STUDIES OF ADVANCED ELECTRIC POWER GENERATION TECHNIQUES AND COAL GASIFICATION

BASED ON THE USE OF HAT CREEK COAL

Prepared for

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

and

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PREFACE

In 1975 B.C. Hydro and Energy, Mines and Resources Canada commissioned five studies to investigate potential uses of Hat Creek coal. Three of the studies were directed towards advanced high efficiency, clean methods of generating electric power, and alternatively, to producing synthetic natural gas, while a fourth examined the use of Hat Creek coal in the existing oil/gas fired Burrard plant.

The fifth study was assigned to a 'co-ordinating consultant' who was responsible for co-ordinating the work of the other four studies. The co-ordinating consultant was also directed to produce a summary report examining and comparing the results which were derived in the other studies. The summary report is included in Volume 1 of this report. The three studies examining advanced electric power generation and gasification are included in Volume 2 and the Burrard conversion study in Volume 3.

STUDY D — ALTERNATE FUELS FOR BURRARD THERMAL GENERATING STATION

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1.0 TECHNICAL AND ECONOMIC SUMMARY

1.1 This study evaluates the technical and economic feasibility of converting the 900 MW Burrard Thermal Generating Station (BTGS) to burn an alternate fuel. The plant is currently designed to burn natural gas or residual oil.

1.2 MODIFICATIONS TO BURRARD

In this study a relatively detailed analysis is done on the combustion of five different fuels in the existing boilers. This analysis demonstrates that the existing units can be modified to produce over 70% of full load, burning Hat Creek coal directly. Alternatively, with a minimum of modification, they will produce 90 - 100% of full load, burning low Btu gas of about 300 Btu/SCF. They can be converted to fluidized bed combustion or crude oil firing without de-rating.

1.3 TRANSPORT AND STORAGE

This study investigates many ways of moving the coal from Hat Creek to BTGS and removing the ash. The preferred conventional method is via a rail/barge route using a Squamish terminal. The transport cost of this route, including the coal cost and charges for ash removal is 78¢ per million Btu's when the station is operating at 900 MW and 80% capacity factor. The cost of coal delivery is quite sensitive to the annual quantity delivered, and if the plant were de-rated, or a lower capacity factor used, the delivered coal price would rise significantly. The comparative cost of delivering different types of fuel to BTGS is shown in the table below.

FUEL PRODUCTION, TRANSPORT & STORAGE-CENTS/MILLION BTU
(Incl. Coal Cost)

COAL (INCL. ASH REMOVAL)	LOW Btu GAS 300 Btu/SCF	SNG	CRUDE OIL ($12 PER BARREL)
78	1.62	2.02	1.88

This table shows that using a cost of Hat Creek Coal of about 24¢ per million Btu, coal delivery increases this price by a factor of 3, while gasification and pumping increases it by a factor of about 7/8. Despite this, the cost of low Btu gas at the station wall is lower than crude oil at $12.00 a barrel, and the gasification plant and pipeline are relatively secure against inflation.

1.4 CAPITAL COSTS

The table below shows the capital costs of the main alternatives, including the cost of the gasification plant and pipeline:

$,000 Sept. 1975

COAL BURNING MODIFICATION	NEW COAL BURNING BOILERS	OXYGEN BLOWN LOW Btu GAS	SNG	CRUDE OIL
217,964	266,738	612,540	730/850,000	11,690

The SNG costs depend on whether existing or new pipelines are used.

The capital costs of the coal burning conversions are high. A large coal terminal is required at Squamish or another intermediate point for transfer of the coal from rail to barge. In addition to new coal fired boilers, or modifications of the existing BTGS boilers, new items such as precipitators, pulverizers and a high stack are required. In addition, substantial modifications are required in other parts of the plant such as the water intake structure, the water treatment plant, and the controls.

The cost of the low Btu gas and SNG alternatives are the highest as they include the high cost of the gasification plant and pipeline. The investment for conversion of BTGS to crude oil is relatively small, even if the highest degree of safety is engineered into the modification.

1.5 FLUIDIZED COMBUSTION AND SLURRY PIPELINE

Two techniques investigated in the study involve relatively unproven technology, these being fluidized combustion and a coal/water slurry pipeline. Both look attractive economically; fluidized combustion can offer almost complete elimination of SO_2 emissions at a price which is theoretically a little below that of conventional coal burning. The technology is not yet proven at ratings over 10 MW. The coal/water slurry pipeline offers the lowest coal delivery costs and protection against inflation, but there are several important problems with this alternative, the most obvious being the potential difficulty of disposing of the slurry water, and the space requirement of the dewatering plant. In any more detailed investigation of converting BTGS to direct coal burning, the slurry pipeline will require further evaluation. It has been the conventional wisdom in North America that where a railroad already exists, a slurry pipeline has difficulty in competing with it. The difficulties which the geography of B.C. present to a transportation system are such that a slurry appears economic for the transport of coal from Hat Creek to BTGS.

1.6 ENVIRONMENTAL

The existing BTGS site area provides adequate coal storage for seven days full load operation, and this is backed up by the ten days storage of residual oil which already exists, and by thirty-two days reserve which would be available at the rail/barge terminal. If more than seven days storage are required at the site, some filling of the inlet would be required.

Conversion of the generating plant itself requires the addition of precipitators and an 880' stack. Using conventional practice this necessitates a certain amount of land reclamation, mainly in the small bay in which the station is located. It would probably be possible, by detailed and imaginative engineering, to reduce this land reclamation or eliminate it completely. One possible means would be to put the precipitators on the turbine hall roof and the stack on the site of the present switchyard, but the detailed engineering assessment which is required to prove the feasibility of this concept is considered beyond the terms of this study.

Landfilling might be one of the principle environmental objections to converting BTGS to coal. Other objections might be the aesthetic ones relating to the visible coal pile and 880' stack, although the lines of the plant itself would be improved by the conversion. The specific emissions of most pollutants would not increase, but it is anticipated that the station would be run on high capacity factor following a coal conversion, and this would lead to increases in the absolute amount of the emissions of NO_x, water vapour, CO_2, SO_2, and heat.

Burning Hat Creek coal provincial objectives for the emissions of SO_2, NO_x and particulate can be met, and estimates include the required precipitators.

The operation of covered coal and ash barges to Vancouver Harbour could cause concern but does not constitute a hazard.

1.7 INFLATION

The effect of inflation on the various alternatives is considered in the study. The low Btu gas alternatives are the least subject to inflation. Coal burning alternatives are subject to inflation on the two-thirds of the delivered cost which relates to transport but to a lesser extent on the one-third which represents the coal price. Oil is not only subject to inflation, but also the resource is assumed to be outside B.C.'s control.

1.8 CONCLUSIONS

There is no cheap or easy conclusion to the problem of supplying an alternate fuel to Burrard Thermal Generating Station. The relative generating costs in Mills/kWhr for the various fuels, at 70 and 80% capacity factor are:

	COAL — NEW BOILERS	LOW Btu GAS	SNG	CRUDE (RESIDUAL)
80% C.F.	11.7	17.1	20.2	19.5
70% C.F.	12.5	-	-	19.6

While these costs are close to those which a new generating plant at Hat Creek would achieve, in 1975 dollars, the BTGS site is too sensitive to environmental pressures and inflation in transport costs to make it competitive with the Hat Creek plant. It should be noted that the relative cost of coal and oil, and the possible higher inflation rate of oil, will mean that if BTGS is to be operated at a capacity factor above 10/15%, the coal conversion is economically justified.

2.0 INTRODUCTION

This study examines the technical and economic feasibility of converting the Burrard Thermal Generating Station to burn Hat Creek coal, or gas produced from the coal. A brief study of burning crude oil is also included, which is primarily based on previous work done by B.C. Hydro.

The study has been arranged to consider modifications at Burrard Thermal G.S., and fuel transport and storage separately. In Section 5 the combustion processes are analysed, and the ability of the existing Burrard plant to handle different fuels is assessed. In Section 6 the modifications required by the existing plant are detailed. Fuel transport and storage are then considered separately in Section 8. The results of these three sections are discussed and evaluated in Section 3. That section also includes an overall economic review of the results of the study.

2.1 HAT CREEK COAL

Hat Creek coal is classified as sub-bituminous B, with high ash and moisture contents. Although it has a low heating value, it compares favourably with other western sub-bituminous coals for use in thermal power generation.

The ash analysis indicates that it is about 90% composed of silica and aluminium silicate and contains a correspondingly low proportion of those metal oxides which cause slagging and fouling such as Fe_2O_3, Na_2O, K_2O. This explains the very high ash softening and fusion temperatures which have been measured. As a result, furnace design for this coal is not restricted by considerations of slagging or fouling, which are the major problems in the sizing of conventional western Canadian sub-bituminous p.f. boilers. In fact, the ash composition is such that one of the limiting design criteria is erosion of the convection tubing by fly ash.

Hat Creek coal also has a reasonable percentage of volatiles and does not present an undue problem with regard to residence time.

2.2 COMBUSTION PROCESSES

Combustion processes using Hat Creek coal, which have been examined in this study, include burning coal, air blown Lurgi low Btu gas, oxygen blown Lurgi low Btu gas, synthetic natural gas, and crude oil. Low Btu gas with some of the carbon dioxide and sulphur removed by the potassium carbonate clean up technique is also considered briefly.

2.3 COMBUSTION EQUIPMENT

The study examines coal burning by conventional steam generators and by fluidized combustion boilers. For each of these, consideration is given to modification of the existing units and to the installation of entirely new facilities. For the burning of low Btu gas, synthetic natural gas, and crude oil, the study examines the required modifications to the existing boilers.

2.4 TRANSPORT & STORAGE

The study includes an extensive examination of coal and ash transportation to and from the generating site. This includes a water and coal slurry system and various unit train to barge alternatives. For each of these, coal storage and operating reserve is examined from the point of view of site development and land reclamation. The economics of these systems are compared with the pipeline transportation of both low Btu gas and synthetic natural gas.

Since power generation using Hat Creek coal will produce a disproportionately large quantity of ash relative to most other coals burnt in Canada, the study includes a complete summary of the technology of ash utilization. Finally, an overview of the environmental impact of the various combinations of transportation and site development of the BTGS is included as a preliminary assessment.

2.5 UNIT RATING

Although the BTGS units are capable of a gross generator output of about 162 MW, the study is based on the rated 150 MW gross. However, the work on combustion processes in Section 5 compares the performance of different fuels with the performance of the units using natural gas. It is anticipated that any excess capacity which exists with natural gas can be applied to the other fuels, i.e. the capacity with coal could be 70% of 162 MW rather than 150 MW. If this 10% excess capacity were to be utilized, the transport quantities in Section 8 would also rise 10%.

2.6 LAND RECLAMATION

The study is based on the use of standard precipitators, ID fans and stack arrangement, although this necessitates some land reclamation from the inlet. The question of landfill is environmentally sensitive and it may be desirable, at a later stage, to give detailed consideration to reducing the space requirement of the precipitators and stacks. There are a number of ways that this could be done including: precipitators with half of the cells positioned above the others in series; axial ID fans either in or around the stack or in a vertical duct beside the precipitators; a stack positioned at the end of the building; twin stacks, one at each end of the building; or a stack behind the switchyard on the mountain with the precipitators on the turbine hall roof. In this study it is unrealistic to try and quantify relatively small savings in land area when an accurate study is required to confirm the validity of such figures. The study drawings are therefore based on a conventional and relatively conservative equipment spacing and illustrate the worst situation with regard to land reclamation. It seems probable that if sufficient imagination were used the modified plant could be designed within the existing shoreline.

2.7 ECONOMIC COMPARISONS

This study does not apply arbitrary penalties to unproven technology, but uses the contingency factors listed in the Base Engineering and Cost Criteria. As a result the slurry pipeline appears very economic. It is the opinion of many engineers that relatively unproven technology, such as a slurry, should be penalized with an additional contingency of at least 25 percent. For this reason the study does not adopt the slurry pipeline as the preferred transport method.

2.8 SYNTHETIC NATURAL GAS

Natural gas is now considered too valuable a natural resource to be burnt in a thermal generating plant.

The report assumes that SNG made from coal will be almost identical to natural gas, and that the same philosophy with regard to its use will apply to it. This statement is true irrespective of the price of the SNG. For this reason the study does not treat SNG in very much depth, although Study C indicates that it is possible to produce this gas at a price which is economic when compared to the world price of oil and the projected price of arctic gas.

2.9 TURBINE MODIFICATIONS

If BTGS is to be run with a rated output of 70% of its current output, the turbines should be modified to maximize their efficiency at that rating. This can be done by reconverting them to nozzle governing so that three governor valves are fully open at the new full load rating. Alternatively, for optimum efficiency and reliability, the first stage nozzles should be replaced.

2.10 OIL SLURRY

A number of alternatives which were considered in the study were rejected and are not covered in the text.

Oil Slurry — discussions were held with Dr. N. Berkowitz of the Alberta Research Institute and ERBC. Dr. Berkowitz has a number of oil slurry patents in his name and was a leading proponent of the coal/oil slurry from Alberta to Ontario. He considers that an oil slurry is not practical for supplying Hat Creek coal to Burrard. The principle reasons are:-

— that the route length is too short.

— that Hat Creek coal has too much water in it, which would lead to retention of oil in the coal and the more difficult problem of high level of water in the oil.

— that there is no oil transport problem between Hat Creek and Vancouver which might be helped by a slurry proposal

— an extensive development programme is required to prove the technique.

In brief, when compared to other localities and coals, there seems to be nothing to commend this alternative and many potential difficulties.

2.11 RESIDUAL OIL

The cost of a crude oil conversion adds about 1% to the generating cost with this fuel at high load factor. This is so insignificant that crude and residual oil are considered together in this study. If oil is to be the principle fuel in future, it is a simple matter for B.C. Hydro to relate the cost of the crude oil conversion to the relative price and availability of the two fuels at the selected load factor.

2.12 SO_2 EMISSIONS

Direct coal burning without flue gas desulphurization gives an SO_2 emission of 15.2 lbs. per ton of coal compared to the provincial guideline of 20 lbs. per ton. Fluidized combustion reduces this emission to between 2.5-5 lbs /ton coal depending on whether limestone or dolomite is used.

2.13 COAL BENEFICIATION

Brief consideration has been given to the effect of washing the coal at Hat Creek prior to shipping it to BTGS.

Calculations indicate that if the coal can be cleaned from 25% to 15% ash content, the saving in coal and ash transportation costs is 50 cents per ton. This is exactly the estimated cost, produced for B.C. Hydro by Birtley Engineering, for such coal washing. Washing the coal would ease operational problems at Burrard, and the subject would merit further study if coal firing is to be used at BTGS.

3.0 ANALYSIS OF RESULTS

3.1 AVAILABLE OPTIONS

The purpose of this section is to assemble and interpret the results of the main body of the report.

This can be done most effectively by reviewing the economics of all the alternatives and by rejecting the least attractive ones. The more economic alternatives can then be subjected to further scrutiny and an investigation of their sensitivity to various financial parameters.

The study considers a large number of permutations of fuel type, transport system, ash disposal and site modifications. These are reviewed in Sections 4-8 of this report, and summarized in Table 3.1.

TABLE 3.1
AVAILABLE METHODS OF GENERATION AT BTGS

FUEL	COMBUSTION	COAL TRANSPORT	ASH
Coal	New P.F.[1] Boilers P.F. Modification New F.B.[2] Boilers F.B. Modification	6 rail/barge alternatives Coal Slurry	Backhaul Land Reclamation
Air Blown Low Btu gas O_2 Blown Low Btu gas Medium Btu gas	Modified Furnace	Gasification at Hat Creek Gasification at Burrard Gasification at 3rd Site	
SNG	-	-	-
Crude Oil	Existing Furnaces with Modifications.		

[1]Pulverized Firing
[2]Fluidized Bed

3.2 SYNTHETIC GAS

The results of Study C by The Lummus Company Canada Ltd. indicate that the Lurgi process is the most economic for producing synthetic gases from Hat Creek coal with available techniques. The Lurgi can be used with air or oxygen as the combustion medium. Depending on the degree of gas treatment which is used, four basic types of synthetic gas may be produced. These are shown in Table 3.1 and are described below.

(a) Air blown low Btu gas — about 185 Btu/SCF.

(b) Oxygen blown low Btu gas — about 300 Btu/SCF.
In Section 5 it is calculated that the existing BTGS boilers burning Oxygen blown low Btu gas would be limited to 89% of their rated capacity.
The rating is dependent on the actual composition of the low Btu gas, and is likely to be up to 100%.
The generating cost is not affected significantly by whether the rating is 89% or 100%, because the main component of the cost is the gasification and pumping which are not sensitive to quantity at the ratings under consideration.

(c) Oxygen blown gas with some of the CO_2 removed — in the text of this study report this gas is referred to as Medium Btu gas. The heating value depends on the extent of the CO—CO_2 shift conversion and subsequent CO_2 removal, but for the purpose of this study a heating value of 442 Btu/lb is used. This represents a gas with about 5% carbon monoxide and very little carbon dioxide.

(d) Synthetic natural gas or SNG — this gas has a heating value of 950/970 Btu/SCF and is 97% methane.

The heating values for types (a), (b) and (c) are calculated by Lummus for Hat Creek coal, based on the information available to them.

A number of the gas fired alternatives which are shown in Table 3.1 can be rejected because they are obviously uneconomic. The four different types of gas can be compared directly by calculating the cost of producing the gas and delivering it to BTGS. This is shown in Table 3.2. In the table the cost of SNG is shown for a new direct pipeline from Hat Creek to BTGS, and alternatively on the assumption that the gas could be transmitted through Westcoast Transmission's existing network. Pipeline and transmission costs were derived from Trans Mountain Pipe Line for the direct routing and Westcoast Transmission for the use of their network.

TABLE 3.2

RELATIVE GAS COSTS AT BTGS

		AIR BLOWN	O_2 BLOWN	MEDIUM BTU GAS	SNG NEW PIPELINE	SNG USING EXISTING PIPELINES
Cost of gas at Hat Creek (from Study C)	$/MMBtu	1.17	1.17	1.68*	1.81	1.81
Pumping Cost	$/MMBtu	.49	.40	.35	.21	.08
Total Cost	$/MMBtu	1.66	1.57	2.03	2.02	1.89
Plant Output	%	70	89/100	100	100	100

*Derived in work by Lummus subsequent to Study C.

The air blown gas is obviously uneconomic when compared to the oxygen blown gas, and can be rejected.

SNG appears to be more economic than the medium Btu gas but for further analysis the two can be considered together because neither requires any significant modifications to BTGS.

3.3 LOCATION OF GASIFICATION PLANT

The choice of the gasification plant location can be made by comparing the cost of moving the coal against the cost of moving the gas. The relative availability and cost of water at the different sites must also be considered. Table 8.12 in Section 8 shows that gasification at Hat Creek is more economic than at BTGS or at a third site. This table shows that the cost of water is not an important aspect of this evaluation.

Environmental considerations would tend to confirm the preferred location of the gasifiers at the mine mouth, because this confines the environmental dislocation of the mine and gasifiers to one site.

3.4 PRINCIPLE ALTERNATIVES

The preceding analysis leaves seven main alternatives for the conversion of BTGS. These alternatives are all reviewed in detail in Sections 5-8.

a) Coal P.F. fired, modified boilers
b) Coal P.F. fired, new 150 MW boilers
c) Coal Fluidized bed, modified boilers
d) Coal Fluidized bed, new 150 MW boilers
e) O_2 blown low Btu gas
f) SNG (or medium Btu gas)
g) Crude oil

The first four may receive coal by a number of rail/barge routes or by a coal/water slurry pipeline, and may have their ash returned to Hat Creek or used for reclamation in the lower mainland.

3.5 ECONOMIC COMPARISON OF ALTERNATIVES

Table 3.3 compares the generating cost of the above alternatives, using costs derived in Sections 6 and 8. The generating costs are shown at 30, 60, 70 and 80% capacity factor for the coal and oil burning alternatives but only at 80% capacity factor for the gas burning plants.

The estimates in Table 3.3 are based on the preferred rail/barge alternative, which uses a Squamish terminal. The cost of back-hauling the ash to Hat Creek is included.

To simplify the comparison in Table 3.3, the cost of the complete existing thermal plant at Burrard is assumed to be written off. This reduces the generating cost by about 4 mills/kWhr at 80% capacity factor when compared to an arbitrary book value of $200 per kW. By writing off the Burrard plant it is possible to examine the alternatives on an incremental cost basis.

TABLE 3.3
GENERATING COST OF DIFFERENT ALTERNATIVE IN MILLS/KWHR — 6 UNITS

	A Coal Modified	B Coal New P.F.	C Coal Mod F.B.	D Coal New F.B.	E O_2 Blown GAS	F SNG	G Crude Oil
Total Capital Cost of BTGS Modifications (Note 1) $,000s	114,138	162,912	133,152	150,654	6,540	6,540	11,790
Capital Charges, dep., tax & ins. $,000s (11.62%)	13,263	18,930	15,472	17,506	760	760	1,370
Operating & Maintenance (Note 2) $,000s	3,700	3,700	3,700	3,700	3,500	3,500	3,500
Total Fixed Charges $,000s	16,963	22,630	19,172	21,206	4,260	4,260	4,870
Cost of Fuel 30% C.F.	110	98	98	98	-	-	1.88
60% C.F.	96	83	83	83	-	-	1.88
Cents/MMBtu 70% C.F.	92	80	80	80	-	-	1.88
(Note 3) 80% C.F.	89	77	77	77	1.57	1.89	1.88 (Note 4)
Plant heat rate Btu/KWhr (Note 6)	10,123	10,123	10,350	10,350	10,173	10,173	9,802
Annual Fuel Costs $,000s 30% C.F.	18,435	23,464	23,990	23,990	-	-	43,586
60% C.F.	32,179	39,745	40,636	40,636	-	-	87,171
70% C.F.	35,978	44,693	45,696	45,696	-	-	101,699
80% C.F.	39,777	49,163	50,265	50,265	89,655	119,206	116,228
GENERATING COSTS MILLS/kWhr							
Fixed Charges 30% C.F.	10.2	9.6	8.1	9.0	-	-	2.1
60% C.F.	5.1	4.8	4.1	4.5	-	-	1.0
70% C.F.	4.3	4.1	3.5	3.8	-	-	.9
80% C.F.	3.8	3.6	3.0	3.4	.8	.7	.8
Variable Maintenance	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Costs 30% C.F.	11.1	9.9	10.1	10.1	-	-	18.4
60% C.F.	9.7	8.4	8.6	8.6	-	-	18.4
70% C.F.	9.3	8.1	8.3	8.3	-	-	18.4
80% C.F.	9.0	7.8	8.0	8.0	16.0	19.2	18.4
TOTAL GENERATING COSTS MILLS/kWhr							
30% C.F.	21.6	19.8	18.5	19.4	-	-	20.8
60% C.F.	15.1	13.5	13.0	13.4	-	-	19.7
70% C.F.	13.9	12.5	12.1	12.4	-	-	19.6
80% C.F.	13.1	11.7	11.3	11.7	17.1	20.2	19.5

C.F. is Capacity Factor. This is annual kWhr produced by plant as percentage of rated capacity in kW x 8760.

NOTES ON TABLE 3.3

Note 1. In this report all capital costs of the coal plant and ash handling are included with the coal transport costs.

Note 2. B.C. Hydro's criteria specify fixed operating and maintenance charges as:

- coal fired plants 2.1625%
- oil and gas fired plants 2.6%

These are applied as follows: The approximate operating and maintenance cost of the existing oil fired plant is $3.5 million per year. A coal fired plant would have operating costs derived from this figure, and from the ratio 2.1625 : 2.6 above, and assuming that the capital cost of a coal fired plant is 1.27 times that of an oil fired one.

Note 3. Total fuel cost includes minemouth cost of coal, transport, BTGS storage and ash backhauling.

Note 4. Based on oil at $12.00 per barrel delivered to site.

Note 5. No allowance is made for reducing the SO_2 emissions of the fluidized combustion unit by injecting lime into the bed.

Note 6. Based on net output 150 MW, gross 157.

A gasification plant can only be justified if it runs at very high capacity factor. Lummus select 90.9% representing 332 stream days for all the gasification alternatives considered in Study C. In this study a gasification plant with 90.9% capacity factor is matched to a generating plant with a capacity factor of 80%. It is assumed that if the generating plant must operate at above 80% capacity factor for any extended period, some natural gas or oil would be required to supplement the synthetic gas. It would be possible to match a smaller gasification plant, operating at 90.9% capacity factor, with BTGS at 70% but this would further limit the ability of BTGS to operate at 100% capacity if required. It is a reasonable assumption that the minimum acceptable gasifier capacity would be that designed to provide BTGS with enough fuel for an 80% annual capacity factor. On this basis any capacity factor lower than 80% leads to sharply higher power costs and is uneconomic. For this reason generation costs are not shown for gasification plant alternatives operating below 80% capacity factor.

In evaluating Table 3.3, the effect of four other factors must be considered:

- the full load rating of the existing units which is between 162 MW and 165 MW gross
- the cost reduction from local disposal of the ash by land reclamation
- the possible cost reduction from a slurry pipeline
- the effect of the new proposal for a rail spur from the C.N. to the B.C.R. (Ashcroft-Clinton)

The effect of these factors is quantified in the following paragraphs and in in Table 3.4

a) If the full load rating is assumed to be 162 MW gross, 157 net, rather than 150 MW, the fixed charges are reduced by 5 per cent, which represents up to 0.25 mills/kWhr for the coal burning alternatives. This change has little effect on the gas and oil burning options because of their low investment at BTGS.

b) Disposal of ash to land reclamation in the lower mainland reduces the total effective cost of coal by about 20% across a wide range of annual delivered quantities. It therefore has the effect of reducing the generating cost of the coal burning alternatives by between 1.6 and 1.8 mills/kWhr at 70 and 80% capacity factors.

c) The slurry pipeline offers a saving, which varies with capacity factor, but which is equivalent to about 0.6 mills/kWhr for 70% capacity factor and 900 MW rating.

d) If the recently announced Federally funded rail link between the existing C.N. and B.C.R. tracks is completed it might lead to a reduction in coal delivery costs via the C.N., but the B.C.R. Squamish alternatives would still be the most economic of the rail/barge options. The generating costs in Table 3.3. would not change.

