASH	0.81	0.21	0.10	0.08	0.03	0.16	0.29	0.02	0.10	0.21
V2O5 % DRY ASH	0.00	0.00	0.06	0.07	0.04	0.04	0.06	0.05	0.03	0.00
P2O5 % DRY ASH	0.32	0.34	0.45	0.24	0.26	0.19	0.04	0.04	0.09	0.29
SO3 % DRY ASH	2.38	3.63	3.40	2.22	0.67	2.80	0.64	1.36	0.69	2.81
UNDET.+ERROR % DRY ASH	1.42	1.00	4.65	0.79	0.65	0.33	1.27	0.89	0.51	0.60
SIO2 % MOLE DRY ASH	31.06	24.91	59.70	70.97	62.92	46.73	74.38	63.92	64.25	35.47
AL2O3 % MOLE DRY ASH	5.17	6.03	14.32	17.16	27.62	18.69	16.30	23.94	25.33	10.99
TIO2 % MOLE DRY ASH	0.29	0.28	0.31	0.89	0.76	0.53	0.76	0.99	0.81	0.61
FE2O3 % MOLE DRY ASH	42.66	5.12	9.21	3.64	1.86	12.20	3.04	3.28	2.09	1.52
CAO % MOLE DRY ASH	7.96	55.76	5.92	2.10	2.02	10.33	2.19	1.74	3.07	42.24
MGO % MOLE DRY ASH	8.00	2.87	5.15	2.14	1.73	6.03	0.83	2.38	2.63	3.34
NA2O % MOLE DRY ASH	1.02	1.70	1.11	0.52	1.79	2.14	1.73	1.12	0.64	3.12
K2O % MOLE DRY ASH	0.11	0.10	0.06	0.43	0.52	0.39	0.08	1.33	0.47	0.23
MN3O4 % MOLE DRY ASH	0.37	0.06	0.03	0.03	0.01	0.06	0.09	0.01	0.03	0.06
V2O5 % MOLE DRY ASH	0.00	0.00	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.00
P2O5 % MOLE DRY ASH	0.24	0.16	0.81	0.12	0.14	0.11	0.02	0.02	0.05	0.13
SO3 % MOLE DRY ASH	3.12	3.01	3.35	1.99	0.62	2.78	0.57	1.26	0.63	2.29
CARBONATE #/MBTU	62.07	35.09	0.90	5.58	1.10	6.63	0.27	1.42	29.13	23.00
S TOT. IN COAL #/MBTU	1.02	1.11	0.29	1.56	0.28	0.22	0.76	1.13	1.23	1.20
S (TOT-PYR) #/MBTU	0.59	0.76	0.17	1.15	0.26	0.17	0.36	0.64	0.79	1.06
DRY ASH/MBTU #	152.11	83.89	21.40	83.98	37.12	28.43	14.19	84.08	120.28	72.88
NA2O+K2O AS NA2O #/MBTU	0.71	0.98	0.20	0.66	0.70	0.47	0.22	1.70	0.93	1.79
NA2O+K2O AS NA2O % IN ASH	0.67	1.68	0.92	0.82	1.94	1.98	1.58	2.05	0.94	3.19
NA2O+K2O AS NA2O% IN COAL	0.31	0.59	0.19	0.38	0.60	0.44	0.24	0.90	0.45	1.13
ASH BASE MOLE %	73.51	69.32	29.05	12.19	9.63	39.47	10.58	12.80	10.78	52.45
MOLE RATIO SIO2/AL2O3	6.00	4.13	4.17	4.14	2.28	2.50	4.56	2.67	2.54	3.23
CAO+MGO/BASE MOLE %	15.75	83.12	36.38	34.25	38.54	38.06	27.90	31.57	52.17	87.79
FEO/BASE MOLE %	83.14	14.33	59.79	58.08	37.68	56.05	55.41	49.71	37.75	5.76

5.3 COAL HANDLING

5.3.1 General

The functions of the coal handling and preparation plant are twofold. Firstly, the system must supply fuel to the power plant at the rate required for power generation. Secondly, the system must prepare the coal in such a way that variations in coal quality are minimized and the removal of undesirable material is maximized.

The conceptual design of the Hat Creek coal handling plant requires special consideration because of the presence of significant amounts of clay in the coal. At Centralia, Wash., a similar clay causes severe coal handling and storage problems. Experience there is that when the coal is stocked-out after washing, it often becomes very sticky and hard to reclaim, and subsequently sticks on conveyors, on feeders and in bunkers. While Centralia experience might suggest that the coal should pass directly from the mine to the power plant without being stocked out, the difference in climate between Hat Creek and Centralia must be considered. Centralia has an annual rainfall of about 60 inches a year and annual evaporation of about 20 inches, but at Hat Creek the gross evaporation of 27 inches a year is substantially more than the average precipitation of 12 inches. It is well known that bentontic clays behave well when the moisture content is below a critical level, but that above that level the clay becomes sticky and difficult to handle. The small amount of evidence now available indicates that the coal drains well, this being the experience of CCRL with the samples sent to them. Coal in contact with the air has also been shown to dry rapidly, and in some cases the clay has dried out and fragmented to a powder. It is therefore possible that stacking the coal will improve its handling characteristics rather than making them more difficult.

This important issue is still unresolved, and in the conceptual design of the coal handling plant allowance has been made for both direct coal feed and stacking/blending.

The beneficiation test programme proposed by Integ-Ebasco will indicate reasonably quickly which of these alternatives should be put into practice.

5.3.2 Coal Preparation

Considering the needs of the power plant it is essential that certain factors be taken into account.

- The boiler must be designed to burn the worst coal it will encounter for any significant length of time.
- It may be difficult to operate the boiler if it is fed coal of rapidly varying quality.
- If clay is not removed from the poorer quality coal, it may cause milling problems.

These factors indicate the necessity to feed the boiler with a relatively consistent coal, in which the clay is sufficiently dried or from which much of the clay has been removed. This can be done by blending all or part of the coal, a method favoured by PD-NCB, or by passing a proportion of it through a preparation plant to remove troublesome clay and some of the ash.

Figure 5.3.1 compares some of the available alternatives for providing the power plant with a less variable quality coal, while minimizing the amount of the coal and hence energy which is to be discarded. It shows the average quality and variation of as-mined coal, and the effects of blending, more careful selective mining and different degrees of washing.

It must be stressed that the methods shown in this Figure may not all be practicable, and can only be proved by a test programme.

The principal broad assumptions, on which some of the paths shown in Figure 5.3.1 depend, include:

- It will consistently be possible to mine the coal selectively on the basis of eliminating low heating value, certain chemical elements, certain clay types, etc.

- That the mined coal can be stacked and blended without deterioration of its handling or fuel properties.

- That the clay can be removed by practicable large scale processes.

- That after clay removal the coal can be washed efficiently in a practicable large scale process.

- As an alternative, one path assumes that no practical means of large scale clay removal will be found.

The figure shows five alternative coal preparation/blending methods which are described below:

A. All the coal is passed through clay removal equipment, then washed. Several streams would be used as a function of size. For illustrative purposes, parallel streams are shown as one in Figure 5.3.1. This process assumes clay removal will be practicable.

B. 70% of the coal is blended in a pile, while 30% with the lowest heating value is passed through a cleaning plant, without clay removal. This process shows the inefficiency of using a heavy media separation plant without prior clay removal, and is based on data supplied by Birtley Engineering Ltd. which is based on their test experience.

C. No coal cleaning but all the coal is blended.

D. It may be found that pile blending is impracticable. In process D 70% of the coal is fed directly to the plant, the remainder upgraded as in B.

E. No coal cleaning, all coal blended but more selective mining than C.

The basis of this process is that if clay removal is found to be impracticable in the preparation plant, it might be more economic to reject more low grade, high clay content coal in the mine. The end results of these different coal handling/preparation techniques are quite similar. All produce a similar quality coal for which the heating value of 95% of the coal lies within 10% to 15% of the mean. The total energy rejected ranges between 10% and 15%.

Based on the possible coal handling and upgrading methods shown in Figure 5.3.1, it is reasonable to assume that the range of heating value for 95% of the coal supplied to the boilers will be $\pm$ 15% of the assumed average. For several of the coal preparation methods shown, this will also be statistically true for 99.7% of the coal. In other words, 95% (or 99.7%) of the coal to the boilers will be in range 5,060 - 6,840 Btu/lb at 20% moisture assuming coal below 3,600 Btu/lb at 20% moisture is rejected in the mining operation.

This corresponds to a range of ash content of 35% - 23.3%. This is the most reasonable value for coal feed range which can be assumed at present until a testing programme is completed.

Paragraph 2.5 shows the worst, average and best coals which result from such assumptions. While that paragraph illustrates a range of heating value and ash content, it cannot be assumed that a process which selectively mines, blends or upgrades the coal heating value would automatically average other properties such as sulphur content, grindability, and fusion temperature. At present, it would be unrealistic to apply such a statistic averaging to all other qualities, and this will only be possible when the mining plan becomes available.

It is concluded that a large number of methods of coal preparation/blending may prove to be possible. A test programme will determine which one will provide the most reliable and economical coal feed to the power plant.

5.3.3 System Selected in Conceptual Study

Although it may eventually be found desirable to pass at least 30% of the coal through a coal cleaning plant, the average coal quality adopted for the purpose of this study does not allow for any coal preparation or beneficiation. It is probable that all the coal will pass through at least one or two stages of rotary breakers for clay removal, but no allowance has been made for any reduction in ash content that this may produce. No increase in ash content has been allowed for the inevitable dilution of coal by mine waste not rejected.

The major disadvantages of any coal washing process are that the properties of the clay deteriorate as it becomes wet, and that disposal of the clay-laden waste water from a wet coal preparation plant may be troublesome.

5.3.4 Proposed Beneficiation Test Programme

To resolve the best means of removing clay from the coal, and indeed the necessity for doing this, Integ-Ebasco have proposed a beneficiation test programme for investigation of clay removal by various techniques including screening, dry cleaning, heavy media separation, Siebra crushers and rotary breakers. The programme would also investigate the handling and stacking properties of the coal, and show the practicability of the alternatives shown in Figure 5.3.1.

The programme will also investigate the possibility of drying the coal to improve the handling properties of the clay. This technique is used in some lignite burning plants where the coal is dried adjacent to the boiler using warm flue gas. Dust or ash removed in the process is collected in the precipitators.

5.3.5 System Design

The conceptual coal handling and preparation system has a coal storage, blending and beneficiation area adjacent to the mine as shown in Figure 5.3.7. Coal is directed out of the mine on two conveyors, each with a capacity of 2,500 tons/hr. A third conveyor of the same capacity can carry coal or waste material. The mine conveyors transport the coal to the interface or transfer point between the mine and coal preparation. Here the coal is directed into the handling and preparation system in two streams.

The first operation combines primary crushing and clay removal in rotary breakers or Siebra crushers. Each breaker has a capacity of about 2,350 tons/hr at minus 8 in. It may be advantageous to place two rotary breakers in series for clay removal, and allowance is made for the location of a second stage of rotary breakers, crushing to minus 4 in. The need for a second stage will be confirmed by the proposed beneficiation test programme.

The secondary crusher can handle coal with a high clay content, but does not reject any clay. Good quality coal from this secondary crusher is blended in 4 live stockpiles deposited in longitudinal rows by means of a traversing stacker-conveyor system. The grade of coal reclaimed from the stockpile depends on the grade of coal delivered and where it is deposited in the pile. Two bucket-wheel reclaimers reclaim from the 4 longitudinal piles on a continuous basis for delivery to the overland conveyor system. The reclaimers can be automated and the reclaim rate varied to suit power plant requirements.

Poor quality coal is stacked in either live or compacted storage by a third radial stacker. This coal can be fed to a beneficiation plant, if test work on the coal indicates that this is desirable. Alternatively, it may be fed to the power plant at times of low system demand when plant reliability is of less importance.

In general, the coal handling plant is designed to be flexible and provide either blending of different grades of coal, direct feed from mine to power plant or beneficiation of low grade coal. Until further data is available on the handling and other properties of the coal, the concept shown in Figure 5.3.2 can only be regarded as preliminary.

The overland conveyor system receives coal reclaimed from the blending storage stockpile located near the mine mouth and transports it up to the generating station site located approximately 3 miles away. The overland conveyor system consists of 2-54 in. wide belts in parallel each rated 2,000 tons/hr and located 150 ft. apart, for security in case of fire or belt failure. Each of the two conveyors is composed of 3 flights, each one mile long.

The conveyors are protected against the weather and have a fire protection system incorporated under each cover. At the top of overland conveyor a surge bin is provided to permit the overland conveyors to be emptied completely on shutdown. In normal operation, the bin is empty, to protect against the danger of a coal hang-up. From the surge bin, separate conveyors feed into the end of the boiler building; either of the belts entering the power plant can supply the coal bunkers of all four units.

A dual system of belts runs the entire length of the boiler building. Each boiler has eight bunkers, four on each side. Each row of bunkers is fed by a twin row of flight conveyors. Each unit has eight hours bunker capacity at maximum pulverizer output. Bunker slopes are 70° to the horizontal to ensure flow of the most difficult material. To ensure coal flow from bunker to pulverizer, 36 in. diameter bunker outlets and 36 in. belt feeders have been selected.

5.3.6 Location of Coal Storage & Coal Preparation

It is proposed that a compacted storage pile of approximately 1½ million tons be located at the mine mouth. This compacted pile can supply the power plant for up to 45 days at 70% capacity factor if the mine production is restricted. Alternatively, it provides storage for times when the mine is producing and the power plant is shut down or at a much reduced load. Accurate sizing for this compacted pile will require a more detailed knowledge of the manner in which the mine will be operated and the future operating role of the generating plant.

The size of this compacted pile is such that it would not be economic to locate it at the power plant site. In addition, the mine requires a storage area for a million tons of coal in its early stages of development, long before the power plant commences operation. It is thus evident that a large compacted coal pile should be located at the mine mouth.

Some live surge capacity is required at the mine mouth to accommodate variations in mine feed rate and the operation of the remainder of the coal handling system. The coal could not be fed from mine to overland conveyor continuously without some live storage. The options, which are therefore available are to provide live storage at both the power plant and the mine, or at the mine only.

It is not considered realistic to install only a single overland conveyor, if there were only 2 or 3 days power plant storage.

The study compared 3 schemes:

Scheme A - Main coal handling at mine, 2-100 overland conveyors, no open coal storage at power plant.

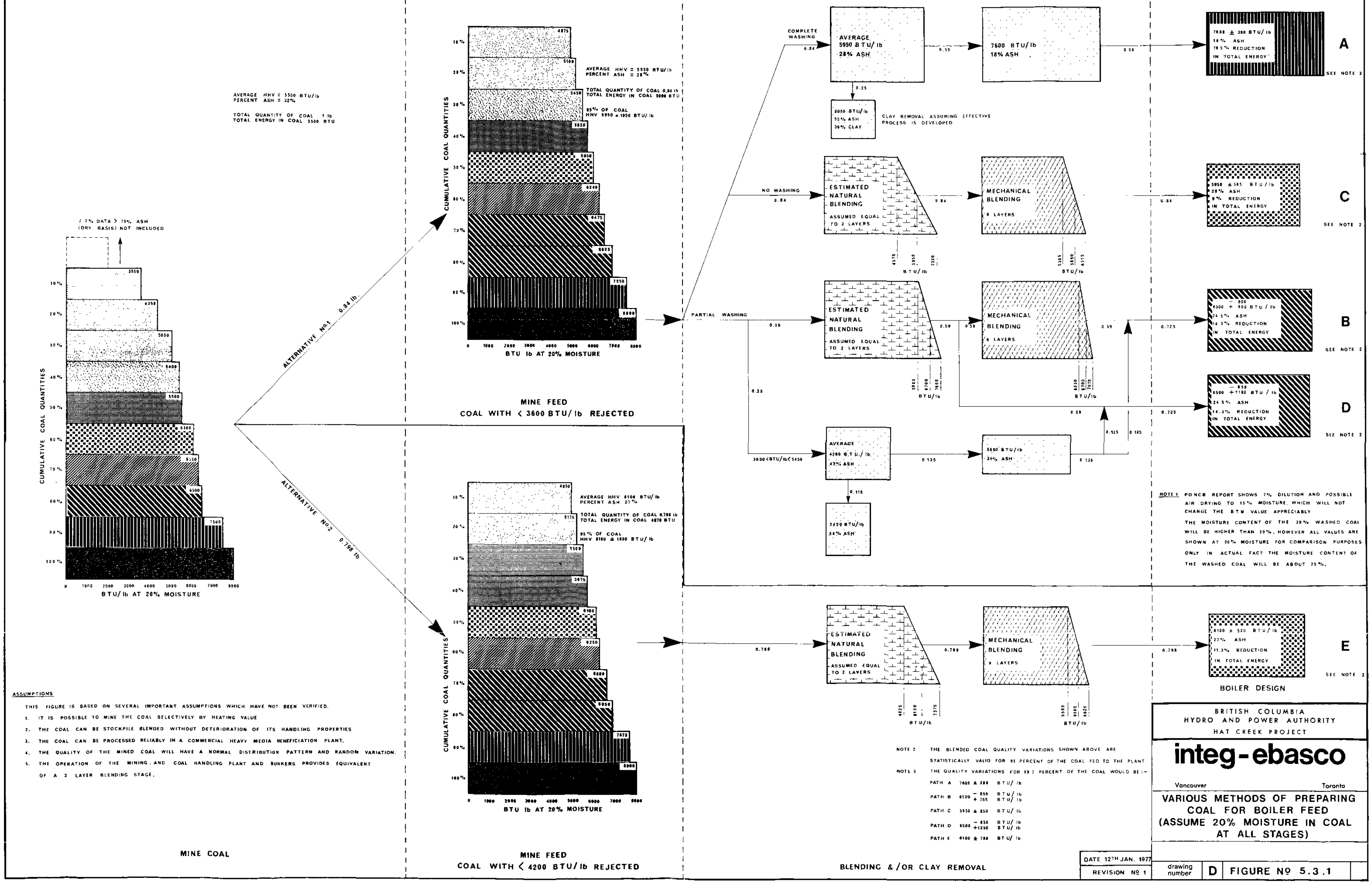
Scheme B - Dead and surge coal storage at mine. 2 x 100% overland conveyors with 2-3 days live storage at power plant.

Scheme C - Dead and surge coal storage at mine. 1-115% overland conveyor with 10 days live storage at power plant.

Scheme A was selected as the most economic and the one providing the least environmental dislocation. It will, however, be necessary to ensure that labour disputes which might affect the mine would not immediately shut down the coal handling plant. During the detail design phase, it may be found desirable to maintain some live coal storage at the power plant.

5.3.7 Location of Beneficiation Plant

A beneficiation plant could be located close to the mine or adjacent to the power plant. A case can be developed in support of either choice. On the one hand the power plant location would bring the beneficiation plant under the power plant management. Most mine mouth power plants depend on a separately owned mine operator for their fuel supply, and the interests of the mine and power plant management are often in conflict. In such a situation it is clearly better that the beneficiation plant should cater primarily to the power plant's needs. At Hat Creek, B.C. Hydro will manage both the mine and the power plant, hence the coal treatment plant located at the mine could



ASSUMPTIONS

THIS FIGURE IS BASED ON SEVERAL IMPORTANT ASSUMPTIONS WHICH HAVE NOT BEEN VERIFIED.

1. IT IS POSSIBLE TO MINE THE COAL SELECTIVELY BY HEATING VALUE
2. THE COAL CAN BE STOCKPILE BLENDED WITHOUT DETERIORATION OF ITS HANDLING PROPERTIES
3. THE COAL CAN BE PROCESSED RELIABLY IN A COMMERCIAL HEAVY MEDIA BENEFICIATION PLANT.
4. THE QUALITY OF THE MINED COAL WILL HAVE A NORMAL DISTRIBUTION PATTERN AND RANDOM VARIATION.
5. THE OPERATION OF THE MINING, AND COAL HANDLING PLANT AND BUNKERS PROVIDES EQUIVALENT OF A 2 LAYER BLENDING STAGE.

NOTE 1 PONCB REPORT SHOWS 7% DILUTION AND POSSIBLE AIR DRYING TO 15% MOISTURE, WHICH WILL NOT CHANGE THE BTU VALUE APPRECIABLY

THE MOISTURE CONTENT OF THE 30% WASHED COAL WILL BE HIGHER THAN 20%, HOWEVER ALL VALUES ARE SHOWN AT 20% MOISTURE FOR COMPARISON PURPOSES ONLY IN ACTUAL FACT THE MOISTURE CONTENT OF THE WASHED COAL WILL BE ABOUT 25%.

NOTE 2 THE BLENDED COAL QUALITY VARIATIONS SHOWN ABOVE ARE STATISTICALLY VALID FOR 95 PERCENT OF THE COAL FED TO THE PLANT

NOTE 3 THE QUALITY VARIATIONS FOR 99.7 PERCENT OF THE COAL WOULD BE:-

PATH A 7600 ± 380 BTU/lb

PATH B 6500 $^{+755}_{-850}$ BTU/lb

PATH C 5950 ± 850 BTU/lb

PATH D 6500 $^{+1350}_{-850}$ BTU/lb

PATH E 6100 ± 780 BTU/lb

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

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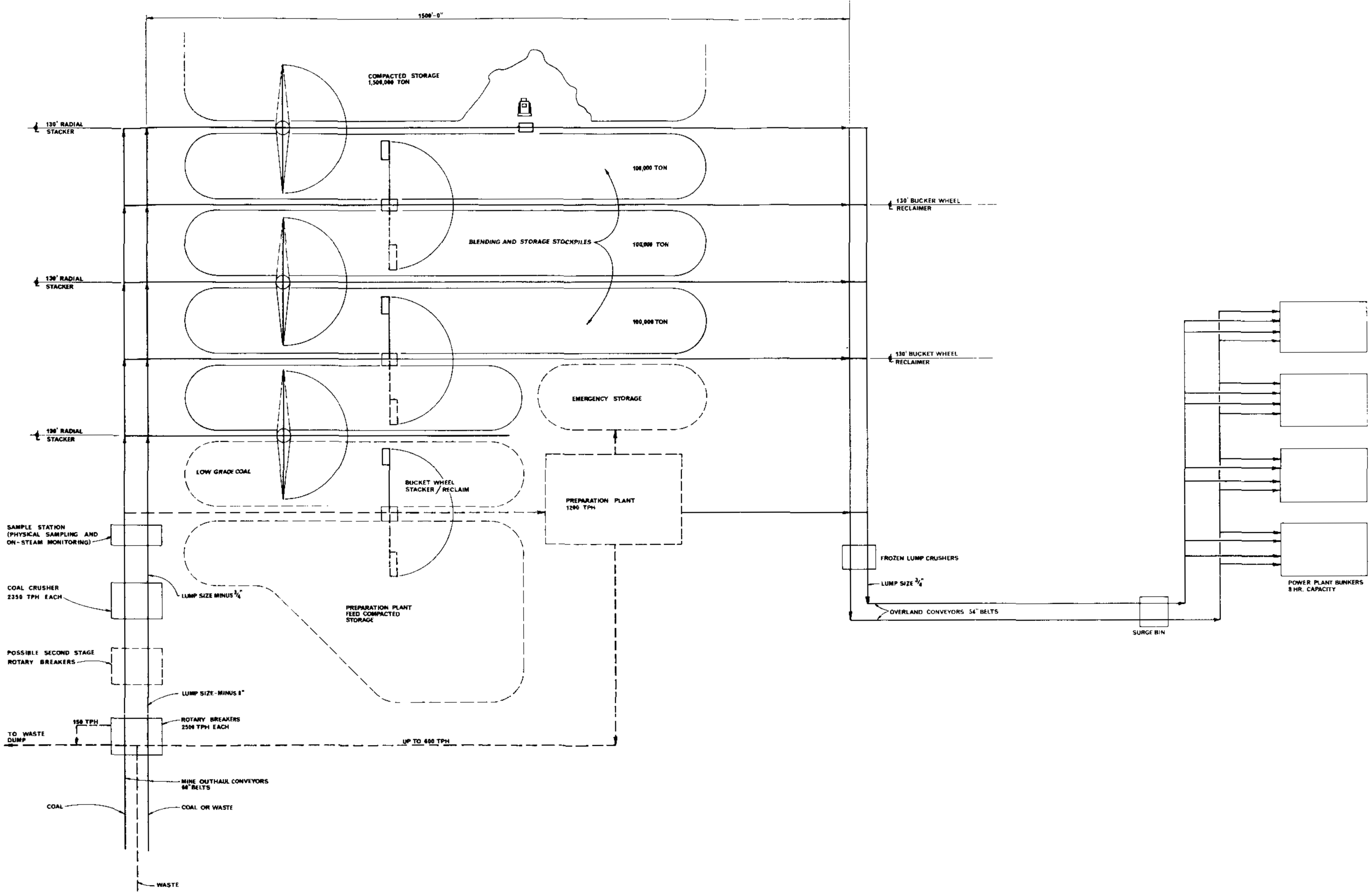
Vancouver Toronto

VARIOUS METHODS OF PREPARING COAL FOR BOILER FEED (ASSUME 20% MOISTURE IN COAL AT ALL STAGES)

DATE 12TH JAN. 1977

REVISION Nº 1

drawing number D FIGURE Nº 5.3.1



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COAL HANDLING PLANT

F FIG. NO. 5.3.2

5.4 ASH

The principal factors involved in the design of the ash plant are:

- the methods by which ash is removed
- the disposal area
- water consumption for ash removal purposes.

These factors are closely interrelated.

5.4.1 Available Alternatives

The options available at the Harry Lake site are listed in Table 5.4.1 Ash Handling & Disposal Alternatives.

Table 5.4.1

ASH HANDLING & DISPOSAL ALTERNATIVES

Method of Transport	Wet Sluicing	Dry Transport		
Equipment or Installation	Pipeline	Conveyor	or	Truck
Disposal Location	Lagoon in Medicine Creek	Mine spoil dumps	Upper Medicine Creek valley	Sale or use for roads

The ash may be transported to the disposal area by a wet slurry system, normally with a ratio by weight of 15-20 percent ash. Alternatively, it may be conveyed in a semi-dry state, with 1 part water to about 6 or 7 parts ash, for dust suppression.

a) Wet Sluicing

The only suitable site for an ash lagoon with an adequate capacity for 20 or 30 years of ash production is the upper Medicine Creek valley. If a 300 ft. high dam were located at the 3900 ft. level in the narrow part of the valley, an area of just over 1000 acres could be impounded.

The storage capacity which would be provided by such a dam is shown in Figure 5.4.2.

The form of the curves in this Figure reflect that the Medicine Creek valley is narrow and relatively steep between the 3900 ft. and 4100 ft. contours but widens out between the 4100 and 4200 ft. contours. The majority of the storage capacity is therefore impouned by the top 100 ft. of the 300 ft. high dam.

During the conceptual study, no map of the upper Medicine Creek valley was available with contours closer than 100 feet so the estimates of storage capacity and area are necessarily approximate.

Although the wet sluicing system would require a large amount of water to transport the ash to the lagoon, in normal practice, most of the sluicing water would be recovered from the ash pond.

The shape of the Medicine Creek valley would preclude the building of a barrier or weir to separate the parts of the lagoon where the slurry would be discharged from the part where the water could be recovered. However, satisfactory separation of the water and ash would probably be achieved by recovering water via a floating intake at least 2000 ft. from the point of ash discharge.

The principal disadvantages of the wet sluicing system which have led to its rejection are:

- It would involve higher water consumption than dry removal.
- The fly ash might not settle satisfactorily from the water in a reasonable time.
- There might be seepage or leaching from the lagoon, unless it were lined.
- About 1000 hp would be required to return recycled water to the power plant.
- Foundation conditions for the dam are uncertain.
- It would be unsightly. Parts of the area of ash would be exposed drying banks liable to cause dusting in dry windy weather.
- The total cost for wet sluicing would be considerably higher than for dry ash removal.

b) Dry Removal

The ash can be removed from the site "dry" (i.e., containing only enough moisture to suppress dust). The most economical method is to transport the ash by conveyor to one of the mine spoil areas, preferably the area located in the lower Medicine Creek valley, for mixing with the mine waste. Figure 5.4.1 illustrates this method which has been selected in this study.

Pneumatic transport or trucking were considered but were found more costly. Furthermore, as the distance to the disposal area increases, trucking becomes even less competitive. Although trucks would normally allow more flexible ash dispersion than a conveyor, in this case the ash will be dispersed into the mine spoil by the equipment already installed for mine spoil disposal.

5.4.2 Water Consumption

The 'dry' ash system requires water for wetting the ash and there may be need for limited spraying to prevent local dusting at the disposal point. The estimated water consumption of the ash disposal system is about 500 USgpm.

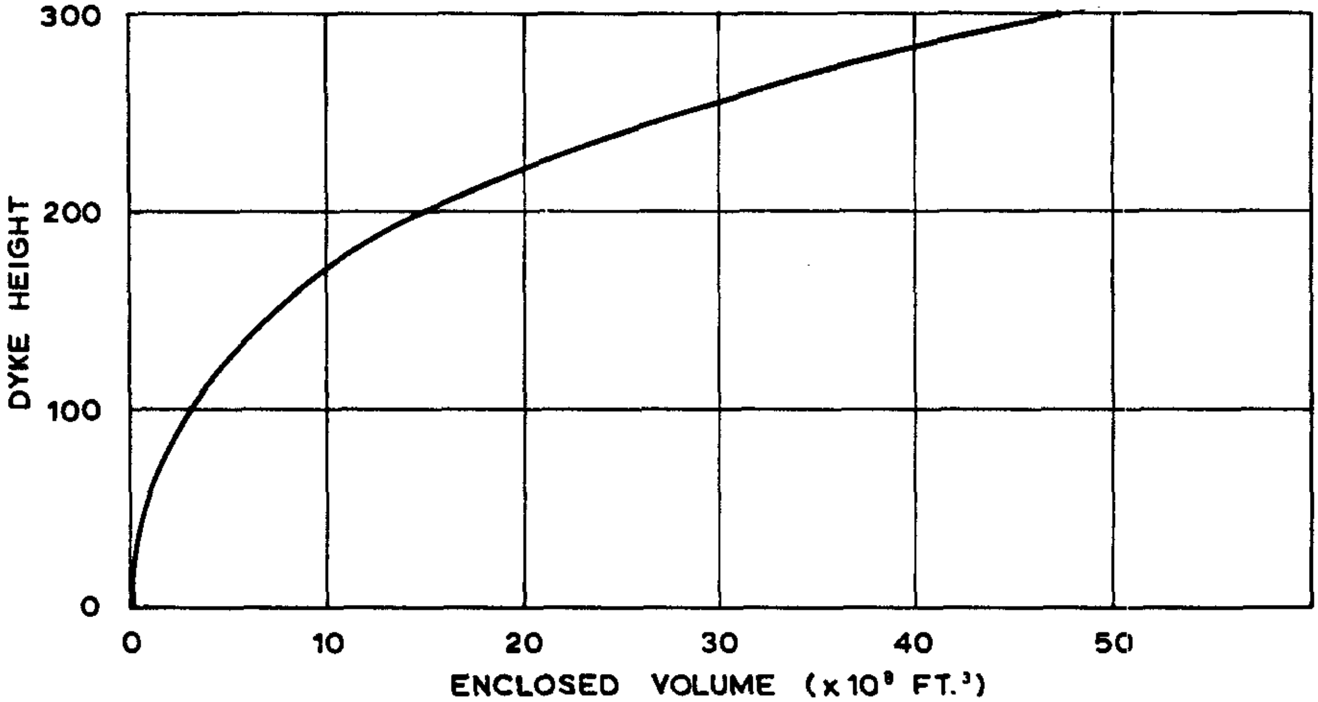
5.4.3 Disposal Areas

In 35 years, assuming an overall average station capacity factor of 50 percent, the plant will produce some 3 billion cu. ft. of ash, equivalent to a cube with sides of 1475 ft. The only suitable disposal areas appear to be the sites selected for mine spoil dumps, or the upper Medicine Creek valley.