TABLE 3.4

GENERATING COST-MILLS/KWHR, FOR DIFFERENT OPTIONS

	A	B	C	D	E	F	G
Base Generating Cost (Table 3.3) 80% Capacity Factor	13.1	11.7	11.3	11.7	17.1	20.2	19.5
a) Rating 162 MW	0.2	0.2	0.2	0.2	-	-	-
b) Local ash reclamation	1.8	1.6	1.6	1.6	-	-	-
c) Slurry pipeline	0.6	0.6	0.6	0.6	-	-	-
Generating Cost — Option 1							
a) Plant rated 162 MW	11.1	9.9	9.5	9.9	17.4	20.2	19.5
b) Local ash reclamation							
Generating Cost — Option 2							
a) Plant rated 162 MW	12.9	11.5	11.1	11.5	17.1	20.2	19.5

Table 3.4 is also intended to show the effect on generating cost of the most reasonable combination of the factors discussed above. The cost saving of a slurry pipeline is not included in either Option 1 or 2 because the saving is small within the context of the technical uncertainties of the slurry system. Options 1 and 2 show the effect of rating the plant at its full unit rating of 162 MW gross, with lower mainland ash disposal (Option 1) or back hauling to Hat Creek (Option 2).

It is clear from Tables 3.3 and 3.4 that if the existing BTGS boilers are converted to burn coal the resulting power cost is over 10% higher than that resulting from the installation of new P.F. boilers or fluidized combustion units. The reason for this is that the price of Hat Creek coal delivered to BTGS is quite sensitive to annual quantity, and the reduced rating of the converted units leads to a higher coal price.

Tables 3.3 and 3.4 also show that SNG or medium Btu gas are more expensive than the 300 Btu/SCF oxygen blown gas.

Atmospheric fluidized combustion gives generating costs which are effectively the same as those of new conventional P.F. units when the accuracy of the fluidized combustion cost estimates is taken into account.

3.6 SELECTION OF PREFERRED ALTERNATIVES

These comments allow the selection of three alternatives for further financial analysis. These are the new conventional P.F. coal fired units (which can also be taken to represent both of the fluidized combustion options for financial purposes), oxygen blown low Btu gas, and crude/residual oil.

These three alternatives conveniently cover the three basic fuels; coal, oil and gas. They also represent very different levels of investment and fuel cost. Gasification requires a very high investment of over $600 million but uses $3.00/ton coal. Coal firing requires a moderately high investment and uses coal at just under $10.00/ton. A crude oil conversion involves a small investment but the oil price is equivalent to coal at over $20.00/ton.

The three options are compared further in the following tables and figures:

Table 3.5 Total Capital Cost Estimates
Table 3.5 Cash Flow Estimates (Uninflated)
Table 3.7 Cash Flow Estimates (Inflated)
Figure 3.1 Generating Cost & Capacity Factor
Figure 3.2 Cumulative Present Worth & Discount Rate.

Table 3.5 shows the total capital costs of the three main alternatives. It includes all coal transport, gasification and gas pipeline costs. It does not include the capital required to develop the Hat Creek mine.

Table 3.6 and 3.7 give September 1975, and inflated, cash flow estimates. Both tables are based on converting all the units simultaneously on a 3 or 4 year programme. While there are many other ways in which the modifications could be scheduled, they would all incur much higher interest during construction charges. The coal burning conversion would bear the interest charges of the coal terminals, ash handling equipment, stack, and land reclamation during the period that successive units were modified. There might also be a heavy penalty cost from the railway if it were required to deliver small quantities of coal during an extended modification programme.

TABLE 3.5
TOTAL CAPITAL COSTS OF COAL, GAS AND OIL BURNING PLANTS
$,000 SEPT. 1975 BASIS UNINFLATED

ALTERNATIVE	B	E	G
Fuel	Coal	Low Btu Gas Oxygen Blown 300 Btu/lb	Crude Oil
Boilers	New P.F. Fired	Modified	Modified
Transport Method	Train — Squamish Barge	Pipeline	Tanker
CAPITAL COSTS			
Coal transport and storage systems	86,620	--	--
Ash transport and handling systems	17,206	--	--
Gasification plant	--	436,00*	--
Gasification boiler plant	--		--
Pipeline	--	170,000	--
Generating plant modifications	162,912	6,540	11,790
TOTAL CAPITAL COSTS	266,738	612,540	11,690

*Adjusted from study 'C' for 57 x 10^{12} Btu/year output.

TABLE 3.6

CASH FLOW — 6 UNITS — ALL UNITS CONVERTED SIMULTANEOUSLY

$,000 SEPT. 1975 BASIS UNINFLATED

YEAR COMMENCING	YEAR 1 SEPT. 1975	YEAR 2	YEAR 3	YEAR 4	TOTAL SEPT. 1979
P.F. Coal New Boilers (B)					
BTGS plant	17,368	69,471	57,893	-	144,732
Coal transport facililties		31,787	47,682	-	79,469
Ash handling facilities		6,315	9,472	-	15,787
IDC	868	6,859	19,023	-	26,750
TOTAL	18,236	114,432	134,070	-	266,738
O_2 Blown Low Btu Gas (E)					
Gasification plant and Boiler plant	26,295	101,297	170,567	67,370	365,639
Pipeline	-	1,927	62,635	93,952	157,514
BTGS plant	-	747	2,989	2,492	6,228
IDC	1,300	7,869	25,466	47,524	82,159
TOTAL	27,595	111,940	261,667	211,338	612,540
Crude Oil (G)					
BTGS	11,226	-	-	-	11,226
IDC	564	-	-	-	564
TOTAL	11,790	-	-	-	11,790

TABLE 3.7

CASH FLOW — ALL UNITS CONVERTED SIMULTANEOUSLY

$,000 SEPT. 1975 BASIS INFLATED

YEAR COMMENCING	YEAR 1 SEPT. 1975	YEAR 2	YEAR 3	YEAR 4	TOTAL SEPT. 1979
P.F. Coal new Boilers (B)					
BTGS plant	-	19,105	84,060	77,104	180,269
Coal transport facilities	-	-	38,462	63,465	101,927
Ash handling facilities	-	-	7,641	12,607	20,248
IDC	-	955	8,514	23,533	33,002
TOTAL	-	20,060	138,677	176,709	335,446
O_2 Blown Low Btu Gas (E)					
Gasification plant and Steam plant	26,295	111,537	206,398	89,670	433,900
Pipeline	-	2,120	75,788	125,050	202,958
BTGS plant	-	822	3,617	3,317	7,756
IDC	1,300	8,484	29,346	57,473	96,603
total	27,595	122,963	315,149	275,510	741,217
Crude Oil (G)					
BTGS	-	-	-	14,942	14,942
IDC	-	-	-	747	747
TOTAL	-	-	-	15,689	15,689

It would be possible to convert the units on a 3-year cycle, one per year, and burn gas or oil in all units, including those that had been converted, until the end of the programme.

The low Btu gas option would not be economic unless the gasification plant and pipeline capacity were utilized immediately. This precludes an extended schedule.

3.7 EFFECT OF CAPACITY FACTOR

The majority of the preceding discourse has been based on a high capacity factor of 80%. In contrast, Figure 3.1 shows generating cost against capacity factor. Low Btu gas is shown at 70% and 80% capacity factors only because the high capital investment of a gasification plant makes it essential that it be operated at high capacity factors.

The results shown in Figure 3.1 are surprising because coal gives lower generating costs than oil down to a capacity factor of about 20%. The future effects of inflation would probably make coal economic at even lower capacity factors.

3.8 CUMULATIVE PRESENT WORTH

Figures 3.2 and 3.3 show the cumulative present worth of each alternative for a 40 year period for 80% and 15% capacity factors including all capital, operating and fuel costs. Inflation is included to the terms of B.C. Hydro's base criteria. These curves allow the effect of varying interest rates to be taken into account. At the high capacity factor of 80% the coal conversion is economic, when compared to oil burning, at interest rates up to and exceeding 20%. At 15% capacity factor the oil burning alternative is the more attractive at all realistic rates of interest, unless the inflation rate of oil is assumed to be 10% to coal's 4%. Curve 3.3 therefore illustrates a possible scenario, indicating that BTGS can only be operated economically at very low capacity factors if it remains an oil or natural gas burning plant. If the price of oil does inflate at a higher rate than that of coal, the economic load factor for BTGS on crude or residual oil may be substantially below 15%.

3.9 COAL/WATER SLURRY — INFLATION EFFECTS

The coal/water slurry has one major attraction in that it is relatively inflation free. Curve 3.4 shows the cumulative present worth of coal delivery by slurry and by train/barge systems. The curve assumes long term inflation of 5% on all labour costs and is based on 40 years delivery of coal sufficient for a 900 MW plant operating at 80% capacity factor. This curve underlines the fact that the slurry is the most economic transport alternative and deserves further study, particularly towards the problems of slurry water disposal, if a coal conversion is to be considered.

3.10 ENVIRONMENTAL PROBLEMS

A number of potential environmental problems are discussed in the text of the study. These are generally considered from the aspect of public and media response in addition to the need to meet provincial and federal objectives.

If BTGS is converted to burn crude oil, no new environmental difficulties are anticipated.

If Burrard is to be converted to burn gas produced at a Hat Creek gasification plant, Study C and U.S. experience indicate that all likely environmental criteria can be met. The pipeline can probably be located close to the route shown which, in the main, runs through sparsely populated regions.

The coal fired alternatives would meet provincial objectives for the emissions of SO_2, NO_x, and particulate, and the thermal pollution would be no greater than that which would result from running the present units at capacity. It would be possible to design the plant so that no landfill were required, if imaginative engineering were used, but it is possible that this would require an additional expenditure. This expenditure cannot be assessed without a detailed review of the existing plant structure and other factors. Other possible emissions and effluents would only increase as a result of a general increase in the station's capacity factor.

There is reason to suspect that, if Burrard were converted to coal, environmental objections would be raised which have no direct bearing on existing or proposed standards. It is impossible to assess the cost of meeting such objections. All the environmental hazards related to Burrard, with the possible exception of aesthetics and thermal pollution, can be overcome by sufficient expenditure but it is beyond the responsibility of a study of this nature to recommend expenditures of B.C. Hydro's resources to provide environment standards higher than those which legislation requires.

FIGURE 3.1
GENERATING COST Vs LOAD FACTOR

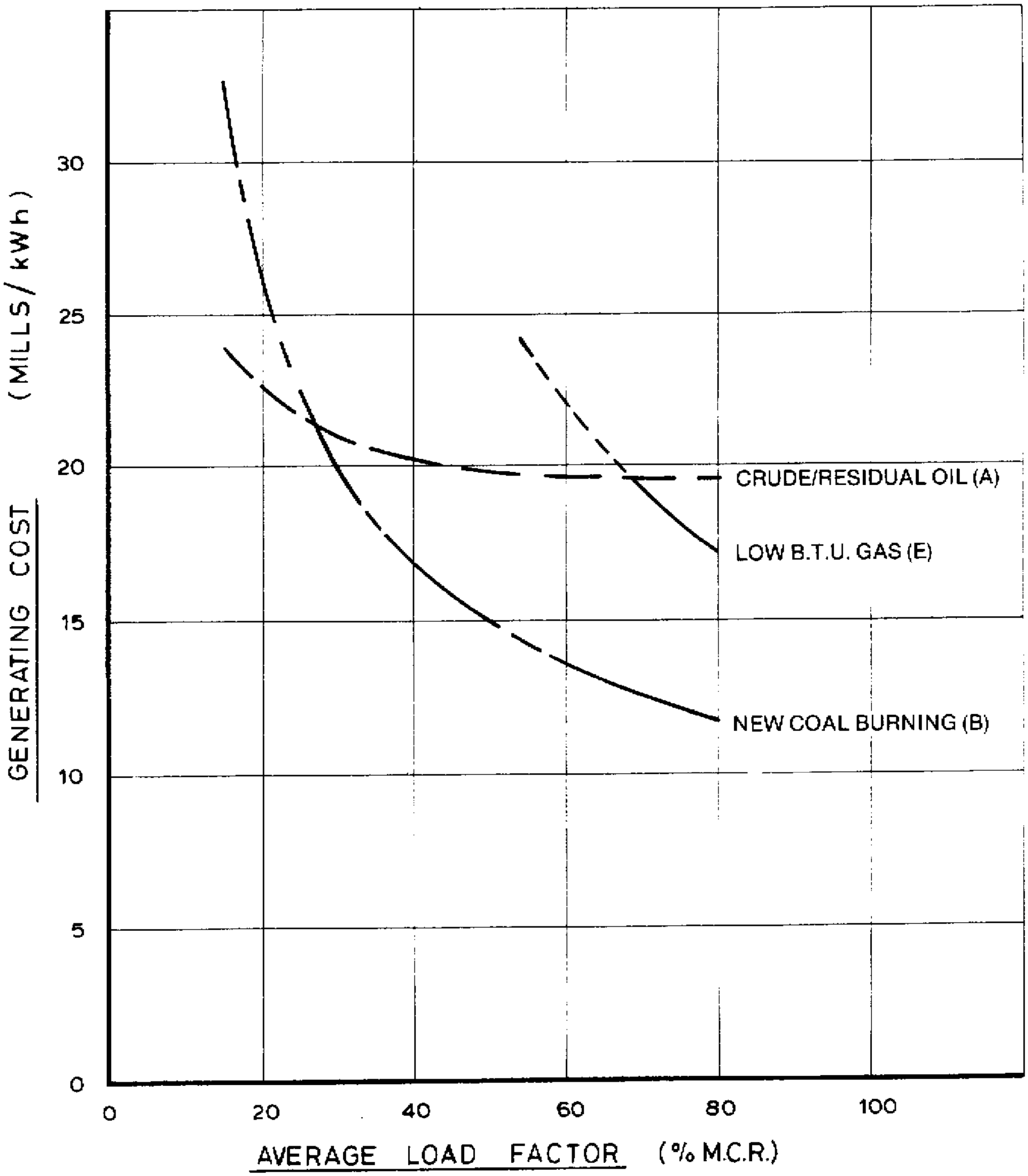


FIGURE 3.2
DIFFERENCE IN PRESENT WORTH OF CASH FLOW
(40 YEARS FROM 1979) — 80% CAP. FACT

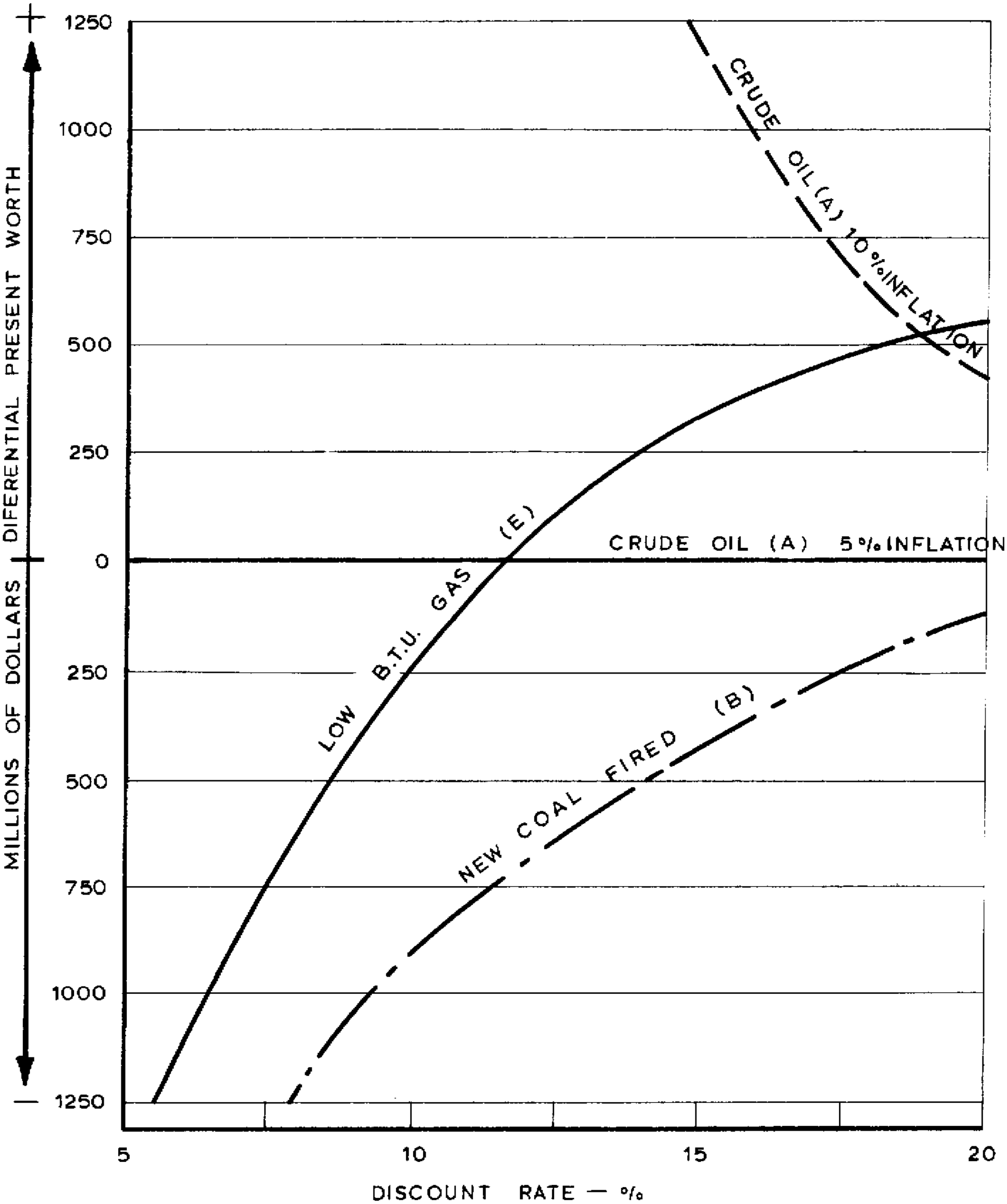


FIGURE 3.3
DIFFERENCE IN PRESENT WORTH OF CASH FLOW
(40 YEARS FROM 1979) — 15% CAPACITY FACT

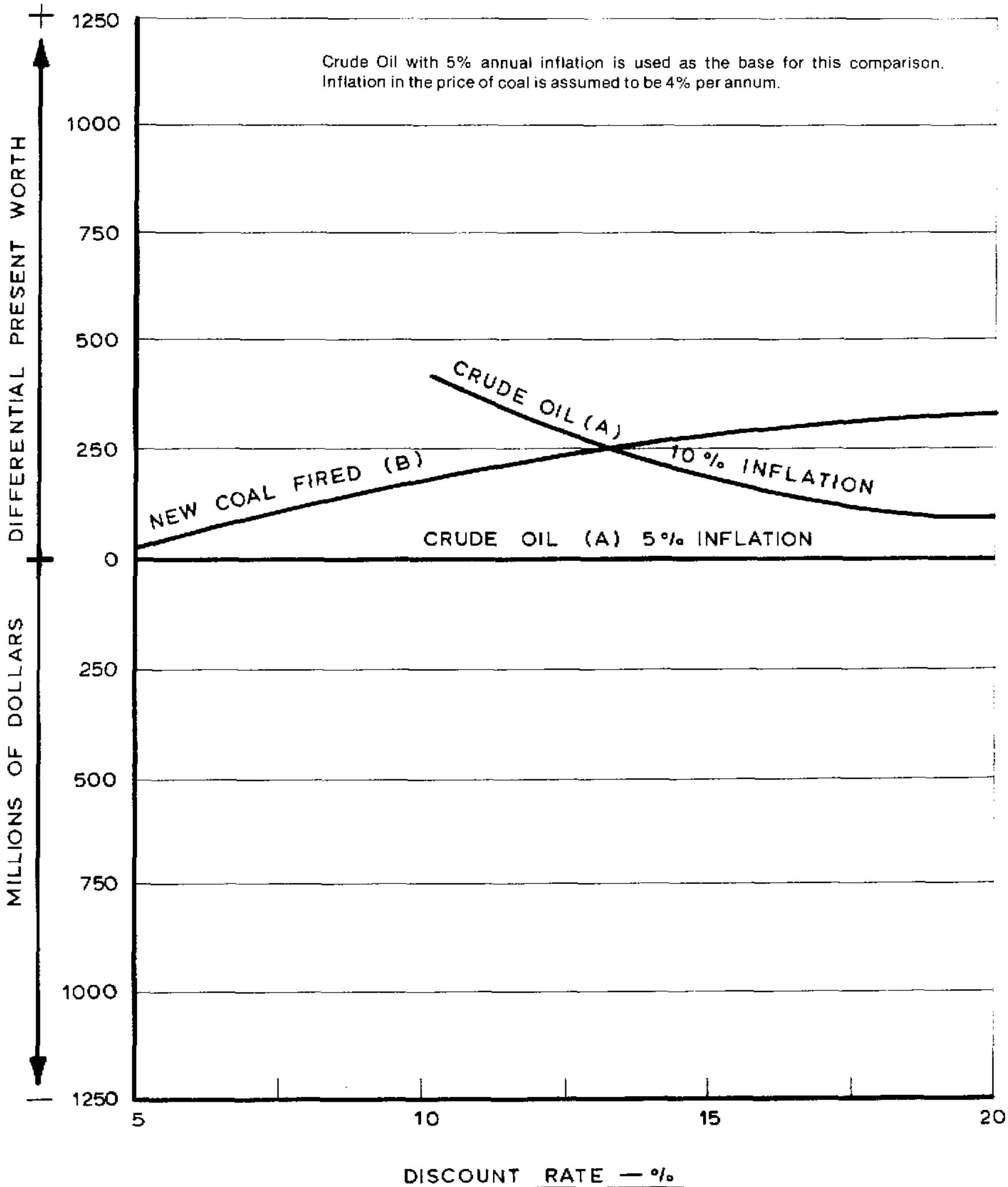
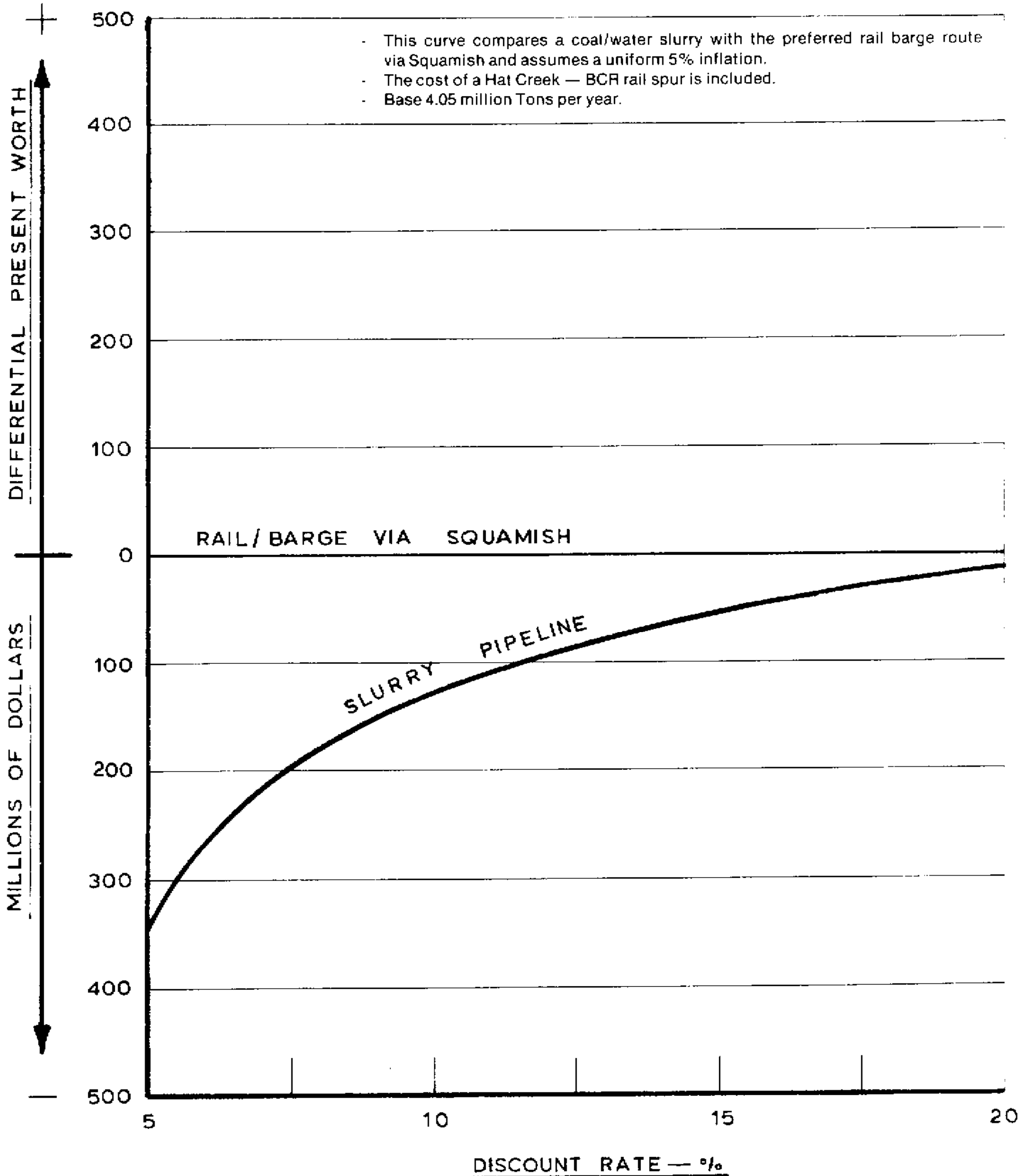


FIGURE 3.4
COAL DELIVERY CUMULATIVE PW OF TOTAL INFLATED CASH FLOW
(40 YEARS FROM 1979)



4.0 TERMS OF REFERENCE AND BASE CRITERIA

4.1 TERMS OF REFERENCE

B.C. Hydro's terms of reference for this study are given below:

1. *Provide engineering services to determine the feasibility and costs of conversion* of the BTGS to coal fuel. Coal handling and transportation is to be included. The study will cover the alternatives listed in the attached Section 6 of the joint *proposal.*

2. The study will incorporate a materials and energy balance for each of the main alternatives.

3. The study report will include a statement on the feasibility and operational flexibility of each of the alternatives considered.

4. Identify the possible environmental impacts of such a station in relation to accepted or assumed emission standards. This will include a flow balance for all gaseous, liquid and solid discharges when burning Hat Creek coal. A comparison will be made between anticipated emissions and those already occurring at the site.

5. *Data from Study C, "Review of Coal Gasification Processes", is to be considered* in the alternatives of gasification on site, near the site, or at Hat Creek. Data from Study A is also to be considered.

6. Resulting energy and capacity costs are to be compared with those from natural gas and both residual and crude oil.

7. *The work shall be in the form of engineering studies carried out utilizing* published information and data from discussions with companies considered to be recognized authorities in the field having regard to present technology and *possible technology in the future.*

8. Power cost estimates expressed in mills/kWh are to be calculated for a range of capacity factors from 60% to the highest considered feasible, for the schemes studied. Coal characteristics and costs will be provided by B.C. Hydro from existing data and, as study progresses, from sample tests. Capital cost estimates shall be broken down to clearly itemize the component costs.

9. Cost estimates shall be in September 1975 dollars and shall be broken down by years. Where possible, agreed common costs received from the co-ordinating *consultant, will be incorporated. The interest on capital and interest during* construction shall be assumed as 10% but itemized in such a way that the effect of an alternative rate can easily be determined. The assumed plant lives *will be agreed with B.C. Hydro.*

10. Project schedules shall be prepared for the earliest in-service dates for various sizes and systems considered.

11. Prepare and submit a report in draft form by 30 September 1975 and in final form by 28 November 1975. In addition, progress reports will be made monthly of the results achieved, the costs incurred and the scheduling of future work and associated costs.

12. The study is to be controlled and co-ordinated by the Assistant General Manager, Engineering, of B.C. Hydro and Power Authority or his appointee.

4.2 BASE ENGINEERING AND COST CRITERIA

The study is based on the assumptions listed in the co-ordinating consultants "Base Engineering and Cost Criteria" issue 4 dated 19 September 1975 together with Addendum 1 dated 14 August 1975.

5.0 COMBUSTION PROCESSES

5.1 INTRODUCTION

Coal has been considered as an energy source for power generation at Burrard Thermal Generation Station, either by burning it directly, or by gasification to a low or medium Btu gas. In either case a variety of arrangements is possible utilizing:

a) The existing steam generators suitably modified;

or b) The existing steam generating plant supplemented by gas turbines in a combined cycle;

or c) Replacement steam generating plant.

For those schemes utilizing the existing steam generating plant, it has been necessary to analyze the performance which would be obtained using the several specified fuels and the bulk of this section is concerned with the determination of boiler performance for each case.

5.2 POSSIBLE FUELS

The fuels which are considered here are:

- Coal fired directly
- Gas from an air blown Lurgi process
- Gas from an O_2 blown Lurgi process
- Gas from an O_2 blown Lurgi process with some CO_2 removed

Appendix 2 contains chemical analyses and combustion calculations for the various fuels.

5.3 DIRECT FIRING IN EXISTING PLANT

5.3.1 PERFORMANCE OF EXISTING PLANT

5.3.1a FURNACE

The component which imposes the major restriction on the performance of the existing plant using fuels other than Natural Gas (N.G.) is the furnace.

The furnace water wall tubes constitute the entire evaporative heat transfer surface in the boiler so that the amount of heat absorbed by them dictates the amount of steam generation which can be achieved.

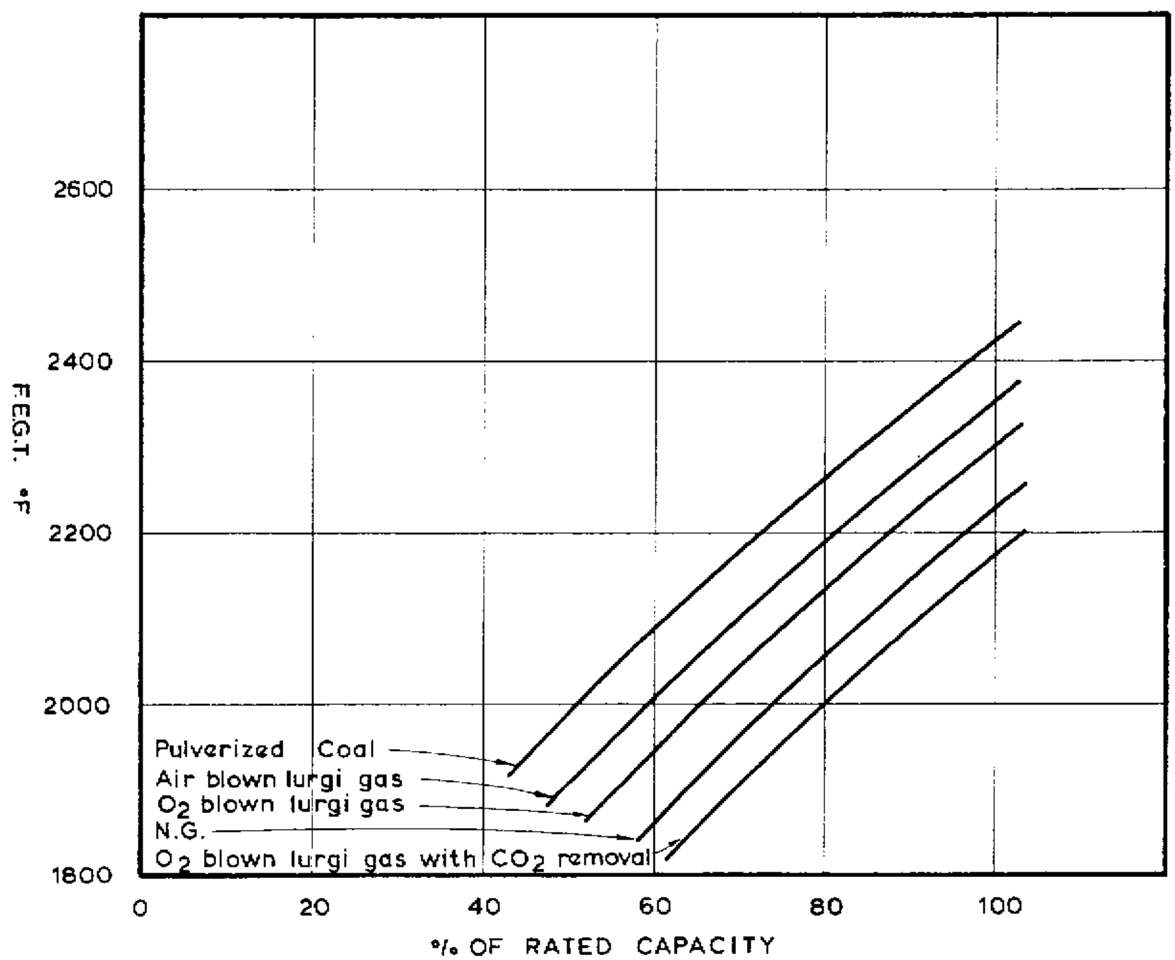
Although all heat transfer mechanisms occur simultaneously in the furnace, the predominant mode is radiation from the products of combustion to the furnace tubes. Radiation heat transfer depends on the fourth powers of the absolute temperatures of the radiating and receiving media, and also on luminosity, emissivity, furnace geometry, etc. Temperatures vary throughout the furnace and as a result, determination of the furnace heat transfer is difficult and not amenable to purely theoretical techniques.

The method used here to estimate the furnace performance when firing the various fuels, is semi-empirical and is based on performance data for Natural Gas (N.G.) firing.

A relationship between Furnace Exit Gas Temperature (FEGT) and adiabatic flame temperature, mass flow of flue gas, and furnace dimensions is developed in Appendix 3. This is used to modify the performance obtained with NG firing, to predict furnace performance when firing a different fuel.

Furnace performance is presented as FEGT plotted against percentage of rated capacity as shown in Figure 5.1.

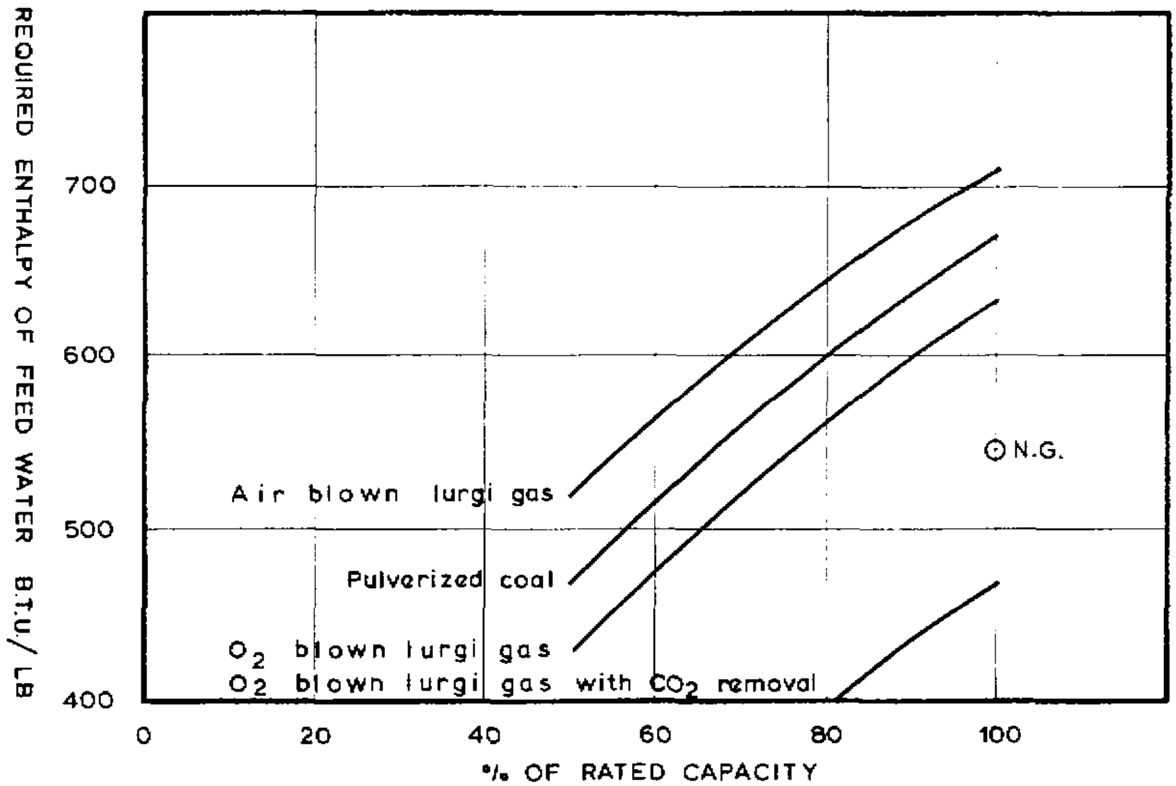
FIGURE 5.1
F.E.G.T. Vs % RATED CAPACITY FOR DIFFERENT FUELS



From a knowledge of FEGT and the moisture content of the flue gas, the heat leaving the furnace in the flue gas can be determined. By subtracting this from the total heat input to the furnace, the heat absorbed by the furnace tubes can be ascertained.

The required feed water enthalpy which ensures that this quantity of heat is sufficient to generate the required amount of steam has been calculated, and this is shown in Figure 5.2.

FIGURE 5.2
ENTHALPY OF FEEDWATER REQUIRED TO ENSURE ADEQUATE STEAM GENERATION Vs % OF RATED CAPACITY FOR DIFFERENT FUELS



To avoid steam generation in the economizer, the maximum economizer outlet water enthalpy which can be achieved is 600 Btu/lb so that from Figure 5.2 the maximum capacities which can be obtained with the different fuels are as shown in Table 5.1.

TABLE 5.1

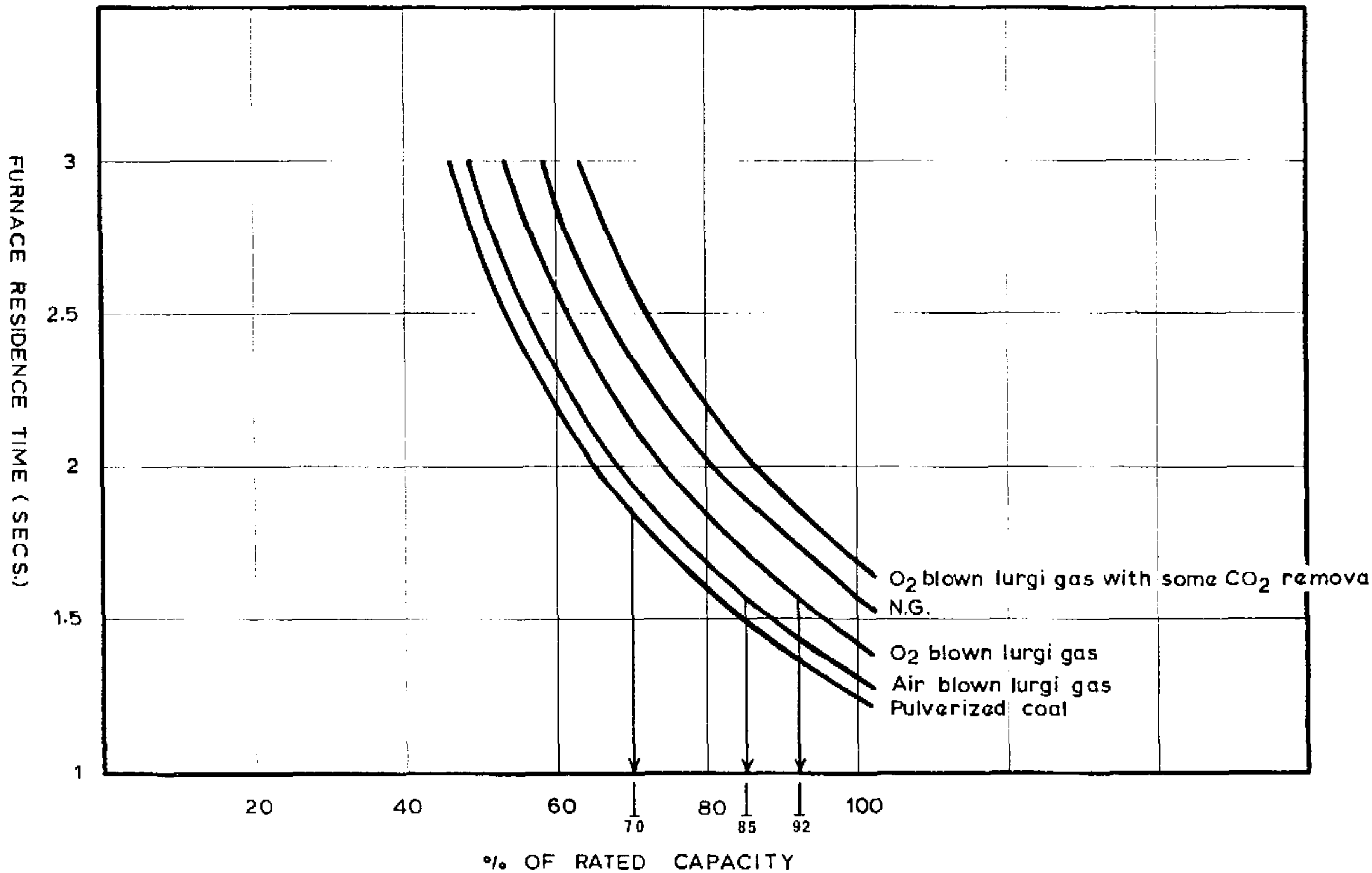
	AIR BLOWN LURGI GAS	O_2 BLOWN LURGI GAS	O_2 BLOWN LURGI GAS WITH CO_2 REMOVAL	PULVERIZED COAL
Capacity	70%	89%	100%	80%

5.3.1b FURNACE RESIDENCE TIME

To determine the residence time of the products of combustion in the furnace, a relationship is derived in Appendix 4 between furnace residence time and adiabatic temperature, FEGT, furnace dimensions, gas constants, and gas mass flow.

Figure 5.3 shows furnace residence time as a function of percentage of rated capacity for the various fuels. Using the relationship in Appendix 4.3 the furnace residence time for N.G. firing is calculated to be 1.58 seconds and this value is taken as the limiting value for gas firing. The limiting furnace residence time for coal firing is derived from examination of similar coal fired units of 150 MW capacity. By using the relationship of Appendix 4.3 with the parameters appropriate to a coal fired

FIGURE 5.3
FURNACE RESIDENCE TIME Vs % OF RATED CAPACITY FOR DIFFERENT FUELS



150 MW unit, the furnace residence time is calculated to be 1.85 secs. This is used as the limiting furnace residence time for coal firing at BTGS.

The capacities which can be obtained, using furnace residence time as a limitation, for the different fuels are therefore as shown in Table 5.2.

TABLE 5.2

	AIR BLOWN LURGI GAS	O_2 BLOWN LURGI GAS	O_2 BLOWN LURGI GAS WITH CO_2 REMOVAL	PULVERIZED COAL
Capacity	85%	92%	100%	70%

For each fuel there are three principle limitations on capacity, i.e. from heat absorption, and furnace residence time considerations, and erosion considerations when firing coal. The gas velocity entering the secondary superheater section at 70% capacity on coal firing would be approximately 40 f.p.s. so that erosion is not a governing limitation.

Other limitations, such as burner spacing, are accounted in cost estimates in this section.

Table 5.3 shows the governing limitation and the corresponding capacities which can be achieved.

TABLE 5.3

	AIR BLOWN LURGI GAS	O_2 BLOWN LURGI GAS	O_2 BLOWN LURGI GAS WITH CO_2 REMOVAL	PULVERIZED COAL
Capacity	70% Furnace Absorption	89% Furnace Absorption	100% -	70% Furnace Residence Time

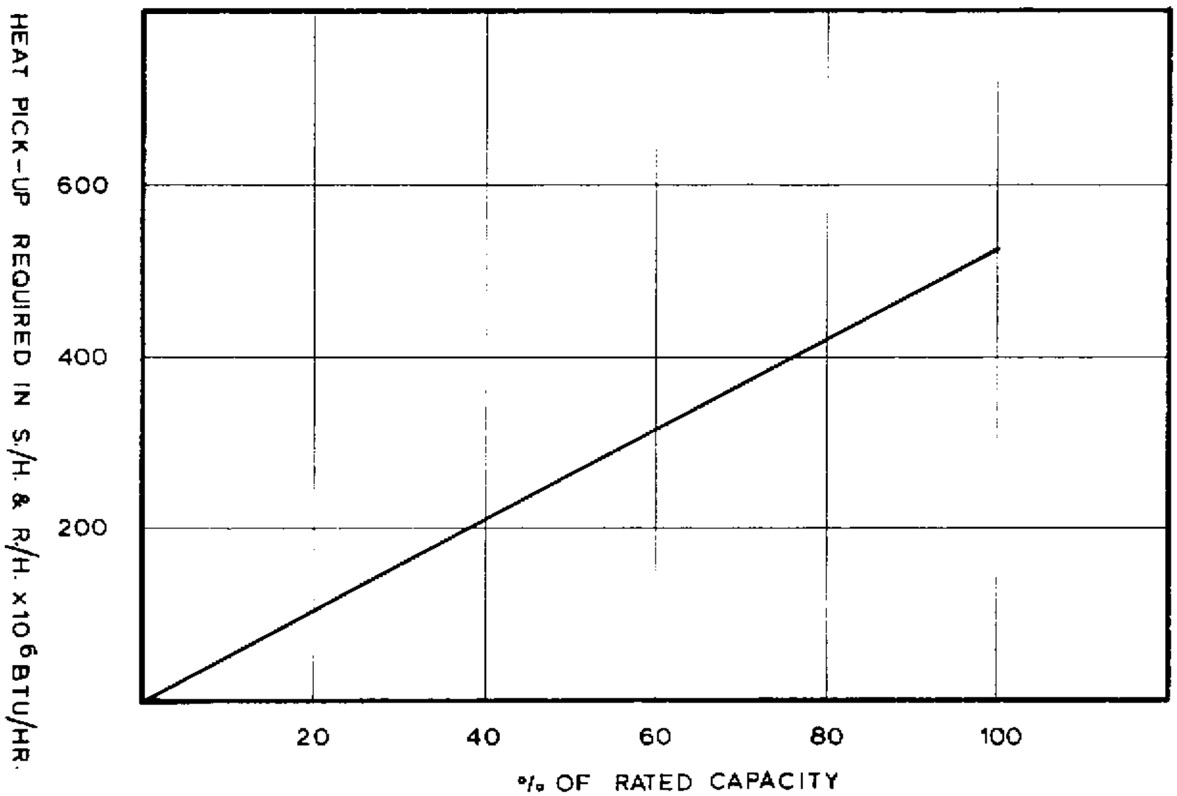
5.3.1.c SUPERHEATER AND REHEATER SURFACE

The required heat transfer in the superheater and reheater can be determined as a function of capacity, assuming that the steam conditions at entry and exit remain the same as for 100% rated capacity when firing N.G. This is shown in Figure 5.4. Calculation of the performance of the existing S/H and R/H surfaces for different fuels is beyond the scope of this study although Table 5.4 indicates whether surface removal or addition would be necessary with each of the various fuels.

TABLE 5.4

	PULVERIZED COAL	AIR BLOWN LURGI GAS	O_2 BLOWN LURGI GAS	O_2 BLOWN LURGI GAS with CO_2 REMOVAL	N.G.
Capacity obtained %	70	70	89	100	100
Gas flow x 10^6 pph	1.071	1.0673	1.226	1.1474	1.228
FEGT °F	2180	2100	2220	2170	2220
Heat pick-up required in S/H & R/H relative to NG firing %	70	70	89	100	100
Heating surface modifications required	removal	removal	removal	addition	-

FIGURE 5.4
HEAT PICK-UP REQUIRED IN S/H & R/H Vs % OF RATED CAPACITY



5.3.1d ECONOMIZER

The performance required of the economizer is shown in Figure 5.2. The actual performance of the economizer for different fuels can be calculated by treating it as a simple heat exchanger and utilizing performance data for NG firing to determine the equivalent heat transfer coefficient. Such an analysis is shown in Appendix 4 and Figure 5.5 shows the performance obtained with different fuels.

For direct coal firing, the fact that the existing economizer comprises off-set finned tubes, precludes efficient sootblowing. As a result a new economizer is required. Therefore, no curve for coal firing is shown in Figure 5.5.

5.3.1e AIR HEATERS

The performance of the existing air heaters with different fuels can be estimated in a similar way as for the economizer, i.e. by treating them as simple heat exchangers where the heat transfer coefficient is determined by reference to performance data on NG firing. Such an analysis is shown in Appendix 5, and Table 5.5 shows the performance obtained with different fuels. In the case of coal firing, primary air and secondary air are supplied at different pressures to the pulverizers and furnace windbox respectively so that one of the two existing heaters is allocated to each of these duties.

FIGURE 5.5
FEEDWATER ENTHALPY OBTAINED FROM EXISTING ECONOMIZER Vs % OF RATED CAPACITY

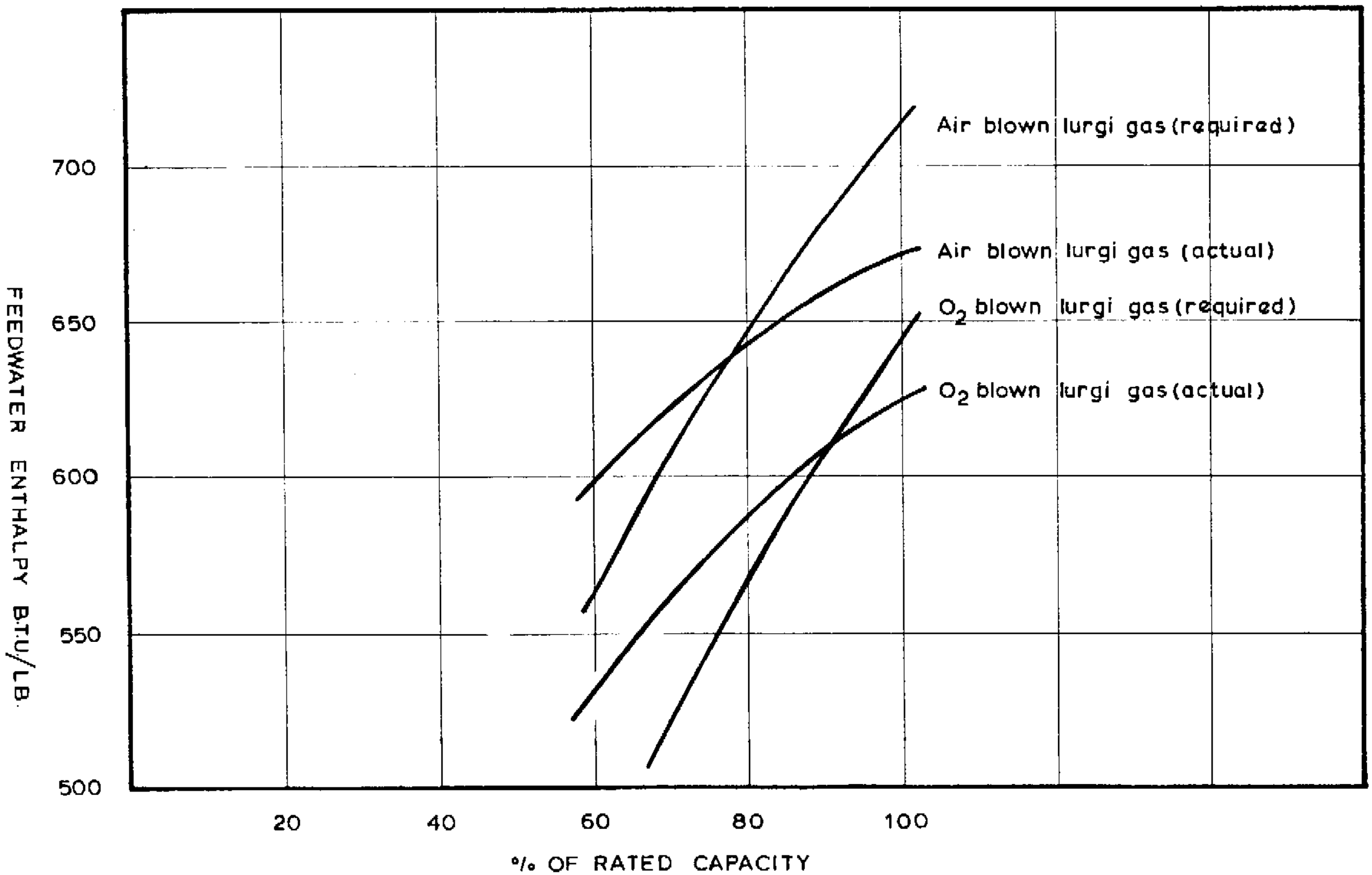


TABLE 5.5

	AIR BLOWN LURGI	O_2 BLOWN LURGI	PULVERIZED COAL
Capacity %	70	89	70
Gas temperature to air heaters °F	630	650	690
Gas flow to air heaters x 10^6 pph	1.007	1.2261	1.071
Primary x 10^6 pph	-	-	0.361
Secondary x 10^6 pph	-	-	0.71
Air flow to air heaters x 10^6 pph	0.7211	0.955	0.9192
Primary x 10^6 pph	-	-	0.3064
Secondary x 10^6 pph	-	-	0.6128
Air outlet temperature °F	558	515	-
Primary °F	558	515	650
Secondary °F	558	515	585
Gas outlet temperature °F	342	349	281
Primary °F	-	-	242
Secondary °F	-	-	300

5.4 COMBINED CYCLE

Gas turbines could be installed at BTGS to provide their exhaust heat to the existing furnaces, as a means of supplementing the heat input to the furnace when firing pulverized coal. Such gas turbines could burn coal by using a fluidized bed air heater combustion unit in place of the gas turbine combustion chamber.