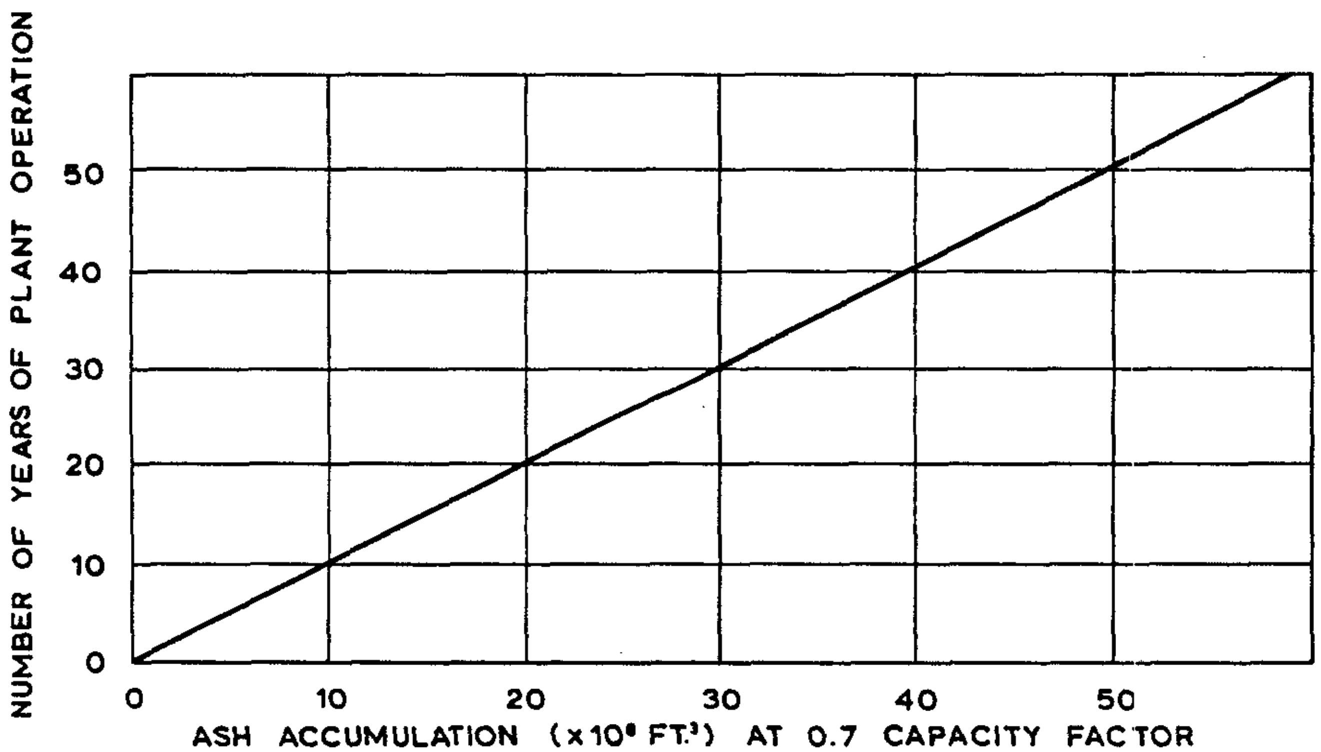
Three mine disposal areas are contemplated at present. Two of them are northwest and northeast of the pit some distance from the Harry Lake site. The third is in the lower Medicine Creek valley and is close to the power plant. This provides the most convenient location for plant ash disposal subject to stability of the area being proven.

5.4.4 Ash Removal from Steam Generator

In the suspension firing of pulverized coal, about 70/80 percent



GRAPH OF DYKE HEIGHT VS. ENCLOSED VOLUME



MEDICINE CREEK ASH POND

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY HAT CREEK PROJECT
ASH ACCUMULATION GRAPH
integ – ebasco · FIG. Nº 5.42

of the ash normally passes through the steam generator and is removed in the precipitator as fly ash, a light material with average particle sizes of about .01 to .06 mm. The remaining 20/30 percent falls to the bottom of the steam generator as bottom ash or clinker, generally in a semi-fused state. The proportion of bottom ash is dependent on the ash properties of the coal and may be as high as 45 percent, as experienced at Centralia G.S. in the state of Washington.

To provide margins for the variance in the percentages of the ash which become bottom ash and fly ash, this conceptual design allows for up to 55 percent as bottom ash, and for up to 85 percent as fly ash. Thus the design can also accommodate fluctuations in the ash content of the coal which is being burned.

Table 5.4.2, Design Ash Quantities, shows the effects of the various assumptions, on calculated quantities of ash to be handled.

TABLE 5.4.2

DESIGN ASH QUANTITIES - (2092 MW net Station)

	Bottom Ash		Fly Ash	
Normal: average coal	30%		70%	
28% ash (1)	158	tons/hr	368	tons/hr
Design: average coal	55%		85%	
28% ash (1)	289	tons/hr	446	tons/hr
Design: worst coal	55%		85%	
35% ash (1)	487	tons/hr	753	tons/hr
(with 15% margin)				

(1) All ash percentages are on a 20% moisture basis.

The manner in which the wide variation in possible ash quantities will be handled is detailed in subsequent paragraphs.

a) Bottom Ash

The bottom ash falls into a water filled hopper below the steam generator.

It is normal practice to remove the ash from the bottom hopper by crushing it and then sluicing it on a cycle of up to 4 hours operation per 8 hour shift. The Hat Creek ash hoppers and water jet pumps must be designed for a maximum ash volume which is about 3 times as great as the anticipated normal volume.

The proposed ash removal system is designed to handle what is judged to be the highest reasonable bottom ash quantity, with a 100% duty cycle, i.e. that from 35% ash coal, with up to 55% as bottom ash and using a 15% margin. The system can remove the normal design quantity of ash shown in Table 5.4.2 with a 60% duty cycle or by operating about 5 hours per shift, and ordinarily operates about 3-4 hours per shift in accordance with normal practice.

Using the philosophy developed above, the bottom ash hopper is designed to accommodate 12 hours accumulation of ash when burning 28% ash coal and on the assumption that 55% of the ash is bottom ash. This represents a capacity of 870 tons/unit. Should a unit burn 35% ash coal continuously, the minimum bottom ash hopper capacity will be 7 hours.

Although the amount of ash which will be produced is high, the Hat Creek units do not present unique or extreme design problems. Naturally, the design of the boiler throat, ash hopper and detailed provisions for clearing "bridging" in the hopper require a realistic approach in respect of the ash quantities considered for design, and due attention to design detail in line with existing experience.

A shortage of fuels has forced utilities throughout North America to look at coal sources which have much higher ash content than was common in past practice. As a result, a number of proposed stations of 2000 MW and larger are now under construction or being designed for conditions at least as arduous as those expected at Hat Creek.

b) Fly Ash

The variation in the amount of fly ash which the units may produce is not as great as the variation in bottom ash. Each unit produces approximately 110 tons/hr of fly ash, at the design condition as shown in Table 5.4.2, for 28% ash coal. Most of this is collected in the hoppers at the electrostatic precipitator. Excessive retention time in these hoppers may cause the fly ash to "pack" or "bridge" with resulting problems in removal. It is therefore customary to specify a fly ash system removal capacity of about twice the accumulation rate, and to operate the system continuously. This allows sufficient margin for the design condition for 35% ash coal.

A pressure or vacuum pneumatic conveying system provides the most convenient method of handling fly ash. The vacuum system involves fewer components and a lower first cost; however, for the Harry Lake site a vacuum system would be severely limited by the reduced atmospheric pressure. The largest "standard" vacuum fly ash system available would have a capacity of 50 tons/hr near sea level. For operation at 4600 ft elevation the manufacturer would predict a capability of only 35 tons/hr, and multiple parallel systems would be required. This must be compared with a maximum capacity of 80 - 100 tons/hr for a pressure conveying system, which would not be significantly affected by altitude.

The vacuum system would also be limited to a conveying distance of about 500 ft, in order to maintain reasonably low line velocity at the terminal end. For greater distances, it would be necessary to discharge to a transfer silo, followed by a second stage of conveying. The required conveying line distance for this station is over 800 ft, which would necessitate the two stage arrangement.

Accordingly, the proposed design has a pressurized pneumatic conveying system including either 2 or 3 parallel trains to achieve the necessary design capacity of about 220 tons/hr. It empties the hoppers on an automatic, continuous sequencing basis and transports the fly ash to one of the two storage silos (per unit) for disposal.

5.4.5 Ash Transportation and Disposal

The concept for ash disposal is to remove it dry, with only enough water to ensure dust suppression. It is estimated that between 400 and 500 lb of water are required per ton of ash. This water is retained by the ash.

a) Bottom Ash

The bottom ash is dewatered in dewatering bins situated close to the plant. The required dewatering bin capacity is obviously dependent on the rate of settlement of the ash and the amount of bottom ash which will be produced, but the major factor in sizing the bins is the planned cycle of loading, dewatering and unloading. Many generation stations have dewatering bins sized so that the ash need not be removed from the site during the weekend or the night shift. This is an important consideration if the ash is removed by truck. However, assuming that

55 percent of the ash will be bottom ash with a wet density of 65 lbs/cu ft, the dewatering bin requirements would be as shown in Table 5.4.3, Dewatering Bin Capacities.

TABLE 5.4.3

DEWATERING BIN CAPACITIES

	Ash volume per unit ,000 cu ft	No. Bins per Unit	Approx. Bin Sizes, ft
Weekend, 64 hours capacity	176	5	45 dia x 55
Overnight, 16 hours capacity	44	3	35 dia x 38
Continuous, 12 hours capacity	33	2	35 dia x 40

It is quite clear from Table 5.4.3 that the quantity of ash produced by the Hat Creek units merits continuous removal of the ash from the site and that the dewatering bin capacity should be the minimum which allows sufficient dewatering time and does not compromise the reliability or ease of operation of the plant.

It will be necessary to provide two dewatering bins per unit so that settling-out can take place in one while the other fills. Experience at Centralia shows that a good ash can be dewatered to a level of 15%-20% water in the ash in four hours. However, considerations of reliability make the choice of a 12 hour capacity more acceptable for this conceptual design. On this basis, the probable mode of operation is shown in Table 5.4.4, Dewatering Bins - Mode of Operation, assuming that the ash is removed from the boilers during 4 hours per shift.

TABLE 5.4.4

DEWATERING BINS - MODE OF OPERATION

Per Unit

	Bin 1	Bin 2
Hour 0 - 4	Empty	Dewater
Hour 4 - 8	Fills	Dewater & Discharge
Hour 8 - 12	Dewater	Empty
Hour 12 - 14	Dewater	Fills
Hour 14 - 16	Discharge	Fills
Hour 16 - 20	Empty	Dewater
Hour 20 - 22	Fills	Dewater
Hour 22 - 24	Fills	Discharge

Dewatering bins can discharge ash at 500 tons/hr, which allows the selected bins to empty in about 1½ hours. The cycle shown in Table 5.4.4 allows each bin to receive the bottom ash corresponding to an 8 hour shift, dewater it and discharge it during the next shift and be available to accept the ash from the third shift. If the bins were designed for 8 hours accumulation of ash it would be possible to overload them, whereas designing them for 12 hours ensures that there is capacity available in case of interruption in operation of the discharge or disposal system.

Accordingly, two bins of about 35 ft. diameter, 40 ft. high are required.

Water from the dewatering bins passes to a surge tank and from there to a settling tank, as shown on Drawing M115 at the back of this volume.

b) Fly Ash

The fly ash is stored in silos near the plant. The fly ash silos can be unloaded while being filled so that it is not essential to install two for each generating unit. However, the required storage volume would be 54,000 cu. ft. if sized for 12 hours and therefore, two silos of 35 ft. diameter and 45 ft. height are proposed.

c) Disposal

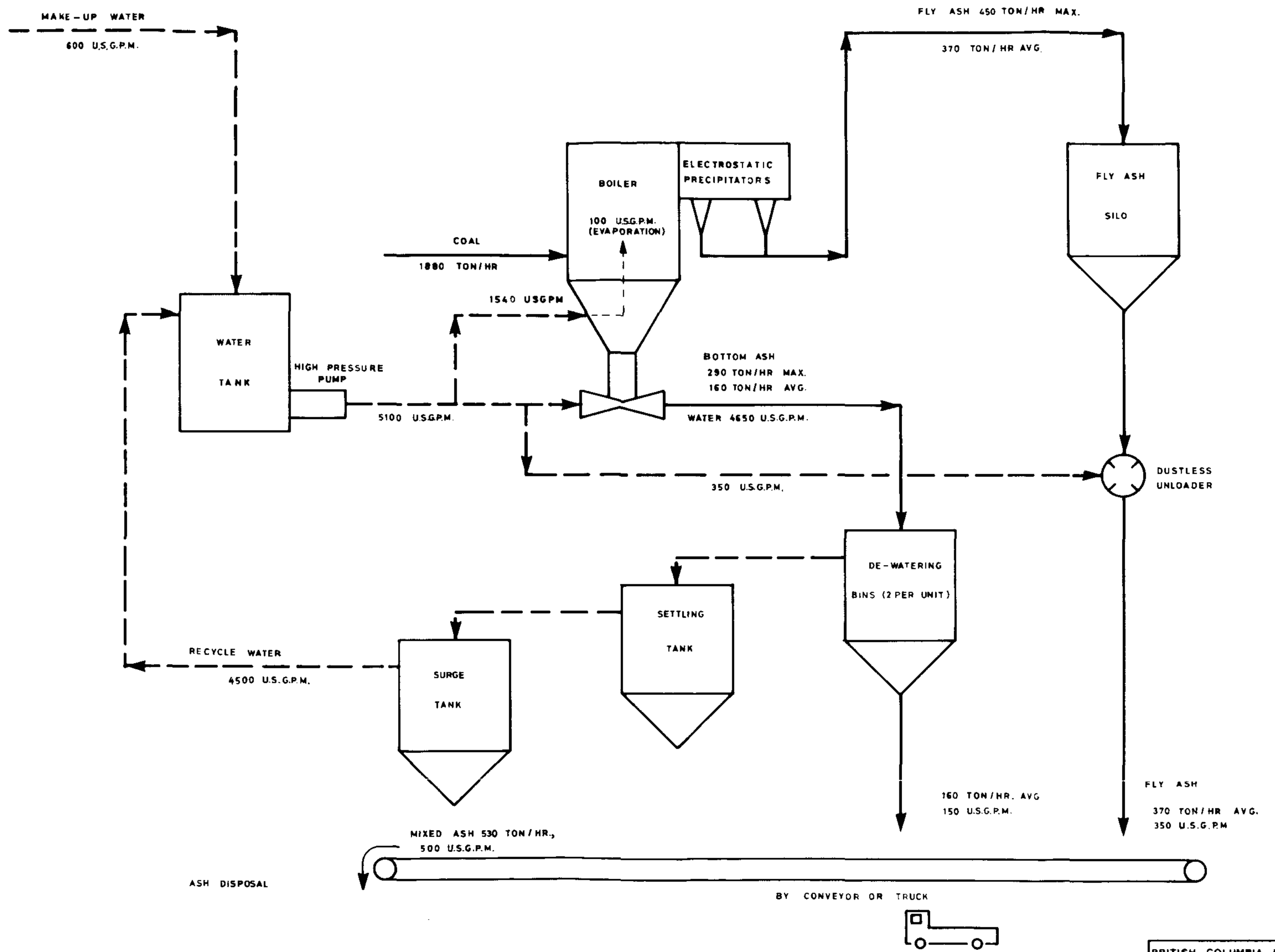
The dry ash is transported to the Medicine Creek valley by conveyor dedicated to ash removal. Fly ash is sprayed with water as it is placed on the conveyor, and subsequently the damp bottom ash placed over it. It is then discharged evenly over the selected areas. In dry weather, the ash will be sprayed by truck, with a moisturizing agent or sealer, which will prevent dusting until the ash can be covered by mine waste or mixed with it.

5.4.6 Medicine Creek Diversion

A diversion of Medicine Creek is necessary for the lower Medicine Creek valley to be used for ash and waste disposal. In fact, all the concepts which are reviewed in this report require that Medicine Creek be diverted into the reservoir which is formed by the Hat Creek diversion. The diverted creek would be carried in a closed pipe large enough to handle the highest probable flow.

5.4.7 Conclusions

The recommended method of ash disposal is a dry ash system via conveyor to the lower Medicine Creek mine disposal area. Should this area be shown to be unacceptable for mine waste disposal, the mine waste area northeast of the mine could be used. The ash represents about a 10% addition



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

ASH REMOVAL
DRY TRANSPORT

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to the total volume of the mine waste material.

Design for removal of the ash from the boilers is conventional, although the ash quantities are unusually large. No unusual or unproven technology is required but the magnitude of the ash quantities, and their variability, require realistic assumptions on sizing and careful attention to detail design.

5.5 WATER

Although the Harry Lake site is in an area of low rainfall and high natural evaporation it is within 15 miles of two of B.C.'s major rivers, the Fraser and the Thompson. The minimum flows of these two rivers are 1.8 million and 2.0 million USgpm respectively, and the maximum anticipated plant demand will represent less than 1.5% of the minimum flow of either river. The problem of obtaining water from these rivers is complicated by the difference in elevation between intake and plant site, and the commercial importance of fish in both rivers.

5.5.1 Plant Water Consumption

In reviewing the amount of water which the plant consumes it is important to distinguish between systems in which water is consumed, and lost from the system, and those in which it is used and recycled. The plant is to be designed for zero discharge, and this dictates that water can only be consumed by evaporation, cooling tower drift, or by disposal of water mixed with ash. Of these three consumptions only the third, disposal of water with the ash, can be altered with reasonable freedom by the plant designer, because evaporation and drift are largely fixed by the type of cooling system used.

The total water consumption of the plant is shown in Table 5.5.1, Water Consumption Summary for the worst design condition of 57°F wet bulb.

TABLE 5.1.1

WATER CONSUMPTION SUMMARY (USgpm)

	Capacity Factor of 2000 MW (nom.) Plant		
	100%	70%	50%
Cooling Tower Evaporation	17600	12320	9240
Cooling Tower Drift	100	70	52.5
Cooling Tower Blow Down	1360	952	714
Less Water Supplied From Boiler Blow Down and Domestic Use (e.g. 480 + 200)	680	536	452
Net Consumption (Cooling Towers)	18380	12806	9554.5
Boiler Blow Down	480	336	252
Soot Blowing	460	322	242
Water Treatment Regeneration	240	168	126
Less From Cooling Tower Blow Down	1000	700	525.5
Net Consumption (Demin System)	180	126	94.5
Domestic Water	200	200	200
Make-Up Reservoir Evaporation	90	90	90
Ash System	600	420	315
Less From Cooling Tower Blowdown and Water Treatment Regeneration (e.g. 360 + 240)	600	420	315
Net Consumption (Ash System)	0	0	0
Total Plant Consumption	18850	13222	9939

NOTE: In a coal washing plant, 300 to 600 USgpm more would be required.

It is obvious that the principal factor affecting water consumption is the type of cooling system which is selected. At rated capacity, the plant rejects 2900 MW of heat or 10×10^9 Btu/hr and if an evaporative system is used, this alone would require 17,600 USgpm during the summer months when ambient air conditions were 65°F dry bulb, 57°F wet bulb. During winter, the consumption of the cooling system at rated plant output is about 13,500 USgpm. The average annual consumption of the plant at 70% capacity factor will be less than 12,000 USgpm, and will depend on the average load produced in the different seasons.

5.5.2 Alternatives Considered

In the analysis of the overall plant water balance and supply system, the following alternatives were considered:

Types of Cooling:	Evaporative Towers Dry Cooling Towers Wet/Dry Cooling Towers Pond Spray Pond
Water Sources:	Thompson River Fraser River Local: Hat Creek, Medicine Creek, Mine drainage
Modes of Operation:	Design for 50% up to 70% capacity factor, with capability to run at 100% capacity factor for up to six months.

It was found that the most economic and practical system employs evaporative cooling and is supplied with water from the Thompson River, supplemented, if possible, by local water supplies.

5.5.3 Water Sources

Only the Thompson and Fraser Rivers are capable of producing approximately 20,000 USgpm which the plant requires if an evaporative cooling system is selected. A study by Sandwell and Company considered routes for supplying water to the Harry Lake site from these rivers, by overland pipe and tunnel. The route selected by Sandwell is from an intake on the Thompson River above Ashcroft via an overland pipeline passing up the north side of Cornwall Creek. The rise in elevation of the pipeline is 3650 ft. from an intake at 1000 ft.

The conceptual design of the pipeline was based on a capacity of 30,000 USgpm which was later modified to 25,000 USgpm. These capacities were determined during the early part of the power plant conceptual study when the exact power plant, coal preparation and mine needs were unknown. An excess capacity was included to provide for maintenance time and to allow the large water pumping capacity to be shut down at times of peak system demand. This concept does not now appear economic because of the high cost of the pipeline. The pipeline should be designed to the minimum capacity which its engineers consider is compatible with providing absolutely reliability of supply.

In paragraph 5.5.1 it is noted that the average consumption over the year is less than 12,000 USgpm while at rated load in summer, the consumption is 18,850 USgpm.

On this basis, it seems probable that the pipeline from the Thompson need only be rated for about 18,000 USgpm, but the exact sizing will depend on the final water requirements of the power plant, mine, and possible coal beneficiation plants.

The power plant reservoir has a total capacity of 4700 acre feet and can supply the power plant with enough water for 30 days operation at rated output in summer, without the level dropping too low for the fire pump intakes.

A fill dam of 130 ft. maximum height impounds a local gully to approximately elevation 4500 ft.

A number of alternate storage sites are available close to the power plant site should the rock conditions prove to be unsuitable at the selected location.

The local rivers, in particular the Hat Creek, have erratic flows, and may almost dry up in summer. However, it will be necessary to divert the Hat Creek as part of the mine development, and some storage will be provided above the mine to prevent flooding during high runoff. Monenco Pacific is currently investigating the diversion.

Monenco estimates that the average flow of Hat Creek just below the Medicine Creek confluence is 24 cfs or 10,800 USgpm. An average annual flow of as little as 8 cfs has been recorded, but Monenco propose sufficient storage to maintain a minimum acceptable flow through such dry periods. The official records of Hat Creek flow are shown in Table 5.5.3, but these do not present a complete picture because the records post-date the original valley water licences.

It is Monenco's preliminary opinion that up to 16-18 cfs or 7200 USgpm could be removed from Hat Creek on a continuous basis, if sufficient storage were provided. The remaining 6-8 cfs would be supplemented by downstream tributaries to a level of 10 cfs, as the Creek flowed north-east towards Carquile. This would be sufficient for existing licences.

Medicine Creek flows will be diverted into the Hat Creek reservoir at 3200 ft. elevation. The estimated average flow from Medicine Creek is 3-4 cfs after allowance is made for existing licences, but this is included in the Hat Creek flows shown in Table 5.5.2, Monthly and Mean Annual Discharges.

TABLE 5.5.2

HAT CREEK NEAR UPPER HAT CREEK - STATION NO. 08LF061

MONTHLY AND ANNUAL MEAN DISCHARGES IN CUBIC FEET PER SECOND FOR THE PERIOD OF RECORD

JAN.	FEB.	MAR.	APR.	MAY	JUN.	JUL.	AUG.	SEP.	OCT.	NOV.	DEC.	MEAN	YEAR
----	----	----	----	----	----	----	----	----	6.5	8.9	7.6	----	1960
6.7	5.8	11.6	10.7	54.4	49.7	10.1	4.2	5.4	8.5	8.0	7.2	15.2	1961
6.9	9.5	----	54.7	93.5	106	22.2	9.7	9.5	15.1	11.7	----	----	1962
----	----	15.4	17.5	59.5	63.9	23.8	9.9	8.7	9.3	8.8	8.4	----	1963
8.0	7.6	9.3	21.9	42.0	253	60.0	17.5	31.2	26.7	19.5	14.2	42.3	1964
10.9	10.1	12.9	46.7	87.6	92.4	43.8	25.1	18.6	12.7	11.9	8.1	31.8	1965
8.3	6.9	22.8	24.8	60.3	65.0	73.1	29.3	12.0	15.2	13.0	10.3	28.6	1966
6.7	5.9	6.5	15.0	90.9	157	26.9	8.1	4.5	7.8	10.4	7.2	28.9	1967
6.3	6.5	8.3	10.1	53.7	96.4	38.0	11.0	8.9	10.0	10.9	9.1	22.4	1968
6.9	5.8	6.8	15.0	107	53.9	83.2	13.6	11.3	12.5	11.8	10.3	28.4	1969
6.5	5.9	7.8	8.8	18.1	28.5	6.4	3.5	3.2	4.1	4.4	4.9	8.5	1970
5.7	7.2	4.5	12.7	80.8	104	32.9	5.6	3.8	6.6	7.5	5.8	23.1	1971
6.0	6.5	13.1	12.0	77.7	141	46.9	16.3	11.3	12.0	9.9	7.3	30.0	1972
6.5	7.4	9.1	13.6	28.4	20.0	7.4	3.2	4.2	6.3	6.2	7.1	10.0	1973
7.1	7.1	10.7	20.3	65.7	94.7	36.5	12.1	10.2	11.0	10.2	8.3	24.5	MEAN

Location - Lat 50 45 22 N
Long 121 35 18 W

Drainage Area 135 sq. miles

Mine drainage may yield a significant water flow, and a study by Golder Brawner and Associates to determine the magnitude of it is now underway. The mine area will collect precipitation equivalent to an average flow of up to 1000 gpm, ignoring seepage and evaporation.

It is therefore tentatively concluded that local sources could produce the quantities of water shown in Table 5.5.3, Local Water Quantities.

TABLE 5.5.3
LOCAL WATER QUANTITIES
USgpm - AVERAGE FLOW THROUGH YEARS

SOURCE	FLOW USgpm
Hat Creek Medicine Creek	7,200
Mine drainage	Possibly 1,000
Total	8,200

Clearly, the use of local water and possible use of the power plant reservoir to provide storage for Hat Creek, require further investigation, in particular when an estimate of mine water is available, and when the Hat Creek diversion study is complete. For the present, the conceptual design makes the conservative assumption that no local water is available and the plant is supplied entirely from the Thompson River.

5.5.4 Plant Water Balance

The plant water balance is shown in Figure 5.5.1 -

Water Balance: Dry Ash Removal System and Evaporative Cooling.

In Figure 5.5.1 cooling tower blowdown corresponding to 14 concentrations is used. The basis for this assumption is that Thompson River water has an average total dissolved solids level of about 55 ppm, (although data received just before submission of this report indicates that it may reach 100-110 ppm during spring runoff). If this is concentrated 14 times to 770-1400 ppm, the resulting water is still quite acceptable for tower operation - up to 2000 ppm for cooling tower blowdown is considered normal.

It is proposed that the blowdown be upgraded by a reverse osmosis system which is the most economic technique available to upgrade water of this quality. At the detailed design stage the level of blowdown and consequently the amount of water requiring reverse osmosis treatment will be evaluated.

The conceptual design concludes that it is undesirable for economic and environmental reasons to install a large disposal pond in the Medicine Creek valley if it is possible to avoid it.

The water balance in Figure 5.5.1 shows that the plant can be designed for zero discharge without requiring a large evaporation pond for water disposal. The surplus "clean" water such as treated domestic waste and boiler blowdown is recirculated to the cooling towers. "Dirty" wastes are neutralized and the water rejected by using it to wet the ash.

5.5.5 Coal Preparation Plant Water

If a heavy media coal preparation plant were required, to upgrade some of the coal by removal of clay, a discharge of water with a high clay content would be produced.

Birtley Engineering estimated that this discharge would be 300 USgpm if the worst 30% of the coal were washed. This water would be disposed of through evaporation in a pond of about 300 acres, through disposal with mine waste, or possibly through the use of a clarifier or other cleansing technique. The clay would settle slowly, so it would in any case not be practical to reject this waste to an ash disposal pond because it would make water recycling difficult.

5.6 EFFECT OF COAL ON BOILER DESIGN

5.6.1 General

While the Hat Creek coal can be classified as mainly sub-bituminous, the deposit is heterogeneous. Many of its characteristics vary widely across the width and depth of the deposit but some blending can be expected from mining and stock-piling the fuel.

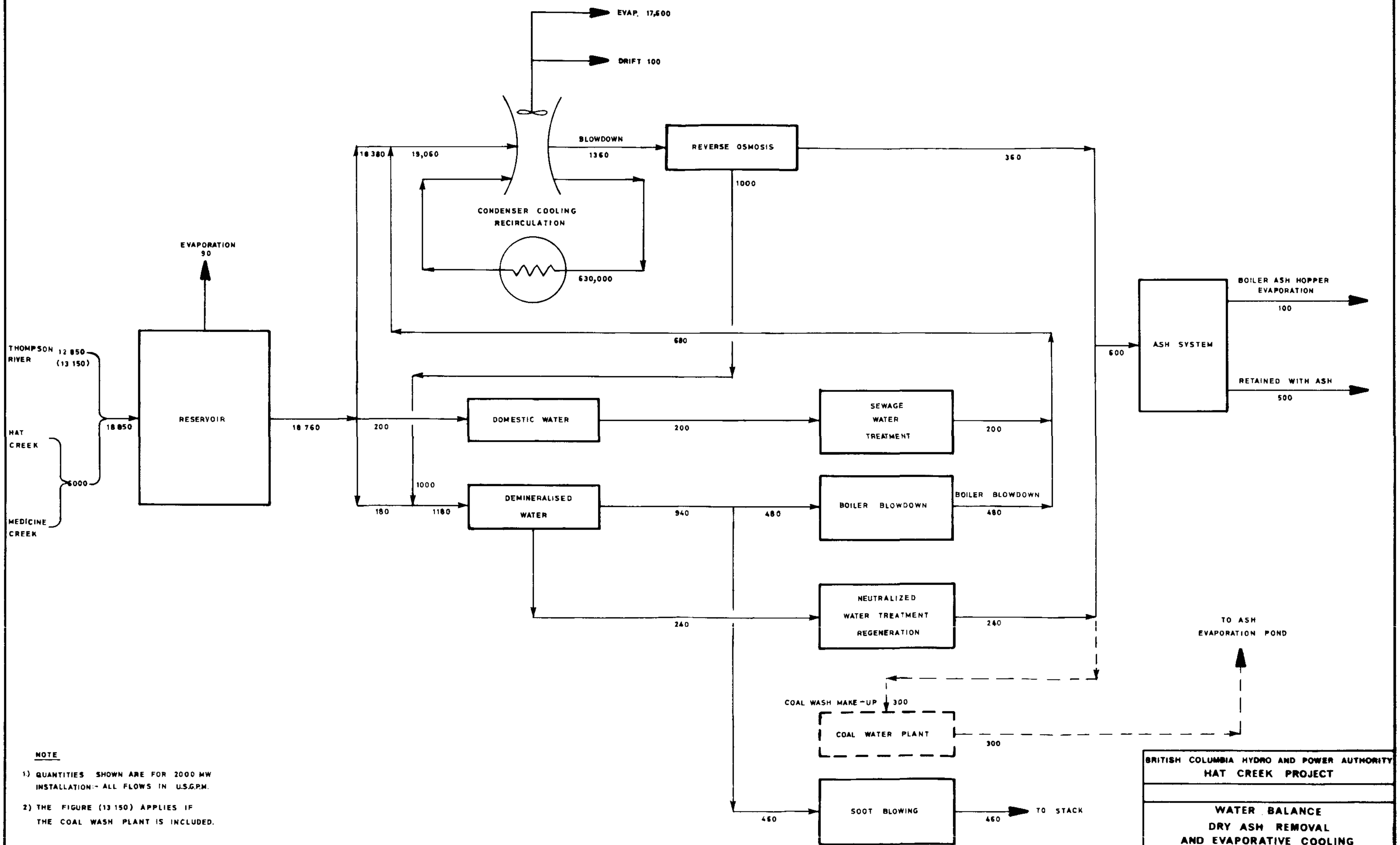
The coal study programme has not advanced sufficiently to permit design of the steam generating unit but information developed to date has been supplied to Canadian boiler manufacturers to enable them to initiate preliminary designs suitable for use in this conceptual design.

The Hat Creek steam generators must be designed to handle a range of coals since all the desirable (or undesirable) characteristics of a coal have yet to appear in any one coal sample. A set of coal analyses will therefore be necessary to define the variations in the characteristics of the coal to be burned.

5.6.2 Discussion of Variables

The coal quality variables that affect boiler design can be listed as follows:

Ultimate analysis
Proximate analysis
Petrographic analysis
Burning profiles



NOTE

1) QUANTITIES SHOWN ARE FOR 2000 MW INSTALLATION:- ALL FLOWS IN U.S.G.P.M.

2) THE FIGURE (13 150) APPLIES IF THE COAL WASH PLANT IS INCLUDED.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

WATER BALANCE
DRY ASH REMOVAL
AND EVAPORATIVE COOLING

integ - ebasco

FIG. Nº 5.5.1

Grindability
Abrasive Index
Ash fusion temperature
Ash analysis
Slag and viscosity

The ultimate, or elemental analysis, is used as a basis for the combustion calculations, which determine the air requirements, the weight of the products of combustion, and heat losses or efficiency.