Combustion Systems Ltd. have supplied an estimate and performance data for a fluidized combustion airheater furnace. This furnace is supplied by pressurized air from the gas turbine compressor exhaust. About 1/3 of the air passes through the bed and returns to the gas turbine as pressurized hot flue gas. The other 2/3 passes through air heater tubes in the bed and also returns to the gas turbine. The exhaust from the gas turbine can be passed to the existing boiler to provide an extra heat input. The exhaust temperature of this gas turbine is 587°F, which is far too low to be of any significant help in providing extra heat absorption in the furnace. The highest exhaust temperature which can be obtained from 1975 base load gas turbines is about 1000°F. which is also far too low to assist heat absorption.

The previous sections demonstrated that the existing furnaces require conditions close to those of natural gas firing, i.e. a high flame temperature.

The concept of installing gas turbines at BTGS to supplement coal firing in the existing steam generators is thus impractical. However, Section 6.8 considers the possibility of gas fired combined cycles for the Burrard site.

5.5 CONVERSION TO FLUIDIZED COMBUSTION

Fluidized combustion offers several advantages over conventional pulverized coal systems. In considering the conversion of the existing units to fluidized combustion, two of these advantages are important from the point of view of performance. These relate to residence time and available heat transfer surface.

In considering pulverized coal firing it was shown that restrictions on furnace performance were imposed by the limited heat transfer surface available in the furnace water wall tubes and the limited furnace residence time obtained with the compact furnace designed for N.G. firing. With fluidized combustion, supplementary heat transfer surface can be included in the beds themselves and the excellent mixing characteristics in the beds ensure that furnace residence time is not a limitation.

In fluidized combustion low excess air is used (5%) so that the flue gas mass flow is less than it would be with pulverized coal firing, where higher excess air is necessary (20%).

Conceptually, with fluidized combustion, the off gas temperature can be increased or decreased by respectively decreasing or increasing the heat transfer surface included in the beds. Figure 5.6 shows the heat absorbed in the fluidized beds as a function of exhaust temperature.

The furnace heat absorption which would occur, when this gas is exhausted into the existing furnace, can be estimated using the relationships developed previously, and this is also shown in Figure 5.6. The exhaust temperature is generally taken as 1600°F. Figure 5.6 shows that at this temperature little heat absorption occurs in the furnace and the heat absorbed in the surface included in the bed is sufficient to carry the balance of the evaporation load as well as all of the reheater load and secondary superheater load.

The gas mass flow and temperature to the primary superheater then approximate that for N.G. firing so that the performance of the existing primary superheater would be satisfactory (Table 5.6).

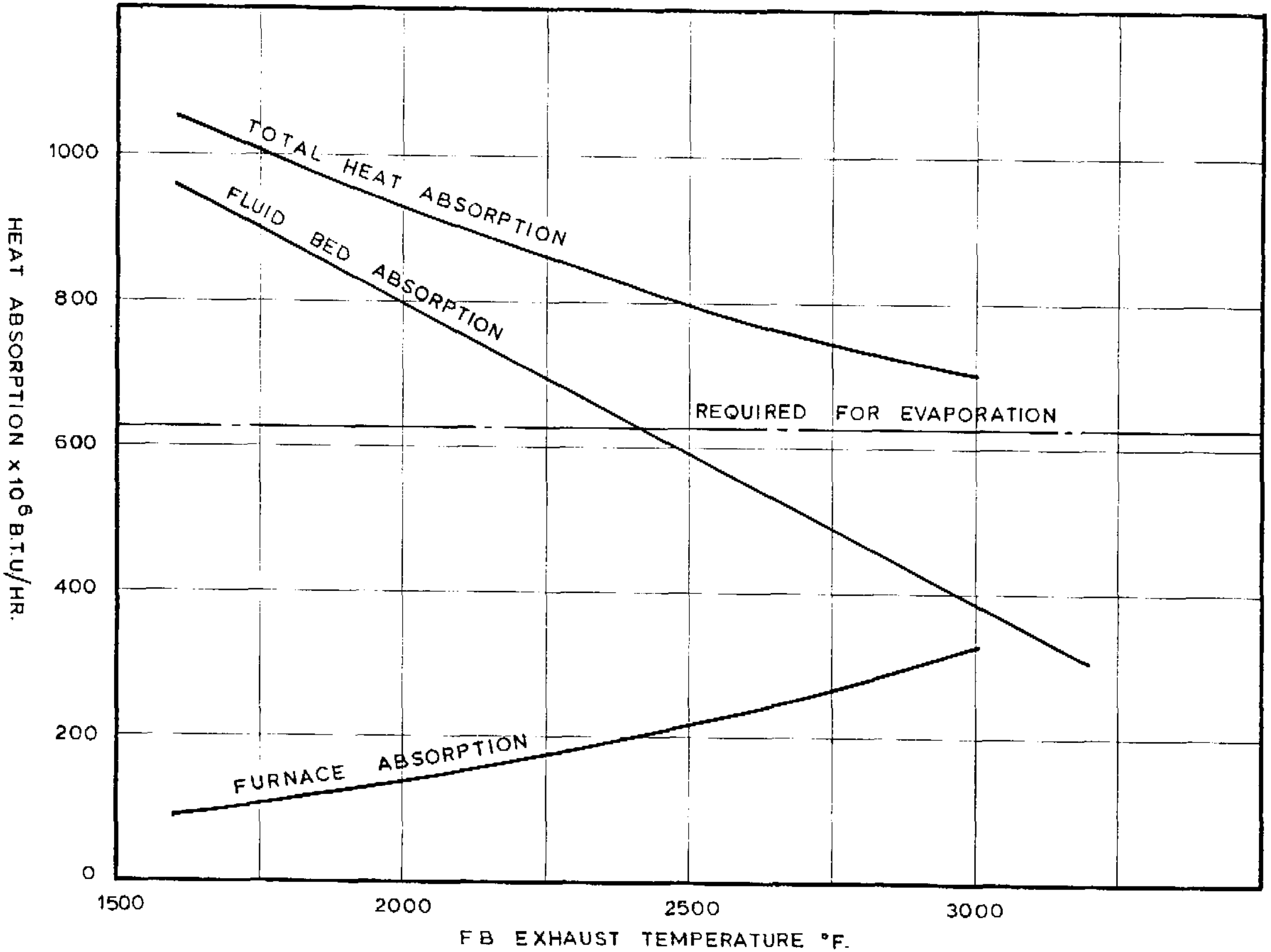
TABLE 5.6

		F.B.	N.G.
Gas temperature to primary S/H	F	1340	1360
Gas mass flow to primary S/H	x 10^6 pph	1.29	1.228

Because the existing economizer comprises off-set finned tubes, satisfactory sootblowing is not possible and the existing economizer would require replacement.

The performance of the existing air heaters would be satisfactory since the gas mass flow and temperature to the air heaters approximate those of N.G. firing.

FIGURE 5.6
HEAT ABSORPTION IN FLUIDIZED COMBUSTORS AND EXISTING FURNACE Vs EXHAUST TEMPERATURE



6.0 MODIFICATIONS REQUIRED TO EXISTING PLANT

The preceding discussion has been limited to the performance of the existing plant using the various fuels. The following text examines the modifications which would be necessary for each of the alternatives.

6.1 PULVERIZED COAL FIRING IN EXISTING STEAM GENERATORS

The following are the principal modifications required:

a) An ash hopper system is required for pulverized coal firing. The available clearance between ground level and the furnace bottom header is 3 feet at present, while the clearance required for a conventional ash handling system is about 15 feet. By modification of the furnace bottom it is only possible to increase the clearance to about 5-6 feet since combustion characteristics require a clearance of some 10-12 feet between the bottom burner and the top of the sloping hopper section.

   Consequently a conventional ash handling system cannot be incorporated. The system which is assumed here, is one having a water trough at the furnace bottom containing a drag chain conveyor. Continuous ash removal to an ash storage bin adjacent to the boiler would result in a satisfactory arrangement. This method of ash handling has been used in Europe.

b) It would be necessary to provide additional sootblowers in the furnace (Approximately 48 extra.)

c) The secondary superheater and reheater surfaces would require removal of heating surface and sootblowers are also necessary here.

d) In the existing economizer it is not possible, because of the configuration of the offset finned tubes, to effect satisfactory sootblowing and a new economizer is necessary.

e) Coal pulverizers and coal/air pipes are required. Drawing SK 15 shows a possible arrangement for these, which allows adequate space for a mill maintenance system.

f) There is insufficient space to allow the installation of large bunkers of the type normally used with a pulverized coal fired unit.

   Therefore an alternative system is adopted here where small storage bins above the coal feeders are continuously supplied with coal by a flight conveyor. By monitoring the amount of coal carry over after the last coal bin, coal supply to all coal bins can be assured. Such schemes are widely used in the industrial sector to supply solid fuels and would prove to be satisfactory for this application.

g) Completely new electrostatic precipitators would be installed together with ID fans and an 880 ft. stack and these are indicated in Drawing SK15. It might be economical to provide three oval flues similar to those used at the CEGB's Drax station. A single stack is chosen for aesthetic purposes, the height being selected by B.C. Hydro from environmental considerations. If the precipitators were installed on the turbine hall roof and the stack on the hill behind the station, land reclamation could probably be avoided.

6.2 NEW P.F. STEAM GENERATORS

6.2.1 450 MW OR 900 MW UNITS

The possibility of installing new coal burning steam generators of above 150 MW is considered. These could be located at the existing site, or at a new location from which steam would be piped to the existing plant. Units of 300 MW, 450 MW or 900 MW would give lower specific costs than new units of 150 MW, but could only be installed if the turbines were operated on a range system (two or more turbines fed from a common boiler).

Following discussions with turbine manufacturers from Europe, North America and Japan it appears that no reheat machines have ever been operated on a range system. Reheat steam turbines have always been supplied as unit packages with one boiler per turbine. Light water reactors have been built to supply two turbines, particularly in Sweden, but the steam is of relatively low temperature and is not reheated.

There would be severe problems to operating more than one reheat turbine on a single boiler. It is probable that these problems have never been investigated in detail because the economics of the single boiler/turbine unit have always been very convincing. Some of these difficulties are listed briefly below:

6.2.1a REHEAT STEAM PRESSURE

The pressure of steam to the reheater is directly dependent upon turbine load, and may vary from a full load value of about 25% of superheater pressure to a slight vacuum. Machines operating on a range would be forced to maintain identical load, or would require separate reheater circuits in the boiler.

6.2.1b HIGH TEMPERATURE STEAM VALVES

The cost of high temperature steam valves would be high, as would the interconnecting piping. It would be difficult to obtain valves which are completely steam-tight.

6.2.1c FEED HEATERS

In converting existing machines to a range system it would be necessary to parallel the feed heating systems. Even with the machines running at identical load, the final feed water temperatures from the two systems would be different, and the pressure from the feed pumps would vary.

6.2.1d CONTROL

Significant extra complications would occur in the control system.

The possibility of large or remote new boiler installations is therefore rejected.

6.2.2 150 MW UNITS

Because of the difficulties of operation on the range system, the provision of six new pulverized coal fired units, each of 150 MW capacity, is considered.

While the design of the boilers can be adjusted to account as far as possible for the existing relatively compact site, the space requirements for those items of equipment peculiar to coal firing, i.e. coal storage facilities, I.D. fans, precipitators and stacks, are such that some land reclamation would be necessary at the existing site if a conventional layout were adopted. Drawing SK21 shows the site plan area required for such a conventional layout.

6.3 AIR BLOWN LURGI GAS & O_2 BLOWN LURGI GAS IN EXISTING STEAM GENERATORS

The modifications necessary for each of these fuels are similar. The major requirement is for enlarged fuel pipes. For both air blown Lurgi and O_2 blown Lurgi gas, surface removal would be necessary in the superheater and reheater sections.

6.4 O_2 BLOWN LURGI GAS WITH CO_2 REMOVAL IN EXISTING STEAM GENERATORS

Only minor alterations to fuel pipes and some additional surface in the superheater and reheater sections would be required.

6.5 CONVERSION TO FLUIDIZED BED COMBUSTION

6.5.1 CONVERSION OF EXISTING STEAM GENERATORS

The plan area of fluidized beds required to burn a given amount of coal depends on the fluidizing velocity used. The amount of coal which will give 100% of rated capacity at BTGS with a fluidizing velocity of approximately 7.6 f.p.s., the value recommended by C.S.L., is such that the required plan area of fluidized combustors makes it necessary to consider a multi-level arrangement. Drawing SK11 shows a typical multi-level arrangement.

Almost all of the evaporation occurs in the evaporative bed at the bottom of the existing furnace, the remainder of the steam being generated in the water cooled furnace walls which form the containment for the fluidized combustors.

The secondary superheater load is carried in the superheater bed located at the second level while the highest bed, the reheater bed, exclusively carries the reheater load. To modify the Burrard Steam Generators, the existing superheater and reheater pendant sections would be removed but the primary superheater convective surface could be retained.

The existing economizer, because its tubes are offset, does not lend itself to sootblowing and would quickly become clogged due to the dust in the gas. A new economizer would therefore be installed and this would be positioned at the same place as the existing economizer.

The existing air heaters would perform adequately and would be retained.

The gases at the outlet from the air heaters would be passed via electrostatic precipitators to a new stack.

The overall dimensions would not differ significantly from the scheme using the modified pulverized coal fired units so that the same amount of land reclamation would be necessary to accommodate coal storage, electrostatic precipitators, I.D. fans and stack.

Ash handling would be by a system of weirs within the beds over which ash would spill to be directed via refractory lined tubes to water troughs, containing drag link conveyors, located at each end of each bed. Vapour would be discharged to the stack and make up water, to maintain an adequate water level, would be supplied via a level control valve.

The drag link conveyors would discharge to belt conveyors which would run the length of the boiler house, and would discharge to storage bins located adjacent to the boiler house.

Coal supply to the fluidized beds would be by pneumatic means. The coal would be dried to facilitate pneumatic transport and then crushed to suit the characteristics of the fluidized combustors.

Prepared coal would be transported to bunkers from which it would be fed through injectors to the pneumatic transport system which would use transportation air from motor driven compressors. By using a system of branching pipes coal would be fed upwards, via multiple inlets, into each bed.

6.5.2 NEW 150 MW FLUIDIZED COMBUSTION STEAM GENERATORS

If new 150 MW fluidized combustion steam generators are installed at the existing site, it would be possible to adopt a design which would fully utilize the basic advantages associated with fluidized combustion.

Fluidized combustion does not require the large radiant surface area necessary when coal is burned in suspension in a furnace so that a more compact arrangement is possible.

All of the reheater load and all of the secondary superheater load can be carried in fluidized combustors, located at ground level thus facilitating the routing of the high temperature pipework between the boiler and the turbo-generator.

A suitable layout is shown in Drawing SK20.

Almost all of the evaporative load is carried by the two evaporative fluidized combustors with the balance of the steam generation occurring in the water walls which form the containment for the fluidized combustors.

One superheater bed is used to carry the load of the secondary superheater and two reheat beds exclusively satisfy the reheater requirements.

On exhausting from the containments of the individual beds, the flue gases pass through a 'conventional' primary superheater convective section, an economizer section, air heater and then via electrostatic precipitators to the stack.

The ash handling and coal supply systems would be identical in concept to those described for the conversion of the existing boilers to fluidized combustion.

The land reclamation necessary to accommodate the electrostatic precipitators, stack, and for coal storage is the same as for new conventional pulverized coal fired units.

6.6 CRUDE OIL FIRING IN EXISTING STEAM GENERATORS

Crude oii has been used as a fuel for steam generation for some time in Japan (since 1957) and also in Israel and the Arab countries. The conversion of the Burrard units to crude oil firing is therefore an alternative which requires examination.

6.6.1 EXISTING STEAM GENERATING EQUIPMENT

The performance of the existing steam generating equipment, with the exception of the burners which do have to be altered, firing crude oil approximates to that firing residual oil and is therefore satisfactory. Full rated capacity would be obtained on crude oil firing.

6.6.2 FUEL STORAGE AND SUPPLY SYSTEMS

Because of its potentially explosive nature, crude oil presents a hazard to the fuel storage and supply systems and for this reason extensive modifications are necessary. The following is not a rigorous list of modifications which would be necessary to allow the safe storage and handling of crude oil but it does highlight the major items.

6.6.2a STORAGE

The two existing 189,000 barrel storage tanks would require floating roofs to exclude the possibility of developing an explosive air/vapour mixture within the tanks.

In addition it would be necessary to install agitators within the tanks to prevent the build-up of deposits which form in crude oils below about 50°F.

Electrical connections within the existing dyke area would have to be converted to the explosion proof type.

6.6.2b SUPPLY

The existing positive displacement pumps operate at 900 r.p.m. and for efficient pumping of crude oil this would have to be increased to 1200 r.p.m.

The existing pumphouse would have to be ventilated and monitored for gas accumulations.

All electrical connections, heat trace equipment, instrumentation, and lighting, would have to be equipped with explosion-proof fittings.

The existing fuel supply and return lines run in the service trench along the south side of the boiler and this trench would have to be equipped with a forced ventilation system and gas monitoring equipment.

The auxiliary steam control houses and desuperheater control stations would have to be ventilated and have gas monitors installed.

The F.D. fan enclosures would have to be ventilated and monitored since gas accumulation could occur when the F.D. fans are inoperative.

Electrical equipment local to or below the oil burner levels would require to be ventilated and have explosion-proof fittings installed.

6.7 SUMMARY OF PERFORMANCE AND NECESSARY MODIFICATIONS USING EXISTING PLANT

	P.C.	AIR LURGI	O_2 LURGI	O_2 LURGI CO_2 REMOVAL	F.B. CONVERSION	CRUDE OIL
Fuel Pipes		X	X	X		*
Furnace Mods	X				X	
S/H & R/H Surface	X	X	X	X	X	
Econ.	X				X	
Sootblower Addition	X				X	
Pulverizers	X					
Crushers					X	
Ash Handling System	X				X	
Precips.	X				X	
Stack	X				X	
Coal Supply System	X				X	
Capacity Obtained	70%	70%	89%	100%	100%	100%

*Fuel handling, storage, ventilation, flameproofing, and control modifications only.

6.8 COMBINED CYCLES — GAS BURNING

6.8.1 1975 UNFIRED COMBINED CYCLE

A conventional gas burning, unfired, combined cycle could be installed at BTGS. Gas turbines which are available in 1975 have a base load exhaust gas temperature of about 1000°F which is inadequate to provide high enough steam conditions for the existing turbines, or to obtain efficient use of the existing boilers. Such a combined cycle would not be able to incorporate any of the existing boiler or turbine hall equipment, with the possible exception of some civil and structural works, and auxiliaries such as the C.W. pumps and switchyard.

6.8.2 ADVANCED COMBINED CYCLE

Gas Turbines will be available in 1985/1990 with exhaust temperatures approaching 1500°F, which is high enough to produce steam at 1800 psi, 1000° F/1000° F for the BTGS turbines. This temperature is still inadequate to obtain satisfactory performance from the existing boilers. In addition, such gas turbines will require about 225 MW of gas turbine capacity to give 150 MW of steam turbine power. Thus the gas turbine capacity required to provide steam to the BTGS Turbines would be quite absurdly high.

6.8.3 STEAG CYCLE

A STEAG supercharged, fully fired, cycle could be installed at BTGS to utilize the existing steam turbines and their auxiliary equipment. The gas turbine capacity required would be about 50 MW per unit or 300 MW. Such a configuration would only be effective if the combined cycle were integrated with the gasification plant. The economics of locating a gasification plant at BTGS are reviewed in Section 8, with the conclusion that the high cost of transporting coal, and the sensitivity of this transportation to inflation, make the site unsuitable for a gasification plant. This conclusion is reinforced by the obvious space limitations of the site, and environmental considerations.

6.8.4 INTEGRATED GASIFICATION/COMBINED CYCLE PLANT

A gasification plant can be conveniently and efficiently integrated with a combined Steam Turbine/Gas Turbine cycle.

The gas turbine supplies some of its compressor discharge to the gasifier, and burns the resulting pressurized gas in its combustion chambers. This alleviates the potential mismatch betwen compressor and turbine flow which a gas turbine burning low Btu gas must face. It also provides the gasifier with an economic source of pressurized air. Steam can be bled to the gasifier both from the turbine cycle, and from the low pressure waste heat steam generator evaporator. The sensible heat of the product gas can be utilized to the maximum efficiency that present low temperature cleaning technology allows. Depending on the degree with which the integrated cycle is optimized, it may give a gasification efficiency of 5 to 8% better than the cold efficiency, where cold efficiency is defined as the heating value of gas produced divided by the energy and heating value of coal used to make it.

This bonus in efficiency is significant. The concept of using a high efficiency combined cycle at BTGS integrated with the gasification plant, is worth a brief review. Table 6.1 compares the unfired cycle of G.E., Westinghouse or United Technologies, against an advanced STEAG supercharged fully fired cycle. An advanced (1985) unfired cycle would have an efficiency close to that of the advanced STEAG and is also shown. This table shows that quite substantial savings can be made with the high efficiency cycles, but with a cost of coal delivered to BTGS of less than $1 per million Btu these savings are insufficient to justify the expenditure on a complete new integrated generating plant at BTGS.

TABLE 6.1

	EFFICIENCY OF ELECTRICITY PRODUCTION	EFFICIENCY INTEGRATED GASIFICATION - GENERATION	ANNUAL SAVINGS FUEL $1 PER 10^6	TOTAL PRESENT WORTH SAVING AT 10% DISCOUNT
A U.S. Unfired Cycle	42	34	11.2	$108 x 10^6
B STEAG or Advanced U.S. Cycle	45	39	22.4	$216 x 10^6
C BTGS units firing low Btu gas	36	29		

A high efficiency cycle produces a total P.W. saving of 216 million dollars or about $240/kW on a 10% discount rate, $166/kW on a 15% discount rate. This is clearly not enough to justify demolishing the existing BGTS plant and the substitution of an advanced cycle, but it demonstrates how convincing the economics of advanced high efficiency power cycles can be if $2 or $3 dollar fuel is being used.

6.9 ECONOMIC COMPARISON

In paragraphs 6.9.1 to 6.9.6 the capital costs of boiler conversions for different fuels are detailed.

6.9.1 CONVERSION OF EXISTING BOILERS TO PULVERIZED COAL FIRING

ITEM	CAPITAL COST PER UNIT $,000 SEPT. 1975 Basis Uninflated
P.A. Fans	$ 60,
Burners, pulverizers & coal air pipes	1,200,
Furnace hopper section modification superheater & reheater modifications	480,
Ducting Alterations	200,
Economizer Replacement	1,300,
Sootblower additions	
— in furnace 48 @ 3000	144,
— in convection passes 8 @ 5000	40,
— in economizer section 8 @ 5000	40,
Ash Handling System	2,200,
Coal Supply System	1,000,
Total	6,664,

6.9.2 CONVERSION OF EXISTING BOILERS TO FLUIDIZED COMBUSTION

ITEM		CAPITAL COST PER UNIT $,000 Sept. 1975 Basis Uninflated
Furnace bottom		$ 420,
Furnace nose alterations		420,
Furnace front wall alterations		420,
Collecting header for steam drum		95,
New d/cs & risers to evap. beds		60,
New Line primary S/H to secy. S/H		35,
Fluidized combustors		3,000,
Removal of S/H & R/H pendants sections		21,
Economizer Replacement		650,
Sootblower additions		
— in convection passes	8 @ 5000	40,
— in economizer section	8 @ 5000	50,
Coal Crushers Coal Driers Coal Supply System		1,868,
Ash Handling System		1,000,
Total		8,079,

6.9.3 CONVERSION OF EXISTING BOILERS TO FIRE AIR BLOWN LURGI GAS

ITEM	CAPITAL COST PER UNIT $,000 Sept. 1975 Basis Uninflated
New Fuel pipes	$100,
S/H & R/H surface modifications	20,
Economizer surface modification	10,
Total	130,

6.9.4 CONVERSION OF EXISTING BOILERS TO FIRE O_2 BLOWN LURGI GAS

ITEM	CAPITAL COST PER UNIT $,000 Sept. 1975 Basis Uninflated
New fuel pipes	$ 65,
S/H & R/H surface modifications	10,
Total	75,

6.9.5 CONVERSION OF EXISTING BOILERS TO FIRE O_2 BLOWN LURGI GAS WITH SOME CO_2 REMOVAL

ITEM	CAPITAL COST PER UNIT $,000 Sept. 1975 Basis Uninflated
New fuel pipes	$ 44,
S/H & R/H surface modications	10,
Total	54,

6.9.6 CONVERSION OF EXISTING BOILERS TO CRUDE OIL FIRING

ITEM	CAPITAL COST PER UNIT $,000 Sept. 1975 Basis Uninflated
Plant Equipment Mods.	$ 392,
Oil Pumphouse & oil storage area	19,
Inner floating roofs	41,
Tank agitators	6,
12" Diameter Buried Pipeline	
Overland section from trans-Mountain terminal	75,
Easements	19,
Burrard Inlet Crossing	88,
Pipe to Plant	4,
Engineering (5%)	33,
Contingency (14%)	96,
Subtotal	773,
Electrical & Instrumentation	426,
Miscellaneous	62,
GRAND TOTAL	$1,261,

The costs derived in this section are used in Table 6.2 to establish the total station conversion cost, on a unit basis, for different fuels.

The cost of equipment which is shared by more than one unit is prorated in this table.

The cost of coal supply and storage, together with ash disposal beyond the generating station wall, are not included in Table 6.2 because they are incorporated in the transport costs discussed in Section 8.

Interest during construction is calculated as follows for all the coal burning alternatives.

12% complete at end of year 1
60% complete at end of year 2
100% complete at end of year 3

Interest is calculated at 10% per annum compound. It is assumed that the gas and crude conversions would only take 1 year and they are charged with a total of 5% interest during construction.

The low Btu gas with some CO_2 removal is not considered in table 6.2 because *virtually no modifications are required.*

TABLE 6.2

BTGS CAPITAL COSTS — PER UNIT *(Including Contingencies)*

$,000 Sept. 1975 Basis Uninflated

	A MODIFIED COAL BURNING	B NEW COAL BURNING	C MODIFIED FB	D NEW FB	E LOW Btu GAS O_2 BLOWN	F CRUDE
Existing Boiler Removal (note 1)	--	--	--	--	--	--
Boiler Modifications	7,997	14,375	10,100	12,375	156	1,450
Relocation C.W. Supply*	142	142	142	142	--	--
Stack*	1,630	1,630	1,630	1,630	--	--
Precipitator	2,680	2,680	2,680	2,680	--	--
Relocation Water Treatment Plant*	68	68	68	68	--	--
ID Fans	156	156	156	156	--	--
Precip. and ID Fan Foundations and Structures	230	230	230	230	--	
--						
Land Reclamation*	440	440	440	440	--	--
Turbine Modifications for 70% load	10	--	--	--	10	--
Instrumentation Controls and Data Logging	850	850	850	850	100	--
Miscellaneous (note 2)	100	100	100	100	50	--
Turbine Spares Holdings * (note 3)	550	550	550	550	550	150
Other Spares *	50	50	50	50	50	50
Development Costs (note 4)			*400*	*400*		
CAPITAL COST (including contingency)	14,903	21,271	17,386	19,671	916	1,650

*PROPORTION OF TOTAL STATION COST

NOTES ON TABLE 6.2

Note 1: It is assumed that the boilers would be cut apart quickly without any effort to retain the various sections intact. The cost of dismantling is therefore covered by the value of scrap steel.

If the boilers were to be dismantled carefully so that the parts could be used again, the cost would be $750,000 per unit. This figure is based on quotations from the demolition companies.

Note 2: Ash handling, dewatering and crushing equipment is included in the ash transport costs.

Note 3: Spares holdings. This depends on operating policy. Spare turbine rotors are covered for all alternatives for which a substantial investment is required, that is for all except the crude oil conversion.

Note 4: Prorated development costs of fluidized bed units have been included on the assumption that the units would be prototype.

Note 5: Contingency included at 20% throughout except:

New 150 MW boiler	—	15%
Boiler and fluidized bed conversion	—	25%

Table 6.3 presents boiler, turbine and overall plant efficiencies for different fuels.

These figures are based on turbine and boiler efficiencies which include manufacturer's margins. In fact, the net heat rate with gas has elsewhere been assumed to be 9600 Btu/kW hr.

TABLE 6.3
PLANT EFFICIENCIES

	BOILER EFFICIENCY %	TURBINE HEAT RATE	AUXILIARY LOAD %	STATION NET HEAT RATE
Pulverized Coal	84	8060 (1)	5.5	10,123
Fluidized Combustion	84	8050	8	10,350
Natural Gas	85	8050	3.5	9,802
Air Lurgi	83	8060 (1)	3.5	10,050
O_2 Lurgi	82	8060 (1)	3.5	10,173
Crude Oil	85	8050	3.5	9,802

Note 1: Turbine modified for throttle governing.

7.0 SUITABILITY OF EXISTING PLANT FOR ADDITIONAL 30 YEARS OPERATION

7.1 BRIEF OPERATING HISTORY

Since the first Burrard unit was taken over in 1963, the plant operation has been subjugated to the requirements of an essentially hydro-electric system. The plant load factor has varied widely from good to poor water years, and has also been affected by the timing of B.C. Hydro's new plant installation.

A condensed operating history of the machines is shown in the table below:

Unit No.	3	2	1	4	5	6
Year Commissioned	1962	1963	1966	1967	1968	1975
Hours Run — approx. to end 1974	45,500	44,900	33,500	24,300	17,500	--

These figures show that the overall utilization or operational factor for the oldest unit, unit 3, was 42% in the 12-year period 1963-1974 inclusive. Unit 2 had a similar utilization. These relatively low figures incorporate periods of continuous base load, and of almost no operation; in the four year period 1965-1968 the utilization for unit 3 averaged above 80%, and in 1966 reached 92.9%. In that year, the capacity factor was over 75%. At the other end of the scale, in 1974 the five units at the station only ran an aggregate 3,800 hours, and in 1971 only 6,700 hours.

The overall station capacity factor from August 1, 1962 to March 31, 1974 was just under 30%.

In the above statements, utilization is defined as hours run as a precentage of the hours in the period. Capacity factor is energy produced as a percentage of maximum possible production at rated output.

In contrast, Calgary Power's Wabamun unit 3 (identical to Burrard unit 3) has operated with a high annual load factor and in its 12 year life has run about 95,000 hours.

7.2 MODE OF OPERATION

During its operating history, the Burrard units have run in many different modes, including:

- continuous base load
- base load with load decreased at night
- spinning reserve with peak cycling
- two shift operation.

Two shift or cycling operation is arduous on any high temperature equipment. Its effect can be seen in short-term and long-term effects; in the short term, machines on cycling duty suffer from more frequent technical problems which result from the continuous thermal stresses and changes in duty imposed on them. In addition, operating errors almost always occur during a mode of change. In the long-term, thermal cycling uses up the creep life of the high temperature components, in particular the main elements such as the superheater and reheater tubes, H.P. and I.P. casings, valve chests and rotors. Turbine manufacturers now define the creep life of their machines in terms of the number of thermal cycles they can withstand at various temperature gradients. A typical machine running with its main components at about 400°F may use up all its creep life in 300 starts at 300°F per hour or 3000 starts at 180°F per hour.

A memo by the Station Manager on January 28, 1974 stated:

"There are several areas in which high maintenance has been required which can be attributed to single- and two-shift-operation.

Large electric motors (900-2700 HP) have suffered extensive damage and have required substantial re-design due directly to the number of times they have been started. Maintaining 600-700 psi on oil fuel in boilers to reduce start-up time and temperature stresses has created highly corrosive conditions in the gas outlet sections and extensive deterioration of the ducting has started. The difficulty in inhibiting the high-pressure feedwater heaters during short-term shut downs has already reduced their ultimate life expectancy due to corrosion and temperature stresses during transient conditions has predisposed flanged joints towards frequent leakages.

However, although serious in themselves, these problems are peripheral to those normally expected during this type of operation. Typically, one would expect to find cracks developing in the more massive components such as turbine shafts, turbine casings and steam valve chests. These have not appeared in the Burrard units as yet, indicating that the operating guidelines previously mentioned are probably soundly based."

7.3 MAJOR PROBLEM AREAS

The equipment which has given the majority of the trouble at Burrard is shown in the table below:

CAUSES OF OUTAGE TIME (%)

Unit No.	3	2	1	4	5
Turbine	76	75	12	7	-
Generator	5	9	-	30	79
Boiler feed pump motors	12	12	47	53	19
Boiler	1	2	23	1	1
Other	6	2	18	9	1

Other items which are not shown above have given trouble, but no other equipment has caused significant or chronic difficulties or has given signs that long-term trouble might be expected.

Of the problems shown above, those related to the boiler feed pump motors have been rectified by the rewinding of the stators and rotors by the manufacturer, and there is no reason to expect that unusual difficulties will arise in an additional 30/35 years of operation.

The boilers have given little trouble at this plant. These units are very conservatively designed by modern standards. On these units, only the superheater and reheater tubing are creep dependent and up to ½ of the theoretical life of the tubes may have been used on the older units. With design margins the creep life should, in reality, be far more than 100,000 hours, but it must be anticipated that the life of these tubes would be exceeded in 30/35 years future operation. The other parts of the boiler are quite suitable for an additional 35 years of operation at rated conditions.

The turbine generators have given most of the technical troubles experienced by the Burrard plant and these are, therefore, reviewed separately below.

7.4 HISTORY OF TURBINE GENERATORS

The turbine generators were manufactured by Associated Electrical Industries' Turbine-Generator Division, a group formed by the amalgamation of Metropolitan Vickers and B.T.H. Turbine interests. At the time the turbines were designed, in the late 1950s, Metropolitan Vickers had a very high reputation which had been gained by the excellent performance of its 30-60 MW machines. In the late 1950s, turbine manufacturers faced a very rapid escalation in machine size. This in itself presented a severe problem, but for companies like M-V which were export-orientated, the problem was magnified because they accepted a number of orders for completely different machine designs, all of which were larger than they had previously built. Their engineering department, which had designed few completely new machines in the last few years, was suddenly faced with a number of totally new designs in a very short time span.

In the late 1950s M-V, in common with most turbine manufacturers, had a very sketchy knowledge of blade and diaphragm vibration patterns. Experience with small turbines had shown that if certain rules were strictly observed, vibration problems were generally avoided — one of the prime rules was a limitation in the overall blade bending stress. The increase in unit size from 60 MW to 120/150 MW was of such magnitude that many of the old design criteria proved inadequate. Thus, M-V machines designed at that time all suffered from vibration problems together with others which are listed briefly below:

1. Blade vibration problems; generally associated with shorter blades and diaphragm excited frequencies, i.e. those of about 100 cycles per revolution.
2. Inadequate shrouding design.
3. Poor thermal efficiency caused by a number of factors.
4. Inadequate stiffening of LP structure.
5. Poor dynamic design. (partly associated with (4)).

In addition to these factors, all machines of that generation suffered from the uncertain quality of castings and forgings, which resulted from the difficulties experienced by the steel companies in meeting the requirements of very rapid escalation in sizes. They also suffered from a universal lack of knowledge about thermal stress in large casings and valve chests and the thermal life of such components.

Most of the above problems have been effectively solved and do not appear to affect the ability of the Burrard units to operate for a further 30/35 years. The manufacturer now has a sophisticated understanding of blade vibration problems, and, in the existing build of the machine, such difficulties have largely been solved, although a reservation should be held with respect to I.P. stage 5. The thermal efficiency has been upgraded, but will never approach the optimistic value originally quoted. This does not affect reliability. Shrouding designs have been strengthened where necessary, and this should be of little concern in the future. Where such problems, and other minor mechanical problems, have not been completely solved, they can be resolved with a modest expenditure in spare parts.

The Burrard turbines sometime show dynamic instability, due to oil whirl, which is very sensitive to vertical bearing alignment. This problem is, in part, due to the design of the I.P. casings which are too flexible. This stability problem can be cured by adjustments to alignment and bearing loadings. It is not likely to be a problem which significantly effects the future life or reliability of the machines.

7.5 TURBINE CREEP LIFE

The economic viability of converting Burrard to an alternate fuel is likely to be based on operating the machines at base load. Future demands on machine's creep life will therefore be reduced. The machines should be able to operate satisfactorily for an additional 30 years at base load. If they are to be two shift operated there may be areas where the creep life would be exceeded. In this case, it is recommended that the manufacturer be asked to do a detailed study of creep life, covering:

1. HP rotor.
2. IP/LP rotor. These machines are of the three exhaust type, with combined IP/LP rotor. This design has the intrinsic problem that the same rotor, the IP/LP, must accept 1000°F steam at one end and the high radial stresses of very long blades at the other. The rotor must therefore be a compromise between high temperature, high creep life steel of a normal HP rotor, and the high tensile strength of a normal LP rotor. This is a difficult compromise even with today's technology.
3. The valve chests may eventually suffer from shrinkage or cracking. To date the experience at Burrard has been good, and chests are items which can be replaced if necessary, without too great an expense.
4. High temperature casings.

7.6 ALTERNATORS

The possibility of insulation tape separation in extended service has been raised, but the manufacturer states that experience of other machines operating at the same current density and heat dissipation levels shows the danger to be low at 30 psig hydrogen pressure. Other machines have operated successfully for 115,000 hours and 560 starts without trouble. Asphalt leakage has been a problem on unit 5. Similar machines in the U.K. and Canada have not suffered from this problem, and the manufacturer does not consider it a long-term danger if the alternators are operated at rated H_2 pressure.

7.7 SPARES HOLDING

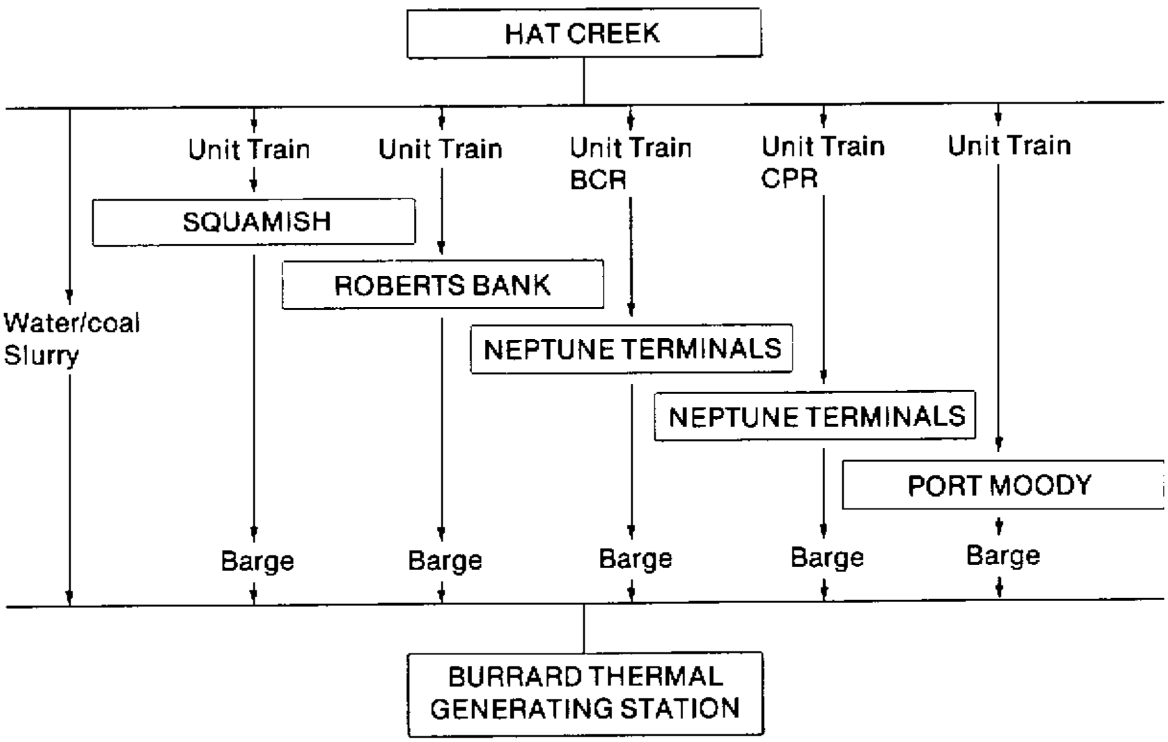
If the Burrard plant is to run for an additional 30 years, it would be wise for B.C. Hydro to invest in an increased stock of spare parts. The cost of these spares is included in the estimates in Sections 3 & 6.

8.0 TRANSPORT AND STORAGE

8.1 COAL TRANSPORTATION ALTERNATIVES

8.1.1 DEFINITION OF ALTERNATIVES

The following block diagram illustrates the various coal transportation media and routes considered worthy of examination and described in this study. Each of these alternatives is examined on the basis of capital costs, overall costs per ton and per million Btu's including capital charges and operating costs, environmental implications, storage capacity, system reliability, and long range B.C. Hydro planning advantages and disadvantages.



8.1.2 QUANTITIES

The evaluation of combustion alternatives described earlier in this study reveals that a fluidized bed conversion of the existing boilers will produce 100% of the station output, and that a pulverized coal conversion will yield approximately 70% of the existing 900 MW output. The building of either new pulverized coal boilers or new fluidized bed boilers will yield 100%. Therefore, for the two predictable station rated outputs of 70% and 100%, the following table shows the daily and annual coal consumption tonnages for various average annual capacity factors.

TABLE 8.1
COAL QUANTITIES

RATED OUTPUT %	AVERAGE ANNUAL CAP. FACTOR %	AVERAGE DAILY COAL CONSUMPTION TONS X 10^3	ANNUAL COAL CONSUMPTION TONS X 10^6
	60	6.65	2.43
	70	7.76	2.83
70 (630 MW)			
	80	8.87	3.24
	100	11.09	4.05
	60	9.50	3.47
	70	11.09	4.05
100 (900 MW)			
	80	12.67	4.63
	100	15.84	5.78

The calculation of effective coal prices at the powerhouse is based on 70% and 100% rated output for an average annual capacity factor of 70%. This data is then plotted to illustrate the approximate effect of annual coal consumption on overall coal cost per ton and per million Btu's.

8.1.3 ECONOMIC SUMMARY

8.1.3a CAPITAL COSTS

Table 8.2 below shows the estimated capital costs incurred in the implementation of the various coal transportation alternatives. Included in these costs are all installations from the minehead to the station bunkers. These estimates conform to the B.C. Hydro base engineering and cost data requirements by including contingencies, engineering costs, corporate overhead and interest during construction. Table 8.2 is a summary of more detailed estimates which are included in Appendix 7.

TABLE 8.2
CAPITAL COSTS Coal Transportation Alternatives

ALTERNATIVE	1975 CAPITAL COST $ x 10^3
Slurry	140,753
Unit Train→SQUAMISH→Barge	86,620
Unit Train→ROBERTS BANK→Barge	71,662
BCR Unit Train→NEPTUNE→Barge	44,126
CPR Unit Train→NEPTUNE→Barge	60,331
CPR Unit Train→PORT MOODY→Barge	95,714

The difference between the B.C.R. and C.P.R. costs in the Neptune Alternatives is explained in Section 8.1.4.

8.1.3b TOTAL FUEL COSTS

Tables 8.3 and 8.4 show the total fuel costs respectively for 900 MW at 70% capacity factor and 630 MW at 70% Capacity factor.

As shown in detail in Appendix 8, the units costs include the minehead coal cost of $3.00 per ton.

TABLE 8.3
TOTAL FUEL COST 900 MW @ 70% CF, 4.05 x 10^6 tons/yr.

ALTERNATIVE	UNIT COST	
	$/TON	¢/Btu x 10^6
Slurry	8.34	66.88
Unit Train→SQUAMISH→Barge	9.07	72.57
Unit Train→ROBERTS BANK→Barge	10.57	84.88
BCR Unit Train→NEPTUNE→Barge	9.41	74.66
CPR Unit Train—NEPTUNE—Barge	10.22	82.39
Unit Train→PORT MOODY→Barge	10.07	80.48

TABLE 8.4
TOTAL FUEL COST 630 MW @ 70% LF, 2.83 x 10^6 TONS/YR.

ALTERNATIVE	UNIT COST	
	$/Ton	¢/Btu x 10^6
Slurry	9.13	73.16
Unit Train →SQUAMISH →Barge	10.49	84.05
Unit Train →ROBERTS BANK →Barge	12.00	96.15
BCR Unit Train →NEPTUNE →Barge	10.33	82.81
CPR Unit Train →NEPTUNE →Barge	11.51	92.15
Unit Train →PORT MOODY →Barge	11.57	92.71

Figure No. 1 shows the expected change of total fuel costs as a function of capacity and load factor.

8.1.4 GENERAL DESCRIPTION

8.1.4a SLURRY

Appendix 11 of this report gives a detailed design description and cost breakdown of a slurry system from Hat Creek to the BTGS. Total fuel costs as described in Section 8.3.1, are 13% to 27% lower for slurry than for other systems shown. Another economic advantage of a slurry is that the system operating costs are less vulnerable to inflation than the unit train and barge combinations. The slurry system offers relatively high reliability of fuel supply from the point of view of labour difficulties and climatic conditions.

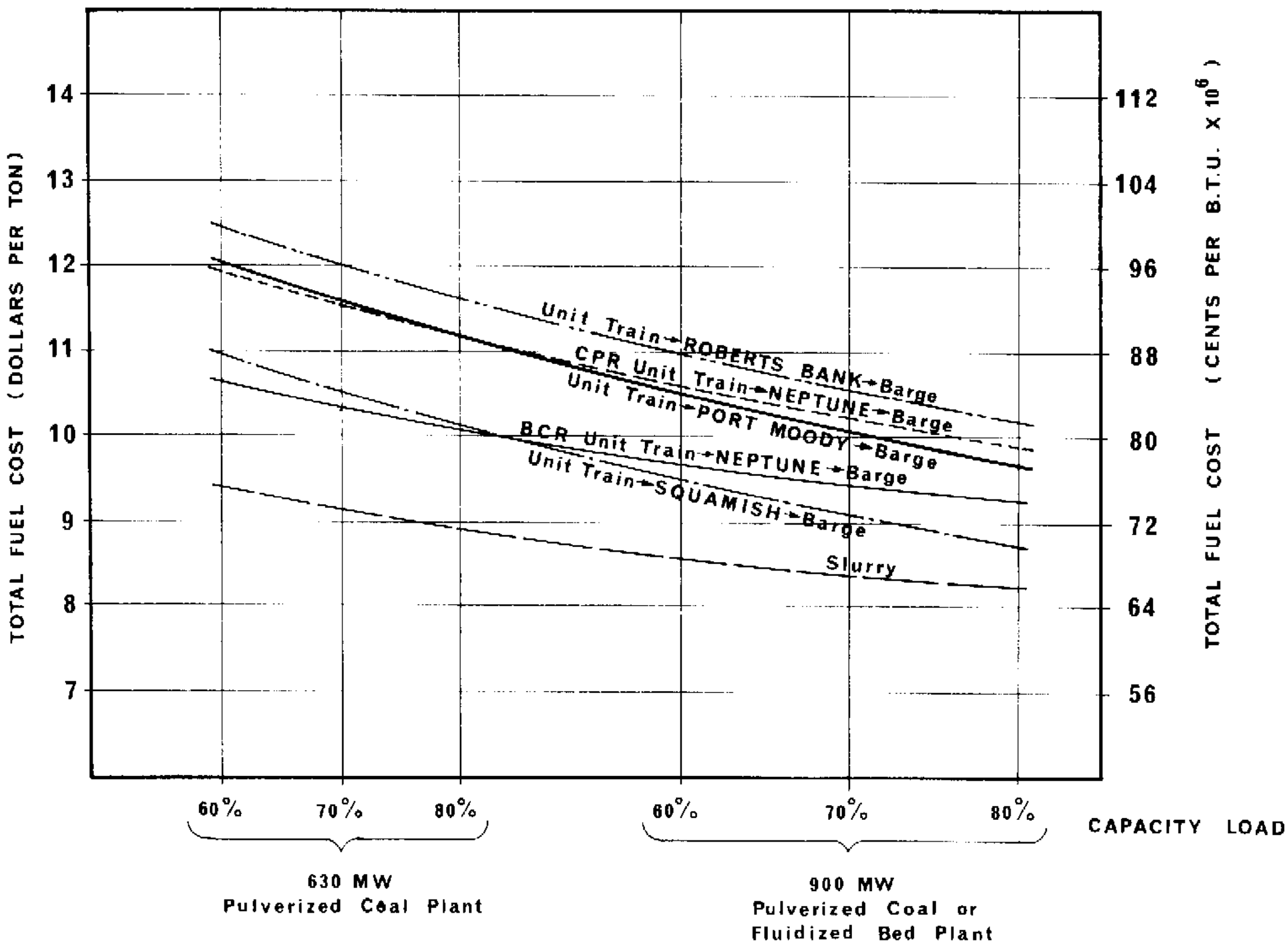
The major difficulties associated with supplying coal by pipeline to a thermal generating plant are those related to the water separation process and the supply of coal, at the optimum moisture content, to the pulverizers.

The primary separation can be achieved by filters or centrifuges. Operating experience is limited to the Mohave Station which uses centrifuges, but their experience with operation and maintenance has not been satisfactory and they have stated they would not use centrifuges on any subsequent installation. The moisture separation which filters can achieve is limited, but as slow speed machines their reliability is higher. With filters, secondary drying may be required before the coal is conveyed to the bunker and mill system.

Moisture content affects the way in which fuel flows from bunkers, through feeders into the mills. The mill inlet air temperature is also dependent on the moisture content of the fuel and very high air temperatures create their own problems with mill operation.

With regard to flowability in the bunkers Stock Equipment Company and Combustion Engineering Inc. recently funded a joint study examining this difficulty.

FIGURE 8.1
TOTAL FUEL COST VARIATION



The parameters found to be important in the coal flowability were surface moisture, inherent moisture, inherent plus surface moisture, bunker conical angle, cone material (mild steel v. stainless steel) welding method, and size of coal particles.

Basic conclusions of the Stock Equipment and Combustion Engineering study were that reasonable flowability was achieved where surface moisture was held within 6% to 10% and where the toal surface and inherent moisture was between 29% and 33%. It is difficult to maintain moisture contents to within these limits. Slight changes in coal fineness change the resulting moisture content for a fixed set of dewatering conditions. It was found that steeper bunker conical slopes in the area of 70 degrees rather than 60 degrees combined with stainless steel rather than mild steel and flush welding methods all reduced the frequency of hangups within the bunkers.

The water flow required to supply station capacity of 900 MW at 100% MCR is 2,960 U.S. gpm. For the pulverized coal conversion of existing boilers which will yield a station capacity of 630 MW, the required water flow is 2,072 U.S. gpm. Availability of this water supply from the Thompson River supplied to the mine head will have to be evaluated in the light of other Hat Creek development and associated water requirements.

Disposal of these quantities of water into the Burrard Inlet represents a further disadvantage. Existing systems of centifuges or cyclones can reduce particulate contamination of the water to between 7 and 9 parts per million. Furthermore, when this very small quantity of coal particulate suspended in the discharge water is exposed to the saline inlet waters, the particulate will precipitate from suspension and settle on the bottom or be carried out by tidal currents. It is possible that some may float. Consequently, the discharge water may be objectionable from the point of view of particulate. At this time, however, the principal area of concern is dissolved solids contained within the discharge water. These contaminants cannot practically be removed in the treatment process.

The Slurry alternative requires extra study before it can be firmly recommended. In particular, tests should be made on the coal (and ash) solubility and the possible flotation of coal particulate should be considered.

Drawing A0036 500 SK13, shows a typical layout for dewatering plant. Slightly more than 22 acres are required. The amount of water front reclamation at the BTGS site for such a water treatment plant is approximately five times as great as that for a dry coal storage area described in the barge transportation schemes. The environmental and nautical infringements associated with site reclamation are therefore significantly greater in the case of the slurry transportation alternative. The environmental significance of reclamation in general is described in Section 10.

8.1.4b UNIT TRAIN—SQUAMISH—BARGE

As is indicated in Figure 8.1, and Section 8.1.3, of the Unit Train to Barge alternatives, the BCR Unit Train—NEPTUNE—Barge and the Unit Train—SQUAMISH—Barge alternatives have the lowest unit costs. The SQUAMISH alternative is 3.7% lower than the BCR NEPTUNE alternative at 4.05 million tons per year, and 1.5% higher at 2.83 million tons per year.

Unit costs for the SQUAMISH alternative are more sensitive to a decrease in annual tonnage than those for the NEPTUNE alternative due to the Barging costs. The SQUAMISH alternative requires the use of three dumb barges, the size of which are dependent upon the daily tonnage required. The most economical operating condition is to have one barge in each of the loading and unloading stages and one on route at all times. The tug operation is $6,000 per day and does not decrease when the barge size itself is decreased from 8,000 DWT to, say, 6,000 DWT in the case of a lower annual tonnage. *It is this lack of proportionality between the tug operation costs and coal* tonnage which makes the unit costs for the SQUAMISH alternative more sensitive to decreasing tonnage than those for the NEPTUNE alternative. NEPTUNE is less sensitive to the tug effect on costs because the round trip is one-sixth the distance and the tug cost is reduced to $3,500 per day due to the more sheltered waters and significantly reduced barge size.