The proximate analysis gives the volatile matter, fixed carbon, ash, and coal heating value, and together with the petrographic analysis and burning profiles gives an indication of the reactivity of the coal, and how it behaves when it is heated in the furnace.

The grindability, expressed as the Hardgrove Grindability Index (H.G.I.) is a measure of the power required to pulverize the coal, and is used to determine the size and number of pulverizers required.

The abrasive index, used in conjunction with the actual amount of ash, determines the allowable velocities that can be used throughout the boiler to prevent unacceptable erosion.

The ash fusion temperature, the ash analysis and the slag viscosity are all used to determine the slagging and fouling characteristics of a coal. Together with the actual quantity of ash present in the coal, these items are used to determine the exit gas temperature that can safely be used in the furnace design.

5.6.3 Steam Generator Design

Steam generator design is a combination of art and science. Experience gained fromunits burning similar coals is used in the design of a new steam generator. A steam generator includes a number of separate (but mutually dependent) components such as the furnace, superheater and reheater, economizer, air heaters, pulverizing equipment and burners.

a) Furnace Design

The function of the furnace is to complete the combustion of the coal in such a way that gases entering the later sections of the unit are sufficiently reduced in temperature to minimize deposition of ash on the convection tubes. In addition, the furnace must also be designed so that operation will not be limited by ash formations (slag) on its wall tubes.

The most important criteria used in furnace design are the heat release rates which determine the exit gas temperature, slagging potential, and retention time required to ensure complete combustion.

The heat available to the furnace includes heat input by the fuel, primary air, secondary air, and gas recirculation (if used) less the unavailable heat due to carbon losses and latent heat of evaporation of moisture in the fuel.

Heat release rates are customarily expressed per unit of furnace volume or area and defined as follows:

1. Volumetric Heat Release (Btu/hr/cu. ft.) is defined as the heat available divided by the furnace volume, and is a measure of the completeness of combustion before the flue gas enters the convection passes. Furnace volume is defined as that volume enclosed by the furnace peripheral walls from the lower furnace headers to the furnace gas exit. Furnace gas exit is the point where the platen tube transverse spacing is less than 18 inches.

2. Furnace Plan Area Heat Release, (Btu/hr/sq. ft.) this is the heat available divided by the area of a rectangle formed by the vertical furnace wall boundary and a horizontal plane at the burner level. This parameter is an indicator of how much slag may form in the burner zone.

3. Net Furnace Heat Release Rate (Btu/hr/sq. ft.) of Effective Projected Radiant Surface (EPRS). is a measure of the average heat released per square foot of furnace water cooled surface, and the heat absorbed by the furnace, and thus the furnace exit gas temperature. This also has an effect on the nature of the furnace wall slag deposits for a given coal ash analysis. EPRS is defined as the flat projected area of all furnace wall heat absorbing surface from the lower furnace headers to the furnace gas exit. EPRS includes the flat projected area of all partition walls. Platen tubes calculated as EPRS must be on 18 in. or greater transverse spacing.

4. Burner Zone Basket Area Heat Release, (Btu/hr/sq. ft.) is

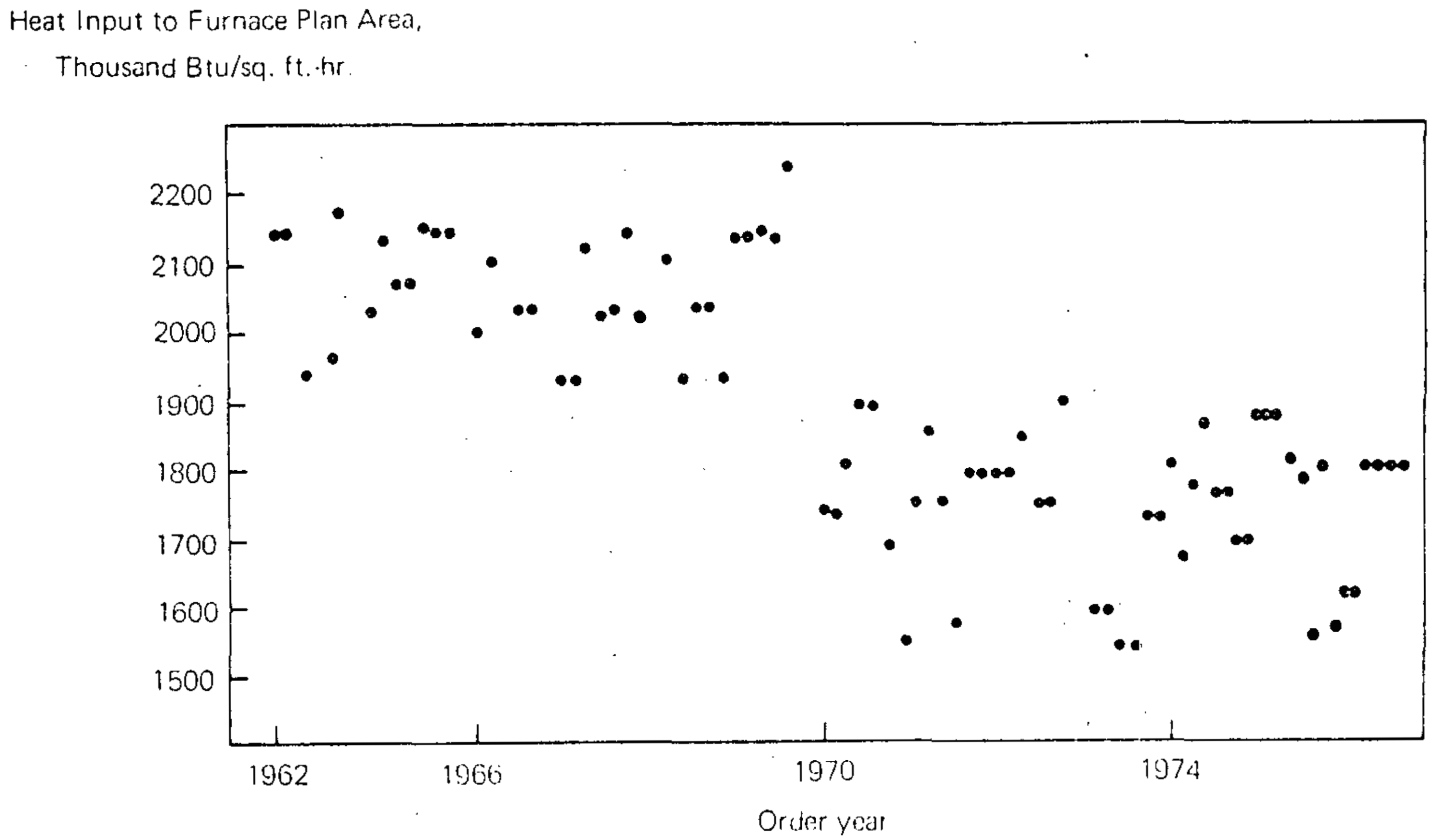
a measure of the intensity of combustion local to the burners. This parameter affects the flame temperature, and consequently slagging in the burner zone and formation of nitrogen oxides. The burner zone basket area is defined as an open top, flat bottom box whose sides include the burner zone area plus 10 feet above and below the top and bottom burner centerline. Comments for this parameter are the same as for furnace plan area heat release (see 2 above).

Table 5.6.1, Comparable Design Parameters, at the end of this section, shows the range of preliminary furnace heat release rates selected by the boiler manufacturers for Hat Creek coal as compared with a Western Canadian sub-bituminous, a Montana sub-bituminous and an Eastern U.S. bituminous coal. These data for the Hat Creek case are necessarily tentative.

Figure 5.6.1 (produced by Babcock & Wilcox) shows the trend towards lower Furnace Plan Area heat release rates and reflects the increased use of a broader range of coals with low ash fusion characteristics. Prior to 1970, the average Furnace Plan Area heat release rate was approximately 2.1 million Btu/hr/sq. ft. After 1970, the average was reduced to approximately 1.8 million Btu/hr/sq. ft.

Major Canadian boiler manufacturers have quoted preliminary furnace area heat release rates between 1.6 and 1.7 million Btu/hr/sq. ft. However, Combustion Engineering state that current designs for low rank fuels can use up to 1.8 million Btu/hr/sq. ft.

All of the manufacturers are recommending furnace exit gas temperatures below 1950°F HVT (high velocity thermocouple), which is



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

PULVERIZED COAL FIRED EXPERIENCE
COURTESY BABCOCK & WILCOX

integ – ebasco

FIG. No 5.6.1

TABLE 5.6-1

COMPARABLE DESIGN PARAMETERS AND PERTINENT DATA

Item	Units	HAT CREEK Proposed Range from Boiler Manufacturers	ALBERTA SUBBITUMINOUS High Slagging and Fouling (Wide Coal and Ash Analyses Range) (Actual Design)	MONTANA SUBBITUMINOUS High Slagging and Fouling (Wide Coal and Ash Analyses Range) (Actual Design)	EASTERN BITUMINOUS (Ohio, West Va., and Kentucky) (Wide Coal and Ash Analyses Range) (Actual Design)
1) Furnace Heat Release Rates:					
a) Volumetric	Btu/hr./cu.ft.	10,000 - 13,500	18,000	9,500	10,600
b) Net Furnace	Btu/hr./sq.ft.	54,800 - 70,000	65,000	70,000	82,700
c) Plan Area	Btu/hr./sq.ft.	$1.61 - 1.7 \times 10^6$	1.325×10^6	1.7×10^6	1.8×10^6
d) Burner Basket	Btu/hr./sq.ft.	300,000 - 332,000	360,000	328,000	393,000
2) Furnace Exit Gas Temperature	^oF	1850 - 1950	1750	1850	1900
3) Conv. Pass. Gas Velocity Range	fps	40 - 60	45 - 58	43 - 55	40 - 65
4) Transverse Tube Spacing at Furnace Exit	inches	18 - 36	27	30	20
5) Excess Air Leaving Economizer	%	18 - 25	17	25	22
6) Flue Gas Temp. Leaving A.H. (uncorr.)	^oF	285 - 325	300	270	260
7) Max. Input per Burner (1 spare mill)	Btu/hr.	$115 - 250 \times 10^6$	115×10^6	290×10^6	141×10^6
8) Predicted Boiler Efficiency	%	81 - 84	83.7	87.6	89.4
9) Max. Pulv. Inlet Air Temperature	^oF	630 - 750	715	700	500
10) Ash Fusion Temperature - Minimum ID (reducing)	^oF	2300 (raw) 2050 (washed)	1960	1900	1950
11) Pulverizer Selection Coal					
a) Heating Value (as received)	Btu/lb.	5000	7250	8000	10,500
b) Hardgrove Grindability Index		35	31	42	42
c) Moisture	%	35	28.5	31.4	15
12) Nominal T.G. Unit Size	MW	500	375	500	600

below the initial deformation temperature of 97% of the coal samples taken. The unit will be designed with major consideration given to the elimination of problems associated with slagging and fouling.

Canadian manufacturers believe that the furnace size for Hat Creek coal will be determined by the retention time required for complete combustion rather than requirements of furnace exit gas temperature.

b) Superheater and Reheater Design

In general, Canadian manufacturers favourthe tower type unit, using drainable superheater and reheater surfaces. For cycling operation, the drainable feature may allow the turbine generator to be synchronized sooner than a unit with pendant type surfaces. With pendant type surfaces, the firing rate is limited until condensate in the tube legs has been evaporated.

Wide spaced platen surface will be used in the areas of highest gas temperature, with a minimum of 18 in. side spacing, and with the tubes tangent in the direction of gas flow.

c) Convection Pass

The design of convection passes considers the minimization of fouling and tube erosion together with the economics of heat transfer.

In order to minimize erosion, gas velocities of 40-60 ft/sec have been selected by the manufacturers. This will be more closely specified when further information on the abrasive characteristics of the ash is developed.

d) Pulverized Coal System

The function of a pulverized coal system is to dry and pulverize the coal, and deliver it to the fuel burning equipment so that complete combustion will occur in the furnace with a minimum of excess air. The system must operate as a continuous process and within the specified design limitations, the coal supply or feed must be varied as rapidly and as widely as required for the combustion process whether this be due to load change or change in heating value of the fuel. A small portion of the air required for combustion is used to transport the coal to the burners. This is known as primary air. In the direct firing system, primary air is also used to dry the coal in the pulverizers. The remainder of the combustion air is introduced at the burner and is known as secondary air.

All steam generator manufacturers have included medium speed mills in their design. Due to the low heating value of the raw coals a large number of mills will be required. All manufacturers have offered 100 ton pulverizers. Although there are no 100 ton mills in operation, several are on order, and some will be operating in 1977. The manufacturers have 80 and 90 ton mills operating so that it is not expected that extrapolation to 100 ton units will create any design problems.

Pulverizer performance with actual ranges of coal samples should be tested by the boiler manufacturers before pulverizer selection is made, as conventional manufacturers' test procedures are not sufficiently valid for developing proper performance characteristics. This is also needed to ensure correct knowledge of the ability to cope with the range of moisture and hardness variation of the fuel.

In order to ensure reliability, one spare mill per unit will be furnished additional to the number required to meet full load when burning the poorest coal.

e) Sootblowing

Either air or steam can be used for sootblowing. The results of a study slightly favour air blowing but the difference in economics is small.

Combustion Engineering accept that air blowing can be used effectively in nonadhesion zones if reduced water consumption is important. Babcock & Wilcox and Foster Wheeler consider that either steam or air is acceptable. The question should be considered more fully when large full scale burn tests have been carried out. For the present conceptual design, steam sootblowing has been included.

f) Fan Design

Centrifugal fans have been used almost exclusively in North America for both forced and induced draft service. Recently, however, variable pitch blade axial fans have been purchased for a number of plants. Axial fans become more attractive for a cycling type plant.

Alternative prices will be obtained during the bidding stage and a decision made at that time.

5.6.4 NO_x Control

NO_x formation can be controlled by burner and windbox design and is partly a function of burner flame temperature. Current designs of burners and windboxes have as their objective the lowering of flame temperature. Several techniques are used:

a) Off-Stoichiometric Firing

Selected burners are operated at air-deficient conditions while the remaining burners are at air-rich conditions.

b) Two-Stage Firing

All burners are operated at less than normal excess air and in some cases actually at air deficient (sub-stoichiometric) ratios. The balance of air required to complete combustion is admitted through separate overfire air ports.

c) Flue Gas Recirculation

A gas recirculation fan can be supplied. Flue gas from the economizer outlet is injected into the combustion process so that the fuel will burn with a less intense flame and consequently a lower flame temperature.

The Hat Creek coal will probably burn with a low flame temperature which should also contribute to reduction in NO_x formation, and it is unlikely flue gas recirculation will be required.

5.6.5 Ash Deposition - Slagging & Fouling

In the design of modern coal fired steam generators, one of the most important factors that must be considered is the deposition of ash that occurs on high temperature surfaces. Ash deposition is important, since the deposits act as insulation to retard heat transfer and thereby upset the overall thermal balance within the steam generator. Furthermore, large accumulations in the upper furnace may fall and damage pressure parts. In convection tube banks, accumulations may also block gas passes, thereby increasing the draft loss. Sometimes, the accumulation may completely plug the gas passes and require a steam generator outage for manual cleaning. Uncontrolled accumulations in either area can reduce steam generator capability.

Ash deposition is a very complex phenomenon. It depends largely on type and, to some extent, the quantity of mineral matter in the coal, but it can also be influenced by operating conditions within a given steam generator. The steam generator design is based on the availability of representative coal and coal ash analyses.

The formation of deposits is caused primarily by the physical transportation of molten or partially fused particles entrained by the gas stream. When the particles strike the wall or tube surface, they become chilled and solidify. The strength of their attachment is influenced by the temperature and physical contour of the surface, and the direction, force of impact, and melting characteristics of the ash. The time in place and the gas analysis also affect the adhesion.

There are two types of high temperature ash deposition that occur on gas-side surfaces of steam generators when firing bituminous coals:

- Slagging: fused deposits that form on furnace walls and other surfaces exposed to predominantly radiant heat.
- Fouling: high temperature bonded deposits that form on convection tube banks, especially the superheaters and reheaters.

Based on the known indices available to date, the steam generator manufacturers have classified the slagging and fouling properties of Hat Creek coal as follows:

- Washed coals: Medium to high slagging, medium to high fouling.
- Raw coals: Medium slagging and medium fouling.

In order to minimize possible clinker plugging, the specified hopper throat opening between tubes should be at least 48 inches.

a) Slagging Indices

Slagging indices have been developed to determine the probability that a particular coal will or will not slag. The base-to-acid (B/A) ratio determined from a coal ash analysis is a rough indicator of the slagging potential for that particular coal ash. If the B/A ratio of coal ash ranges between 0.5 and 1.2, there is a possibility that slagging problems might be experienced. The Hat Creek data shows that more than 95% of the samples have a B/A ratio less than 0.3. The slagging indices used for sub-bituminous western coals are based on the initial deformation temperature (IT), and hemispherical softening temperatures (HT), or the plastic viscosity-temperature relationship of a coal ash. The temperatures at which plastic (semi molten) slag forms in the furnace as a coal burns, and the range of temperatures over which the ash will be plastic, are indicators of the severity of slagging.

An important indicator of potential slagging for western coals is the viscosity-temperature relationship of the coal ash. Considerable information can be obtained from a viscosity curve since it clearly defines the plastic temperature range in both oxidizing and reducing atmospheres.

b) Fouling

The volatile constituents in coal ash (i.e. Na_2SO_4 or $CaSO_4$-Na_2SO_4) cause fouling, and can be used as an indicator of the fouling potential of a given coal. These constituents condense on fly ash particles, and on boiler tubes, and deposit in areas where the temperatures are in a range where the constituents remain liquid. These constituents react chemically with fly ash to form bonded deposits.

Considerable research has been done on obtaining a fouling index that can be used with low rank sub-bituminous coals having lignitic-type ash characteristics. A relationship was developed between sodium (Na_2O) content in the ash and the volatile constituents of the coal ash. As the sodium content increased, the volatile constituents also increased, providing a basis for using Na_2O content of a coal with a lignitic type ash as an indicator of its fouling potential. Fouling classification as a function of Na_2O in the ash is as follows:

Fouling Classification	% Na_2O
Low to Medium	less than 3
High to Severe	3 to 6
Severe	greater than 6

The Hat Creek coal may on this basis be classified as medium fouling, both in the raw and washed state.

The design parameters for the convection pass relate convection section spacings to gas temperature levels,and these are correlated with sootblower placement and required input pressure from the blowers. Bank depths (rows in parallel with the gas stream) are also established to suit the amount of ash, its sintered strength, and the blower cleaning radius.

Control of fouling rests on full knowledge of the range of fuel characteristics so that the furnace exit gas temperatures can be maintained at predicted levels sufficiently below minimum fusion temperature across the entire width and depth of the furnace exit area. This keeps the convection deposits at design temperatures, and allows the blowers to achieve their designed effectiveness.

5.6.6 Operational Considerations

It is anticipated by Combustion Engineering that with the specified coal the units could operate down to 15% load without the use of stabilizing fuel such as oil or gas. This would represent two pulverizers each operating at approximately 50% load.

Combustion Engineering note that the large number of mills provides good turn-down. For start-up, oil is fired until approximately 12% load is achieved at which time one pulverizer can be started and oil and coal fired simultaneously until 25% load is achieved, from which stage coal can be fired alone.

5.6.7 Steam Generator Designs Offered

Three North American steam generator manufacturers offered designs based on the preliminary coal data available.

Thé unit designs offered were as follows:

Two of the manufacturers offered balanced draft, open furnace, tower design units, where the superheater, reheater, and economizer tubes are horizontal and drainable. The superheater and reheater tube banks are located above the furnace with flue gas flowing upward. The down flow gas pass section includes the economizer, with the flue gas discharging into a single regenerative type primary air heater and two secondary regenerative type air heaters, arranged in parallel in the direction of flue gas flow. Each unit is equipped with 8-medium speed air-swept pressurized pulverizers in which heated primary air is used to dry the coal and serves as the transport medium for the fine coal passing through the burner pipes and to the burners for ignition. The units differ in that one is a natural circulation type unit with circular burners installed in both the front and rear furnace walls, with possible gas recirculation for steam temperature control. The other manufacturer offered a controlled circulation unit where circulating water pumps are used for furnace wall tube circulation, with tilting tangential corner fired burners. They also differ slightly in that one takes hot flue gas from between the economizer tube banks for flue gas feed to the primary or pulverizer air heater with the flue gas to the secondary air heaters taken from the bottom of the economizer flue gas outlet. The other manufacturer takes flue gas from the bottom of the economizer gas outlet and feeds directly into the primary and secondary air heaters. Both manufacturer's units utilize "cold" primary air fans for supplying the required pulverizer air at the proper temperature.

Final rated reheat outlet steam temperature at reduced boiler loads is maintained with the tilting burners by tilting the burner flame upward. The other manufacturer offers an option of either gas recirculation or increased excess air for reheat outlet steam temperature control at reduced loads.

The third steam generator manufacturer offered a balanced draft open furnace natural circulation unit, designed so that the high temperature superheater behind the furnace nose is a pendant non-drainable type. The flue gas makes a turn downward to a split downflow parallel gas pass, which consists of horizontal reheater tube banks in one downflow pass and horizontal low temperature superheater tube banks in the other downflow pass. Reheat steam temperature at reduced loads is maintained by passing more flue gas through the reheater downflow gas side by modulating a set of flue gas dampers located below the reheater and low temperature superheater banks. The flue gas then flows downward through a full width horizontal economizer and into two regenerative type primary air heaters and two regenerative type secondary air heaters, all arranged in parallel with respect to flue gas flow. The unit is equipped with twelve medium speed air-swept pressurized pulverizers in which heated primary air is used to dry the coal and serves as the transport medium for the fine coal passing through the burner pipes and to the burners for ignition. Circular burners are installed in both the furnace front and rear walls. "Cold" primary air fans are used for supplying the required pulverizer air at the proper temperature.

When a complete determination of the range of fuel properties is available, it will enable the boiler manufacturers to define their design parameters more accurately, and provide suitable offerings for final evaluation and selection.

5.7 MAIN CYCLE OPTIMIZATIONS

5.7.1 Steam Conditions

Turbine steam inlet conditions relevant to the Hat Creek project fall within the following ranges:

Main steam inlet pressure	psig	1800 - 3500
Main steam inlet temperature	^{o}F (^{o}C)	up to 1000 (538)
Reheat steam inlet temperature	^{o}F (^{o}C)	up to 1000 (538)

As the steam inlet pressure and temperature and reheat temperature increase, the turbine efficiency also increases with the result that subcritical units greater than 350 MW generally have utilized the standard cycle with main steam inlet pressure and temperature of 2400 psig and 1000^{o}F (538^{o}C) and reheat temperature of 1000^{o}F (538^{o}C), i.e. the 2400/1000/1000 cycle.

These conditions represent the highest pressure and temperature which current North American practice would employ on a subcritical unit. However, because of the relatively low cost of Hat Creek coal, the 1800/1000/1000 cycle could possibly be justified economically despite its efficiency being about 2% less than the standard cycle.

The main objection to the 1800/1000/1000 cycle is that it would require a non-standard turbine with larger inlet stages and valves and which would operate at higher exhaust wetness. Consequently, the 1800/1000/1000 cycle was rejected.

The supercritical cycle involves a once through boiler which does not employ a steam drum. Although experience with this type of unit exists in the U.S. and Europe, such a boiler would be an innovation for Canadian boiler manufacturers.

A further disadvantage with the supercritical boiler is the inherent difficulty of operating it in the two shift regime anticipated for the later life of Hat Creek. Two shift capability can be obtained by a steam bypass system but this in turn is a relatively complex system. In keeping with the philosophy that the Hat Creek project should not include novel or unconventional items of plant, the supercritical cycle is rejected.

For the above reasons, the standard 2400/1000/1000 cycle, is selected as the most acceptable technically and economically.

5.7.2 Optimization of Cooling System

A 2000 MW thermal power plant rejects a large amount of heat (approximately 10 x 10^9 Btu/hr) to the cooling water in the turbine condensers and this heat must be rejected to the environment by one of several possible schemes. These are:

- A once through, or open, system where cooling water is taken from some large natural body of water and returned to it at a higher temperature.

- A closed system where cooling water absorbs heat in the condensers, rejects the heat in cooling ponds, spray ponds or cooling towers and then is recirculated to absorb more heat in the condenser.

The absence of a suitable natural body of water near the Harry Lake site precludes the use of an open cycle. Table 5.7.1, Summary of Comparative Costs of Cooling Alternatives, summarizes the total capital and operating costs of the various closed cycle cooling system alternatives, while Table 5.7.2, Cooling System Alternatives, gives a rough comparison of the other factors which must be reviewed in making a choice.

TABLE 5.7.2

COOLING SYSTEM ALTERNATIVES

EVALUATION POINTS

Item	Ponds	Sprays	Natural Draft Towers	Mech. Draft Towers	Wet/Dry Towers	Dry Condenser
- Environmental Considerations:						
Plumes	5	4	2	3	5	5
Ground Fog	1	1	4	2	5	5
Drift/Icing	4	1	3	2	2	5
Noise	5	4	5	3	2	2
Aesthetics	5	4	2	4	2	2
Water Consumption	3	2	3	3	4	5
- Operating Considerations:						
Flexibility	2	5	2	4	4	3
Experience	4	2	4	5	1	1

EVALUATION POINTS SCALE:

1 - Poorest
2 - Below average
3 - Average
4 - Above Average
5 - Best

TABLE 5.7.1

SUMMARY OF COMPARATIVE COSTS OF COOLING ALTERNATIVES - ($ millions)

	Spray Pond	Rectangular Mech. Draft Towers (Wooden)	Rectangular Mechanical Draft (Concrete)	Cooling Pond Supplemented By Mechanical Draft Towers	Mechanical Draft Tower Round	Hyperbolic Natural Draft Towers	GEA Air Cooled Condenser Base Size	GEA Air Cooled Condenser with 14% Higher Capacity
Total Capital Cost	3.8	Base	5.1	18.1	7.5	13.5	13.8	23.4
Total Present Worth of Operating Costs	- 4.9	Base	-	8.0	-	- 6.1	4.7	0.2
Total Cost	- 1.1	Base	+ 5.1	+ 26.1	+ 7.5	+ 7.4	+ 18.5	+ 23.6

Capital costs include items such as land, the CW system, fire protection, the condenser and make-up water system. Operating costs include fan and pumping power, maintenance costs and heat rate penalties.

A scheme based on a cooling pond located in Medicine Creek might conceivably be adapted as a local pumped storage plant with capacity of up to 300 MW over a 6-hour period. However, the complications in the cooling system, such as high-lift pumps and recovery turbines, necessitated by the difference in elevations between plant and cooling pond, would be unwelcome. In view of the implications for system reliability, and some present uncertainties regarding the cost and feasibility of the necessary Medicine Creek dam, this scheme is rejected.

A spray pond system would cost slightly less than the wooden rectangular mechanical draft scheme. Against this, spray ponds do not have proven reliability in a severe climate for a large installation, and there would be a layout problem due to the limited available land near the plant. Problems of ground fog and icing would be much more predominant with the spray pond system. For these reasons the spray pond system is rejected.

Wet/dry cooling has attractions because the required water supply from the Thompson would be reduced or eliminated and cooling tower plume formation could be controlled or even obviated. Current estimates received from manufacturers indicate the wet/dry cooling option is not economic.

Adoption of dry cooling, such as the direct air cooled condenser arrangement offered by GEA, would remove the need for the water pipeline from the Thompson River. However, when ambient temperatures were above 50°F the plant capability would be severely reduced, as shown in Figure 5.7.5. An important disadvantage of the dry cooling system is its very high capital cost. For these reasons it is rejected.

The hyperbolic natural draft cooling tower system has less flexibility and its high capital cost more than offsets the value of fan energy as shown in Table 5.7.1. The hyperbolic cooling tower may be more attractive for environmental reasons because of its superior plume dispersion. The conceptual study has not selected the hyperbolic tower but it is recognized that environmental studies now underway, may favour it.

By the above reasoning the preferred system is the mechanical draft cooling tower. The more economical conventional rectangular form is adopted at this stage, but consideration might be given to the round tower with its superior plume dispersion characteristics during the project implementation stage. This detail does not affect cycle optimization.

Mechanical draft evaporative towers are sized for specified ambient wet-bulb temperature, approach, range and circulating water flow. The range is the difference in temperature between incoming hot water and cooled return water. The approach is the difference in temperature between the cooled water leaving the tower and the wet-bulb temperature of the air entering the tower.

Figure 5.7.1 shows wet bulb design temperature versus percentage of year that the actual plant capacity would fall short of rated output, and also average monthly wet bulb temperatures. For the selected value of 57^{o}F, output would be restricted only during the warmest 5% of the year, which would not be a significant limitation.

The required optimization deals with cooling tower size, condenser size, circulating water flow and turbine back pressure. The procedure is a complex one involving at least 25 variables, and was carried out using an established computer programme. Essentially it involves the trade-off between the value of cycle efficiency, which is directly affected by turbine back pressure, and the cost of the system components. As the back pressure goes down, the turbine cycle efficiency improves, but the sizes of the turbine exhaust, condenser, and cooling towers increase and the amount of circulating water also rises.

The programme calculates the total annual cost for a large number of permutations of cooling tower, condenser size and configuration, and circulating water flow, making allowance for the variations in heat rate corresponding to the particular system and the year-round variations in ambient temperatures.

Two typical turbines were assumed in the optimizations, having exhaust areas of about 220 square feet and 266 square feet. These correspond to four exhausts of about 30 in. blades or four exhausts of 33½ in. blades; exhaust areas of about this size would be offered by most of the major turbine manufacturers.

The following main variables were fed into the computer:

Cooling tower design approach	13^{o}F - 28^{o}F
Cooling tower design range	20^{o}F - 35^{o}F
Condenser configuration	Single and Double Pass
Condenser length	40 ft., 50 ft., 60 ft.
Condenser tube outside diameter	1.00 in., 1.25 in.
Condenser tube velocity	7 ft./sec. - 9 ft/sec.

At valves wide open and 5% overpressure and with a design wet-bulb temperature of 57^{o}F, the maximum circulating water temperature entering the condenser will be 80°F and the turbine backpressure will be 3.5 in. Hg. Abs. At low ambient temperatures, which occur over more than half the year at Harry Lake, the circulating water inlet temperatures will be between 45°F and 65°F and the turbine backpressure will be between approximately 1.5 in. Hg. Abs. and 2.5 in. Hg. Abs.

Figure 5.7.2 shows turbine backpressure plotted against condenser cooling water inlet temperature for the optimum system with the 50 ft. double pass condenser. Figure 5.7.3 shows the typical variation in turbine capability with exhaust pressure. Figure 5.7.4 shows the variation of total annual cost for the optimum system against cooling water flow for different design approaches.

The selected design approach is 23 °F and the selected design cooling water circulation rate is 640,000 USgpm.