The Squamish alternative provides for a maximum of 500,000 tons of live storage at the barge loading terminal. The amount of live storage which can be provided at BTGS depends on whether any land fill is used to increase the storage area. Using the existing shoreline 110,000 tons can be stored. Figure 8.4 shows an aerial view of the plant with an overlay showing 110,000 tons of live storage. Figure 8.2 shows the operating reserve which different coal storage quantities represent. It can be seen that the 500,000 ton Squamish storage represents about 31 days, at 900 MW while 190,000 and 110,000 tons at BTGS represent an addition 12 and 7 days which, when supplemented by existing oil storage, give 22 and 17 days isolated operation.

Figures 8.5 and 8.6, show various aerial views of the BTGS site.

The Unit Train—Barge transportation system described in the SQUAMISH and PORT MOODY alternatives are the only ones which provide a B.C. Hydro owned and operated tidal water coal terminal. There are significant long range power development implications inherent in this advantage. These implications include lower incremental transportation costs to possible future Vancouver Island Thermal Stations and lower incremental transportation costs associated with power development at Squamish itself.

8.1.4c UNIT TRAIN—ROBERTS BANK—BARGE

The ROBERTS BANK alternative has higher coal unit costs than any of the other alternatives considered. Relative to SQUAMISH, ROBERTS BANK unit costs are 16.5% and 14.4% higher respectively for 4.05 million tons per year and 2.83 million tons per year. This is partly due to the combination of the longer Unit Train distance of 205 miles combined with the 39 nautical mile barge trip. The total distance for the ROBERTS BANK alternative is 250 miles which compares with 187 miles for the SQUAMISH alternative.

ROBERTS BANK, PORT MOODY, AND CPR NEPTUNE alternatives all require a rail spur-line from HAT CREEK in an easterly direction to connect with the existing CPR or CNR lines. The cost of such a line has been estimated at $22 million which compares with $10.5 million for a spur-line to the west of HAT CREEK connecting with the BCR line. The $22 million for an eastern rail spur-line, which is used in those transportation alternatives using the line, is approximate. The terrain between HAT CREEK and the CPR line indicates that substantial tunnelling will be required as well as a fairly indirect route. The estimate provides for a total rail length of 21 miles including eight miles of tunnels. Tunnelling estimates were based on recent BCR costs for the Horseshoe Bay tunnel.

Storage for the ROBERTS BANK alternative will be equivalent to the SQUAMISH alternative with 500,000 tons provided at the terminal and an additional 190,000 or 110,000 tons at the BTGS site.

Figure 8.4

B.T.G.S.
Site Modifications

Aerial View

FIGURE 8.2

OPERATING RESERVE, 900 MW PLANT

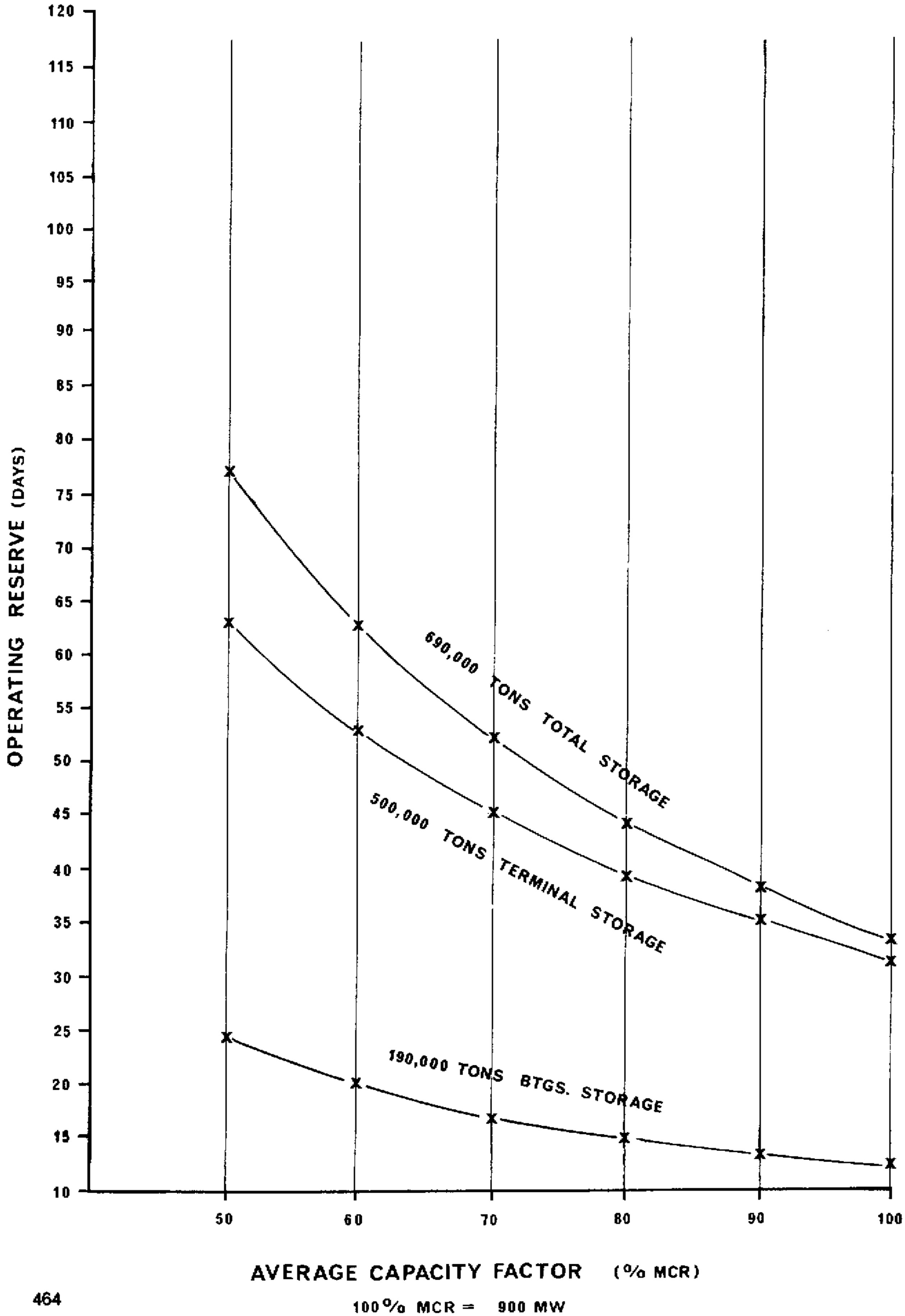


FIGURE 8.3

OPERATING RESERVE, 630 MW PLANT (PULVERIZED COAL BOILER CONVERSION)

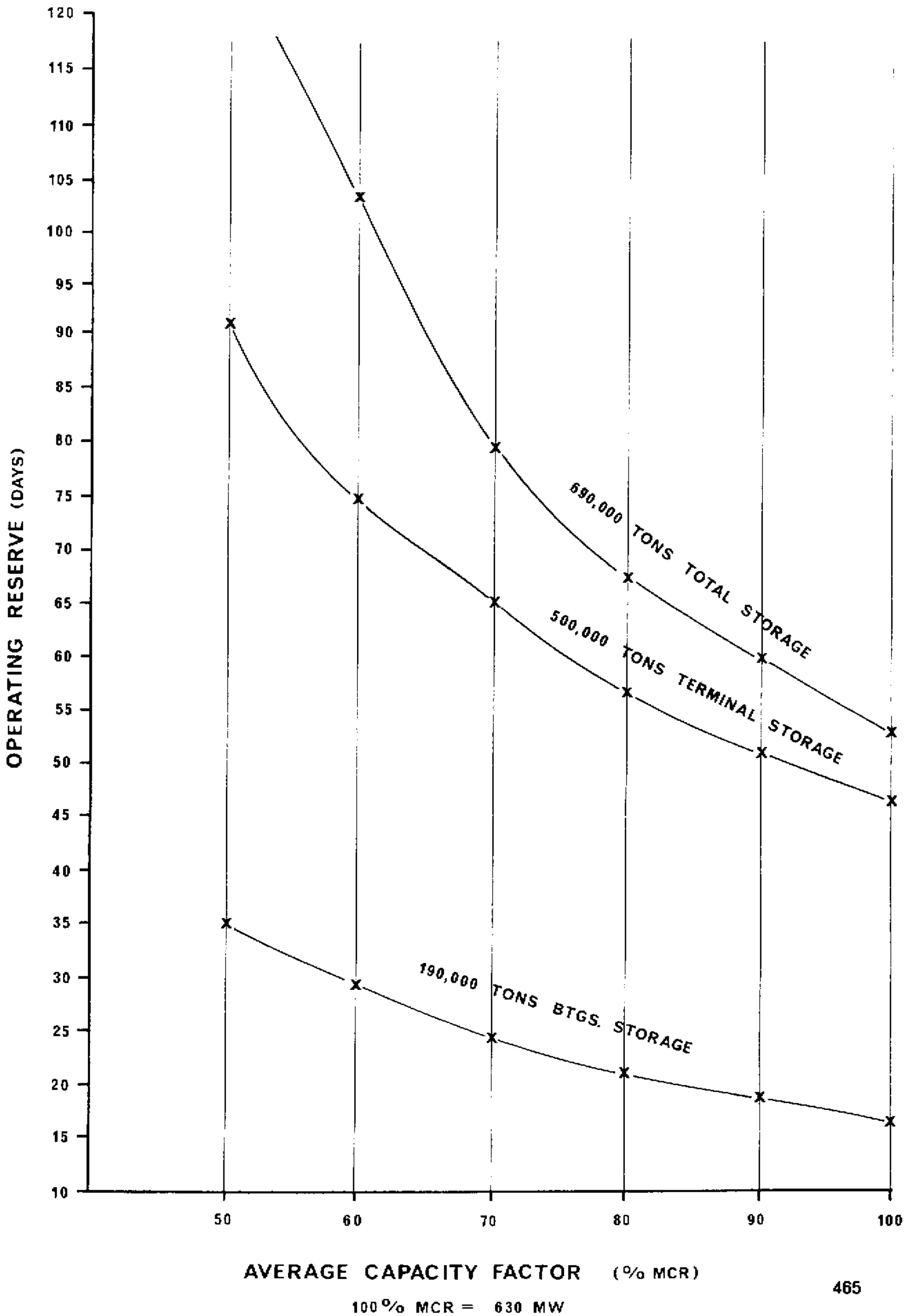


FIGURE 8.5

FIGURE 8.6

FIGURE 8.7

8.1.4d BCR UNIT TRAIN—NEPTUNE—BARGE

As shown in Figure 8.1, the BCR—NEPTUNE alternative has slightly lower unit costs than the SQUAMISH alternative for a 630 MW plant and slightly higher costs for a 900 MW plant.

Neptune terminals, shown in Figure 8.7, have offered their entire North Vancouver facility to B.C. Hydro at a current service charge of $1.25 per ton. This charge includes the unloading of unit trains, coal storage, reclaiming, and the loading of barges. It compares with $0.90 for the same services at Roberts Bank.

Storage facilities exist for approximately 500,000 tons at NEPTUNE in addition to the storage which can be provided at the BTGS site. The 7.1 nautical mile barge trip from NEPTUNE to the BTGS may result in a very slightly more reliable barge supply service than in the cases of ROBERTS BANK or SQUAMISH. The NEPTUNE advantage of smaller barges with shorter cycle times and lower tug charges have been accounted for in the derivation of unit costs.

8.1.4e CPR UNIT TRAIN—NEPTUNE—BARGE

This alternative was examined exclusively to show the cost penalty incurred by approaching NEPTUNE from the east via CPR and the second narrows crossing rather than the environmentally vulnerable passage through North and West Vancouver. Relative to the BCR route to NEPTUNE, the CPR route increases costs by 8.7% at 4.05 million tons per year and 11.4% at 2.83 million tons per year. This increase in cost is due to higher capital charges of a more expensive rail spur-line at Hat Creek to the CPR line, combined with a longer travelled distance.

8.1.4f UNIT TRAIN — PORT MOODY — BARGE

Drawing Numbers F0036-500-SK3 and SK4 show alternatives for a coal terminal development on the PORT MOODY waterfront directly to the south of the BTGS. Each provides for a total of 500,000 tons of coal storage. SK3 shows the terminal and storage area to the north of the rail line while SK4 shows it to the south. The environmental comparison of these alternatives is presented in Section 10.

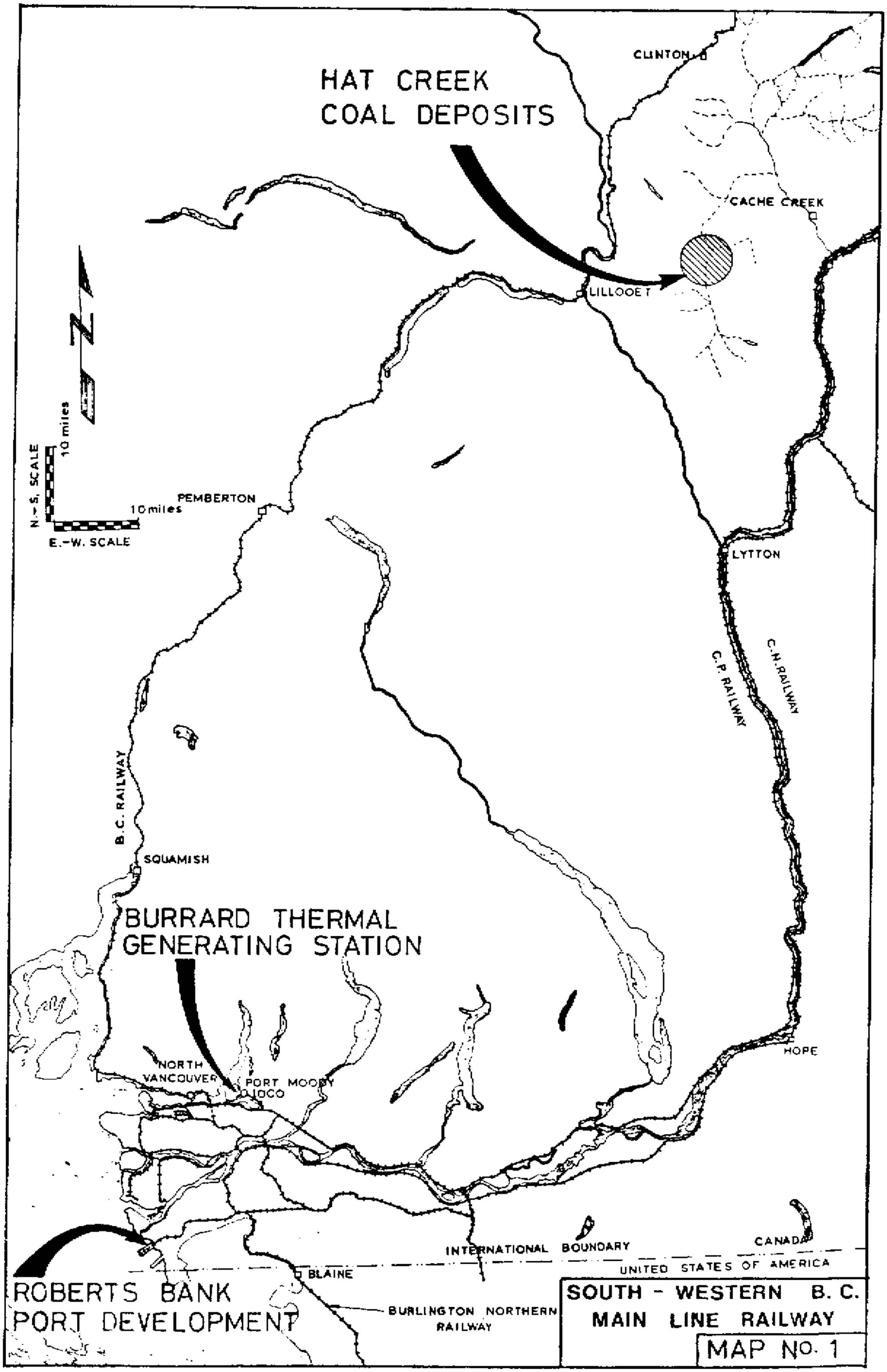
The main advantage to such a PORT MOODY development is to locate the terminal on an existing Unit Train line within close proximity of the BTGS. This reduces the barge operation to a shuttle service of two 2,000 DWT self-unloading covered barges. This simplified tug and barge operation may improve system reliability if the tug as well as the barges can be B.C. Hydro owned and operated. At $10.07 per ton for 4.05 million tons per year, this alternative is 11.0% more costly than the SQUAMISH alternative. The higher unit costs are due to higher capital charges associated with the more costly Hat Creek spur-line to CPR, capital charges of the PORT MOODY terminal, and the longer total travelled distances.

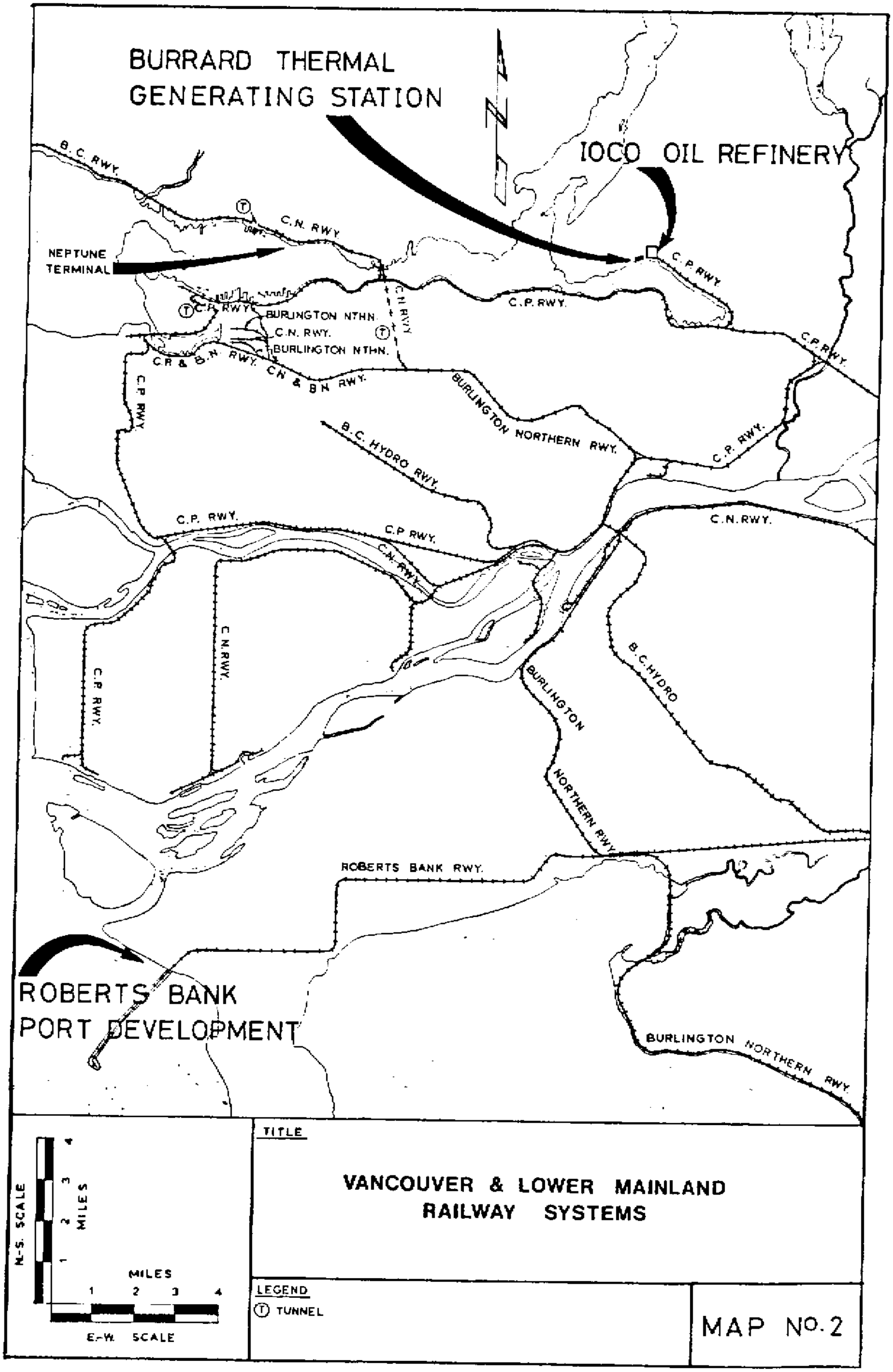
Maps 1 and 2, following, show the rail routes which pertain to the various alternatives.

8.1.5 OTHER TRANSPORTATION CONSIDERATIONS

8.1.5a PORT MOODY TUNNEL

Some evaluation was given to a dry conveyer tunnel from the PORT MOODY coal terminal storage area to the BTGS as an alternative to a barge shuttle service.


HAT CREEK
COAL DEPOSITS
CLINTON
CACHE CREEK
LILLOOET
N
N.-S. SCALE
10 miles
10 miles
E.-W. SCALE
PEMBERTON
LYTTON
C.P. RAILWAY
C.N. RAILWAY
B.C. RAILWAY
SQUAMISH
BURRARD THERMAL
GENERATING STATION
NORTH
VANCOUVER
PORT MOODY
IOCO
HOPE
INTERNATIONAL BOUNDARY
CANADA
UNITED STATES OF AMERICA
BLAINE
ROBERTS BANK
PORT DEVELOPMENT
BURLINGTON NORTHERN
RAILWAY
SOUTH - WESTERN B. C.
MAIN LINE RAILWAY
MAP No. 1


BURRARD THERMAL GENERATING STATION
IOCO OIL REFINERY
NEPTUNE TERMINAL
B.C. RWY.
C.N. RWY.
C.P. RWY.
BURLINGTON NTHN.
C.N. RWY.
BURLINGTON NTHN.
C.P. & B.N. RWY.
CN & BN RWY.
BURLINGTON NORTHERN RWY.
B.C. HYDRO RWY.
C.N. RWY.
C.P. RWY.
C.N. RWY.
B.C. HYDRO
BURLINGTON NORTHERN RWY.
ROBERTS BANK RWY.
ROBERTS BANK PORT DEVELOPMENT
BURLINGTON NORTHERN RWY.
MILES
N-S. SCALE
E-W. SCALE
TITLE
VANCOUVER & LOWER MAINLAND RAILWAY SYSTEMS
LEGEND
Ⓣ TUNNEL
MAP No. 2

Investigation revealed that soft sedimentary materials lie beneath the inlet water to a depth of some 200 or 300 feet which prohibits the conventional boring method for a tunnel. The technical feasibility of sinking precast tunnel sections to form a tunnel is somewhat questionable due to the very poor load bearing characteristics of the large silt deposits within the sedimentary material. For these reasons a dry conveyer tunnel was given no further consideration.

8.1.5b AERIAL TRAMWAY

Another alternative to the barge shuttle service to transport coal from the PORT MOODY terminal to the BTGS is an aerial tramway across the narrowest section of the inlet which is approximately two miles to the west of the site. Such an aerial tramway would be capable of the tonnage rates required for the station. On the south side, conveyers would be used, possibly parallel to the rail line. The topography on the north shore is difficult from the point of view of conventional conveyers and may require the continuation of the aerial tramway for the two miles eastward to the BTGS site, or as an alternative, a tunnel may be provided.

This alternative is considered undesirable environmentally and at this time does not warrant an accurate cost evaluation.

8.1.5c SHORT RUN SLURRY

As an alternative to barge transportation of the coal from the terminals considered, a slurry system in which the contaminated slurry water is recycled may be considered. Based on the slurry investigation for coal transportation from Hat Creek to the BTGS, a very short distance slurry system is not economic. The high capital costs for a slurry preparation plant, de-watering plant, and supply and return pipelines are not offset by any significant operating cost saving relative to a barge shuttle over the same short distance. The general consensus of opinion in the pipeline coal industry is that the capital costs and operating difficulties can be justified only when distances significantly in excess of 200 miles are considered. Only in such cases are the operating savings of the pipeline system, relative to conventional media, sufficient to warrant the disadvantages.

8.1.5d SPUR-RAIL LINE TO THE BTGS

The BTGS can potentially be reached by rail from either east or west. From the west, previous studies have been executed examining an Indian Arm causeway. This involves a 3.4 mile extension of the CNR tracks from the north end of the Second Narrows bridge eastward along the north shore of the Inlet, across a 1.0 mile causeway to the Borrow Area, and through a 2.0 mile tunnel to the BTGS. The line would then link with the CPR track in Ioco. Studies by Swan-Wooster & Wenco from 1967 to 1970 have examined this concept. To the present, it has not been accepted as a viable development and is given no further consideration in this report.

From the east the CPR lines can be extended through the Imperial Oil property to the BTGS. At this time, opinions differ as to whether unit train operations would be hazardous to the refinery. In order to unload coal at the station from a one mile long unit train, (10,000 tons of coal) one mile of track would be required to the west of the station. This could either be straight or in a loop. Due to the topography to the west of the site, the entire mile would have to be within a tunnel through the rock. An additional ten acres of reclaimed land would have to be made available for the unloading apparatus and track laydown.

Less track would be required to the west of the site if it was feasible to build a shuttle yard to the east of the site at the end of the Inlet and break the 100 car unit train into somewhat smaller sections. This, however, would significantly disturb the economies of unit train operation and would result in more frequent rail traffic through the residential area to the east of the plant.

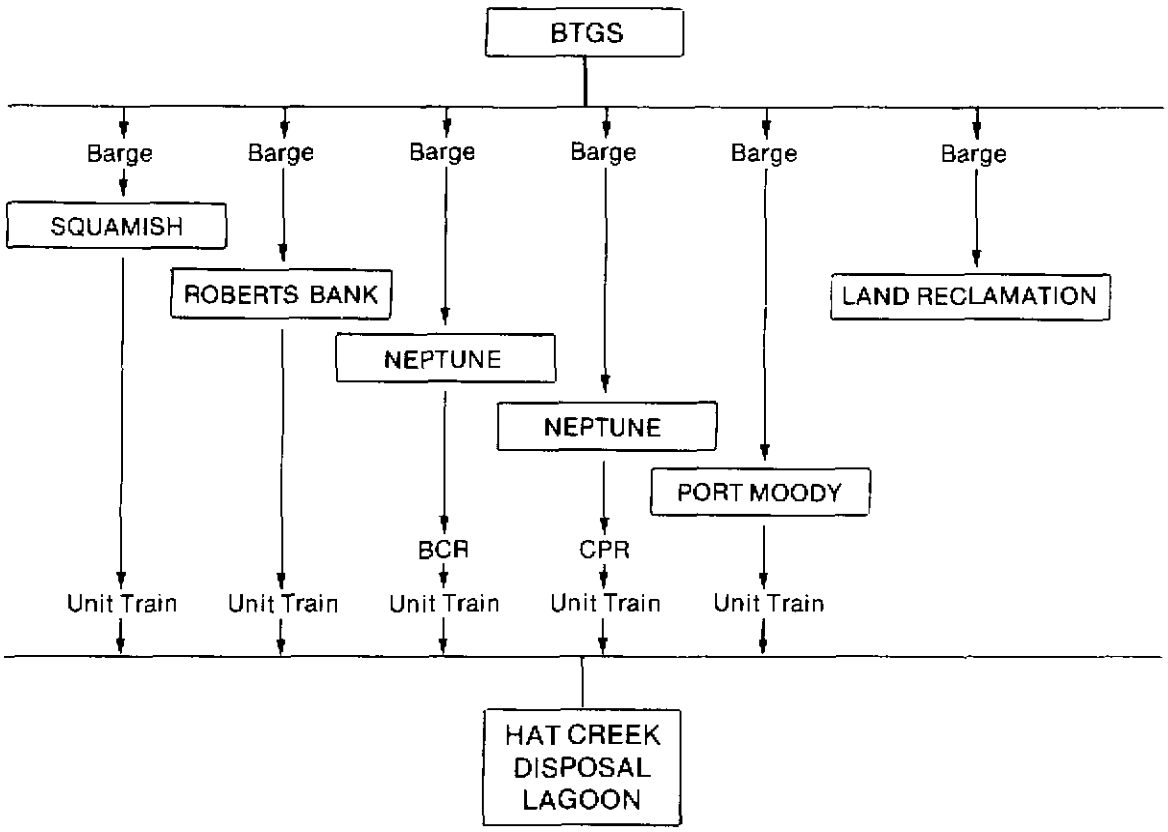
8.1.6 COAL STORAGE

Figures 8.2 and 8.3 following show the reserve periods in days for various plant ratings and capacity factors for the storage amounts identified in the alternatives discussed.

8.2 ASH TRANSPORTATION ALTERNATIVES

8.2.1 DEFINITION

The following flow diagram illustrates the ash disposal alternatives.



8.2.2 QUANTITIES

For the rated outputs and average capacity factors indicated the following Table 8.5, gives the corresponding ash production tonnages for the periods stated. These tonnages assume that Hat Creek coal, as delivered to the BTGS, has an average ash content of 26%. This gives a small margin over the average value of 25% assumed for these studies.

TABLE 8.5
ASH QUANTITIES

RATED OUTPUT (%)	AVERAGE ANNUAL LOAD FACTOR (%)	AVERAGE DAILY ASH PRODUCTION (TONS X 10^3)	ANNUAL ASH PRODUCTION (TONS X 10^6)
70 (630 MW)	60	1.73	.63
	70	2.02	.74
	80	2.31	.84
	100	2.88	1.05
100 (900 MW)	60	2.47	.90
	70	2.88	1.05
	80	3.29	1.20
	100	4.12	1.50

8.2.3 ECONOMIC SUMMARY

8.2.3a CAPITAL COSTS

The capital costs shown in Table 8.6 below have been derived for the Barge—Reclamation Site, and Barge—TERMINAL—Unit Train alternatives for ash transportation. The derivation of these costs is shown in Appendix 9. All costs include contingencies, engineering, construction supervision, corporate overhead and interest during construction. The costs shown for the Barge—TERMINAL—Unit Train alternatives apply to any of the terminals described in Section 8.2.1.

TABLE 8.6
TOTAL 1975 CAPITAL COSTS

ALTERNATIVE	\$ x 10^3
Barge-TERMINAL—Unit Train	17,206
Barge—Reclamation Site	11,472

8.2.3b TOTAL ASH DISPOSAL COSTS

Total ash disposal costs as derived in Appendix 10, are shown in Tables 8.7 and 8.8 for the various alternatives described and rated outputs. Figure 8.8 illustrates the variation of ash disposal costs with rated output and load factor variation.

TABLE 8.7
TOTAL ASH DISPOSAL COST

ALTERNATIVE	900 MW @ 70% C.F. 1.05 x 10^6 Tons/yr. COST \$/TON
Barge→Reclamation Site	2.24
Barge→SQUAMISH→Unit Train	4.33
Barge→ROBERTS BANK→Unit Train	5.04
Barge→NEPTUNE→Unit Train	4.62
Barge→NEPTUNE→Unit Train	4.92
Barge→PORT MOODY→Unit Train	4.78

TABLE 8.8
TOTAL ASH DISPOSAL COST

ALTERNATIVE	630 MW @ 70% C.F. $.84 \times 10^6$ Tons/yr. COST $/TON
Barge→Reclamation Site	2.43
Barge→SQUAMISH→Unit Train	4.99
Barge→ROBERTS BANK→Unit Train	5.86
Barge→NEPTUNE→BCR Unit Train	5.36
Barge→NEPTUNE→CPR Unit Train	5.71
Barge→PORT MOODY→Unit Train	5.59

8.2.4 GENERAL DESCRIPTIONS

8.2.4a BARGE—RECLAMATION SITE

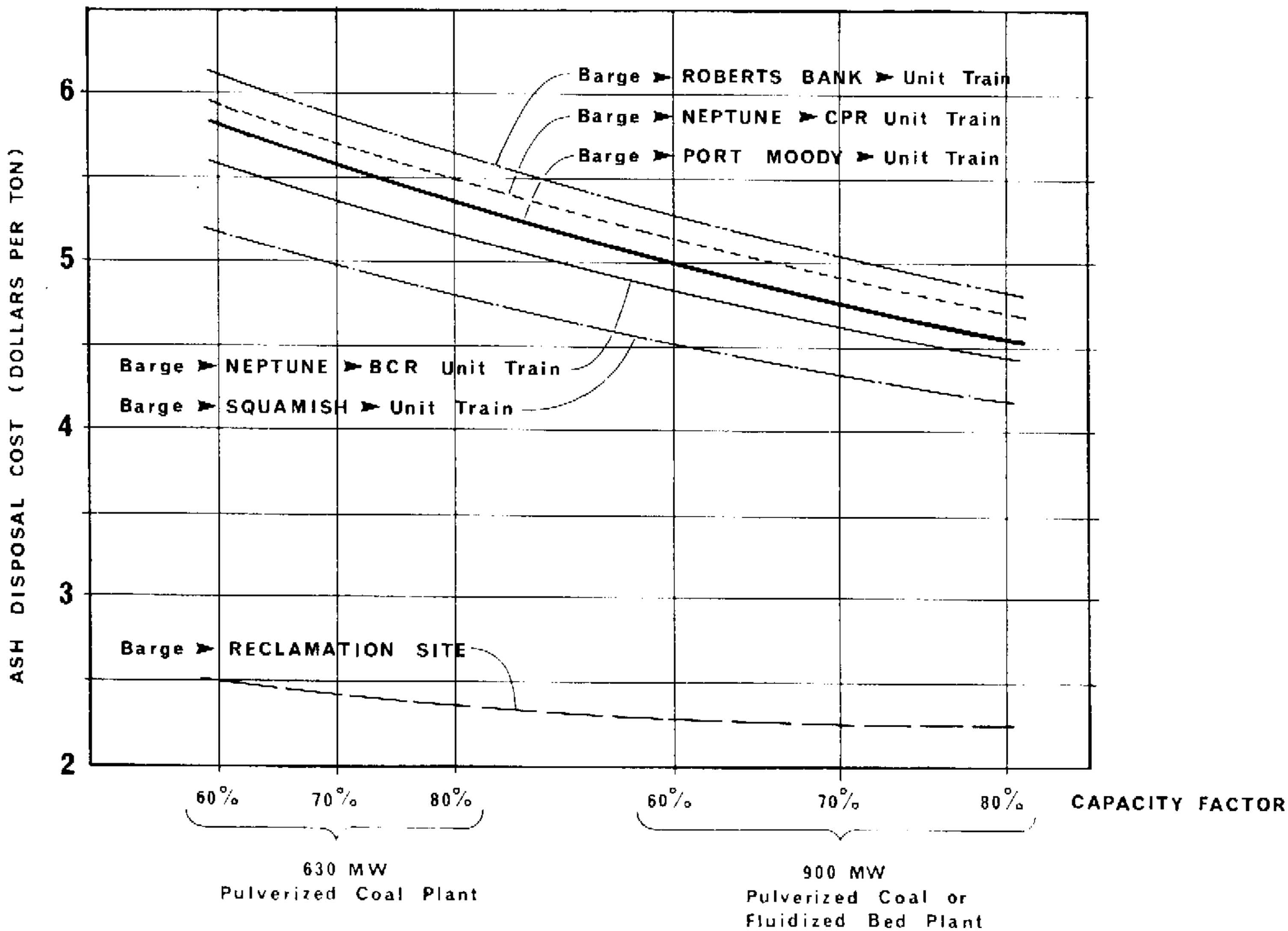
As shown in Table 8.7, Table 8.8, and Figure 8.8, the Barge-Reclamation Site alternative for ash disposal is approximately one-half the cost of the least expensive Barge—Unit Train alternative. The saving is $2.20 a ton to $3.50 depending on annual tonnage. These costs assume that a suitable reclamation site could be found within 40 nautical miles of the BTGS, and that any dyke work associated with the land reclamation would be provided by the municipality or institution benefitting from that reclamation. It is also assumed that B.C. Hydro would neither receive nor pay any fee for the ash disposal.

Such ash disposal operation, if it is less than 40 nautical miles and greater than 15 nautical miles from the BTGS, would require two 4000 DWT self-unloading covered barges dedicated solely to ash disposal and not relating to coal transportation. Within these assumptions, one of the barges would be at the station in the loading stage while the other was on route. As described in Appendix 9, accommodation has been made in the pricing of such barges to include a retractable 150' discharge boom in the self-unloading mechanism of each barge. This would permit discharge from the barge to an area within a dyked perimeter, or to a portable hopper and conveying system. The barges themselves could be designed to have a very shallow draft to facilitate discharging in areas of minimum water depth.

Some preliminary investigation has been done to identify potential areas of land reclamation in the lower mainland. Two such areas are identified on Map 3. Area 1 is just west of the Iona sewage treatment plant which lies between two man-made dykes extending west/north-west and west/southwest from the shore. The existing dykes protect this area from erosion due to river currents.

It is anticipated that a reclamation procedure would require construction of dykes of rock and earth fill behind which the ash fill will be placed. Area 1 shows a series of such dykes which will be built as the reclamation procedure progressed. At a 70% average annual capacity factor, plants burning Hat Creek coal and having capacities of either 900 MW or 630 MW will produce 540 acres feet per year or 432 acre feet of ash per year respectively. If it is assumed that an average depth of 15 feet is required to bring the reclaimed land to an elevation of 5 feet above the high tide water level, then 36 acres and 29 acres will be reclaimed annually by ash production from plants of 900 MW and 630 MW capacity respectively. If it is required that ash is mixed in some

FIGURE 8.8
ASH DISPOSAL COST VARIATION



ratio with conventional earth fill, then those reclamation acreages would increase proportionately.

Area 2 shows reclamation on the western shore of the Vancouver International Airport. Although this site is attractive and may well be feasible for a reclamation project, it is slightly more vulnerable than Area 1 to currents. This disadvantage however, may be minimized by the dyke design. Another potential area for effective use of the ash fill may be the Roberts Bank Port Development. Initial contact with the Harbours Board, however, has revealed that most of the anticipated reclamation in that area will have been completed before the B.C. Hydro ash will be available.

Although this report does not include a detailed environmental evaluation of such forms of land reclamation, it is understood that if water contamination due to the solubility of elements within the ash or leaching are found to be potentially detrimental, then the land reclamation procedure can be so designed to minimize these ill effects. The permeability of the dykes will be dependent upon their fabrication. Leaching due to precipitation absorption through the ground can be reduced by compacting fill material and by providing one foot deep layers of compacted clay within the depth of the fill material if required, and certainly as a final cover before topsoil and grass. Landscaping, to maximize run-off and minimize absorption, also reduces leaching. Another control parameter is the degree to which the ash is mixed with conventional earth fill particularly in the areas below the water table. The earth to ash mix ratio, the degree of compactness, and the use of clay layers will all affect the load bearing characteristics of the final reclaimed land. The vegetation which can be supported by ash fill is described in Section 9.0.

Land reclamation and improvement projects have been successful at a great many sites throughout North America. The concept of gainfully utilizing waste material is basically good. If due respect is paid to the potential environmental hazards of this concept, and if the available technologies are carefully applied to minimize the hazards to within acceptable limits, then several hundred acres of land may be reclaimed or improved for public use. Relative to ash disposal by transportation back to Hat Creek, ash disposal by reclamation based on the assumptions described herein, will save between $2.1 million and $2.8 million annually depending on the annual tonnage of ash and the transportation route back to Hat Creek. These funds may partly or wholly offset other costs relating to the reclamation process resulting in reduced effective reclamation costs.

8.2.4b BARGE—TERMINAL—UNIT TRAIN

Tables 8.7, 8.8 and Figure 8.8 show the unit costs associated with ash disposal by transportation back to the Hat Creek area. The Squamish alternative is between 7% and 17% less expensive than other Barge to Unit Train alternatives defined. The costs as derived in Appendix 9, cover the BTGS modifications, unloading, silo storage facilities at whichever terminal is used, (no existing terminal has this facility) Hat Creek terminal modifications for unit train unloading, and provision for ash transportation to a nearby lagoon. Construction costs for the lagoon itself are not included. These will depend very much on the terrain of the area and the possibility of lagoon requirements for Hat Creek power development.

All barge — unit train alternatives also account for the additional costs of larger barge capacities due to the increased cycle time for each barge resulting from ash-loading and unloading times. It will be more economical to back haul the ash in the coal delivery barges than to have separate ash barges. This is because by increasing the barge capacity to accommodate the ash back haul, the alternative described will still require the service of just one tug and crew. With the sole exception of the Port Moody alternative, hauling ash in the separate ash barge and back hauling that barge empty to the BTGS will require the service of a second tug and thus the incremental unit costs associated with ash transportation will be substantially higher.

It has been confirmed that self-unloading barges can successfully load both coal and ash separately although their flowability differs. A provision for a self-unloading capability in all barges eliminates the requirement of dock-mounted unloading facilities at either or both of the BTGS and the intermediate terminal. Self-unloading barges also offer the advantages of 100% discharge and more rapid discharge rates.

8.2.5 OTHER ASH DISPOSAL CONSIDERATIONS

The traditional method of the disposal of ash from thermal generating stations has been via ash lagoons. Fly ash from precipitators and economizer hoppers as well as bottom ash water is sluiced to an ash pond or lagoon. The ash settles to the bottom and the cleaner surface water is either decanted to a series of ponds through which further decantation purifies the water before release, or it is recycled back through the sluicing system. Depending on the particular installation, operating costs for such an ash disposal system are in the order of 30¢ per ton.

The ash disposal problem at the BTGS is unusually severe. For a 900 MW plant capacity operating an average annual capacity factor of 70%, the plant will produce 1.05 million tons of ash per year. This is slightly greater than the total 1975 ash production from all Ontario Hydro coal burning units (9,000 MW). The low calorific value and high ash content of the Hat Creek coal accounts for this disproportionality. For a pond depth of 20 feet, 35 acres of pond surface is required for every year of operation of the plant for 900 MW capacity, and 24.5 acres for 630 MW capacity. For a 20 foot depth therefore over 35 years 900 MW and 630 MW plants will require 1,225 acres and 857 acres respectively. For greater pond depths these acreages will decrease proportionately.

Examination of topographical maps combined with some aerial reconnaissance over the area within a 10 mile radius of the BTGS, reveals that no potential site exists in that area with even a remote chance of environmental acceptability. For this reason the disposal of the ash to a nearby lagoon was given no further consideration.

Land reclamation or improvement in inland areas within 20 road miles of the BTGS could be provided with dry ash by truck for approximately $6.00 per ton. Current costs of Ontario Hydro for delivery of ash from the Lakeview Generating Station to a quarry four miles away has a unit cost of $2.00 per ton. With the use of 40 cubic yard trucks, plants of 900 MW capacity and 630 MW capacity would require 117 trucks per day and 82 trucks per day respectively for 100% MCR operation.

8.3 COMBINED COAL AND ASH ECONOMIC SUMMARY AND CONCLUSIONS

Table 8.9 following shows the combined coal and ash unit costs for the various alternatives defined for coal and ash transportation. For every 1.0 ton of coal transported to the BTGS, .26 tons of ash are transported from the station. Cost shown in Table 8.9 are the sum of 100% of the coal costs per ton for the alternatives defined, plus 26% of the ash costs per ton and indicate total combined coal and ash unit cost for the combinations of coal and ash transportation identified.

TABLE 8.9
COMBINED COAL & ASH UNIT COSTS

ALTERNATIVE		900 MW @ 70% C.F.		630 MW @ 70% C.F.	
COAL	ASH	$/TON	¢/Btu × 10^6	$/TON	¢/Btu × 10^6
Train—SQUAMISH—Barge	Barge—SQUAMISH—Train	10.19	81	11.79	95
Train—ROBERTS BANK—Barge	Barge—ROBERTS BANK—Train	11.88	95	13.52	108
BCR Train—NEPTUNE—Barge	Barge—NEPTUNE—BCR Train	10.52	84	11.72	94
CPR Train—NEPTUNE—Barge	Barge—NEPTUNE—CPR Train	11.50	92	12.99	104
Train—PORT MOODY—Barge	Barge—PORT MOODY—Train	11.31	91	13.02	104
SLURRY	Reclamation Site	8.92	72	9.76	78
Train—SQUAMISH—Barge	Reclamation Site	9.65	77	11.12	89
Train—ROBERTS BANK—Barge	Reclamation Site	11.15	89	12.63	101
BCR Train—NEPTUNE—Barge	Reclamation Site	9.99	80	10.96	88
CPR Train—NEPTUNE—Barge	Reclamation Site	10.80	87	12.14	97
Train—PORT MOODY—Barge	Reclamation Site	10.65	85	12.20	98

TABLE 8.10
COMBINED COAL & ASH ECONOMIC COMPARISON:
Annual & 35 Year Coal & Ash Costs RELATIVE TO SQUAMISH Unit Train——Barge

ALTERNATIVE		TOTAL COST $ x 10^6 900 MW @ 70% C.F.		TOTAL COST $ x 10^6 650 MW @ 70% C.F.	
COAL	ASH	ANNUAL $ x 10^6	35 YEARS & 10% PRESENT VALUE	ANNUAL	35 YEARS @ 10% PRESENT VALUE
Train—SQUAMISH—Barge	Barge—SQUAMISH—Train	0	0	0	0
Train—ROBERTS BANK—Barge	Barge—ROBERTS BANK—Train	6.84	69.22	4.90	49.55
BCR Train—NEPTUNE—Barge	Barge—NEPTUNE—BCR Train	1.34	13.52	-.20	-2.01
CPR Train—NEPTUNE—Barge	Barge—NEPTUNE—CPR Train	5.30	53.69	3.40	34.37
Train—PORT MOODY—Barge	Barge—PORT MOODY—Train	4.54	45.90	3.48	35.23
SLURRY	Reclamation Site	-5.14	-52.05	-5.75	-58.14
Train—SQUAMISH—Barge	Reclamation Site	-2.19	-22.13	-1.90	-19.19
Train—ROBERTS BANK—Barge	Reclamation Site	3.89	39.35	2.38	24.06
BCR Train—NEPTUNE—Barge	Reclamation Site	-.81	-8.20	-2.35	-23.77
CPR Train—NEPTUNE—Barge	Reclamation Site	2.47	25.00	.99	10.02
Train—PORT MOODY—Barge	Reclamation Site	1.86	18.85	1.16	11.74

Table 8.10 is an overall economic comparison of the combination of coal and ash alternatives. It shows, relative to the Squamish alternative for both coal and ash, the incremental annual and 35 year present value costs of the combinations of coal and ash transportation.

Although the land reclamation alternative of ash disposal is the least costly of all alternatives, it is assumed that back hauling the ash to Hat Creek is required.

For the purposes of fuel costs as applied to the various combustion alternatives described in Section 5.0 the Squamish alternative for both coal and ash will be used. It has clear economic advantages over other terminal alternatives as well as the long range advantage of a B.C. Hydro owned and operated tidal water coal terminal.

8.4 BARGE OPERATION

This section was prepared by Captain George A. Veres of Interport Consultants Ltd. specifically in regard to waterborne transportation of coal and ash.

8.4.1 OBJECTIVES

The objectives of this preliminary assessment are to provide the Consulting Engineers with an independent overview of those economic and technical factors that influence the waterborne transportation of coal, from alternate sites to the B.C. Hydro and Power Authority's Burrard Thermal Generating Station; and to provide the required preliminary data on which properly operational criteria can be systematicaly developed, eventually leading to investment commitments predicated on technically feasible and economically viable waterborne transportation concepts.

8.4.2 ALTERNATE SITES UNDER CONSIDERATION ARE:

8.4.2a

An area on the South Shore of the Port Moody Arm (Burrard Inlet), approximately located on a True Bearing of 168° from the centre of the Westerly fuel storage tank at the generating station.

8.4.2b

Neptune Terminals, located on the North Shore of Burrard Inlet, at 123° 03' W. long.

8.4.2c

Squamish, at the head of Howe Sound, on a site presumably adjacent to Squamish Terminals.

8.4.2d

Westshore Terminals at Roberts Bank, in the Straits of Georgia.

8.4.3 SYSTEM THROUGHPUT

The Generating Station would require an assured system throughput of up to 16,000 tons of coal per day. Up to 4,000 tons of ash per day also have to be moved to a suitable disposal site.

8.4.4 STEAMING DISTANCES

Round trip distances from and to alternate sites are:

South Shore, Port Moody Arm	—	1 nautical mile
Neptune Terminals	—	14.2 nautical miles
Squamish	—	81.4 nautical miles
Roberts Bank	—	77.5 nautical miles

8.4.5 SYSTEM RELIABILITY

Although theoretically one barge only could handle required tonnage throughout from the South Shore of the Port Moody Arm site or from Neptune Terminals, the need for a high degree of system reliability would demand that two barges be employed from these site alternatives. From Squamish or Roberts Bank two self-propelled or two towed barges would be required.

8.4.6 RECOMMENDED BARGE CAPACITIES

8.4.6a

South Shore of Port Moody Arm Site — Based on a 6 hrs. cycle (loading @ 2,000 tons/hr. — 2 hrs., discharging @ 1,400 tons/hr. — 3 hrs. and in-transit time 1 hr. including mooring and unmooring), 2 · 4,000 DWT capacity barges would satisfy the system requirements, assuming a 12 hr.-day operation.

Guidance Note: Should this site be eventually selected, it would be recommended that a comparative system analysis be carried out, considering the above alternative as well as the employment of 2 · 2,000 DWT capacity barges operating round the clock.

8.4.6b

Neptune Terminals Site — Predicated on the assumption that a dedicated loading facility would be made available at this site for the B.C. Hydro coal movement, the same 2 - 4,000 DWT barges, working a 14 hr. day, could satisfy the system requirements (loading at 2,000 tons/hr. - 2 hrs., discharging at 2,000 tons/hr. - 2 hrs., steaming time, including mooring/unmooring - 3 hrs.)

8.4.6c and d

Since the round trip steaming distances from Squamish and Roberts Bank Terminals are identical for practical purposes, these two alternative sites would be serviced by identical size barges and are therefore considered together.

There are two alternative systems to be considered:

i) 2 - 10,000 DWT self-propelled barges, each with a service speed of 10 knots.

ii) 3 - 8,000 DWT barges, serviced by one dedicated tug. Under this alternative one barge is loading, one barge is discharging and one barge is underway. Both loading and discharging rates can be reduced to the lowest economical figure, since such operations would be carried out whilst the third barge and tug are in transit. The systems-economics of this alternative might well be found to be more attractive, even though the tug would require the employment of three crews.

The relevant round trip cycles would be:

	SELF-PROPELLED	TOWED
Steaming time	8 hrs.	10 hrs.
Loading	4 hrs.	4 hrs.
Discharging	4 hrs.	4 hrs.
	16 hrs.	18 hrs.

8.4.7 BARGE PROPULSION SYSTEMS

8.4.7a

For the South Shore of Port Moody Arm Site, a cable drive system with the power unit located in a cable drive house situated ashore should be considered, in view of the short-distance shuttle type of service.

Either of two alternative cable driven systems could be adopted. In the first of these, the cables would be fitted with struts having hinged attachment to the bottom of the barges and a rigid attachment to the cable. The lift of the cables would be limited to the difference between the depth of water and the length of the struts. This alternative would represent no hindrance or danger to other shipping in the area.

The second cable drive alternative would consist of endless stud-link chain cables driven by a power windlass mounted ashore. The cables would be attached to the barges via specially built wild-cats. The drawback of this system is the potential interference with shipping caused by the length of suspended catenary. Both the above systems would require that the mooring arrangements at either end should be of the fingerpier or slot type, aligned with the direction of the cables.

It is understood that a conventional tug could also be employed to shuttle the barges across the Port Moody Arm. Considering the very short distance and the concomitant idle time of the tug and its crew, such propulsion method is not likely to prove economic.

Shore power would be used to energize the barge-mounted unloading gear.

8.4.7b

Should the coal storage site be located at Neptune Terminals, there appear no economic alternatives to the barges being moved by one dedicated tug, whose horsepower will depend on whether the two barges are to be moved individually or in tandem. Also, a purposely designed and built tug could be so equipped as to be able to supply the power required for the unloading gear, should shore power not be conveniently available for this purpose. This umbilical concept would, however, necessitate that the barges be moved in tandem.

Whether the barges are moved individually or in tandem, the push-two concept is recommended for this application, since the movement would take place in high traffic density waters.

8.4.7c and d

For the Squamish or Roberts Bank Site alternatives the recommended alternative propulsion methods have already been outlined under Item 8.4.6 c and d above.

Should either of these two sites be finally chosen, it is suggested that a comparative benefit-cost analysis be carried out of the alternative systems recommended, since both are strongly favoured by those firms employing one or the other (and one major operator employs both systems) on dedicated-run services.

The principal economic advantage of the self-propelled units lies in the fact that a single plant provides the propulsion power and the power required for the unloading gear; whilst the three dumb-barges-with-one-tug concept offers the attraction of the most efficient utilization of the tug for towing purposes and the economies attainable from a slower rate of unloading.