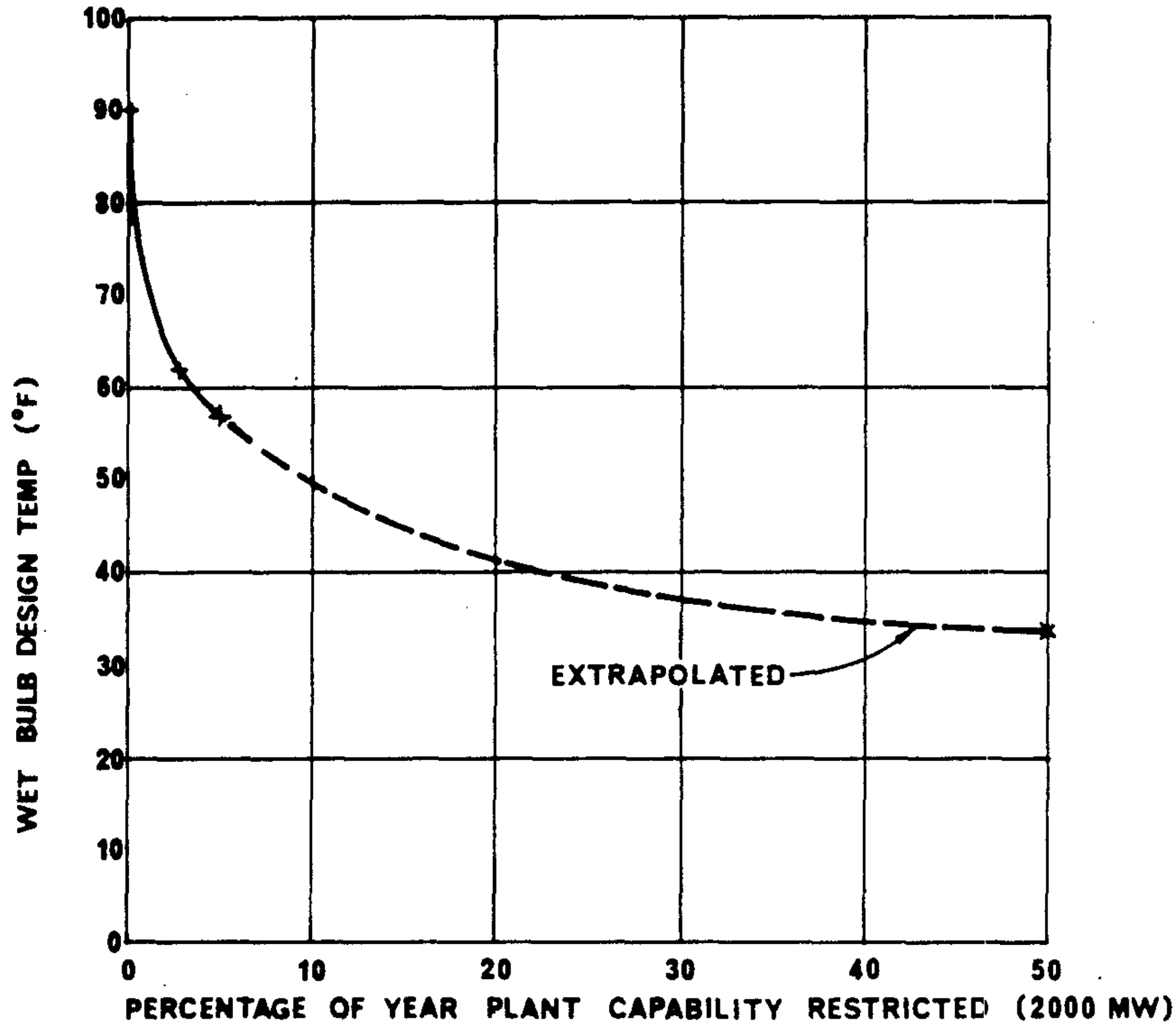
5.8 PLANT LIQUID WASTES

The principal plant liquid wastes are:

- Water treatment regeneration chemicals
- Boiler chemical cleaning wastes
- General in-plant drainage

5.8.1 Water Treatment Regeneration Chemicals

The water treatment plant is designed to operate on the basis of one regeneration per day per train. Each regeneration requires approximately 3 hours at a flow rate of 1920 USgpm, i.e. a total of



AVERAGE MONTHLY WET BULB (°F)

JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
12.5	20	26	34.5	41.5	49	52.5	51.5	43.5	34	24.5	14.5

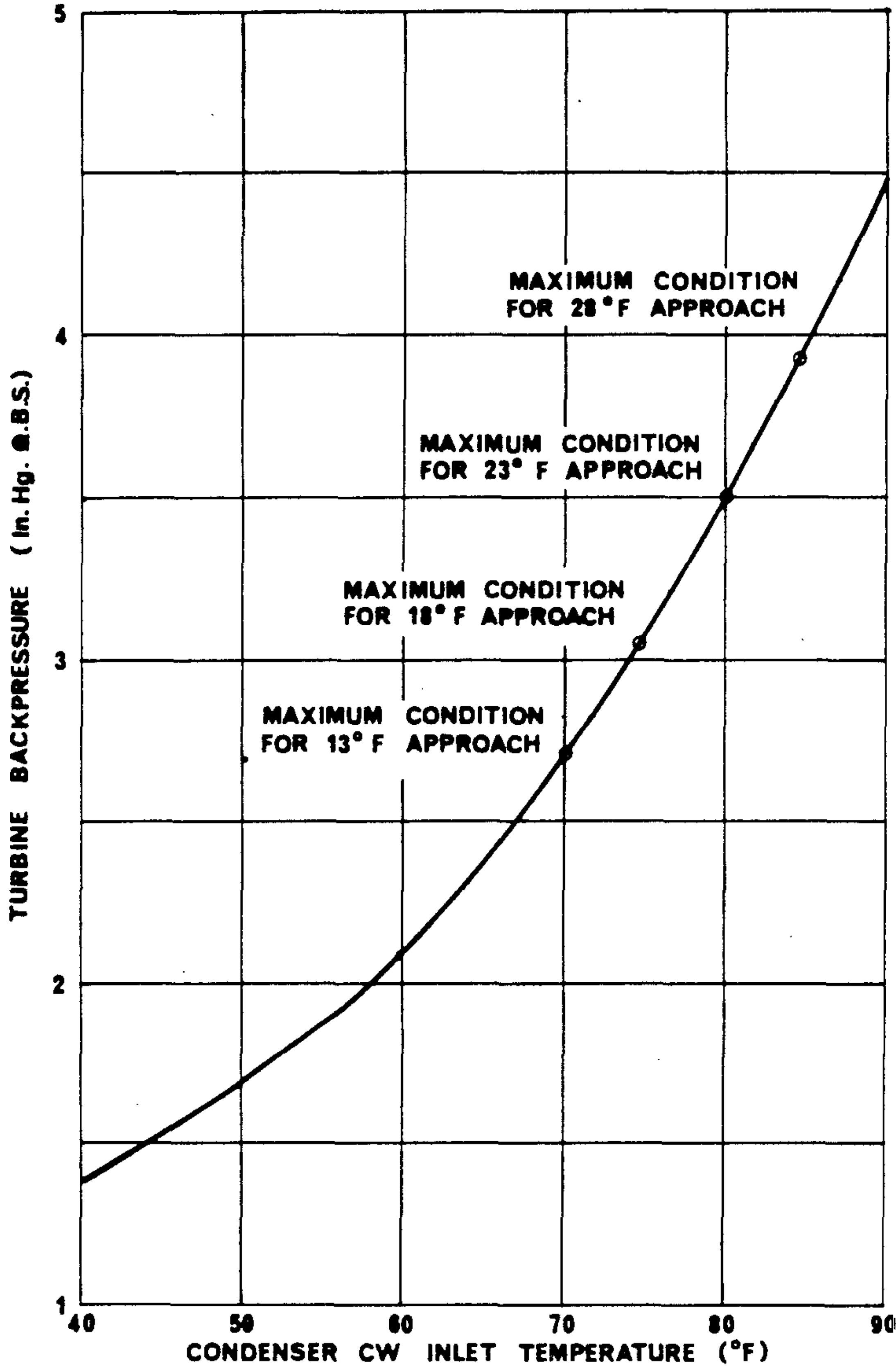
AVERAGE WET BULB 33.7°F

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

WET BULB
DESIGN TEMPERATURE SELECTION

integ - ebasco

FIG. No. 5.7.1



NOTE

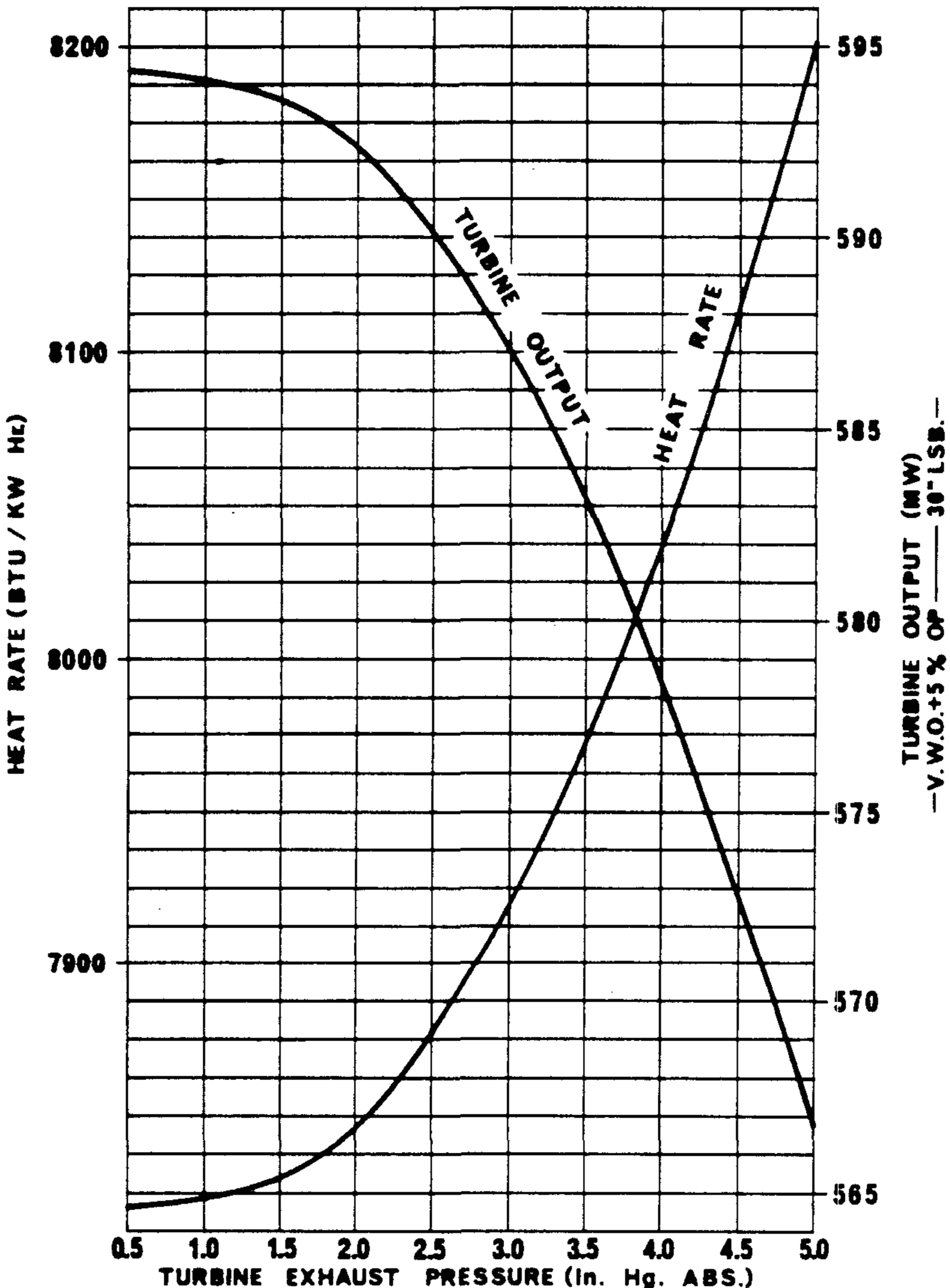
1	FLOW	160,000 USGPM
2	ΔT ACROSS CONDENSER	33.7°F
3	TUBE VELOCITY	7 FT/SEC
4	TUBE DIAMETER	1" O.D.
5	TUBE MATERIAL	S.S.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

50' DOUBLE PASS CONDENSER SYSTEM
CW INLET TEMPERATURE
VERSES BACKPRESSURE

integ – ebasco

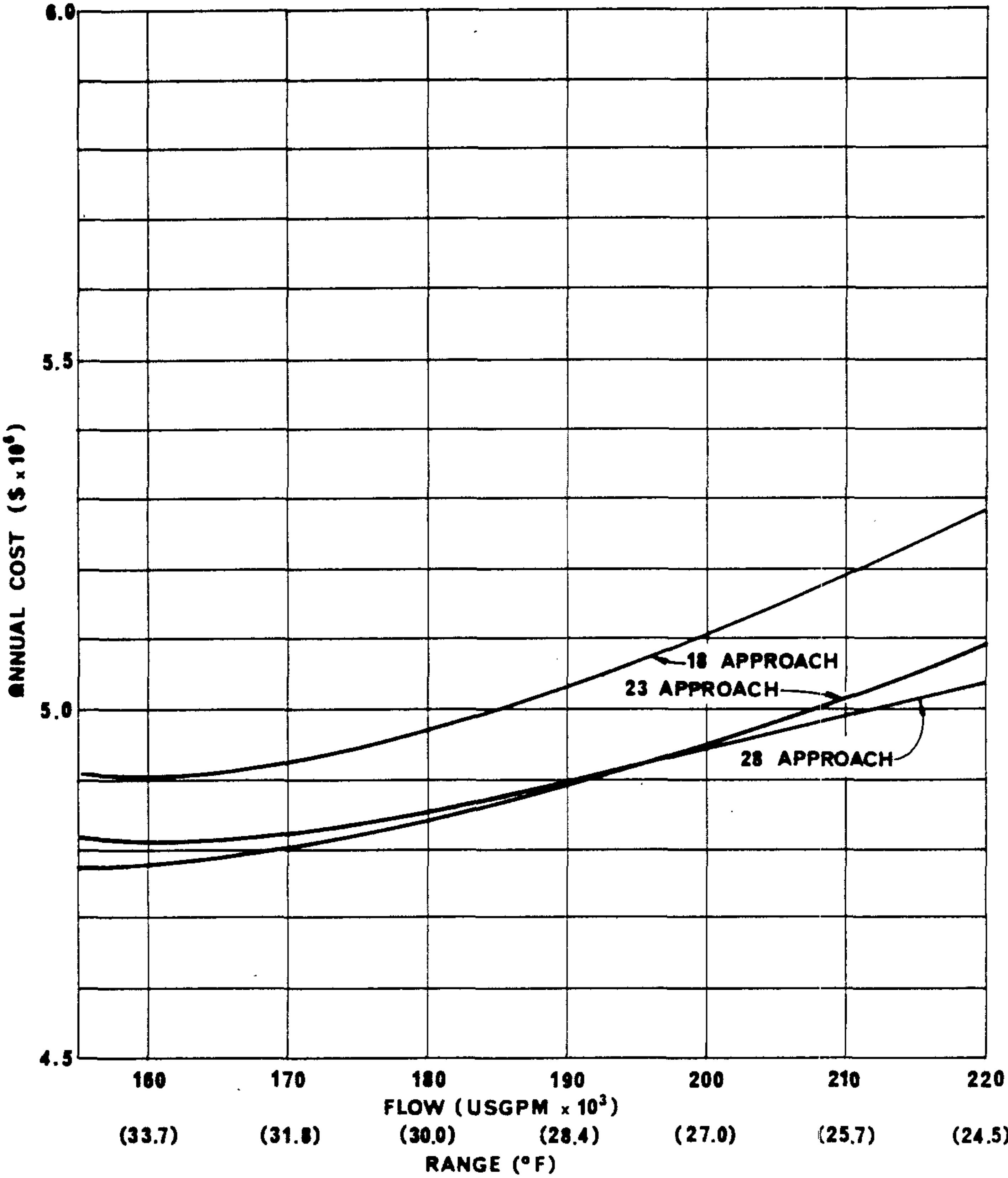
FIG. № 5.7.2



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

TURBINE OUTPUT & HEAT RATE
VS EXHAUST PRESSURE

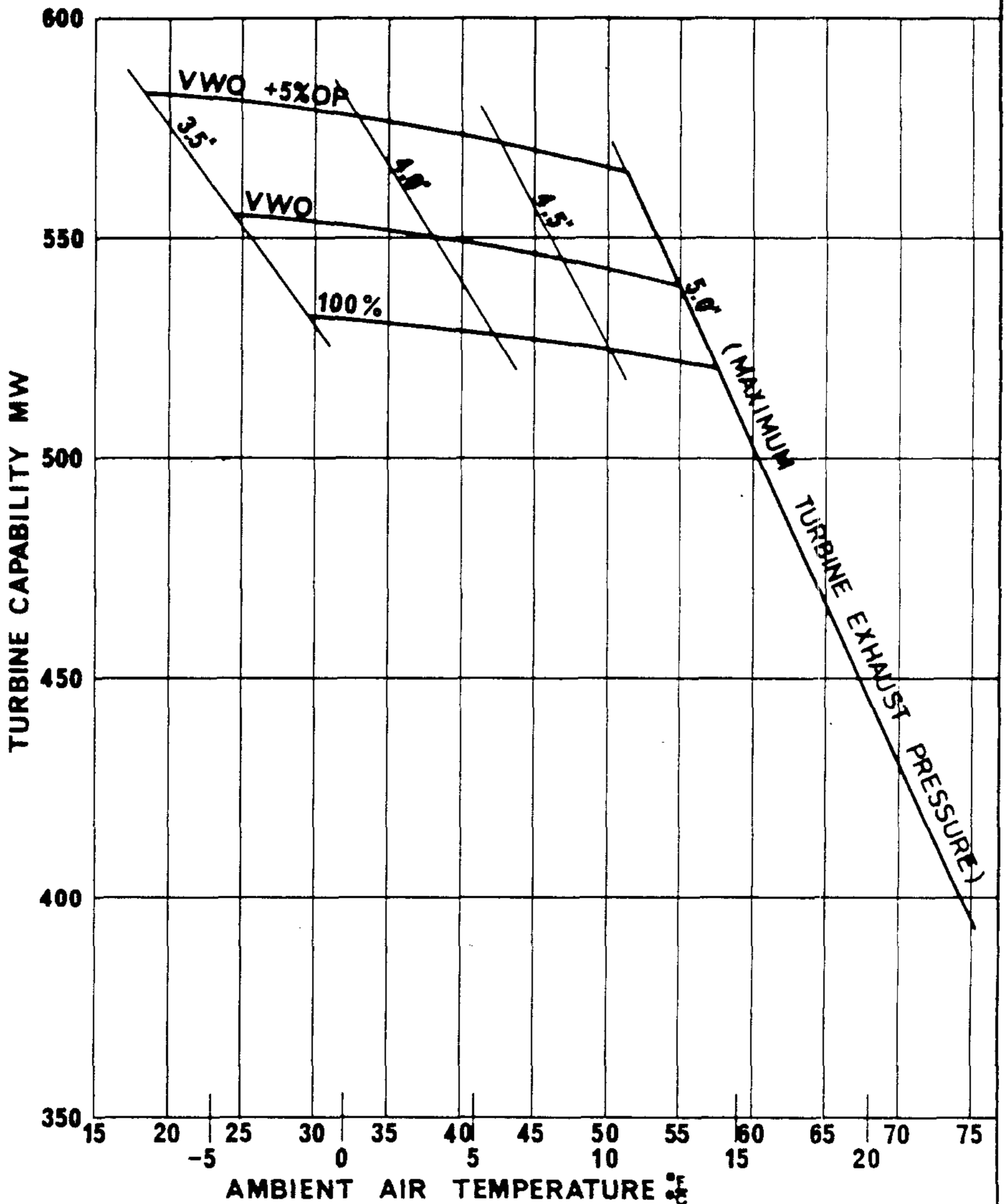
integ – ebasco | FIG Nº 5.7.3



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

50' DOUBLE PASS CONDENSER SYSTEM

integ - ebasco | FIG Nº 5.7.4



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

AIR COOLED CONDENSER SYSTEM
CAPABILITY -30" L.S.B. TURBINE

integ-ebasco

FIG. Nº 5.7.5

345,600 US gallons of water and chemicals per regeneration. The chemicals used would be caustic soda and sulphuric acid, each diluted to the required regeneration concentration.

Spent chemicals and rinse water are collected in a neutralizing sump, which holds the mixture until the pH becomes neutral. The waste is then discharged to the ash disposal system at the bottom ash dewatering bin.

5.8.2 Boiler Chemical Cleaning

High pressure boilers require regular chemical cleaning to remove accumulations of iron oxide and copper from the internal heating surfaces. Cleaning is generally required every two to three years of operation. The most common solvent used is dilute inhibited hydrochloric acid at a concentration of approximately 5%, while the spent acid drained from the boiler has a concentration of about 3%. After draining, the boiler is flushed, neutralized with a dilute caustic soda solution and reflushed to remove remaining traces of neutralizing solution. For the Hat Creek units the volume to be discharged, including the rinse water, is approximately 300,000 US gallons per cleaning, per boiler. This is discharged to a tank for neutralizing and monitoring prior to discharge into the bottom ash disposal system.

5.8.3 General Drainage

The effluents from all in-plant floor drains together with water used for motor, bearing and compressor cooling purposes, are directed to the bottom ash dewatering bin for incorporation in the re-circulating ash sluicing water.

All in-plant drains likely to receive oil spillage or contamination are provided with oil interceptors where the waste oil is collected for storage in tanks. When sufficient quantities have been collected this oil is sold for reclaiming. After oil removal, the water component is directed to the bottom ash dewatering bin.

In summary it is planned that all plant liquid discharges would be disposed of through the bottom ash sluicing system, as noted in Section 5.5.

5.9 PARTICULATE AND GASEOUS EMISSIONS

5.9.1 Relevant Standards

The function of air quality control systems is to control emissions of fly ash particulates and the gaseous oxides of nitrogen and sulphur, formed during combustion of the coal, within acceptable limits.

This section examines emissions from the power plant chimney but does not consider ambient concentrations of particulates or gases. Ambient levels are dependent on local meteorological and topographic considerations discussed in the site evaluation report and are also the subject of on-going studies.

The existing Provincial pollution control objectives that apply to industrial coal combustion were drawn up to cover the food processing, agriculturally orientated and other miscellaneous industries. Specific objectives relating to the particular case of the power generation industry do not yet exist.

It is useful to compare the B.C. standards with those of other provinces and countries. A comparison of in-stack concentrations set by various regulatory agencies is shown in Table 5.9.1.

TABLE 5.9.1

IN-STACK CONCENTRATIONS

Regulatory Agency	Parameter	Level
British Columbia	Sulphur Dioxide Nitrogen Oxides Particulates	300 ppm 600 ppm .1 gr/SCF
Alberta	Sulphur Dioxide Nitrogen Oxides Particulates	Not Specified " "
Ontario	Sulphur Dioxide Nitrogen Oxides Particulates	Not Specified " "
Puget Sound Washington State	Sulphur Dioxide Nitrogen Oxides Particulates	1000 ppm @ 50% excess air Not Specified .05 gr/SCR @ 12% CO_2
Environmental Protection Agency - Federal (U.S.)	Sulphur Dioxide Nitrogen Oxides Particulates	*520 ppm @ 20% excess *304 ppm @ 20% excess *.05 gr/SCF
Environment Canada - For 1985 implementation	Sulphur Dioxide Nitrogen Oxides Particulates	800 ppm @ 3% O_2 dry 500 ppm @ 3% O_2 dry 0.2 gm/kg

* Levels converted from units specified in pollution control regulations, using Hat Creek combustion parameters.

It should be noted that several American States propose limits which are more stringent than those of B.C.

5.9.2 Nitrogen Oxides (NO_x)

The formation of nitrogen oxides occurs in all high temperature combustion processes using air as the oxidant. The concentration of nitrogen oxides (NO_x) increases with increased excess air, higher flame temperatures and increased furnace residence time.

Modern boiler burner-windbox designs are arranged to provide minimum air to the primary ignition and combustion zone. The remainder of the combustion air is added via separate air-only ports, and mixes with the fuel within the furnace to cause complete combustion before the furnace exit. Design provisions such as these reduce excess air and flame temperature to a minimum, as noted in Section 5.6.4.

The relatively high ash and moisture contents of the Hat Creek coal are such that flame temperatures will be comparatively low. Low flame temperatures have been confirmed by the CCRL burn tests.

There is no doubt that a modern boiler can burn the Hat Creek coal and meet the Provincial regulations on NO_x emissions. The conceptual design provides for in-stack gas analysis equipment. Compliance with the Provincial objectives will be confirmed by in-stack analyses performed at a frequency determined by the Director of Pollution Control.

5.9.3 Particulate Emissions

It is estimated that a collection efficiency of 99.4% is required to meet the British Columbia Pollution Control Board objective for particulates (0.1 grain per SCF) using the average coal (28% ash) and assuming that 70% of the ash is fly ash. It will be *necessary to attain a precipitation efficiency of about 99.7% to meet* the Provincial objective for the poorest coal in the range assumed in paragraph 2.5, i.e. a coal with 35% ash. The exact precipitator efficiency which is required depends on the proportion of ash becoming fly ash and the coal handling/preparation system finally selected.

There are three methods of achieving these high collection efficiences. These are:

- Cold-side electrostatic precipitators, located after the air preheaters.
- Hot-side precipitators, located before the air preheaters.
- Baghouse air filters, located after the air preheaters.

Based on preliminary particle size and resistivity data, the baghouse air filter appears unsuitable. The very small particle sizes, indicated by the dust samples obtained during the CCRL tests, would necessitate a low air-to-cloth ratio thus making the fabric filter uncompetitive. The intended use of oil for auxiliary firing would lead to frequent plugging of the filter material. A baghouse installation for a 500 MW coal fired boiler would incidentally be larger than any yet ordered, although not fundamentally different from existing smaller installations.

Preliminary results from the CCRL test burns indicate ash resistivities such that there is little to choose between a hot precipitator and a cold precipitator in respect of necessary collecting plate areas. However, the cold precipitator offers approximately 20% lower capital cost and is therefore the alternative selected at the present stage. This decision is subject to review when the pilot precipitator test results are available from the large scale test burn.

A hot precipitator is only economically more attractive than a cold precipitator when electrical resistivities in the cold temperature range exceed 10^{12} ohm - cm. In this case, resistivities are about 10^{10} ohm - cm, in the optimum range for a cold precipitator. There is therefore no justification for the higher ducting, cladding and structural costs of a hot precipitator. Furthermore, the cold type is more tolerant of load changes and has better part-load efficiency.

5.9.4 SULPHUR EMISSIONS

In this section the approximate level of SO_2 emissions from the power plant are estimated and are compared with the limits and objectives published by the British Columbia Pollution Control Board and other Provincial, Federal and U.S. agencies.

The emphasis which different countries, notably the U.S. and Japan, place on control of sulphur dioxide emissions can be understood by referring to Table 5.9.2 Projected Total Emissions of SO_2.

TABLE 5.9.2

PROJECTED TOTAL EMISSIONS OF SO_2

1968-1980 without special abatement measures

MILLIONS OF TONS

	1968	1980	1985	2000
Finland	.23	.36		
Sweden	.52	1.1		
Norway	.10	.15		
U.K.	5.7	6.0		
Germany	3.2	5.4		
Turkey	.18	.65		
Canada	1.2	1.5 (1)		
U.S.A.	25.4 (33)2	51.7	(75)(2)	(100)(3)
Japan	4.0	14.0		

(1) of this, 0.71 is projected to come from power plants. Source - O.E.D.C.

(2) Source - Electrical World May 15, 1971

(3) Source - EPA Interview Power Engineering June, 1971

In order to estimate the level of SO_2 emissions it is necessary to:

- Estimate the average sulphur content of the coal in the proposed 600 ft. pit, and the range in content

- Determine whether it is practicable to reduce either the amount or the variability of sulphur content

- Determine the proportion of the sulphur entering the boiler which is oxidized to SO_2

a) Estimate of Sulphur Content of Coal - 600 ft. Pit

Sampling of special drill holes 135 and 136 indicates that the sulphur content of the coal varies through the different coal strata. Dolmage Campbell have divided the deposit into four main zones, and their estimate of the average sulphur content in these zones is shown in Table 5.9.3, Sulphur Content of Zones A, B, C, D.

3

TABLE 5.9.3 SULPHUR CONTENT OF ZONES A, B, C, D.

No. 1 Deposit - 20% moisture
(coal with more than 44% ash rejected)

	Sulphur Content %
Zone A (highest zone)	0.58
B	0.66
C	0.35
D (lowest zone)	0.22

Figure 5.9.1 shows the relationship between sulphur content and coal heating value for each of the zones. The relationship is generally random for three of the zones, but it appears that the sulphur content drops slightly with heating value.

At constant load the coal heat energy entering the boiler is constant, therefore the important criteria in determining the level of SO_2 emissions is the sulphur content as a proportion of its heating value. This index is lower for samples of Hat Creek coal with higher heating value and thus a mining technique which tends to selectively reject coal of low heating value will lead to lower SO_2 emissions.

Dolmage Campbell estimate that when the sulphur content is weighted by the overall size of the zones, a mean value of 0.41% is obtained for the whole deposit (based on 20% moisture). This includes 0.11%, i.e. 27% of the total sulphur, which is pyritic.

Dolmage Campbell estimate that the average sulphur content of a 600 ft. deep open pit is about 0.43%, reflecting the lower proportion of zone D coal which such a mine will yield.

As this figure is based on an extrapolation of data, this report is based on an average sulphur content of 0.45% with 0.12% pyritic (based on 20% moisture). This corresponds to the mean figure quoted in paragraph 5.2.7.

The average sulphur content per million Btu of heating value is therefore 0.76 lb, or 0.55 lb excluding pyritic sulphur.

b) Sulphur Content Reduction or Averaging

Sulphur occurs in coal in three forms: organic, pyritic (FeS_2) and sulphate. Over 70% of total sulphur in Hat Creek coal is organic sulphur, which as part of the coal molecule is not removable by present technology. Most of the remaining sulphur is pyritic. Whereas the organic sulphur content in the Hat Creek coal is relatively constant, the pyritic content varies quite widely, and causes a few samples to show high total sulphur contents. Since pyrites is nearly four times as heavy as coal, it is usually practicable to separate nearly all of it from the coal. However, the clay which occurs in Hat Creek coal will make the removal of pyrites more difficult.

The alternative approaches to coal preparation have different effects on sulphur content. The dry coal blending process will average the sulphur content, thereby moderating occasional peak values. A coal washing plant will remove some of the pyritic sulphur, reducing the total sulphur content per million Btu of heating value. It is possible that some pyritic sulphur will also be removed in the mills or the rotary breakers.

The total amount of pyrites which will be removed will depend on the coal preparation method which is selected. The effects of removing all pyrites or half or none of it, are considered.

In section 5.3 it was noted that it will be difficult to selectively mine, blend or beneficiate for the optimization of more than one variable or quality. If coal of a consistent heating value is to be delivered to the power plant it may be difficult to maintain a consistent sulphur content.

The range of sulphur content, on a 20% moisture basis, varies from about 0.1% to about 2% while 95% of the coal appears to have between 0.1 and 0.92% sulphur.

If successful blending is assumed in two stages:

1) Mixing in the shovel and truck to the equivalent of a two layer pile.
2) Pile blending with six layers.

95% of the coal should have a sulphur content between 0.35% and 0.61%. This would be valid firstly if blending proves to be possible and also if the variation in sulphur is statistically random. This is far from the case because the average sulphur content in Zone D is 0.22 while in Zone B it is 0.66%. In a pit which contains about 200 million tons of Zone D coal and about 50 million tons of Zone B coal it is hard to believe that the range of sulphur delivered to the plant will be narrower than 0.22 to 0.66, on a 20% moisture basis.

Obviously until a mine plan is completed the range of sulphur content which will be delivered cannot be predicted with confidence. In addition only when a mine plan is available will it be possible to investigate the duration of swings in sulphur content; obviously if the excursions represent a few minutes of boiler feed they are of less concern than if they represent several hours.

c) Percentage of Sulphur Converted to SO_2

To provide a conservative estimate of SO_2 emissions it is assumed that all the sulphur entering the boiler becomes SO_2. In fact Dolmage Campbell have shown that in laboratory tests, practically all of the pyritic sulphur remains in the ash, but these tests may not be representative of firing in a full scale unit. In addition some SO_3 may be absorbed in the calcium which occurs in the ash, especially in view of the high ash content of this coal.

d) Estimated Level of Emissions

SO_2 emission levels may be quoted in 3 different ways:

- Amount of emission per ton of fuel burned.
- Concentration of emission in parts per million by volume or by weight.
- Amount of emission per million Btu of fuel burned.

These three bases are reviewed in turn:

Emission per ton of coal

The B.C. Pollution Control Board has published an objective for new plants of 20 lb. of SO_2 per ton of coal burned. The calculated emission level for the average coal with 0.45% sulphur is about 18 lbs. per ton of coal. This is slightly below the objective without any removal of pyritic sulphur even assuming all the sulphur is oxidized to SO_2, as shown in Table 5.9.3. It is likely that the actual average level of emissions would be lower.

The emissions under this definition are not effected by the heating value of the coal.

TABLE 5.9.3 SO_2 EMISSIONS

	Lbs. SO_2 Per Ton of Fuel
PCB Objective	20
Emission with average Sulphur content 0.45%	
- No pyritic removed	18
- All pyritic removed	13.2

Emission in ppm

Figure 5.9.2 shows calculated SO_2 emissions in ppm, assuming that all, or none of the pyrites removed, and assuming any sulphur not removed is converted to SO_2. From this figure it can be seen that even if all the pyritic sulphur is removed the average emission level will exceed Level A of the stringent British Columbia objective which is 300 ppm. To meet this objective the sulphur content/million Btu must be limited to 0.40 lb., a level which few coals meet. In fact even Alberta plains coals which typically have about 0.65 lbs. of sulphur per million Btu at sites such as Battle River and Sheerness, produce emissions of 500-600 ppm. It is interesting to note that Zone D coal, on average,does meet the B.C. objective, even without pyrites removal.

The average coal would meet Level B of the B.C. objective which is 600 ppm provided that all the pyrites is removed.

Emissions per million Btu of Coal

The U.S. EPA limit is 1.2 lb. SO_2 per million Btu. This corresponds to 0.6 lb. of sulphur per million Btu, on the basis that all sulphur in the furnace becomes SO_2. Table 5.9.4 shows emissions under this definition for the 0.45% sulphur coal with different degrees of pyrites removal.

TABLE 5.9.4 SULPHUR EMISSIONS

	Total Sulphur %	Average Emission lb.$SO_2/10^6$ Btu No pyrites removed	½ of pyrites removed	All pyrites removed
Average or performance coal	0.45	1.52	1.31	1.10
EPA emission standard		1.2	1.2	1.2

This table shows that, based on the assumed 0.45% sulphur content, the average coal from the 600 ft. deep pit will meet the EPA level if all the pyrites is removed. If any sulphur or SO_2 is retained or absorbed in the ash, as is likely, the emission levels shown in Table 5.9.4 would be reduced.

It should be noted that EPA limits are not applied to average values, but to peaks,which qualifies the results of Table 5.9.4.

The relationship between sulphur content, coal heating value and SO_2 emission level is also shown in figure 5.9.3, again with the EPA limit shown as a reference point.

Environment Canada has produced a new recommendation which is to be applied in 1984. This limit is 800 ppm, dry, corrected for 0.3% oxygen. Figure 5.9.2 shows that the average coal and average sulphur content meet this limit almost exactly with no pyrties removed.

e) Conclusions

Further work is necessary to confirm the average and range of sulphur content of the pit and the possibility of rejecting pyrites in a coal beneficiation plant, or in the mills. In addition the beneficiation test programme will confirm whether the coal can be blended or upgraded to reduce the variation in sulphur content. Tests must also be conducted to show how much, if any, of the pyrites will remain in the ash.

At present it appears that the average coal and average sulphur content will meet most regulations or objectives with the exception of the B.C. level A of 300 ppm.

Although the sulphur emissions will vary with the quality of coal and the sulphur content, the importance of emission standards relates ultimately to ambient levels. Even the U.S. Environmental Protection Agency limits are aimed at reducing ambient sulphate and SO_2 levels through the reduction of total emissions. The consideration of average emission levels contained in this section is therefore of some validity.

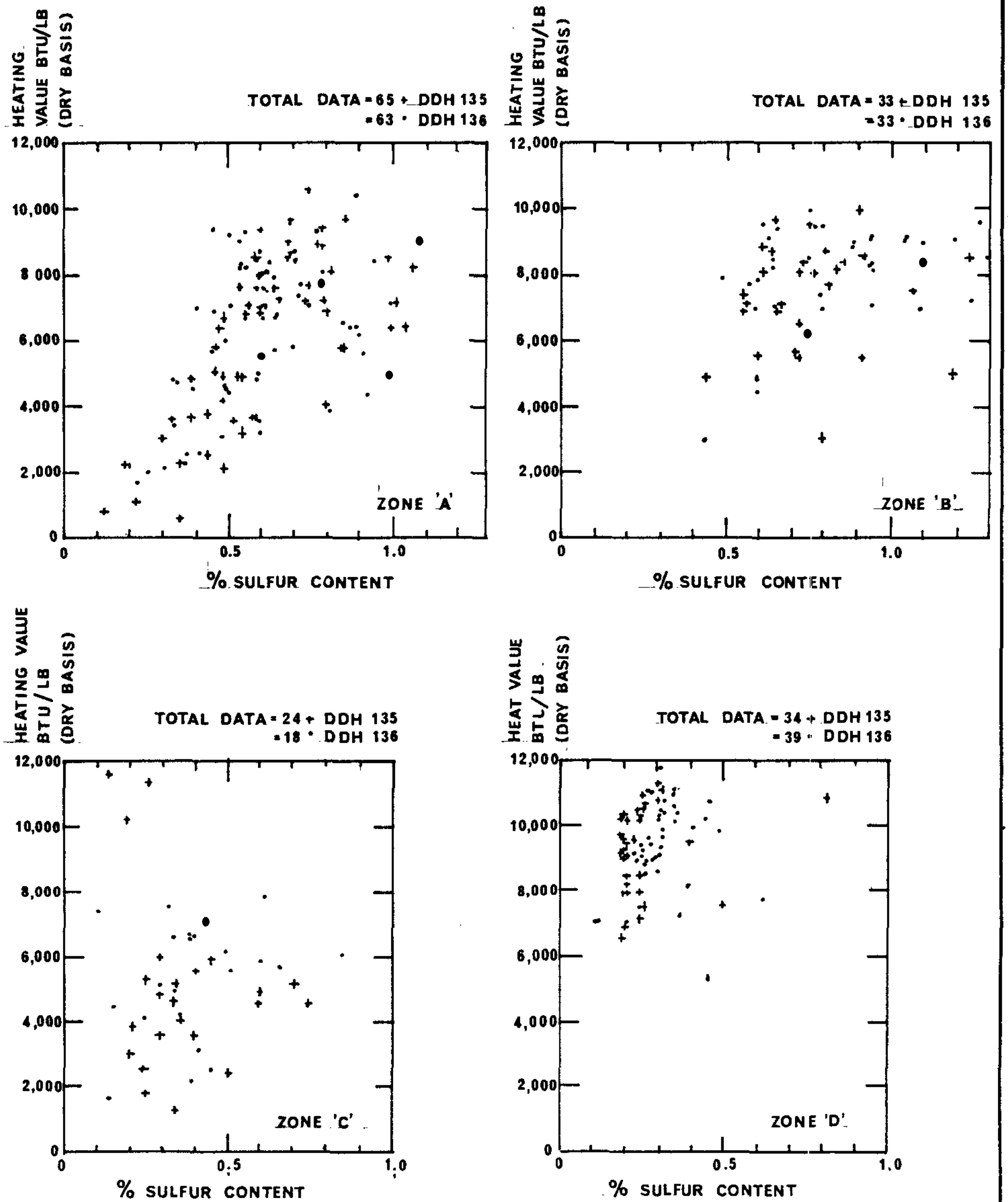
f) SO_2 Scrubbers

The conceptual design does not include SO_2 scrubbers but has allowed space for their installation if this proves necessary. The capital and operating costs of scrubbers are exceptionally high and at present they suffer from poor reliability and severe waste disposal problems.

5.9.5 Chimney

The function of the chimney is to effect adequate dilution of the flue gases in the atmosphere and to enable the gases to penetrate any inversion layers.

During the site selection study a chimney 1100 ft. high was considered for preliminary calculations, but the calculation of ground level concentrations of pollutants, for various chimney heights, is a part of further studies now in progress. Chimney optimization will not be completed until some time in the future. For the purposes of the conceptual design study a chimney 800 ft. high, containing four separate 21 ft. diameter flues, is proposed.



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

HEATING VALUE OF COAL VS % SULFUR

integ – ebasco | FIG № 5.9.1

Neither the height nor the provision of multiple flues is unique. The Pullman-Kellogg Company has recently completed two multiple flue chimneys for Ebasco projects, one a 550 ft. two flue chimney and the other a 500 ft. three flue chimney.

Single chimneys from 550 ft. to 850 ft. high have been provided for a large number of plants over 2000 MW in Ontario and in the U.K.

In the past little reliable information was available on design of steel liners for chimneys. Recently, the ASCE published the findings of their Task Committee on steel chimney liners, entitled "Design & Construction of Steel Chimney Liners". This describes some previous problems and proposes guidelines for conceptual and structural design. At a height of 800 feet the concrete shell design presents no unusual problems. There are at least a dozen power plant chimneys with a height equal to or exceeding 800 feet.

Accessories for such chimneys include ladder, monitoring equipment platforms, aviation obstruction lights and access platforms, and inspection platforms within the annular space.

A personnel hoist is provided for access to the various interior platforms. The annular space is ventilated by means of louvres at the top and bottom of the chimney. With the liners properly insulated the temperature within the annular space under normal operating and maximum ambient temperature will not exceed approximately 140^{o}F (40^{o}C). The proposed design makes it possible to service an individual lines while all other liners are in operation, and allows access to the annular space with all units in service.

5.10 DESIGN FOR WINTER CONDITIONS

Plant design will require careful consideration of the effect of winter conditions. This is a normal part of the design of thermal plants in Canada, and the winter conditions at the Harry Lake site are not expected to be as severe as those at other plants such as Sundance in Alberta.

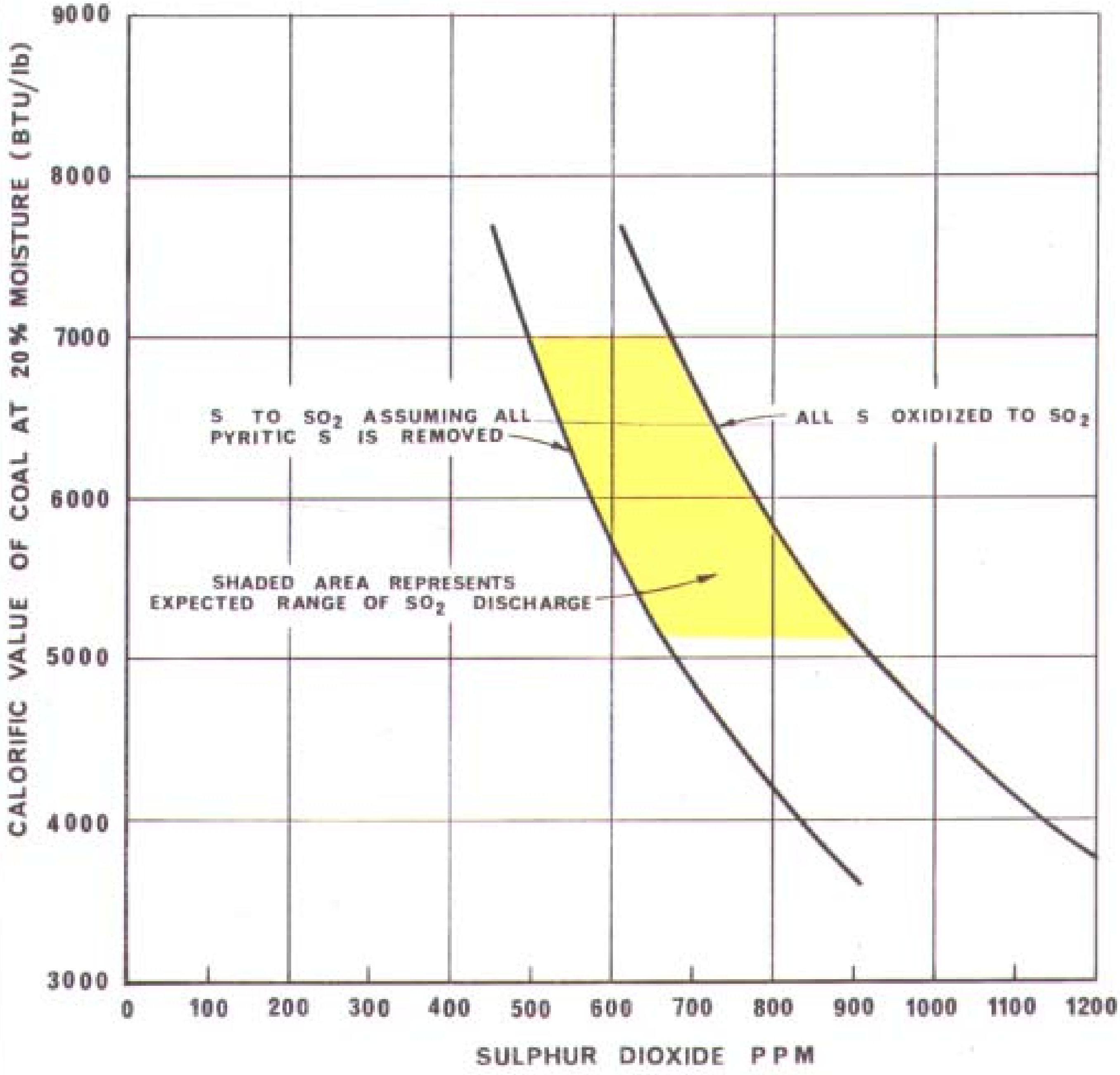
In this section, comments are made on the normal areas that require attention for winter conditions, and more detailed consideration is given to problems which are peculiar to the Harry Lake site.

5.10.1 Usual Aspects

The following discussion covers those systems and items of plant which have given problems in severe winter conditions, and normally require detailed attention in Canadian generating plants.

a) Water Intakes

Reservoir intakes must be protected against icing by locating them at a suitable depth, or by the provision of re-circulated warm water. The make-up water reservoir at Hat Creek would be fitted with a water intake that is below the anticipated level of the ice.



TOTAL SULPHUR IN COAL = 0.45 %

PYRITIC SULPHUR IN COAL = 0.12 %

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

SITE EVALUATION STUDY

CALORIFIC VALUE OF COAL VS SO_2 DISCHARGE CORRECTED TO 3% OXYGEN IN DRY STACK GASES

integ – ebasco

FIG. Nº 5.9.2

as water is drawn out of the reservoir, the ice will tend to collapse, and it will never build up to a great thickness.

b) The Coal Handling System

The coal handling system at Lambton G.S. originally suffered difficulties due to the freezing of the stored coal. The top crust of the coal pile was frozen, and the coal below was damp and froze on contact with the chilled steel of the stack reclaimer bucket, wheels, chutes, belt pulleys, and reclaim hopper plating. There is however no shortage of experience in successful design and detailing to avoid such problems.

At Hat Creek all coal bunkers are indoors with the exception of the surge bin at the top of the overland conveyors. Stainless steel buckets are provided for the stacker/reclaimer wheel, and chutes at transfer points are lined with stainless steel. Rubber skirtings at transfer points minimize spillage. Provision is also made for heating the storage bunkers, and certain transfer points as well as many vulnerable points on the conveyors.

c) Building and Combustion Air Heating

The design of the air heating systems for the Harry

Lake conditions requires care to ensure that heating coils will not freeze up during an outage or when they are shut down.

d) Spring Break-up

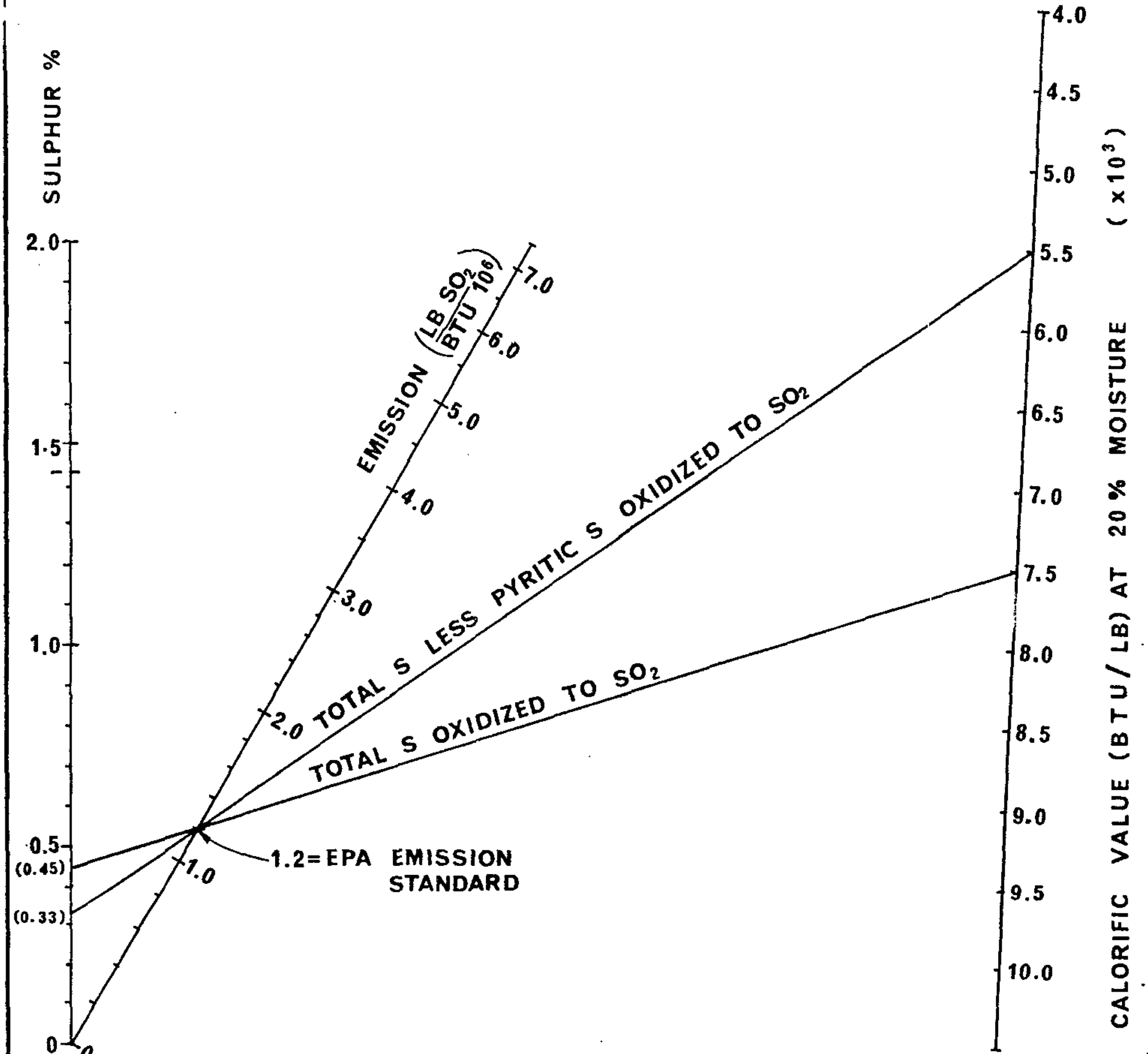
Construction and operating activities must be scheduled so that there is no requirement to move heavy loads on rural roads during the break-up period.

e) Outside Water Lines

There will be a number of outside water lines which will require protection against frost by electric tracing.

f) Construction Access: Use of Doors

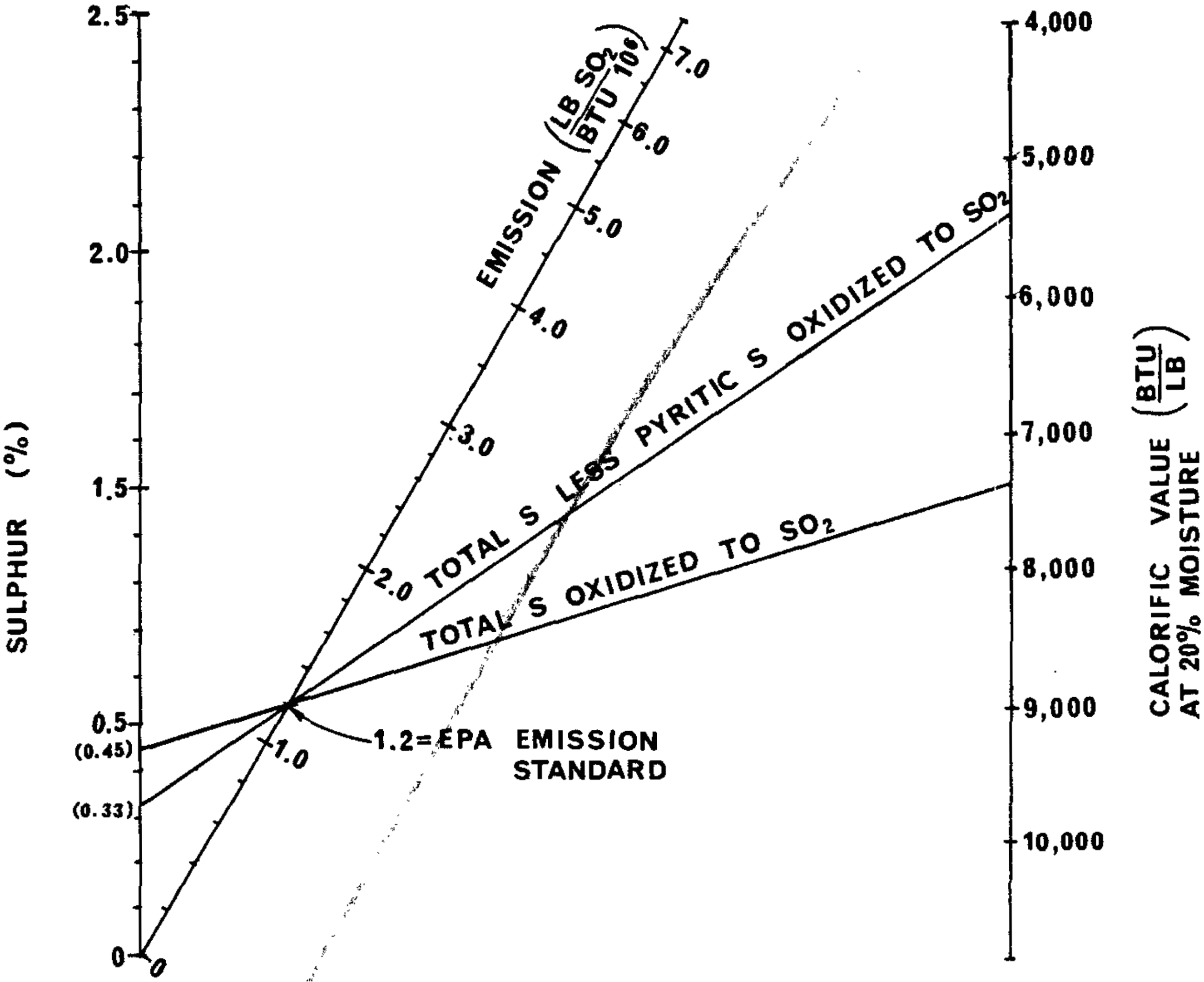
Stations designed for very cold climates must have attention paid to the effect of opening doors during the construction of later units. Main equipment doors can often be open for a limited time only during winter.



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

% SULPHUR IN COAL AND SO_2 DISCHARGE PER MILLION BTU

integ – ebasco | FIG. 5.9.3



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

% SULPHUR IN COAL AND SO_2 DISCHARCE PER MILLION BTU

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FIG. 5.9.3

5.10.2 Problems Requiring Particular Attention at Hat Creek

The two potential winter problems at Hat Creek which are site-related are the main water supply line from the Thompson River and the cooling towers.

a) Thompson River Pipeline

Protection of the Thompson River pipeline against icing is part of the study by Sandwell & Co. who recommended that the pipeline be buried, that allowance be made for continuous flow, and that it be drainable.

b) Cooling Tower Fogging

The problem of cooling tower fogging requires investigation as part of the environmental studies. In the conceptual design the cooling towers will generally be downwind of the plant and if fogging develops it should not affect the switchyard, the coal handling plant or other vital outdoor equipment. If further studies show that fogging may be a danger and may affect the plant, further consideration should be given to hyperbolic or mechanically assisted towers, above the ground.

c) Cooling Tower Winter Operation

During periods of low temperature operation (32 F and below), ice may form on the wet parts of the tower in contact with the incoming air. This includes the louvres and adjacent structural framing.

Ice-forming characteristics on any given tower will vary, depending on velocity and direction of wind, circulating water rate and heat load. Ice formation can be controlled by regulating air and water flow through the tower. The means employed include reducing fan speed or even reversing the fans, to reduce the cooling effect and raise the water temperatures. It is also possible to direct additional warm water adjacent to the louvres.

d) Cooling Tower Winter Shutdown

The cooling towers are connected on a station basis so that warm water can be circulated through the basin of each, when less than 4 units are operating. Provision is made to drain the basin and all water lines, should any tower be shut down for an extended period.

5.11 MAJOR EQUIPMENT TRANSPORTATION

5.11.1 General

To ensure that the major pieces of equipment for the 4 - 500 MW generating units can be shipped to site special attention is given to the transportation routes and transport methods available.

Some major equipment such as the main transformers, the generator stators and the steam drums are too heavy to be transported over most of the existing Provincial highways owing to restrictions imposed by the Department of Highways. Rail transport must therefore be used to move such equipment to Ashcroft or Lilooet from where it would be shipped to the site by road.

5.11.2 Dimensions of Major Components

Table 5.11.1, Weights and Sizes of Major Components, summarizes the weights and dimensions of typical items of major equipment:

TABLE 5.11.1

WEIGHTS AND SIZES OF MAJOR COMPONENTS

Equipment	Length	Width	Height	Weight
Toshiba Generator Stator	28 ft.	13 ft.	14 ft.	260 tons
Combustion Eng. Steam Drum	75 ft.	7.5 ft.		275 tons
Westinghouse Transformer	35 ft.	25 ft.	18.5 ft.	342 tons

The above components cannot generally be split for shipping, although the size of the generator stator can be reduced by a few inches by making a separate outer case, which acts as the pressure vessel.

These are the largest and heaviest components required for a generating plant. All other components, such as the turbine, can be dismantled for shipment. The dimensions shown above are typical for all manufacturers.

5.11.3 Availability of Railcars

Special railcars must be used to transport equipment of this type. Depressed flat railcars of very large capacity are not available in Canada, except that a number of manufacturers such as CGE own their own railcars which can be used for shipping items of their own manufacture.

Offshore manufacturers of generator stators or power transformers must use a limited number of railcars which are available to Canadian railway companies through agreements they have with U.S. companies such as Penn Central (Conrail Corp.).

The steam drum may be transported on two special Penn Central railcars having bolster centres in the middle of each car to support the ends of the drum.

Generator stators may be transported on Schnabel or depressed flat railcars. A Penn Central car has been used for most major stator shipments across Canada.

Such types of car must be ordered at least one year in advance to guarantee availability when the equipment is to be delivered.

5.11.4 Terminals

Two rail terminals, Ashcroft and Pavilion, are available near the site for transfer of equipment to heavy trucks for transport over local roads to the plant site. Mobile lifting and jacking equipment will be required to transfer the equipment from the rail cars on to the trucks.

Suitable heavy trucks are not at present available and one may have to be specially purchased.

5.11.5 Transport Routes

Three potential routes appear practicable for rail transport of heavy equipment. These routes are:

- C.N. rail from Centennial Pier in Vancouver to Ashcroft.
- Barge from Centennial Pier to Squamish, then B.C. rail from Squamish to Pavilion.
- C.N. rail from Eastern Canada (Manufacturers' works or Montreal docks).

All the above routes have tunnel or cutting restrictions. The B.C. Rail limit is about 12 ft. 10 in. while C.N. Rail limits loads to 13 ft. 6 in. width. B.C. Rail tunnel profiles appear tight for the generator stator, but it seems likely that the typical stator shown in Table 5.11.1 could pass up the B.C. Rail route. It is possible that minor widening would be required at some spots, to permit clearance.

The two C.N. routes do not pose a problem for the equipment sizes chosen.

Specifications for the major equipment must have regard to the restrictions imposed by rail transportation.

SECTION 6. DESCRIPTION OF POWER PLANT

CONTENTS

6.1 TECHNICAL SUMMARY

Table 6.1.1, Technical Summary, provides principal technical data of the power plant. The plant heat balance and materials balance are illustrated in Figures 6.1.1 and 6.1.2.

TABLE 6.1.1

TECHNICAL SUMMARY

Site	
Location:	Near Harry Lake in Trachyte Hills east of Hat Creek valley, at elevation 4600 ft.
Site area:	625 acres
Manpower	
Average construction force	1000
Approximate number of operating staff (four units)	171
Building	
Total length of powerhouse	928 ft.
Total width of powerhouse	290 ft.
Height of boiler room roof	300 ft.
Height of turbine room roof	110 ft.
Chimney	
Number of chimneys	1
Number of flues	4
Height of chimney	Provisionally 800 ft.
Diameter of inner flues	21 ft.

TABLE 6.1.1 (cont'd.)

Inside diameter of stack	66 ft.
Flue gas exit velocity	90 ft./sec. (@ 300°F & MCR)
Electrical Power Output	
Net output (4 unit station)	2100 [redacted] MW @ MCR*
Generator voltage	24 kV
Transmission voltage	500 kV
Frequency	60 Hz
Steam Generator (per unit)	
Design steam output @ MCR*	3,960,000 lb/hr
Superheater outlet pressure @ MCR*	2620 psig
Superheater outlet temperature	1,005°F
Reheat steam temperature	1,005°F
Coal consumption @ MCR*	1877 tons/hr
Number of pulverizers	8 per unit (tentative)
Water temperature to economizer	485°F
Ignition System	
Fuel	No. 2 fuel oil
Capacity of fuel tank (2 tanks/station)	250,000 US gal./tank
Turbine	
Steam pressure @ throttle	2520 psig
Steam temperature @ throttle	1000°F

* Maximum continuous rating at VWO, 5% overpressure.

TABLE 6.1.1 (cont'd.)

Reheat temperature	1000°F
Condenser vacuum	3.5 in. Hg. Abs. for design ambient of 57°F
Number of extraction points for feedwater heating	7
Turbine heat rate including BFP turbine	8000 Btu/kWhr
Rating	583 MW at VWO and 5% overpressure
Boiler Feed Pumps	
Number of main pumps/unit	2 main + 1 start-up @ 20% cap. @ 50% capacity
Capacity of the 50% pumps @ MCR (without capacity allowance)	4,500 USgpm
Discharge pressure @ MCR (without head allowances)	7,290 ft.
BFP turbine rating @ MCR	17,360 hp
Normal rpm	5000-6000 rpm
Coal Handling	
Capacity of overland conveyors (total)	4,600 tons/hr.
Bunker storage	8 hrs.
Dust & Ash Handling	
Flue gas flow @ MCR (20% excess air)	5,949,000 lb./hr. from 1 unit
Flue gas temperature	300°F

TABLE 6.1.1 (cont'd.)

Type of fly ash precipitator	Electrostatic ("cold")
Efficiency of precipitator	99.7%
Bottom ash	Approx. 158 tons per hour from 4 units
Fly ash	Approx. 368 tons per hour from 4 units

Station Heat Rate

Estimated turbine heat rate at maximum continuous rating	8000 Btu/kWhr.
Calculated boiler efficiency with average coal defined in paragraph 5.2.4	83.5%
Station heat rate including plant auxiliaries only (43MW)	10,344 Btu/kWhr.
Station heat rate, including as above, plus overland coal conveyor and water pump power (53MW)	10,538 Btu/kWhr.
Station heat rate, including as above, also plus mine power* (58MW)	10,639 Btu/kWhr.

*Note - Mine power cost is also included in the coal price used in this study, which is derived from the PD-NCB work.

Table 6.1.2, Motor List, shows the derivation of the plant auxiliary load.

TABLE 6.1.2 MOTOR LIST

UNIT LOADS

No. per Unit	Equipment	Motor HP	Connected HP	Normal Running Load (HP)
2 x 50%	F.D. Fan	3,500	7,000	5,100
2 x 50%	I.D. Fan	6,500	13,000	9,500
2 x 50%	P.A. Fan	4,500	9,000	7,300
8	Pulverizers	1,250	10,000	8,750
1 x 25%	Standby B.F.P.	4,000	4,000	-
3 x 33%	Cond. Pump	700	2,100	2,100
3 x 50%	Ash Sluice Pump	900	2,700	1,800
4	Boiler Circulating Water Pump	800	3,200	1,600
1	B.F. Booster Pump	1,200	1,200	1,200
				37,350
8	1500 KVA Power Centre	1,500	12,000	6,000
			TOTAL HP	43,350

STATION LOADS

No. per Unit	Equipment	Motor HP	Connected HP	Normal Running Load (HP)
4 x 100%	C.W.Pump	5,000	20,000	18,000
3 x 50%	Crusher	1,000	3,000	2,000
				20,000
16	1500 KVA Power Centre	1,500	24,000	13,000
			TOTAL HP	33,000

Shared load, per unit = $\frac{3300}{4}$ = 8250 HP

Total auxiliary load/unit = 43,350 + 8250 = 51,600 HP

Assume 0.90 efficiency and 0.9 demand factor

Actual load = $\frac{51{,}600 \times 0.746 \times 0.9}{0.90 \times 1000}$ = 39 MW (approx.)

Contingency	4
TOTAL:	43 MW per unit

6.2 PLANT ARRANGEMENT

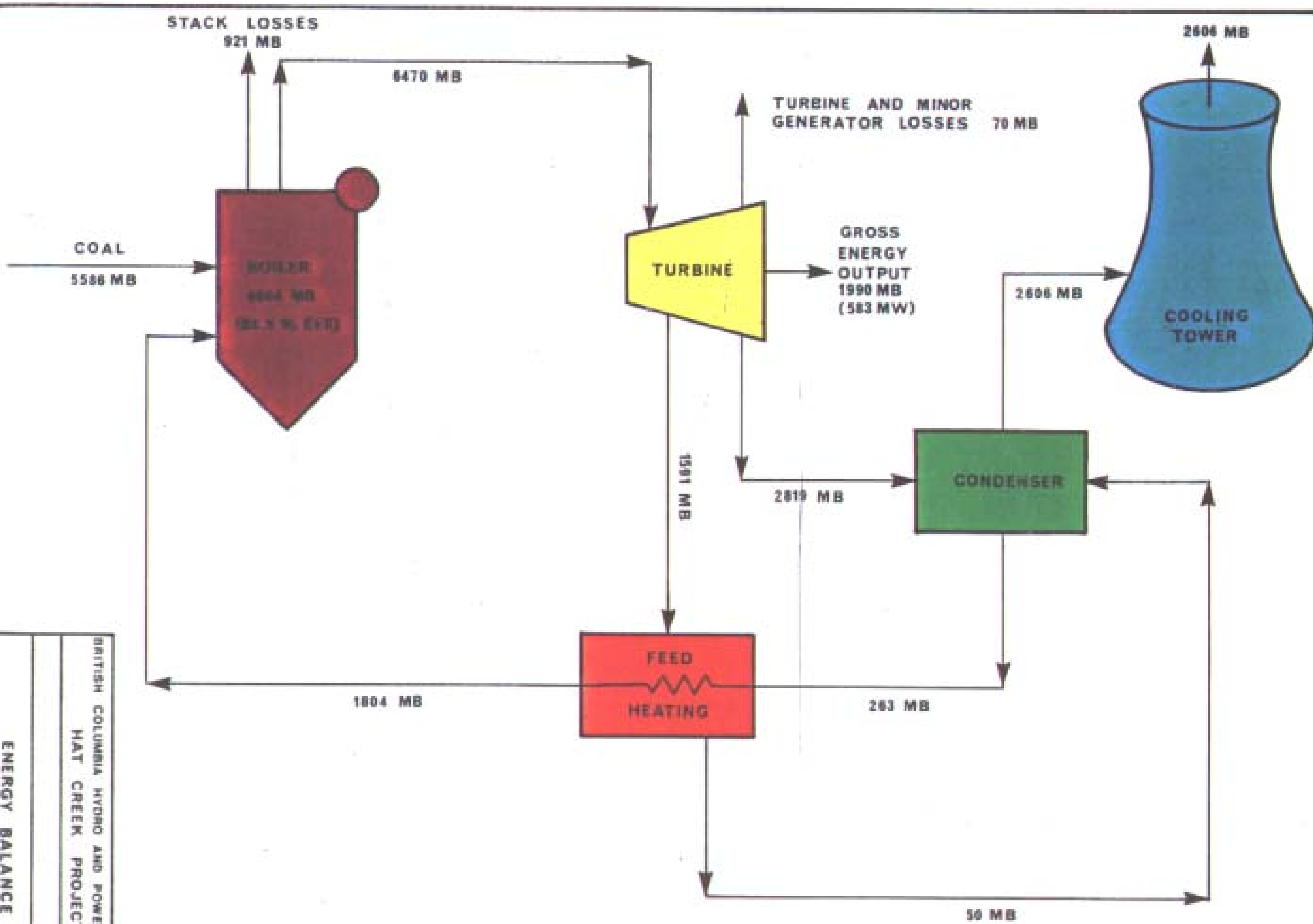
6.2.1 Site Layout

The site selected for the thermal plant is a gently sloping plateau situated almost due east of the mine site and 1600 ft. higher. South of the site the ground drops steeply to the Medicine Creek valley some 700 ft. below. Drawing M-100 at the back of this volume shows the local topography.

The exact site location was selected from the existing 100 ft. contour map, and visual observations of the terrain. When an accurate survey has been completed, and geological data becomes available, it may be necessary to adjust the exact plant location.

The principal station buildings are aligned approximately north-south, with the switchyard at the west side.

The boilers and chimney are located on the east side. The single chimney serves all four units, to achieve maximum possible plume rise and dispersion. Electrostatic precipitators are located at the rear of the boilers. Space for possible future equipment designed to remove SO_2 is also provided, although such equipment is not in the present concept.



NOTE:– MB = x 10⁶ BTU/HR
THIS FIGURE IS BASED ON 2092 MW NET 2332 MV GROSS
TURBINE HEAT RATE 8000 BTU/KW HR. VWO OVERPRESSURE RATING

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

ENERGY BALANCE
PER UNIT

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FIG. Nº 6.1.1

A water storage reservoir is impounded by a dam to enclose a natural basin located northeast of the plant. Cooling towers are also located to the northeast, which is generally the downwind side of the site, particularly during the cold months which are of most concern. This location is also convenient for the makeup water supply line.

There is no coal yard at the plant site. Facilities are confined to those required for termination of the overland conveyors and transfer to the plant coal handling system.

Drawing M101 at the back of this volume, shows the general arrangement of the generating station.

Drawings M100 and M101 are based on wind data which is available from the Hat Creek valley meteorological station, and it may be necessary to modify the plant orientation when wind data from the Harry Lake area becomes available.

6.2.2 Plant Arrangement

The layout of one unit of the station is shown on the general arrangement Drawings included at the back of this volume. These depict the principal features and configuration of the major components, as well as the locations of various items of ancillary equipment. By necessity, the latter may change when specific information is available on each item. In general, priority is given to minimizing the length of pipe runs, with particular emphasis on large-bore and high temperature systems. However, in some instances, flexibility and proper drainage of these lines will require additional length. Other considerations in equipment layout are provision of sufficient access for maintenance, avoidance of obstruction to other units, and the most practicable arrangement of building structural steel.

The plant island is arranged with the four turbine generators on a common centreline running the length of the turbine hall. This layout provides a short span for the overhead station crane. Overall length is actually determined by the width of the boilers. As the length of turbine generator units is not limiting, it will probably not be necessary to overlap generator rotor withdrawal spaces. The resulting design allows a turbine operating floor with ample laydown area for unit maintenance. A shared control room is located between each pair of units. The turbine generators are arranged in a "mirror image" configuration with the generators together. This results in a substantial saving in cable runs between generators and the control room. It also offers a significant improvement in plant layout because these major cable runs do not cross the main piping corridor running between each boiler and turbine. An unloading bay is provided at each end of the turbine hall. It will permit the largest components of the turbine generators to be lowered to or be recovered from ground level by the station cranes.

The main boiler feed pumps and turbines are located on the operating floor to facilitate maintenance by the station crane. This also permits a bottom exhaust from the turbine to be run to a convenient location in the condenser neck, thereby relieving the need for internal baffling, and providing good drainage.

The start-up/standby boiler feed pump and boiler feed booster pump are located on the ground floor and are serviced by an overhead monorail. These barrel-type pumps require little overhead clearance for maintenance.

The two lowest pressure feedwater heaters are positioned in the condenser neck, with the advantages of shorter lengths of their large extraction steam lines and economy of space. The remaining feedwater heaters are in the "heater bay" between the boiler and turbine.

Some items of equipment on the mezzanine and ground floors may require large headroom for removal. Examples are the turbine stop and governor valves, combined reheat valves, lubricating oil coolers and the condensate pumps. In these cases removable grating is provided, to allow withdrawal up to the operating floor by the station crane.

Air compressor facilities will be grouped per pair of units. The associated receivers and driers will be in the same vicinity.

A single "Batch Lube Oil Tank" is provided to serve all four turbines. It will be located indoors and a small transfer pump will supply any required clean make-up oil from this tank to the lubricating oil reservoir at each turbine.

In the boiler area, the arrangement of pulverizers and coal silos has the greatest influence on the configuration of the station. In this case, the number and volume of bunkers prohibits the most convenient arrangement - a single row across the front of the boiler. The pulverizers are arranged on either side of the boiler with a generous access aisle outboard. Routine maintenance of the pulverizers is performed with the assistance of a permanent monorail system serving four units. This is principally for the replacement of rollers. For a major overhaul there is sufficient clearance for a small mobile crane to enter through the rear doors, for removal of the largest components.

Access for removal of the forced draft and primary air fan rotors is also through these rear doors of the boiler house. However, this infrequent requirement does not warrant permanent lifting facilities.

A clear vertical access shaft is provided in the back corner of each boiler house. With suitable hoisting apparatus, this provides for maintenance and removal of equipment around the coal conveyors above the bunkers, the air preheater baskets, coal feeders, sootblowers, etc.

A common water treatment facility is provided for the entire station, and is situated on the ground floor of the administration and service building. This provides a convenient location for the routine delivery of chemicals by truck, without obstructing any area around the plant island. Since these facilities are normally under the jurisdiction of specialized operators, it is not necessary to locate it in the vicinity of the units.

6.2.3 Civil Engineering

The general graded level for the plant area is at elevation 4600 ft., with concrete foundations for all major structures and equipment constructed directly on sound rock.

Turbine foundations, and floors generally, are in reinforced concrete. Main superstructures are steel-framed, with insulated metal cladding.

The powerhouse is equipped with 2 main overhead travelling cranes, each of 90 tons maximum lifting capacity.

6.3 TURBINE GENERATOR

6.3.1 Rating

The turbine rating will not be finalized until detail design has commenced, because it depends on an accurate knowledge of the plant auxiliary load. The breakdown of the unit auxiliary requirements on which this report is based is shown below in Table 6.3.1, Auxiliary Loads.

TABLE 6.3.1 AUXILIARY LOADS

Nominal output (unit)	500 MW
Station auxiliaries	43 MW
Mine and conveyor power (per unit)	7 MW
Water pumping power (per unit)	6 MW
Transformer losses	2 MW
	558 MW
Allowance for possible future SO_2 scrubber	10 MW
Allowance for possible coal preparation plant	5 MW
Contingency	10 MW
	583 MW

The normal European concept for determining the turbine generator rating which is normally used in Western Canada, is to provide a guaranteed turbine rating equivalent to the gross output required. In fact all manufacturers provide a margin above the guaranteed rating, but while European manufacturers often do not quote the margin, which may be 2-3%, U.S. manufacturers quote a bona-fide 5% extra capability which is referred to as the valves wide open (VWO) rating.

In addition the rating of all turbines increases in almost exact proportion to the inlet pressure and it is common U.S. practice to rate the turbine for 5% overpressure and valves wide open. Thus on this basis the calculated gross turbine rating is often about 10% above the guaranteed figure.

The disadvantage of the European concept is that purchase of a U.S. designed and rated turbine would not utilize the VWO margin of the machine or its ability to run at 5% overpressure. However, if the station is designed for 5% overpressure the cost of the boiler would increase slightly (in terms of dollars per unit of heat output).

The exact turbine rating is not vital in the conceptual design because the 4 exhaust machine which has been selected is economic in the range 530-600 MW plus. Until the auxiliary load is known more accurately, the conceptual design is based on a machine which is rated for 583 MW at the VWO overpressure condition. The same machine will therefore produce about 560 MW at the VWO condition and will have a guaranteed rating of 532 MW at steam conditions of 2400 psig, $1000^{\circ}F/1000^{\circ}F$ ($538/538^{\circ}C$) with final feedwater temperature (FFWT) of $480^{\circ}F$ ($249^{\circ}C$), and 3.5 in. Hg. Abs. back pressure. The guarantee condition is shown in heat balance BCH 6802 M-120.

The net output of the power plant is 2100 MW based on the 58 MW normal auxiliary load shown in Table 6.3.1.

Final selection of the specified net and gross ratings per unit, and the preferred rating basis, should be based on more detailed discussions with boiler and turbine manufacturers in the project implementation phase.

6.3.2 Turbine Data

In the process of selecting a turbine, a limiting factor is the provision of sufficient exhaust area in the last stage blading. The volume of steam flowing to the condenser for this unit will require a total exhaust area of about 220 sq. ft. This is conveniently achieved by four flow configuration with 30 inch last stage blades, which is standard with one manufacturer. Other manufacturers' standards vary slightly from this size. This results in a mass flow of approximately 11,600 lb/hr/sq. ft. of exhaust area, as compared with the maximum of 15,000 allowed by most manufacturers. The 30 in. blade design has been well proven in service. The turbine will probably have a combined HP/IP cylinder, which offers a significant saving in first cost and a reduction in overall unit length of about 15 ft. The combined HP/IP configuration is at present offered in units up to 600 MW rating for both base load and cycling service.

With the requirement for two-shift operation, the provision of a steam bypass system will reduce the turbine thermal stresses on startup and prolong component life. A two-stage system, providing steam flow from the main steam pipes through the reheater and thence to the condenser will allow faster boiler start-ups as well as permitting optimum matching of main and reheat steam temperatures to the turbine metal temperatures. Based on the turbine cooling curve for a typical 500 MW unit, it can be shown that a bypass capacity of about 25% MCR steam flow will permit accurate steam temperature matching after a 6 hour shutdown. Certified curves of boiler steam temperature versus load are required for the precise sizing of this facility, but a typical system for a 500 MW turbine is shown on Figure 6.3.1.

Table 6.3.2, Summary of Turbine Data, gives typical performance data for the turbine.

TABLE 6.3.2

SUMMARY OF TURBINE DATA

	Nameplate (Guaranteed) Rating	VWO Rating	VWO 5% overpressure Rating
Rating (MW)	532	560(approx)	583
Throttle Flow (lb/hr)	3,582,000	3,750,000 "	3,960,000
Heat Rate (Btu/kWhr)	8,017	8,007	7,972
Steam Pressure (psig)	2,400	2,400	2,520
Steam Temperature [°F (°C)]	1,000 (538)		
Number of stages of feedheating	7		
Condenser design back pressure (in. Hg Abs)	3.5 at design ambient		
No. of rows of last stage blades	4		
Last stage blade length (in.)	30		
Number of cylinders	3		

$$\text{Net Turbine Heat Rate} = \frac{QT(HT-hffw) + Qr(Hro - Hri)}{KWE}$$

Where:
QT = Throttle flow, lb/hr
HT = Throttle enthalpy, Btu/lb
hffw = Final feed water enthalpy, Btu/lb
Qr = Reheat flow, lb/hr
Hro = Enthalpy out of reheater, Btu/lb
Hri = Enthalpy into reheater, Btu/lb
KWE = Generator output at the terminals, KW

The heat rate of the turbine at VWO + 5% OP will be approximately 7970 Btu/kWhr. For the purpose of this conceptual design a turbine heat rate of 8000 Btu/kWhr is utilized. Subtracting station auxiliary power and allowing for the boiler efficiency, which is estimated to be 83.5%, the station net heat rate will be 10,344 Btu/kWhr.

If the water supply and mine power are also considered, the design heat rate becomes 10,639 Btu/kWhr.

The cycle optimization has confirmed the economic justification for seven stages of feedwater heating by extraction steam. This includes five low pressure heaters, the last one being the deaerating stage. It is followed by 2 - 50% duty turbine driven boiler feed pumps and two high pressure heaters. The arrangement is conventional for units above 400 MW. Two 25% duty motor driven start-up boiler feed pumps are provided. Feedwater heater drains are handled by a cascading system, without the use of drain pumps.

6.3.4 Generators

Each generator is provisionally rated at 648 MVA at 0.9 power factor, 24 kv 3 phase 60 Hz and has a static excitation system. Final parameters of the generator and the characteristics of the excitation system will be selected to meet system stability requirements.

The neutral of each generator is grounded through a resistance loaded dry type distribution transformer.

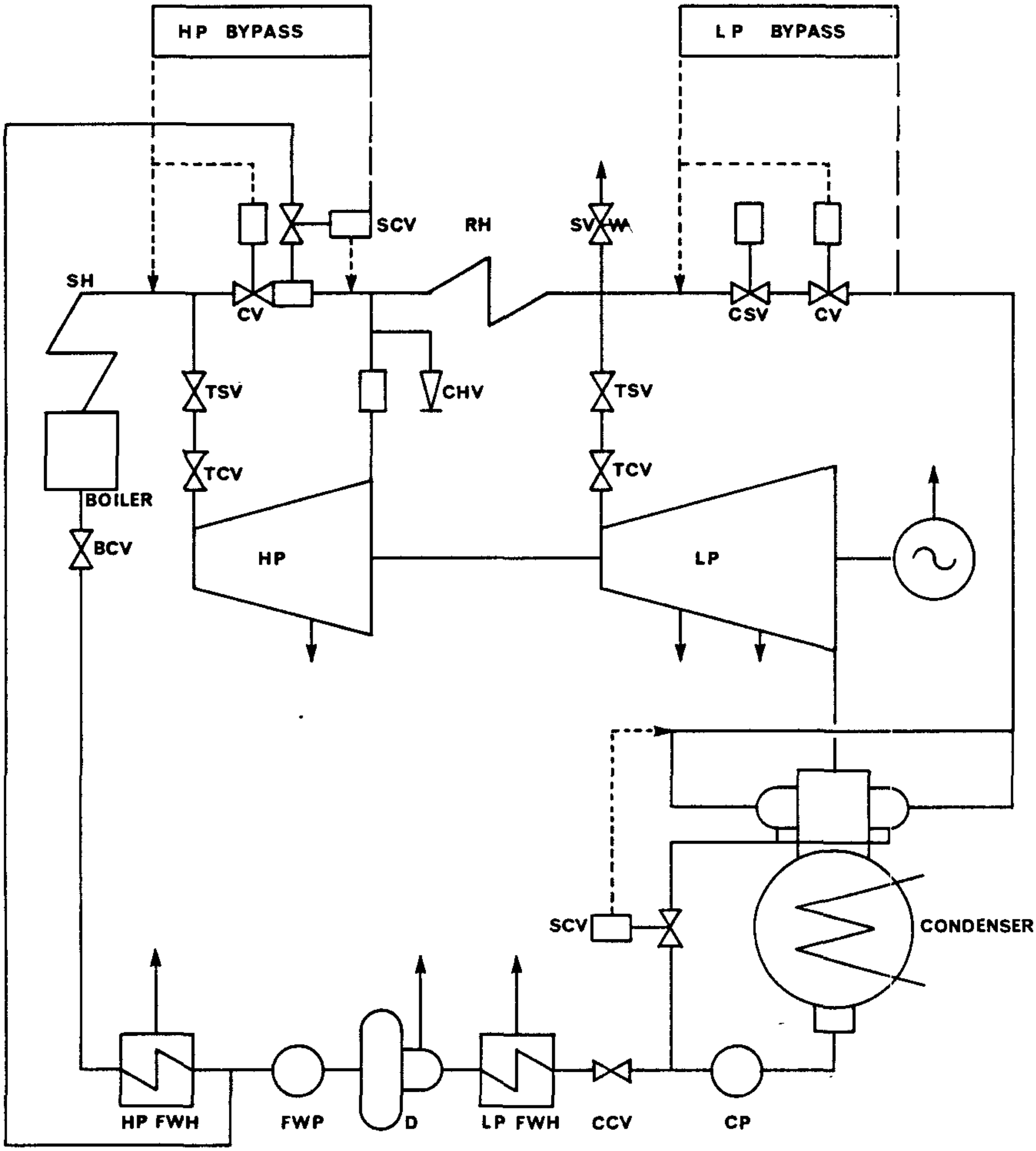
Generator protection includes surge protection and a conventional protective relaying scheme, typical for this type of machine.

6.4 ELECTRICAL SYSTEMS AND EQUIPMENT

6.4.1 Main Connections

Power from the four main generator units is delivered to the B.C. Hydro 500 kv switchyard through step-up transformer banks, as shown on the block diagram Figure 6.4.1.

Each main transformer bank consists of three single phase transformers, with isolated phase bus connections from the generators. Each transformer is rated at approximately 200 MVA to match the



SCV - SPRAY CONTROL VALVE
CV - CONTROL VALVE
CHV - CHECK VALVE
CSV - EMERGENCY STOP VALVE
BCV - BOILER CONTROL VALVE
CCV - CONDENSATE CONTROL VALVE
CP - CONDENSATE PUMP
SV - SAFETY VALVE
FWP - FEED WATER PUMP
D - DEAERATOR
RH - REHEATER

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TURBINE BYPASS SYSTEM

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generator net output, allowing for the possibility of full output operation with 50% of the auxiliary power supplied from a start-up/standby transformer, should a unit auxiliary transformer be out of service for any reason.

Power to the mine and the overland conveyor system is transmitted by two 60 kV transmission lines. Power to the coal conveyors is tapped off these lines through two step-down transformers.

6.4.2 Auxiliary Electrical System

During normal operation, electrical power to unit auxiliaries is supplied by the generator via two unit auxiliary transformers.

During start-up and shutdown, electrical power is supplied from the 500 kV switchyard to the station auxiliary transformer, and the start-up/standby transformers. Each of the start-up/standby transformers is sized as a full capacity replacement for one of the unit auxiliary transformers. During normal operation, the start-up/standby transformers supply power only to those auxiliaries not directly associated with the running of the unit. There are two station auxiliary transformers and each is sized to take the load of two start-up/standby transformers and the mine and conveyor load.

In the event of loss of supply from a main generator unit or a unit auxiliary transformer, power supply to the unit auxiliaries is transferred automatically from the unit auxiliary transformer to one of the two start-up/standby transformers.

The medium voltage 4.16 kV systems provide the primary power distribution for the unit and station auxiliary loads including 250 hp and larger.

The low voltage 600 volt systems are radially fed from 4.16 kV buses. The 600 volt supplies are distributed by power centres and motor control centres located at strategic locations as close as possible to the centre of load groupings they supply. The 600 volt systems supply the lighting systems and transformer rectifier loads associated with the electrostatic precipitators. 120/208 volt systems are also provided for miscellaneous small loads and for non-vital control requirements.

6.4.3 Transformer Fire Protection

Transformer fire protection will be provided for large transformers by a permanently installed automatic spray system having automatic deluge valve, water spray nozzles, temperature detectors, supervisory control panel, and a signal alarm to actuate the central control room annunciators.

6.4.4 Emergency Diesel Generator

Each unit is provided with an emergency diesel generator set rated 600 kW, 0.8 p.f., 600 volt, 3 phase, 60 hz, for supply of certain auxiliary equipment considered vital to safety of personnel and equipment during the loss of all external ac power from the system. Start-up of the diesel generator is automatic. The provision of large diesels to supply more than one unit does not lead to significant cost savings.

6.4.5 Uninterruptible Power Supply Systems

120 volt ac uninterruptible power supply systems are provided for vital ac loads such as boiler analog controls, burner controls, turbine electro-hydraulic controls, computer systems, transducers and other vital instrumentation. These systems are supplied by the batteries or unit diesels.

6.4.6 125 Volt DC Supply Systems

125 volt dc supply systems will be provided consisting of lead-calcium batteries, solid state battery chargers, 125 volt dc switchgear and dc panels to provide stored power to vital dc loads such as emergency bearing oil pump, hydrogen seal pump, emergency dc lighting switchgear controls, protective relaying controls, communications and alarms, and other vital control systems.

6.4.7 Black Start of Units

The predominance of hydro electric power generation in the B.C. Hydro system makes it unnecessary to provide "black start" facilities for this installation. It is presumed that if power cannot be imported into the Hat Creek station to start the units, there would be no available transmission lines to export the resulting power.

6.4.8 Wiring System

All conduit above ground is standard galvanized steel or aluminum. All underground conduit is plastic, utilizing special reinforcing under roads or other heavy equipment crossings. Conduits entering equipment enclosures are sealed where necessary to prevent ingress of water or moist air into the equipment.

Wherever possible use is made of overhead cable trays and racks rather than conduit. Where required, trays have covers to keep out sunlight, dirt and foreign matter or to provide an additional shield. Separate trays for power, control and instrumentation are provided. The vertical and horizontal trays have fire stops below and above the floor and on both sides of the wall penetration respectively.

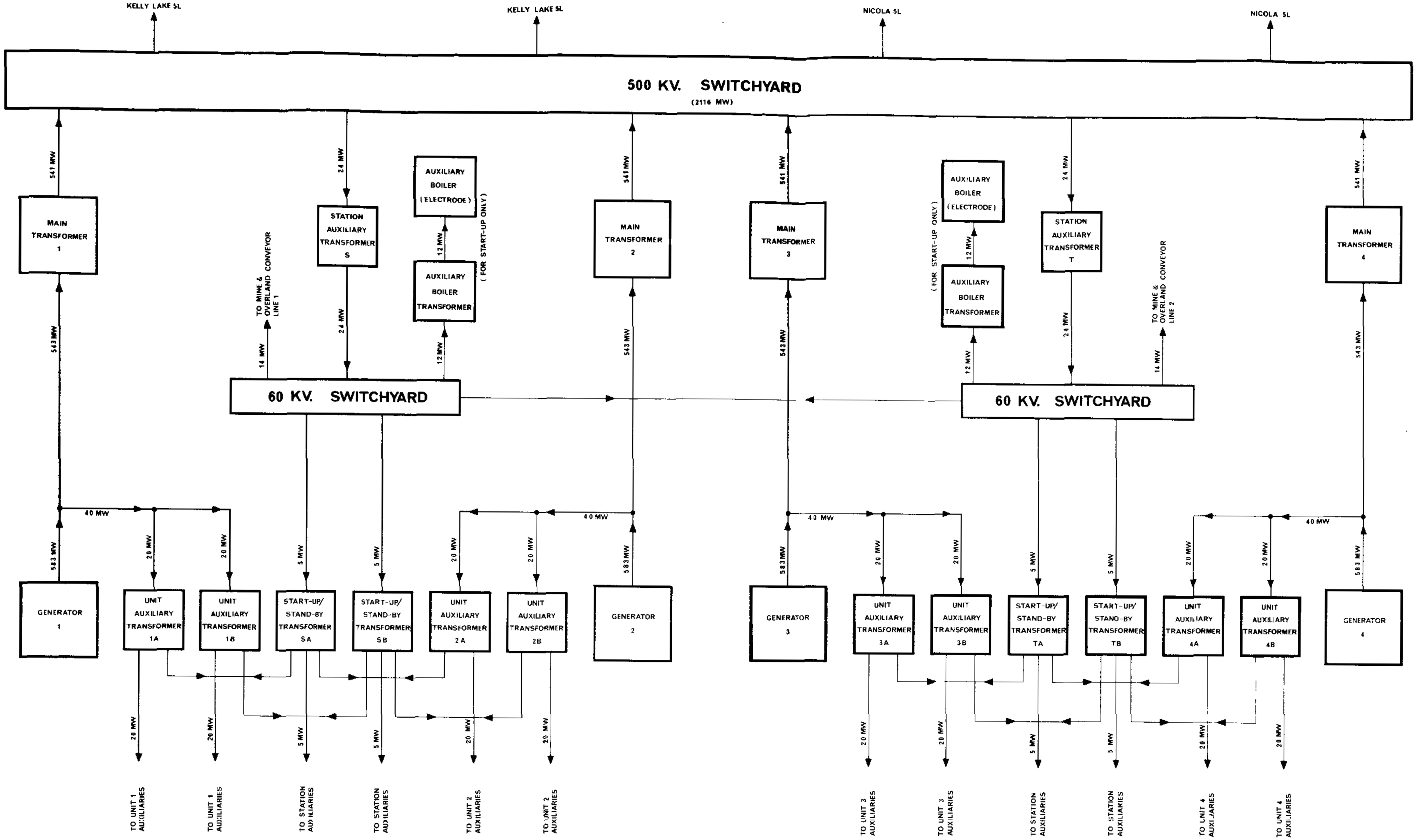
Power and control cable runs between the plant and outlying areas are installed in underground concrete-encased PVC duct banks as required. They are reinforced under roads and in areas where heavy equipment may be moved over the duct bank.

6.4.9 Lighting

Normal ac, normal/emergency ac, and emergency dc lighting is provided for the generating station, associated areas, roadways, pumphouse, coal handling plant, etc. as necessary.

6.4.10 Grounding and Cathodic Protection

The conceptual design envisages provision of appropriate grounding and cathodic protection, to be based on a survey which will be carried out in the project implementation stage. The survey will



NOTES

(1) POWER FLOW SHOWN IS UNDER NORMAL OPERATING CONDITIONS.

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Vancouver Toronto

ELECTRICAL SYSTEM

drawing number F

FIG. Nº 6-4-1

determine the grounding requirements for the safety of personnel and equipment as well as the corrosion suppression requirements for such equipment as buried metallic structures, piping and condensers.

6.4.11 Site Telecommunications

A complete site telecommunications systems is provided and consists of an electronic PAX/PBX dial telephone system, sound telephone intercom system, solid state paging system and FM radio communication system.

6.5 INSTRUMENTATION AND CONTROLS

6.5.1 Basic Philosophy

The basic objectives are the control of the power plant for optimum operation and to ensure maximum plant availability and performance consistent with safety. The effective development of instrumentation and controls for these objectives requires the co-ordination and integration of several related control systems related to the boiler, turbine and generator. The control of the plant is integrated by the provision of central control rooms from which all major equipment is controlled.

To achieve maximum advantages of operating ease and flexibility consistent with reliability, safety and ease of maintenance of plant equipment, operationally oriented computer systems are applied and integrated into the overall scope of plant instrumentation.

To maintain reliability, the equipment is arranged for environmental protection and ready access for maintenance and calibration. As an example, all instrumentation located outdoors is mounted in temperature-controlled and dust-tight enclosures. Indoor instruments are mounted on racks or panels depending on the degree of protection required. An instrument shop with facilities for repair and testing of instruments is provided.

An important aspect is that the control systems and equipment are consistent with the preferences and practices of B.C. Hydro. The design of the central control rooms is based on the consideration that the operator is an integral part of the control of the plant.

6.5.2 Central Control Rooms

Two air-conditioned central control rooms, one for each two units, are provided to serve as the nerve centres for the respective units. These contain all controls, indications and records needed by the operator to start up, shut down, change load and to handle emergencies.

The control room facilities are designed to ensure that the operator can carry out his tasks expeditiously, and laid out with distinct functional areas for normal and emergency operations, infrequent operations, and historical records, etc.

Main features include:

- Control boards and panels designed compactly with functional groupings to permit rapid scanning by the operator.

- Forms of presentation including analog and digital indication and recording, signal lamps and alarm annunciators, and selectable CRT displays of data.

- A computer system an an operating tool and for monitoring plant functions and performance.

Each control room is the central core of a larger area in the control building for each two units, which includes electronic equipment rooms, a computer room and instrument shop.

The centralized control facilities for each unit consist of the BTG (boiler-turbine-generator) board, auxiliary control board, soot blower control panel, and computer console, with alarm and logging typewriters. These facilities are designed to reduce the burden on the operator of continued regulation duties, and are backed up by separate interlock or safety systems.

The BTG board is a compact, functional board combining all the important operating controls and instruments required to accomplish start-up, shutdown, load change and to handle various emergencies. The board is the operating centre for turbine and boiler controls (including feedwater control, fuel firing rate, main and reheat steam temperature control, air preheater temperature, start and stop control of turbine generator) and switching control of main and auxiliary transformers and auxiliary buses. Major motor and valve controls together with necessary indications of plant conditions, such as boiler drum water level, are also located on these boards. Lamp-window type annunciators provide indication of abnormal operating conditions for any of the unit equipment, and CRT's associated with the computer give detailed information to the operator. A message CRT is provided to aid the operator during the start-up and shutdown of the turbine and other major equipment.

All instruments on the BTG board are electric receiver type. Miniature recorders are used for trend recording of steam temperature, excess O_2, steam, feedwater and air flow readings, steam pressure, turbine load and other selected values obtainable from the computer. The board contains the manual/automatic stations for the main analog control systems, and provides for the remote operation and status indication of other essential unit auxiliaries.

6.5.3 Major Unit Controls

The major controls systems for each unit include:

- Boiler analog control systems - These are designed to perform start-up and on-line regulation of drum level, feedwater flow, fuel feed, air flow, superheat and reheat temperature.

- Burner control system - The function of this system is to provide remote manual or automatic operation of ignition system, pulverizers and feeders.

- Fuel safety system - This provides for tripping the minimum necessary amount of equipment, upon reaching unsafe boiler operating conditions. This system is fully integrated with the systems described above, for start-up and shutdown in the safest manner.

- Monitoring and results computer system (MARC) - This computer is included as an integral part of the overall design for each pair of units. It monitors the status of all major equipment, reduces data for presentation to the control operator, logs necessary historical data, displays critical trends and gives alarm for "out-of-limit" conditions. A group of "demand functions" permits the operator to follow any important plant readings or group of related readings from the control room. Some plant performance calculation facilities are included.

6.5.4 Miscellaneous Controls

The necessary equipment for automatic control of heater levels, condenser hot well level, condenser hot well fill and reject, boiler feed pump recirculation, condensate recirculation, condensate makeup, generator hydrogen temperature, turbine lube oil temperature and other miscellaneous sub-loops normally found in a power plant is included.

Adequate margins are incorporated in the design and sizing of the various control systems to maintain proper operation under all operating conditions.

6.6 WATER TREATMENT

6.6.1 Make-up Water Treatment

The make-up water treatment system is designed to supply four steam generators producing a total of 15 million pounds of steam per hour. The water from the Thompson River is relatively high quality: 55 to 110 ppm total dissolved solids, and moderate suspended solids. Filtration is required in the pretreatment cycle, and carbon filters are used to remove residual organics and trace chloride residuals.

The demineralizers consist of 3 parallel trains, each with a nominal capacity of 400 USgpm, and delivering 313 USgpm (net), sufficient for service, outages and regeneration. Each train consists of a cation unit of 8½ ft. diameter delivering water to a common deaerator where carbonic acid is stripped to a level below 10 ppm. The decarbonated water falls into a 10,000 gallon clearwell storage tank, from which it is pumped into the anion unit. This is also an 8½ ft. diameter vessel, furnished with strong based resin. Effluent is then polished with a mixed-bed unit to reduce the silica level to below 0.02 ppm and the specific conductivity to less than 0.1 micromho.

The system is fully automatic in operation and regeneration. A rinse recycle is used to economize on rinse water and minimize the volume of wastes discharged. Following regeneration, the operator places the unit back in service manually.

6.6.2 Condensate Polisher

Two-shift operation places considerable emphasis on condensate polishing, since high levels of dissolved silica and metal oxides are prevalent on start-up, even after only an overnight shut down. Two 50% capacity powdered resin polishing units are provided for each boiler. Each unit includes a pre-mix batch tank with transfer and holding pumps, and an 8 ft. diameter vessel for the bed. A run of about two weeks is expected between reagent changes.

Since the polishing units are only required during and shortly after a start-up, the duty cycle allows ample time for regeneration, and no standby capacity is needed. It may also be advantageous to arrange for side-stream polishing by one of the 50% units during normal operation of the boiler and turbine, or recycling to the hotwell during a unit outage.

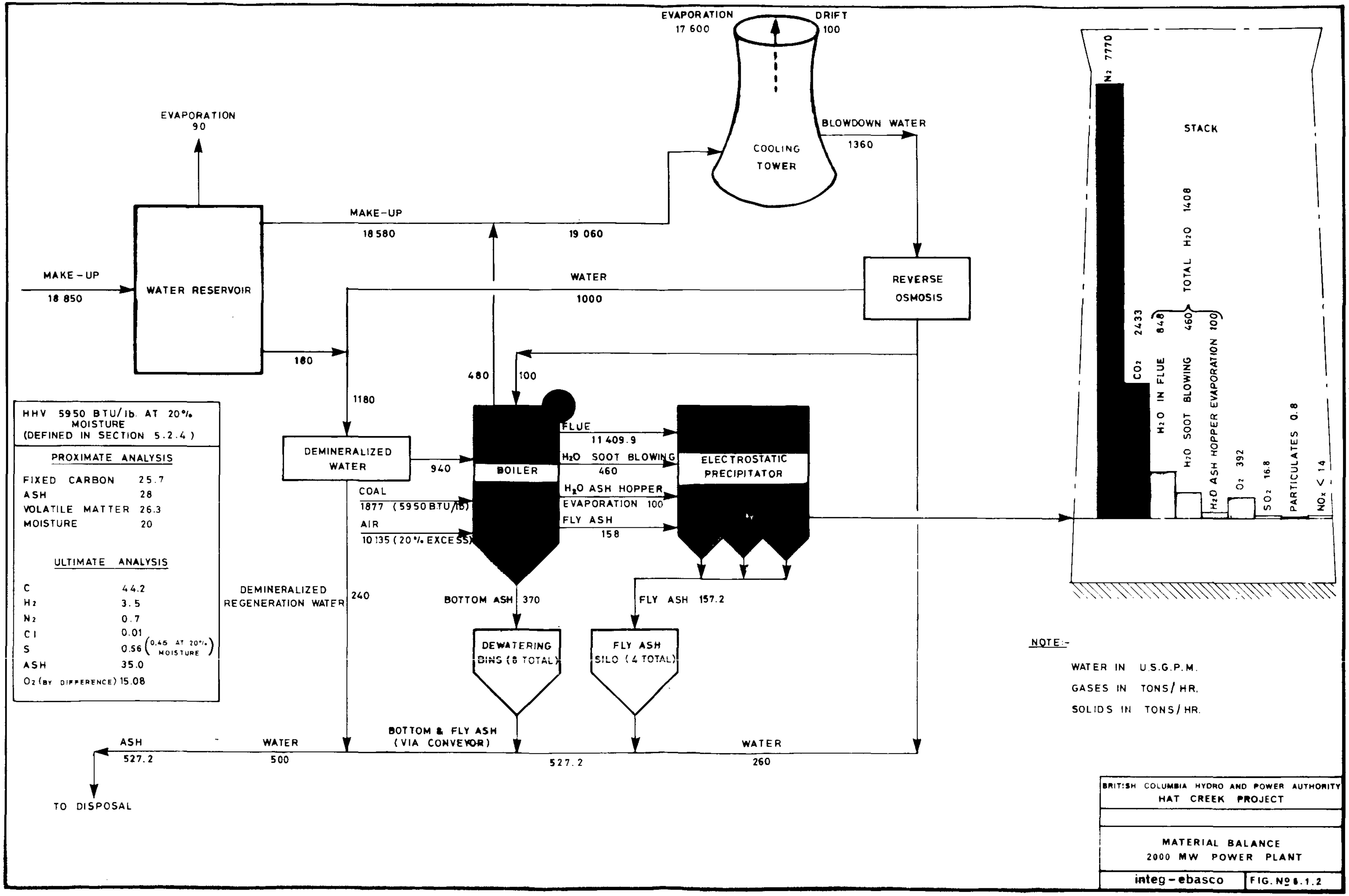
The alternative to this sytem would be a deep bed demineralizer sized for full condensate flow. As against the proposed unit, it would have considerably longer regeneration time, an increased space requirement, and additional capital cost of approximately $300,000 per boiler.

6.7 COOLING SYSTEM

Evaporative rectangular mechanical draft cooling towers have been selected as the most economical means of heat release for the condenser cooling water system. Studies to date indicate that hyperbolic natural draft towers could only be justified by considerable emphasis on plume dispersion, and the currently available climatic data does not indicate this to be a problem.

Four towers serve the station, each with 9 cells. Their basins discharge into a common channel, from which four vertical pumps withdraw circulating water. These pumps are powered from a station service bus, and are thus independent of the operation of any one unit. They discharge into a common header and two separate 120 in. diameter reinforced concrete conduits convey the cooling water to the condensers. A similar pair of conduits return the warm water to a header, from which it can be directed to any or all of the towers. The cooling tower fans are also fed from a station service bus.

The provision of a common circulating water system allows the optimum number of cooling towers and pumps to be operated for the seasonal variations in ambient conditions. The cooling tower/condenser optimization study has shown 3.5 in. Hg. Abs. back pressure to be the most economic balance between, on the one hand, cooling tower and condenser size (capital investment), and on the other hand, increased generating capability and efficiency. The ambient temperature conditions adopted during this study were those that will be exceeded only during the warmest 5% of the time. During these rare occasions the back pressure will vary between about 3.5 and 4.0 in. Hg. Abs., with a corresponding reduction in generating capability of up to 5 MW per unit.


EVAPORATION 17 600
DRIFT 100
COOLING TOWER
BLOWDOWN WATER 1360
STACK
N_2 7770
CO_2 2433
H_2O IN FLUE 848
H_2O SOOT BLOWING 460
H_2O ASH HOPPER EVAPORATION 100
TOTAL H_2O 1408
O_2 392
SO_2 16.8
PARTICULATES 0.8
NO_x < 14
EVAPORATION 90
MAKE-UP 18 850
WATER RESERVOIR
MAKE-UP 18 580
19 060
WATER 1000
REVERSE OSMOSIS
180
1180
480
100
HHV 5950 BTU/lb. AT 20% MOISTURE (DEFINED IN SECTION 5.2.4)
PROXIMATE ANALYSIS
FIXED CARBON 25.7
ASH 28
VOLATILE MATTER 26.3
MOISTURE 20
ULTIMATE ANALYSIS
C 44.2
H_2 3.5
N_2 0.7
Cl 0.01
S 0.56 (0.45 AT 20% MOISTURE)
ASH 35.0
O_2 (BY DIFFERENCE) 15.08
DEMINERALIZED WATER
940
BOILER
COAL 1877 (5950 BTU/lb)
AIR 10 135 (20% EXCESS)
FLUE 11 409.9
H_2O SOOT BLOWING 460
H_2O ASH HOPPER EVAPORATION 100
FLY ASH 158
ELECTROSTATIC PRECIPITATOR
DEMINERALIZED REGENERATION WATER 240
BOTTOM ASH 370
FLY ASH 157.2
DEWATERING BINS (8 TOTAL)
FLY ASH SILO (4 TOTAL)
NOTE:-
WATER IN U.S.G.P.M.
GASES IN TONS/HR.
SOLIDS IN TONS/HR.
ASH 527.2
WATER 500
BOTTOM & FLY ASH (VIA CONVEYOR) 527.2
WATER 260
TO DISPOSAL
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT
MATERIAL BALANCE
2000 MW POWER PLANT
integ-ebasco
FIG. No 6.1.2

SECTION 7. PLANT OPERATION

CONTENTS

7.1 REGIME OF OPERATION

An operating regime for the generating station has not been clearly defined in terms of estimated duration of each mode. It has, however, been established that the plant must be capable of operating in the base load or two shift modes, and eventually on either one or two shift basis with seasonal lay-up. Features are incorporated in the design to facilitate each of these modes of operation, and to ensure that they will have minimum impact on the service life of equipment.

7.1.1 Base Load

Base load operation requires no design features which would be considered special in a modern power plant. Emphasis is on generation at the best practicable heat rate and with minimum operating labor. Selection of the cycle, monitoring and control equipment, auxiliary plant equipment and the plant arrangement all have this purpose in view.

7.1.2 Two Shift Operation

Two shift operation may involve weekend shutdowns as well as the nightly 6-8 hours interruptions. Following a weekend shutdown, the start-up is classified as merely "warm" and the problems more nearly approach those involved in cold starting. However, because of the frequency of warm and cold starts operating aids for turbine temperature matching and run-up are justified.

The start-stop cycles of two shift operation are among the principal factors affecting the service life of equipment, particularly the boiler and turbine. Severe local stresses are created by relatively moderate temperature differentials in large metal sections and the emphasis is on reducing such differentials.

The daily problem in two shift operation is the relatively hot start encountered after an overnight shutdown. A large high pressure, high temperature steam turbine, well insulated, will cool quite slowly. Indeed, to reduce the severity of temperature cycling, and to reduce starting and loading time, it is advisable to hold the first stage steam temperature to a value as high as possible during shutdown. The application of variable pressure capability to the boiler reduces steam temperature loss due to throttling.

Owing to the slow turbine cooling rate, the steam normally would be too "cold" for proper temperature matching after an overnight shutdown. The solution to this problem is to fire the boiler at a rate sufficiently high to provide a proper steam temperature. A number of steam bypassing schemes are available, all of which are essentially turbine bypasses, in which steam from the superheated steam line bypasses the high pressure cylinder with appropriate pressure and temperature regulation. This steam then flows through the reheater and thence, with further pressure and temperature regulation, to the condenser. Sufficient bypass capacity is provided to permit a steaming rate appropriate to the steam temperature required. This scheme permits starting and loading in a relatively short period of time, generally less than one hour.

7.1.3 Long-Term and Seasonal Lay-Up

Long term shut-down is interpreted, in this case, as exceeding three months. It is further understood that the system peak is in winter so that long lay-up will occur in the summer when freezing will not be a consideration. For these reasons "wet" lay-up is recommended.

The principal objective is to prevent, or at least inhibit, corrosion by oxygen attack. To accomplish this it is proposed that all water and steam systems be filled completely with condensate suitably treated for oxygen scavenging. This requires some special attention to items such as pump seals to prevent excessive leakage, but needs little equipment except for extra condensate storage capacity.

The turbine and condenser are not included in the "wet" section but would be filled with inert gas. Nitrogen is most commonly used for this purpose and will be stored at the site in bulk cylinders.

Attention must also be given to ancillary facilities such as the condenser circulating water system, which should be kept filled and a low level of circulation maintained. Common facilities may not have to be laid up if one or more of the generating units is retained in operation. No special consideration need be given to the make-up water supply line as it must be maintained full under all circumstances. Pumps are provided for this purpose.

These lay-up procedures are not intended for units which are on a cold standby basis. After lay-up, a number of days will be required to prepare and test each system prior to returning to operation.

Operating and maintenance instructions must include lay-up and re-commissioning procedures for each piece of equipment.

7.2 STAFFING

No differentiation in staffing requirements is made between base load and two shift operations since the plant is designated to be capable of both modes from the start. During extended lay-up only a skeleton operating staff would be required but maintenance work undertaken during such periods might require a substantial maintenance crew.

B. C. Hydro have established their own staffing levels and the matter is not reviewed in this report.

SECTION 8. PROJECT SCHEDULE AND CAPITAL COST ESTIMATE

CONTENTS

8.1 PROGRAMME OF DEVELOPMENT

The latest B.C. Hydro load growth forecasts indicate that the Hat Creek units should be brought on line in the following sequence:-

Unit #1	January 1984
Unit #2	January 1985
Unit #3	January 1986
Unit #4	January 1987

The detailed project schedule and specification writing, procurement and drawing office schedules which have been prepared are geared to commercial operation of the first unit on January 1, 1984. These schedules are summarized in the milestone schedule shown on Figure S - 101 at the back of this section.

It may still be possible to achieve commercial operation of the first unit by January 1, 1983 if circumstances necessitate this. A Proposed Milestone Schedule showing how this date can be met is shown on Figure S-100. It should be noted that detailed engineering would have to begin early in 1977 and that two major items of equipment (i.e. main turbine-generator and boiler) should be ordered by October, 1977 to achieve this earlier schedule without serious problems.

The milestone schedules are derived on the basis that:

- Time from start of construction to trial operation (first steam to turbine) is 48 months.

- Commissioning time from trial to commercial operation would be six months.

- Start of detailed engineering would precede the start of construction by a period of 12 to 18 months.

Applying these precepts to the January 1, 1984 unit in-service date results in the following milestone schedule:-

- Start detailed engineering	January 1 - July 1, 1978
- Start construction	July 1, 1979
- Trial operation	July 1, 1983

However, since it would be prudent to take maximum advantage of the summer months in the first construction season, April 1, 1979 appears to be the optimum date for the start of construction and these milestones become:

- Start detailed engineering	October 1977 - April 1, 1978
- Start construction	April 1, 1979
- Trial operation	July 1, 1983

Considerable detailed engineering could be accomplished before October 1, 1977 to facilitate permit applications and to ensure readiness of key aspects of design prior to start of construction. This would appear a prudent policy affording maximum assurance of meeting the desired in-service date.

8.2 ESTIMATED CAPITAL COST

Table 8.2.1 Capital Cost Estimate summarizes the capital cost estimate dated October 1976. It is expressed in 1976 dollars. These figures do not include cost of transmission lines, interest during construction, land acquisition costs, B.C. Hydro overheads, or the cost of preliminary investigations and studies.

TABLE 8.2.1

CAPITAL COST ESTIMATE ($1,000)

	#1	#2	#3	#4	TOTAL
TOTAL DIRECT CONSTRUCTION COST	243,692	171,890	175,803	172,013	763,398
INDIRECT CONSTRUCTION COST	4,067	3,011	3,011	3,048	13,137
SUBTOTAL	247,759	174,901	178,814	175,061	776,535
CONTINGENCIES 12%	30,368	20,700	21,796	20,816	93,680
TOTAL CONSTRUCTION COST	278,127	195,601	200,610	195,877	870,215
ALLOWANCE FOR ENGINEERING	12,175	7,565	7,565	7,659	34,964
TOTAL PLANT COST	290,302	203,166	208,175	203,536	905,179
WATER SUPPLY SYSTEM	55,000				55,000
COAL TRANSPORTATION SYSTEM	41,169	14,500			55,669
TOTAL PROJECT COST	385,471	217,666	208,175	203,536	1,015,848

8.3 SUMMARY CASH FLOW ESTIMATE

TABLE 8.2.2

CASH REQUIREMENT ESTIMATE ($1,000)

	#1	#2	#3	#4	TOTAL
1978	4,000	3,000	1,000	1,000	9,000
1979	15,000	6,000	3,000	2,000	26,000
1980	57,000	9,000	5,000	5,000	76,000
1981	118,000	27,000	9,000	6,000	160,000
1982	162,000	68,000	18,000	9,000	257,000
1983	29,000	81,000	63,000	65,000	238,000
1984	1,471	22,000	86,000	87,000	196,471
1985		1,666	22,000	21,000	44,666
1986			1,175	7,536	8,711
	386,471	217,666	208,175	203,536	1,015,848

Unit #1 Includes $ 55,000,000 for water supply
$ 41,169,000 for mine site coal handling and one overland conveyor

Unit #2 Includes $ 14,500,000 for one overland conveyor

Costs, as per estimate BCH1523 MC-2 of January 21, 1977, are based on October 1976 prices and are unescalated.

Commercial Operation Dates -

Unit	#1	January 1, 1984
	#2	October 1, 1984
	#3	October 1, 1985
	#4	July 1, 1986

SECTION 9. ECONOMIC FACTORS

CONTENTS

9.1 BASE DATA

The calculations contained in this study and appendices are based on financial base criteria which have been established with B.C. Hydro.

The most important financial criteria adopted are as follows:

- All costs are based on October, 1976 prices.
- Auxiliary power costs are charged at 20 mills/Kwhr.
- No capital cost penalty to be applied to auxiliary power needs. The 20 mill power cost includes the capital component.
- The following annual charge data have been applied:

Operations & Maintenance	- 1.45%	of	capital	cost
Administration and general	- 0.36%	"	"	"
Insurance	- 0.25%	"	"	"
Interim Replacement	- 0.35%	"	"	"
Taxes	- 1.0 %	"	"	"
Interest Expense	- 10 %	"	"	"
Depreciation	- 0.37%	"	"	"

  In addition, a variable maintenance charge of .3 mills/Kwhr has been applied.

- No allowance has been made for B.C. Hydro corporate overheads.
- Debt: equity ratio - It has been assumed that the financial structure represents 100% debt.
- Federal and Provincial sales taxes - No Federal sales tax is included. The amount of Provincial sales tax (which would apply if not tax-exempt) is shown separately.

- Inflation - In calculations which have included inflation the following rates have been used:

Fiscal year (Apr-Mar)	Rate
1976/77	Base
1977/78	11
1978/79	9
1979/80	8
1980/81	7
1981/82	5
Thereafter	5

- Base date October, 1976.
- Method of comparing alternatives - Alternatives have been compared by plotting the total differential present worth (allowing for inflation) versus interest rate. Present worth includes discounted values of all capital and operating costs for a 35 year life.

9.2 INFLATION

Recognizing the failure of financial authorities worldwide to predict inflation rates, B.C. Hydro have adopted the philosophy that historically, interest rates exceed inflation rates by about 5%. Therefore, in discounted present worth calculations involving inflation, an inflation rate of 5% and an interest rate of 10% has been used.

It is anticipated that contract prices for most of the equipment in the power plant would be fixed, but subject to partial adjustment for inflation on the basis of published Federal indices together with increases in site labour costs which are tied to indices of provincial construction wage rates. In general terms this means that inflation for purchased equipment will if anything usually be lower than the national rate of inflation.

9.3 RELIABILITY

It is anticipated that the units will attain their design capacity factor in the first 12 minths of operation after the commercial in service date of January 1, 1984.

The statistical forced outage rate for units of this size is 9.5% based on U.S. Edison Electrical Institute (EEI) Statistics. Canadian Electrical Association statistics for 1965-1973 for units of 500-599 MW, while having a much smaller data base, indicate a forced outage rate of only 5.7%. It is interesting to note that the equipment figure for 1965-1970 was 11.9%. The Canadian figures show the effect of maturity on the first units installed with Ontario Hydro.

In both cases the forced outage rate is defined, in approximate terms as:

$$\frac{\text{Number of hours of unit outage (FOH)}}{\text{Number of hours of operation + FOH}} \times 100$$

This definition favours base load units.

It should be expected that units burning a relatively low grade and highly variable coal would experience a higher than normal forced outage rate. However the forced outage rate of the Hat Creek units will gain, when compared with EEI's historical statistics, through advances in technology in a number of areas.

Thus considering the opposing effect of these factors an overall forced outage rate similar to the quoted EEI's figure of 9.5% is anticipated.

9.4 INTEREST DURING CONSTRUCTION

Interest During Construction (IDC) charges have not been applied to the estimates in this study.

Multi-unit stations suffer proportionally higher IDC charges than a single unit plants, because it is usually economic to provide common facilities, such as the stack, which are built with the first unit. Offsetting the higher IDC charges the multi-unit station gains from economy of scale in the common facilities, in the ability of contractors to complete major civil and structural works at one time, and in the case of equipment manufacturers, to build up and maintain a staff site team.

9.5 EFFICIENCY

The total present worth of 1% efficiency used in these studies is about $5 million. This has been calculated from an estimated price of coal of $5.60 per ton and the financial criteria in Section 9.1.

A number of the more critical financial analyses have been performed using a coal cost of $11.20 per ton to determine the effect on results. The use of such a coal price would put a premium on efficiency. This would lead to an optimized cooling system employing a lower back pressure, and would favour the substitution of hyperbolic cooling towers. It would not have other major effects on the design of the plant.

9.6 CAPACITY FACTOR

The financial calculations in the study are based on a capacity factor of 72% where capacity factor is defined as:

$$\frac{\text{Total MW produced in year}}{\text{Rated Output x 8760}}$$

Long term calculations of the amount of coal which will be consumed, and of ash production, are based on an overall 50% capacity factor. The lower figure reflects the fact that the units will probably be operated on a two shift basis after 15 or 20 years.

Using the higher figure for discounted present worth calculations is valid, because of the weighting which such calculations give to the early years. The maximum practical capacity factor for units of this size is estimated to be 78%.

9.7 OPERATING COSTS

Table 9.7.1 shows plant estimated operating costs using the criteria detailed in paragraph 9.1. These charges are based on a capital cost of 1,015,848 with 25% interest during construction added.

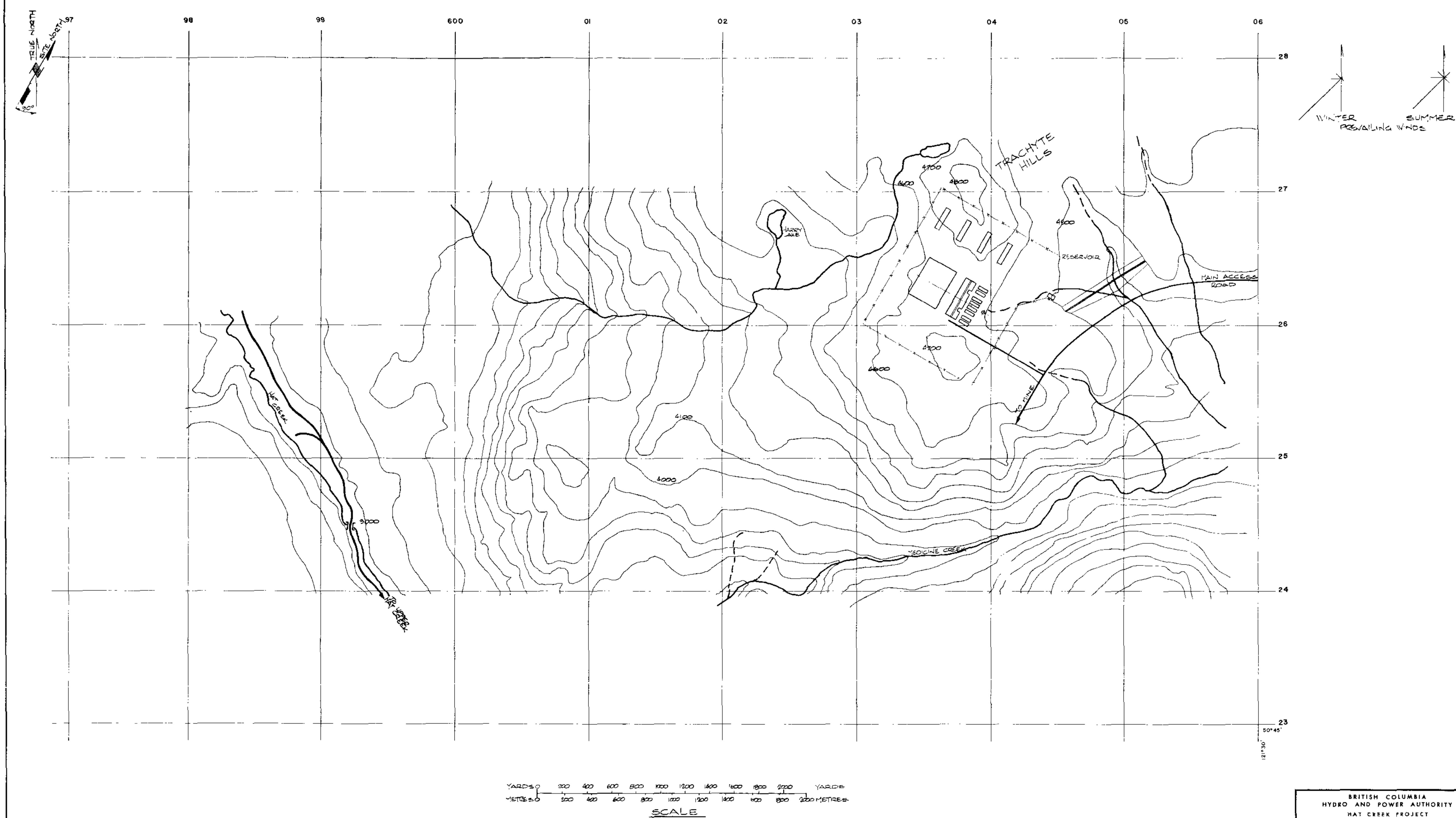
TABLE 9.7.1

OPERATING COSTS MILLS/KWHR - 2092 MW (NET) STATION

Capacity Factor	78%	72%	60%	50%
Annual Capital Charges 11.37%	10.1	10.9	13.1	15.7
Fixed Operating And Maintenance 2.41%	2.2	2.3	2.8	3.3
Variable Maintenance	0.3	0.3	0.3	0.3
Coal ($5.60 per ton)(1)(2)	5	5	5	5
Total Operating Cost	17.6	18.5	21.2	24.3

(1) Using station heat rate of 10,679 Btu/Kwhr.

(2) Does not allow for part load efficiences.



BRITISH COLUMBIA
HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

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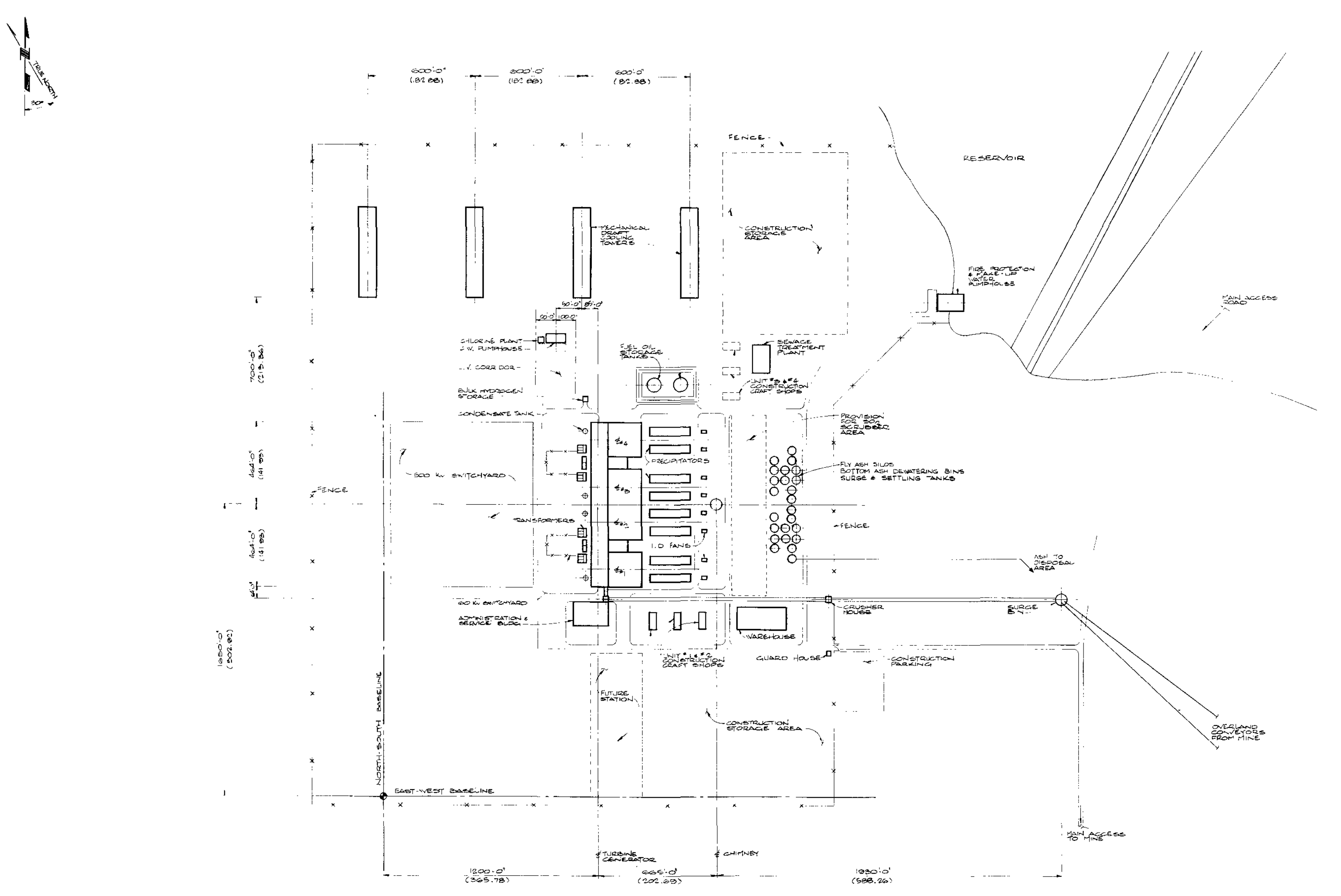
Vancouver Toronto

SITE PLAN

SCALE: AS SHOWN

drawing number F BCH6802 M-100



SCALE: 1" = 200'-0" (60.96)

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

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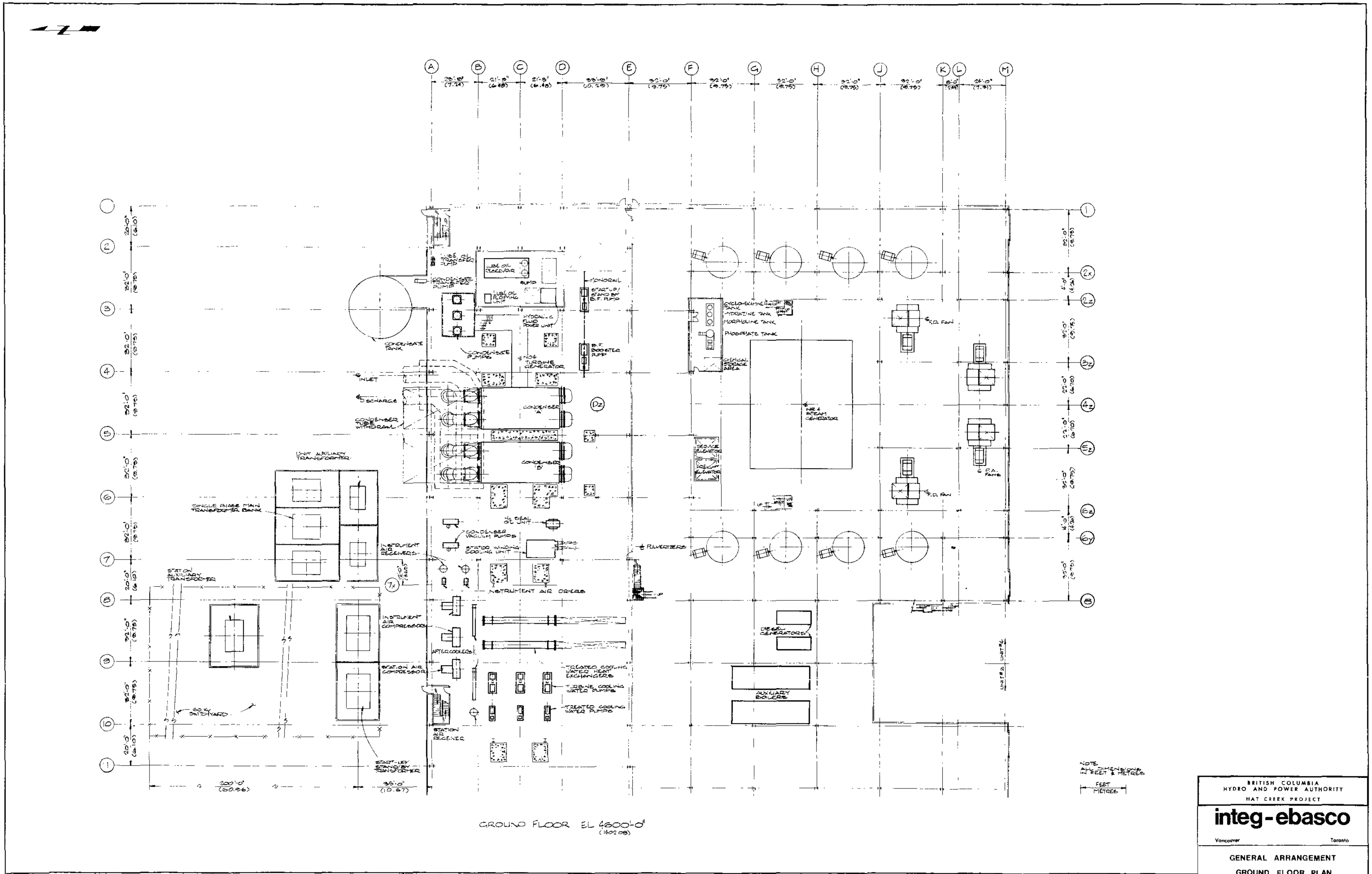
Vancouver Toronto

PLOT PLAN

drawing number F BCH6802 M-101



BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

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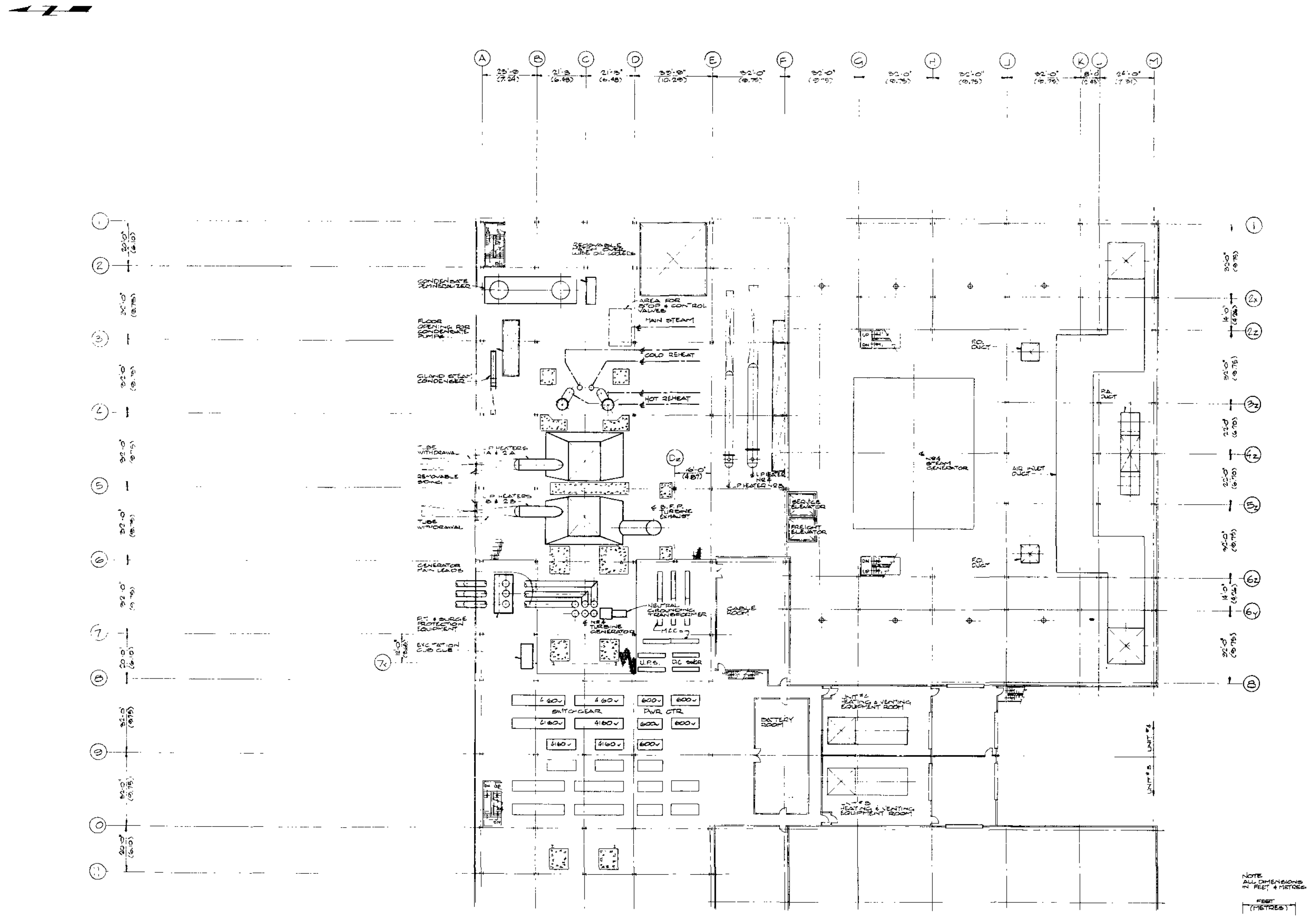
GENERAL ARRANGEMENT
GROUND FLOOR PLAN

drawing number F 8CH 6802 M-102



MEZZANINE FLOOR EL 4622'-0"
(1408.79)

NOTE
ALL DIMENSIONS IN FEET & METRES

FEET
(METRES)

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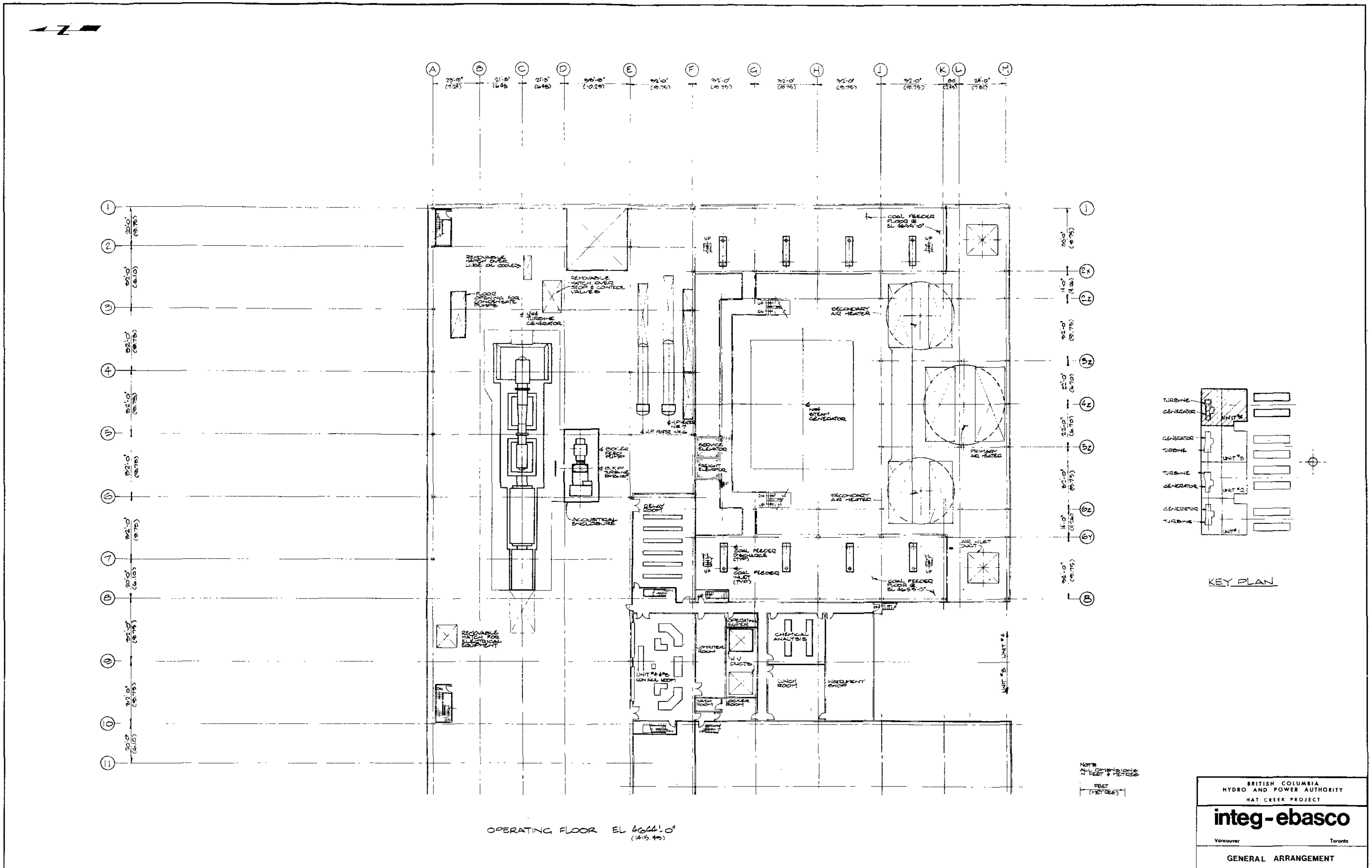
GENERAL ARRANGEMENT
MEZZANINE FLOOR PLAN

SCALE: 1/16" = 1'-0" (0.3048)

drawing number F BCH 6802 M-103



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HAT CREEK PROJECT

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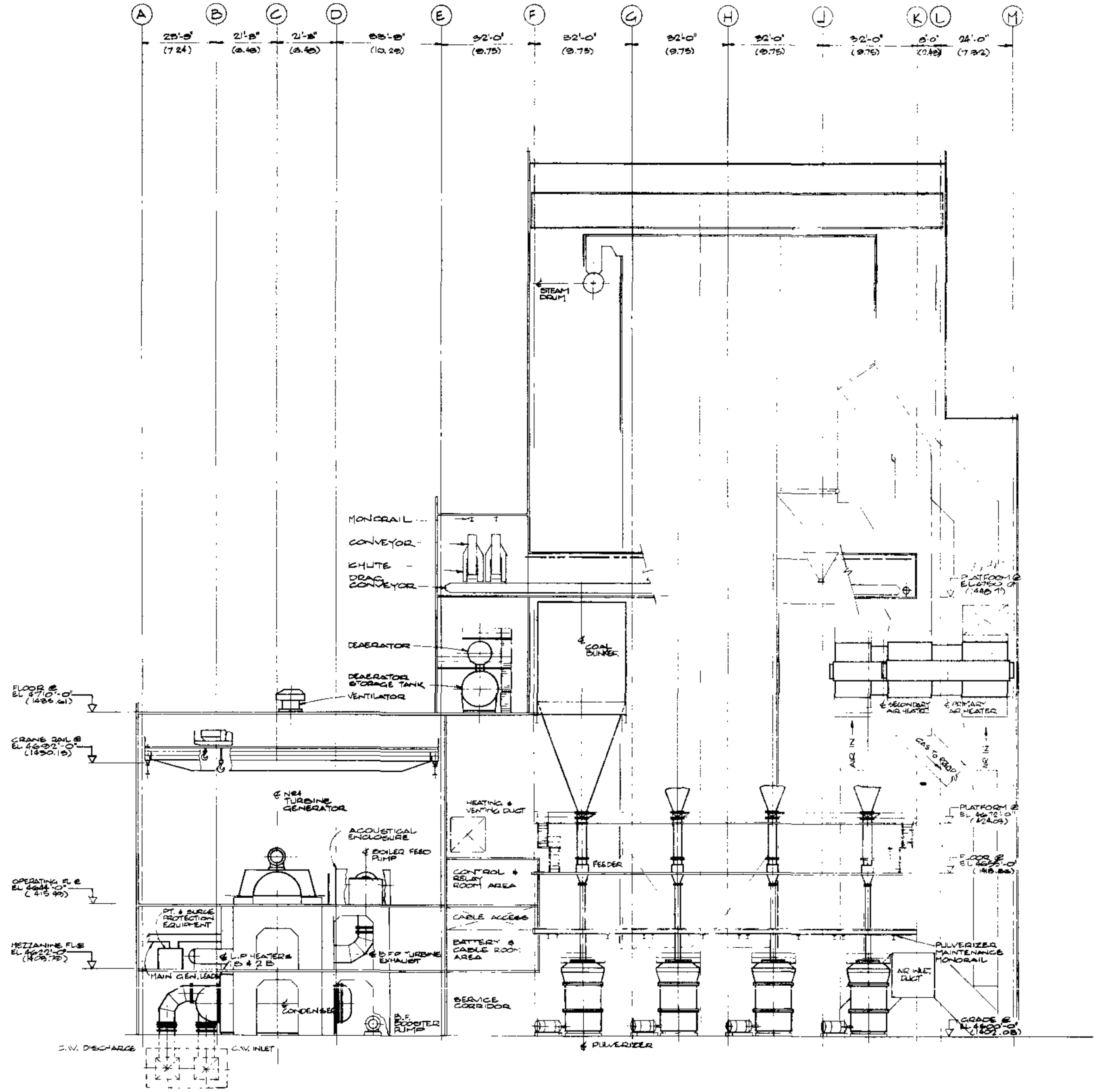
GENERAL ARRANGEMENT
OPERATING FLOOR PLAN

drawing number F BCH 6862 M-104



NOTE
ALL DIMENSIONS IN FEET & METRES

FEET
(METRES)

BRITISH COLUMBIA
HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

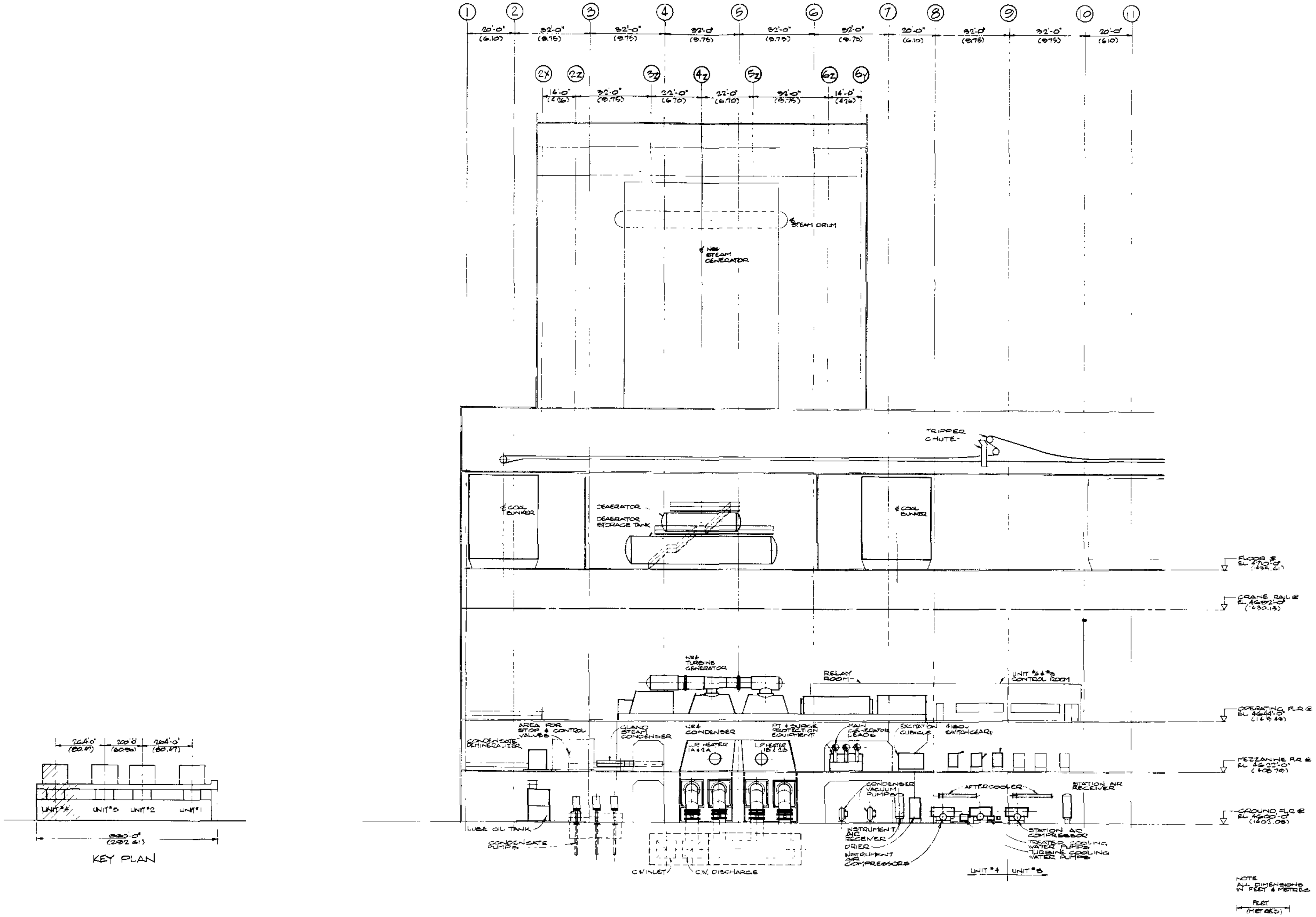
integ-ebasco

Vancouver — Toronto

GENERAL ARRANGMENT
SECTION LOOKING EAST

SCALE: 1/16"=1'-0" (0.5048)

drawing number: F | BCH 6802 | M-105



BRITISH COLUMBIA
HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

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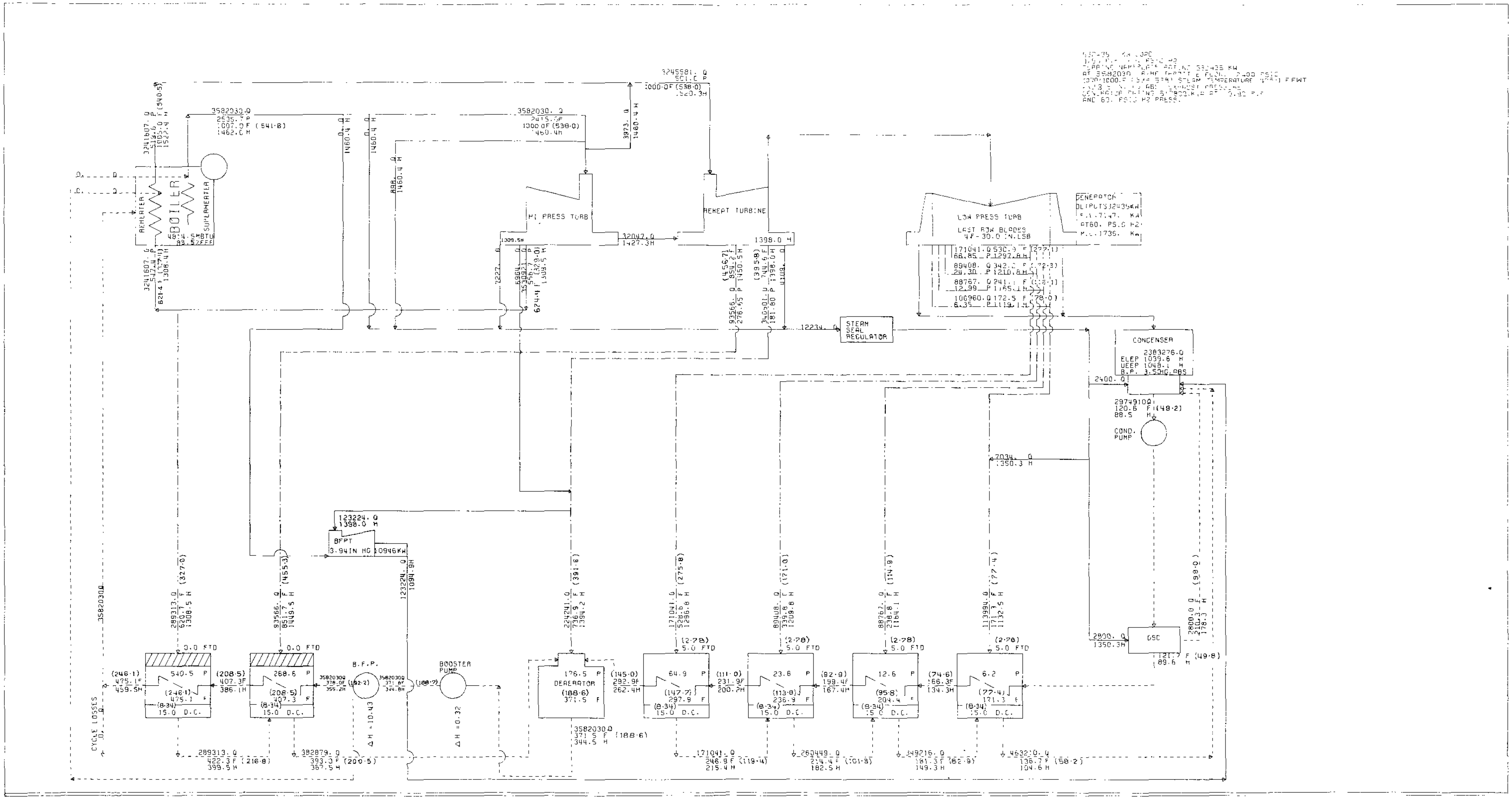
Vancouver Toronto

GENERAL ARRANGEMENT
SECTION LOOKING SOUTH

drawing number F BCH 6802 M-106



PERFORMANCE

GROSS GENERATION KW	AUXILIARY POWER KW	NET OUTPUT KW	BOILER EFF. %	NET STATION HEAT-RATE BTU/KWHR
532435.				

NET TURBINE HEAT RATE = $\frac{4268384072}{532435}$ = 8016.7 BTU/ KWHR

LEGEND

Q----FLOW-LBS/HR
P----PRESSURE-LBS/SQ.IN ABS.
F----TEMPERATURE-°F (°C)
H----ENTHALPY OF STEAM-BTU/LB
FTD-TERMINAL DIFFERENCE (F) (°C)
ELEP-EXPANSION LINE END POINT
UEEP-USED ENERGY END POINT
D.C.- DRAIN COOLER APPROACH (F) (°C)
S.C.- SUBCOOLING (F)
— - - — — STEAM
— - - - - WATER
— - - —— EXTRACTION STEAM

SHEET NO.	THROTTLE FLOW LBS/HR	THROTTLE PRESSURE PSIA	BACK PRESSURE IN. HG ABS	BLOW DOWN LBS/HR	CYCLE LOSSES LBS/HR
1.	3582030	2415.	3.5	0.	0.

DESIGN	DRAWN	CHECK DWG.	CHECK DESIGN	APPROVAL DIVISION	APPROVAL PROJECT	ISSUED FOR	DATE	REV	DESCRIPTION OF REVISION	REFERENCE	NO.	DWG. NO.
	EHM.											

B. C. HYDRO & POWER AUTHORITY
HAT CREEK POWER DEVELOPMENT

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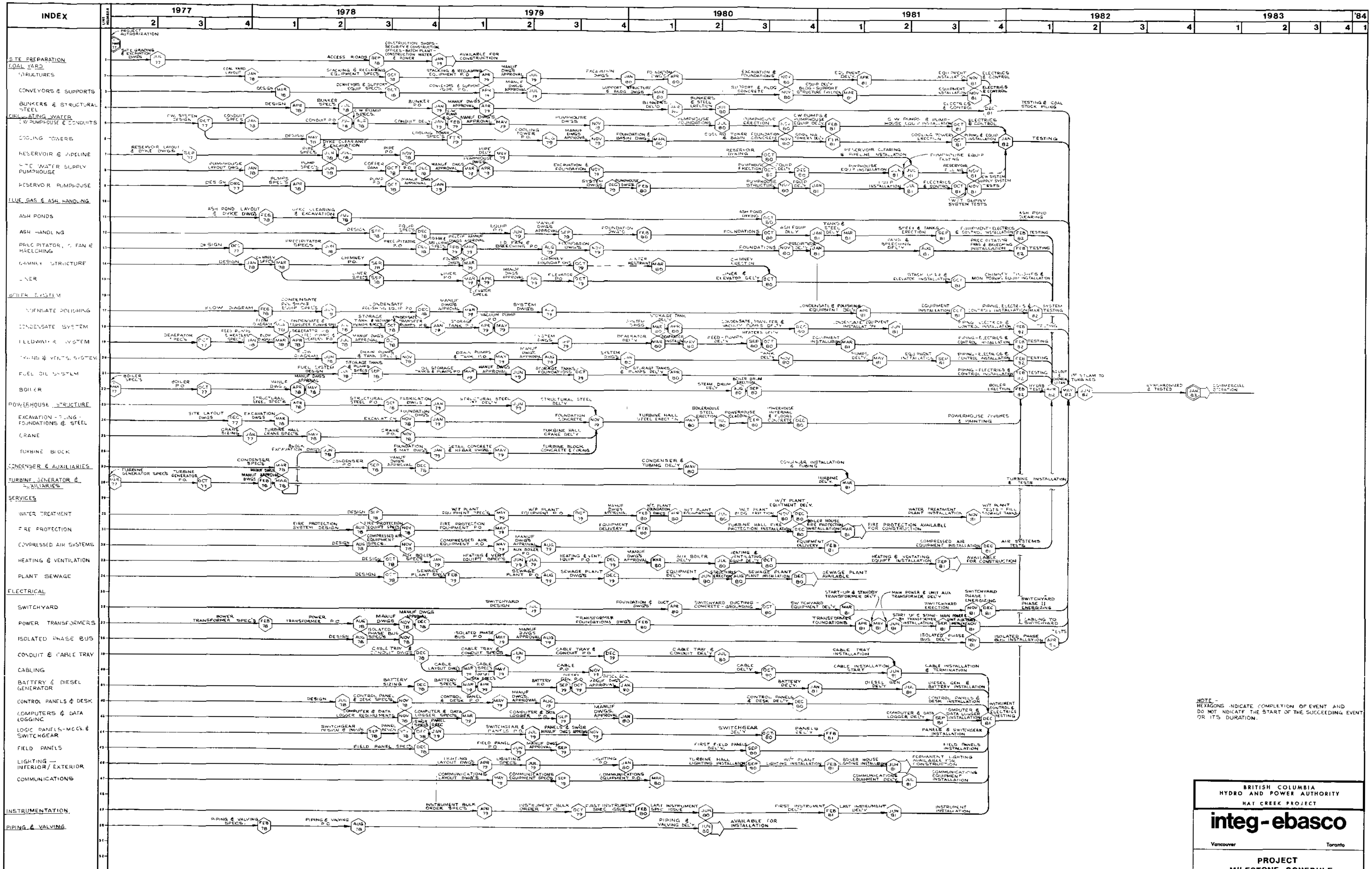
HEAT BALANCE
GUARANTEED LOAD
PRELIMINARY

drawing number F BCH 6802 M-120



NOTE -
HEXAGONS INDICATE COMPLETION OF EVENT AND DO NOT INDICATE THE START OF THE SUCCEEDING EVENT OR ITS DURATION.

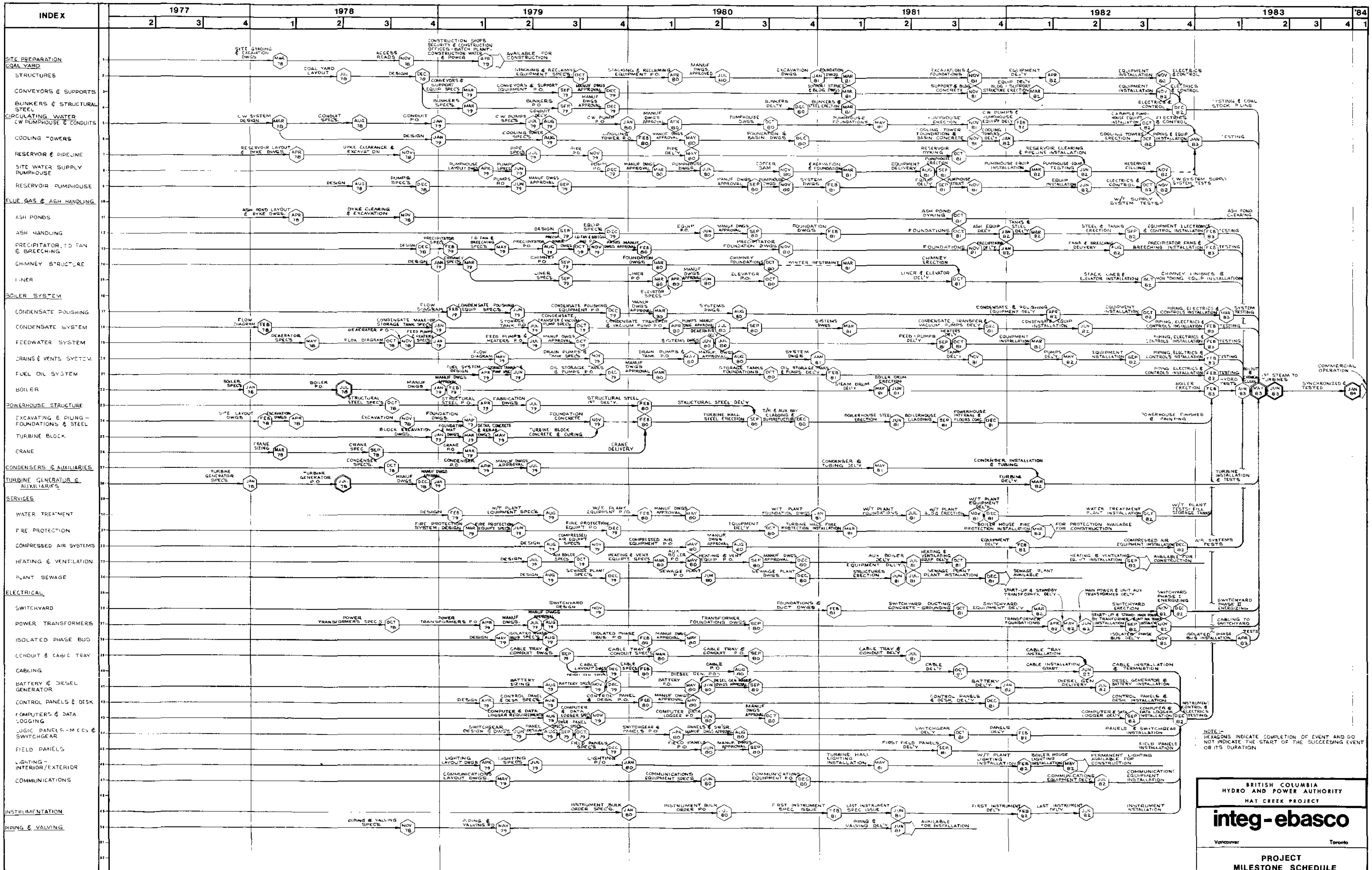
BRITISH COLUMBIA
HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

integ-ebasco

Vancouver Toronto

PROJECT MILESTONE SCHEDULE "1983 IN SERVICE"

drawing number	F	BCH 6802	S-100



NOTE:- HEXAGONS INDICATE COMPLETION OF EVENT AND DO NOT INDICATE THE START OF THE SUCCEEDING EVENT OR ITS DURATION

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

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PROJECT MILESTONE SCHEDULE "1984 IN SERVICE"

drawing number F BCH 6802 S-101