8.4.8 BARGE SIZES

The approximate overall dimensions of the barges having the recommended deadweight capacities are:

a) 4,000 DWT	280' x 57' x 16.5'	—	11.6'
b) 8,000 DWT	320' x 64' x 22'	—	16'
c) 10,000 DWT	375' x 75' x 26'	—	21' (self-propelled)

It should be observed that these dimensions are somewhat larger than an ordinary dumb-barge without unloading gear, due allowance having been made for a hopper-type hold design, elevating and cross conveyors, etc.; also that these dimensions could be adjusted at the design stage to meet the exigencies of the service (e.g. beamier vessels with shallower draft, etc.).

8.4.9 ORDER OF MAGNITUDE CAPITAL COSTS

The undernoted capital costs are expressed in current terms, Sept. 1975 dollars. They take, however into consideration the latest increases in the cost of shipbuilding steel.

VESSEL	EACH $ MILLION	OF WHICH THE SELF UNLOADING GEAR IS $ MILLION
4000 DWT barge	2	.75
8000 DWT barge	4	1.25
10000DWT self-prop. barge	11.5	1.75

The foregoing costs are based on current shipyard prices in Vancouver. They require adjustment in respect of: Canadian Shipbuilding Subsidy (14% currently, 13% for contracts entered into during calendar year 1976 and decreasing annually by 1% to 1981, when it becomes 8%).

8.4.10 THE SELF UNLOADING CONCEPT

Whichever site is eventually selected as offering the most attractive combination of efficiency and economy for locating the coal transfer storage from unit trains to floating equipment, all vessels discussed in the foregoing sections are assumed to be equipped with self unloading gear. The alternatives would be either a shore mounted cranes-clamshell buckets unloading system or a crane supported continuous bucket-chain reclaiming system. Neither of these systems are likely to prove desirable. The former because of the reduced speed of unloading, unless several clamshells are operating simultaneously; and the latter because the initial capital cost would exceed the cost of the shipborne installations.

It should be observed that the ship-mounted cross conveyor booms will not reach the designated storage areas at the Generating Station (for instance the outreach of the cross-conveyor boom of the 4,000 DWT barge would be approximately 12'6" - 13'0" beyond the ship's side). Therefore shore based movable hoppers and transfer conveyors would be needed (this is already shown on INTEG Drawing F-0036/500/Sk-5).

8.4.11 PIER ALIGNMENTS

As a general comment it should be mentioned that pier alignments in line with or parallel to the direction of the approach movement of a vessel is preferable and it facilitates speedy berthing and unberthing. This would be particularly important — in fact essential — for the cable drive suggested across the Port Moody Arm.

In all other cases the direction and intensity of the tidal currents will have an important bearing on pier alignments and are likely to necessitate offshore piers parallel with the shore line.

The "Atlas of Tidal Current Charts" published by the Canadian Hydrographic Service, Easterly current velocities up to 2 knots are shown at the Generating Station, during flood tides; and Westerly currents of up to the same speed at the proposed site on the South Shore, during ebb tides. Neptune Terminal is located in waters that are fairly well sheltered and current velocities do not generally exceed ½ knot.

It will be important that the exact location of the proposed piers be determined at an early stage and their location in relation to the existing Harbour Headlines clearly established. "Trespassing" beyond the Harbour Headlines requires a permit under the Protection of Navigable Waters Act, the issue of which is a rather lengthy process and it will eventually lead to a change in the Harbour Headline itself.

8.4.12 WATER DEPTHS AND IMPLICATIONS ON MARITIME TRAFFIC

Sufficient water depth is available, whichever alternative site is eventually chosen, for any and all of the vessels shown in Section 8, except at the Generating Station itself and at the South Shore, Port Moody Arm Site. At these locations a limited amount of dredging will be necessary in the approach channel and at the birth. The Canadian Hydrographic Chart No. 3484 indicates that the length of approach channel to be dredged on the South Shore Site would not exceed 300' and less at the Generating station site where an offshore pier arrangement could obviate the need for dredging altogether.

As far as potential interference with maritime traffic is concerned only the North-South movement across the Port Moody Arm need to be considered, since traffic from all other sites would be parallel to the existing East-West traffic pattern.

Disregarding the recreational traffic, the commercial traffic has three major origin-destination points in the area, viz.:

Pacific Coast Bulk Terminals —

— handling an average of 12 deep sea ships per month (24 movements) and up to to ten barges per month (20 movements). Total 44 movements per month.

Imperial Refinery at Ioco —

— average two ships or barges per day or a total of 120 movements per month.

Weldwood Plant —

— up to 12 barges per month or 24 movements.

Other, miscellaneous —

— say, 10 units or 20 movements per month.

The foregoing movements total 208 per month or an average of seven movements per diem. With eight daily movements envisaged across the Port Moody Arm to and from the Generating Station (2 barges, each making two round trips per day) no objectionable interference would be created with existing shipping patterns, and this view was informally endorsed in discussion with the National Harbour Board, Vancouver.

8.4.13 CONCLUSIONS

From the point of view of the waterborne transportation component of the overall supply system aimed at a throughput of 16,000 tons per diem of coal, none of the alternate sites suggested present problems that would not be capable of efficient solution; nor are the solutions suggested in any way extraordinary and therefore more capital intensive than would normally be expected.

As the program is further studied and developed, consultation and co-operation with the Regulatory Authorities is recommended to ensure the most efficient and cost effective solution.

8.5 GAS TRANSPORTATION

8.5.1 TRANSPORTATION OF GAS TO SITE

Trans Mountain Pipe Line Limited have done a brief study on the cost of moving SNG and low Btu gas from a gasification plant at Hat Creek to the Burrard site. This study is included in paragraph 8.6. The TransMountain work is based on the use of gas turbine drives in the pumping stations burning product gas. This has been general practice in the Canadian gas pipeline business for some time. Recently some major gas pipelines including Canadian Arctic Gas, Trans-Canada Pipelines and Alberta Gas Trunklines have investigated the use of electric drives because of the need to conserve natural gas, and the relative market pricing of natural gas and electricity. The use of electric drives has been rejected by two of these parties because:

- cost of variable speed electric drives in the range of 20,000-30,000 HP is very high
- motors of this size have not been built for variable speed application
- the cost of supplying electric power to most pumping stations makes the alternative uneconomical.

In the case of a pipeline from Hat Creek to Burrard, the pumping stations would be at Hat Creek and in the Alta Lake-Pemberton area. It is quite possible that a 4.4 KV or 13.8 KV supply could be made available at the pumping station with relatively low transmission costs, and as a result, electric drives would be economic in terms of capital cost. However, it seems illogical to pump the product gas to Burrard for conversion into power which is transmitted back to the pumping station.

Even if electric drives are more economic than normal gas turbines, this does not greatly affect the overall pumping cost shown in Section 8.6. An in depth study of the pipeline and pumping stations would be required to resolve this question. For the purpose of this study, the use of gas turbine drives gives a conservative estimate based on proven technology.

The TransMountain study was based on two gases which were defined early in the study. As a result the low Btu gas heating value does not correspond exactly to the final figures produced by Lummus in Study C. However, the TMPL results have been used to interpolate gas pumping prices for gases of different heating values and these are shown in Table 8.11. In all cases gas is received at 300 psi from the gasifier.

TABLE 8.11
GAS PUMPING COSTS
HAT CREEK TO BTGS (¢/BTU x 10^6)

CAPACITY FACTOR	GAS HEATING VALUE HHV (Btu/lb) 185	200	300	400	970
60%	69	67	56	50	31
70%	61	59	49	44	27
80%	54	53	44	39	24
90%	49	48.5	40	35	21.5

8.5.2 LOCATION OF GASIFICATION PLANT

Three locations for the gasification plant were considered:

Hat Creek
BTGS
Site on B.C. Railway close to ample fresh water

Table 8.12 compares the cost of gas delivered to BTGS from the three sites. This table considers the following factors:

— It is cheaper to pump medium Btu gas (300 Btu/Scf) from Hat Creek to BTGS than to transport coal by the preferred route; 49 cents per million Btu versus 81. This rather surprising result stems from the difficulties of shipping coal from Hat Creek to Burrard via rail and barge, the low heating value of the coal (i.e. the amount of water and ash shipped in the coal) and the high cost of ash disposal from BTGS.

— A low Btu gasification plant for 900 MW consumes about 2000 gpm of water and steam and may require an additional 1000 - 2000 gpm for cooling. Total water consumption would be about 2000 gpm at a tidewater site and up to 4000 gpm at a cooling tower site such as Hat Creek (assuming 2½% evaporation and tower blowdown). The actual amount would depend on how much of the sensible heat of the raw gases is rejected, and whether it might be economical to use some of it to reheat the clean fuel gas.

— The cost of supplying and cooling the extra water at Hat Creek is equivalent to about 4 cents/million Btu product gas, including the water pumping costs.

— The cost of generating steam for the gasification plant is assumed to be relatively high at BTGS or the 3rd site, because of the cost of shipping Hat Creek coal. The price of the coal at BTGS is about 3 times its cost at Hat Creek.

Table 8.12 shows conclusively that the cost of gas delivered to BTGS is lower with the gasification plant at Hat Creek than at either of the other two sites, even ignoring the very real environmental and space limitations of the BTGS site.

TABLE 8.12
ENERGY TRANSPORTATION COSTS (CENTS/MILLION BTU OF GAS PRODUCED)

1. Gasification Plant	Hat Creek	Burrard	3rd Site
2. Means Moving Energy	Low Btu pipeline	as coal	pipeline/coal
3. *Cost Moving Energy* to Burrard cents/ 10^6 Btu	44	79	44+
4. Water Cost Penalty (including supply & costing of water)	4	-	-
5. Differential Steam Cost	8	25	15+
6. Total	56	104	59+

NOTE: This table ignores possible efficiency benefits of an integrated gasification plant/combined cycle.

The table shows that the cost of supplying water to Hat Creek has relatively little effect on the end cost of the low Btu gas. The comparison in line 4 is based on the *conservative assumption that water supply at the other two sites is effectively free. In* line 5, the cost of steam for the gasification is compared using a price of $3 for Hat Creek coal, $9 for coal at Burrard and about $6 for coal at a 3rd site. The overall conclusion of the table is that it is cheaper to pump the low Btu gas to BTGS than to move the coal, and the only economic disadvantage of the mine mouth gasification plant which is the remoteness of its water supply, is insignificant.

8.6 TRANS MOUNTAIN PIPELINE STUDY

8.6.1 INTRODUCTION

This project was requested by Intercontinental Engineering Limited (INTEG) as per their letter of July 17, 1975 and their subsequent phone call of July 28, 1975 to Mr. K.L. Hall of TransMountain.

The estimate for the pipe line and compressor station has been based on the following alternatives:

Case I — Low Btu Coal Gas, nominal heating value 200 Btu/SCF 1088 million SCF per day supplied at Hat Creek @ 300 psig.

Case II — Synthetic Natural Gas (SNG), nominal heating value 970 Btu/SCF 224 million SCF per day supplied at Hat Creek @ 300 psig.

8.6.2 SYSTEM PARAMETERS

A computer program has been run to determine an approximate optimization for pipe line/compressor station combination. The following selection was made:

Case I — Pipe line wall thickness: .344" to .562"
Pipe line size: 36" O.D.
Required horsepower: 78,760 hp
Installed horsepower: 100,000 hp
Units: 5 turbines @ 20,000 hp each
Stations: 1
Discharge pressure: 1226 psig
Delivery pressure: 150 psig
Pipe line length: 171.6 miles

A study was made for a 30" diameter pipe line. Horsepower requirements were exhorbitant. Furthermore, 2 stations would be required (total required installed horsepower 180,000 hp). A 42" O.D. pipe line was also considered, and although horsepower requirements were somewhat less, the increased pipe line and construction cost did not warrant further exploration of this alternative.

No study was made on gas being delivered at atmospheric pressure (14.4 psig) as horsepower requirements would be extremely large.

Case II — Pipe line wall thickness: .25"
Pipe line size: 20" O.D.
Required horsepower: 14070 hp
Installed horsepower: 22500 hp
Units: 3 turbines @ 7500 hp each
Stations: 1
Discharge pressure: 1055 psig
Delivery pressure: 150 psig
Pipe line length: 171.6 miles

A study was made for a 24" diameter pipe line. The horsepower requirement was thus reduced to approximately 8000 hp. The cost reduction for the latter was more than offset by the cost for the larger diameter pipe. This alternative was therefore considered not to be economically feasible.

No study was made on gas being delivered at atmospheric pressure (14.4 psig) as horsepower requirements would be extremely large.

8.6.3 PIPE LINE ROUTING

The route was selected on a preliminary basis from Survey and Mapping Branch, British Columbia, maps. Contour interval 100 feet, scale 1:50,000. The measured pipe line length was increased by 10% to allow for horizontal/vertical correction. No field inspections were made.

Route description is as follows (see Drawing SK 10).

APPROXIMATE MILE POST	PIPE LINE MILE	LOCATION
0	0	Hat Creek
6.6	7.2	Fountain Range Summit
19.0	21.0	Lilloet
32.0	35.4	Shalath
50.0	55.4	D'Arcy
58.5	64.8	Berkin
72.5	80.3	Pemberton
90.0	99.6	Alta Lake
99.0	109.6	Brandywine Falls
104.0	115.0	Garibaldi
116.0	128.4	Checkeye
122.0	135.0	Mamquam River
151.0	167.0	Buntzen Aquaduct
155.0	171.6	Ioco — Burrard Steam Plant

The profile of the pipe line is shown on Drawing 75-11-2.

8.6.4 COSTS

8.6.4a PIPE LINE COSTS

The pipe line cost estimates including the following:

- Various size of pipe (Z245 Grade 52)
- Casing pipe
- Coating materials
- Rock shield
- Gunniting
- River and swamp weights
- Casing seals and insulators
- Main line valves
- Fencing, valve boxes, ROW markers
- Scraper traps (sending and receiving)
- Cathodic protection

Cost of pipe is taken at $500/ton; other materials at current market prices.

8.6.4b CONSTRUCTION COSTS

The construction costs cover:

- Pipe stringing, laying, ditching, welding, cleaning, lowering in, backfilling and cleanup
- ROW clearing, grading and grubbing
- Rock removal (on ROW)
- Rock removal (in ditch)
- Extra coating at crossings
- Padding and rock shielding
- Installing river and swamp weights
- Test welds
- Installation of block valves
- Costs for boring and casing of crossings
- Installation of scraper traps
- X-raying
- Individual costs for major river crossings
- Contract extras based on a per footage
- 100% hydrostatic testing
- Freight charges

8.6.4c ROW COSTS

The costs directly associated with the right-of-way include the following:

- Survey costs (old and new ROW)
- Working room allowance
- General considerations
- Damages

Note: No allowances have been made for right-of-way acquisition.

8.6.4d INCIDENTALS

The incidentals cover the following:

- Environmental Impact Study
- Timber cruising reports
- Stumpage fees for timbered areas
- Aerial photography and mapping
- Rip rapping, sandbagging and corduroying
- ROW access roads
- Aerial markers
- Revegetation
- Field and administration, inspection, testing of materials and other miscellaneous outside services
- An allowance for expediting, communications, engineering and design work.

Where at all possible up-to-date costs have been obtained.

Comparison of final cost figures have been made with recent construction work and costs as indicated are reasonably comparable.

8.6.4e COMPRESSOR STATIONS

Cost estimates include:

- Compressor, speed increaser & prime mover
- Buildings and control room
- Land and land rights
- Grading and excavation
- Foundations
- Piping, valves and fittings
- Electrical & instrumentation facilities
- Cathodic protection facilities
- Air compressor

TABLE 8.13
$,000s Sept. 1975 Basis Uninflated
GAS PIPELINE & PUMPING COSTS

	LOW BTU GAS 36" LINE NOMINAL 200 Btu/SCF	SNG 12" LINE NOMINAL 970 Btu/SCF
Materials including pipe	47,860	19,575
Construction	50,186	39,670
Environment Impact Studies	1,920	1,920
Compressor Stations	57,300	15,492
SUB TOTAL	157,266	76,657
Contingency 15%	23,590	11,499
SUB TOTAL	180,856	88,156
Engineering or procurement 8%	14,468	7,052
SUB TOTAL	195,324	95,208
Corporate O/H 5%	9,766	4,760
SUB TOTAL	205,090	99,968
Interest During Construction	13,331	6,498
TOTAL CAPITAL COST	218,421	106,466
Annual Cost (12.455%)	27,204	13,260
Fuel Cost 70% Cap. fact.	5,268	1,569
Assumed fuel price	$1.20 per million Btu	$2.00 per million Btu
Variable maintenance	540	97
TOTAL ANNUAL COST	33,012	14,926
Gas throughput per year (70% CF)	55,600 10^9 Btu	55,600 10^9 Btu
Cost per Million Btu/cents	59	27

9.0 ASH UTILIZATION

9.1 INTRODUCTION

In view of the very large quantities of ash which will be produced from combustion of Hat Creek coal, this section was prepared to review the current usages of ash and its by-products. In North America, much of the promotion of the technology of ash utilization comes from the National Ash Association, which was formed ten years ago under the U.S. Bureau of Mines. Currently, North American utilization of ash is about 15%, although it has very recently gained significantly more attention. This is partly due to the growth of conservationist values and partly due to the higher economic value of ash and its by-products resulting from the diminishing resources of substitute products. The State of Maryland has declared ash a natural resource and is endeavouring to achieve its full utilization. The total production of ash in the U.S. is 50 million tons, which makes it the seventh largest of all solid minerals.

In Europe, where the two forces of economic and conservationist values have been more prevalent than those in North America, utilization is more advanced. The Central Electricity Generating Board of Britain in recent years has achieved 60% utilization of the ten to twelve million tons of ash produced annually.

9.2 BUILDING MATERIALS

9.2.1 BOTTOM ASH FILL

The granular characteristics of bottom ash are similar to natural aggregate in regards to handling, spreading, and compaction. Consequently, it is suitably used as fill either in the raw form or mixed in some proportion with fly ash. West Virginia has made extensive use of ash in this way. Experimentation there has revealed that the optimum mixture is a blend of 70% bottom ash with 30% fly ash. The fly ash provides high compaction and binding characteristics while the bottom ash provides particle interlocking.

Whether bottom ash is used in its raw form or in a mixture with fly ash, the resulting fill is approximately 30% lighter than conventional fill materials weighing between 110 pcf and 140 pcf. Consequently it lends itself well to applications where settlement of the soil supporting the fill is of some concern. Such applications are highway embankments and bridge approaches. The low density, high frictional resistance, and high permeability of bottom ash mixtures are an advantage in back fill applications behind retaining walls. The lower lateral backfill pressure on the wall allows for more economical design of the retaining wall.

In addition to being used as a fill material for road beds, bottom ash can be used as an aggregate in emulsified asphalt paving mixtures. The resulting asphalt has improved skid resistance and wearing characteristics over conventional asphalt. These improved characteristics are primarily due to the higher abrasive and angular properties of bottom ash relative to conventional stone aggregates. This application has been developed primarily in Michigan and West Virginia.

9.2.2 LIGHT WEIGHT AGGREGATE

Light weight aggregate is essentially sintered granules of pelletized fly ash. In the process of aggregate production, economizer hopper and precipitator ash is water sluiced to dewatering and storage bins. When the moisture content is reduced to approximately 22%, the ash enters a pelletizer. Placed on a grate, pellets are then sintered. At this stage, an oil fired flame is directed downward on the surface of the pellets some 12" deep on the grate. Air is drawn through the grate to propogate the flame.

The carbon content of the ash sustains the burning process of the pellets to completion, during which the hardness of the pellets is increased. The ideal carbon content to sustain the sintering process is between 4% and 6%. Ash with less than 4% carbon can be mixed with pulverized coal before the dewatering process.

On completion of the sintering process, pellets go through crushing and sizing stages. The desired granular size will depend on the particular concrete usage. Granular sizes in the area of 3/16" diameter are used for ready-mix and precast concrete, while finer particles are used for concrete block. The pellet strength and consequently the sintered aggregate strength, is affected by the compaction of the fly ash into pellets and its cohesion. This in turn is influenced by the degree of fly ash fines. In general, fly ash used for aggregate production must be of such constituency that a minimum of 70% of it passes through a 325 mesh.

The main advantage of the aggregate produced from fly ash is its light weight, although it sells for approximately twice as much as a conventional stone aggregate. The resulting concrete with light weight aggregate is adjusted to the strength of an equivalent section of conventional concrete by the cement content. For equivalent strength, light weight aggregate concrete has a density of 125 pcf versus 150 pcf for conventional stone concrete. The aggregate plant at the Lakeview Generating Station of Ontario Hydro recently supplied the Harbour Square hotel and apartment complex on the Toronto waterfront. With the use of light weight aggregate, 6 floors were added to the design of the building without changing the design of the steel superstructure. Further attractions of light weight aggregate are the reduced labour costs and higher concrete pumping elevations associated with its lighter weight.

When light weight aggregate is used to make concrete block, the weight is reduced from about 40 lb. to about 28 lb. per block. The advantages are lower shipping and placing costs. The current sale price of light weight aggregate in Ontario is $9.00 per ton. (F.O.B. Ontario Hydro Plant).

9.2.3 CEMENT SUBSTITUTE

Fly ash passing through a 325 mesh is defined as pozzolan, and its application is a direct substitute for Portland cement in the mixing of concrete. The segregation of this class of fineness fly ash can be combined with production of light weight aggregate. Light weight aggregate requires that only 70% of the fly ash pass through a 325 mesh. The fines in excess of this amount can be separated by classifiers from the economizer hopper and precipitator fly ash. The resulting proportions of light weight aggregate and pozzolan vary with the fly ash produced in the combustion process. Typical proportions are 55% light weight aggregates and 45% pozzolan.

Part of the reaction process in the mixing of Portland cement is the formation of a certain amount of lime. By replacing 25% to 30% of the cement with pozzolan, the pozzolan will then react with the lime to form a cement-like binder which adds substantially to the concrete strength. Pozzolan is currently sold in Toronto as a cement substitute for $9.58 per ton (F.O.B. cement plant). This is approximately 25% of the cost of Portland cement. Recent applications in Toronto are the Royal Bank Tower, and the T.T.C. Subway extension.

In addition to separating pozzolan from the fly ash, it is possible to magnetically separate iron oxide particles. Depending on the coal burned, iron oxide represents about 7% of the ash by weight. It currently sells for $7.00 per ton and is used in sewage and water treatment plants to remove pollutants.

9.3 AGRICULTURE

The Central Electricity Generating Board in Britain has done extensive work to determine whether fly ash can support crops with little or no top soil. Where a depth of 12" of top soil can be provided it was found that a full range of crops could be supported. In the case where no top soil was provided, certain crops could be sustained depending on the degree of fertilization of the ash to provide the deficient nutrients.

Research has shown that the principal toxin in fly ash which deters vegetation is boron. Normal concentration of boron in soil is in the order of 1 to 2 parts per million, while it is about 30 parts per million in fly ash. The pH is alkaline at 8.5 compared to 6.0/7.0 for normal soil. This alkalinity is attributable to the chalk content of the coal.

Chemical methods for reducing the boron content have been examined but to date have proved to be uneconomic. Consequently, considerable work has been done to identify those forms of vegetation and crops which survive most successfully on ash. They are identified below.

White sweet clover
White wild clover
Red clover
Lucerne (alfalfa)
Rye grasses
Beets
Cabbage

Those found least tolerant of ash conditions are as follows:

Oats
Barley
Peas
Beans
Potatoes

As the ash weathers and certain elements are diluted with leaching, more varieties of plants become tolerant. Examples of these are:

Carrots
Radishes
Parsnips
Celery
Onions
Leeks

In all cases, nitrogen and phosphate contents must be increased by the use of fertilizers. The use of clovers as a pioneer crop is advantageous in this regard since its bacterial activity supplements the nitrogen content of the ash. Thereafter, arable food crops and cereals can be cultivated. With continued growth, the agricultural qualities of the ash improve so that it can support a wider variety of crops, beneficial bacterial processes, and earth worms.

Ash which has been lagooned for many years more readily supports vegetation. The water seepage or drainage from an ash removes some of the more toxic dissolved solids leaving the remaining material more arable. Trees do not grow well on ash unless it has been weathered for several years. Where a 12" compacted layer of top soil can be provided, a wider variety of small trees can be sustained. Examples are:

Spirea Menziessi
Ribes Sanguineum
Philiadelphus Avalanche
Cotoneaster Bullata
Escallonia Langleyensis
Hypericum Elatum
Cytisus Scoparius

10.0 ENVIRONMENTAL EVALUATION

10.1 INTRODUCTION

Beak Consultants Limited was requested by Intercontinental Engineering Ltd. (INTEG) to briefly review alternate coal handling methods involved in the potential conversion of the Burrard Thermal Generating Station from oil-firing to coal-firing, and to comment on the relative advantages and/or disadvantages each method would have on the environment.

Due to the nature of the assignment, and the time frame involved, no field work was performed, and the conclusions reached in this report are based upon judgement, upon published data, and upon data collected by BEAK during previous biological surveys of Burrard Inlet. Before any definite or absolute environmental impact assessment can be made, the area should be subject to a detailed environmental impact study.

10.2 COMPARISON OF ENVIRONMENTAL IMPACT

In order to permit a reasonable evaluation of the relative environmental impact of the alternates, only a small number of major factors were included in the impact comparison. The comparison deals with the effect of coal transportation by unit train and by barge, and the effect of barge loading and unloading and coal storage on:

Fish
Fish Habitat
Wildlife
Wildlife Habitat
Water Quality
Outdoor Recreational Values
Land Values
Visual Aesthetics
Social and Political Reaction to each Alternate

10.2.1 GENERAL

It should be recognized that a proposal to change the Burrard Generating Station from oil-firing to coal-firing will generate considerate resistance from environmentalists, special interest groups, concerned citizens and possibly some government agencies. The objections will probably be based on two major factors:

— the change will increase the amount of pollutants emitted to the atmosphere and to the water. Principal concerns are sulphur oxides, fly-ash, ash leachates and coal-pile drainage. Ash disposal will also be a concern.

— the transportation of coal to the plant site by barge, introduces a new element into the plant operation. At present fuel is not usually transported to the site by water transport. The use of coal will increase marine traffic density in the east end of Burrard Inlet.

10.2.2 COAL STORAGE ALTERNATES

The alternatives of 12 day or about 7 day coal supply in storage at the Burrard Generating Station have been evaluated separately. Unquestionably the least amount of fill at the plant is the most desirable. It would be best if the existing site could accommodate the necessary coal handling and storage without change. If this is not possible the amount of filled area must be minimized. If possible the majority of the coal stockpile should be at the shipping port, provided that regular fuel deliveries can be assured.

Loss of habitat at the plant, because of filling, will be opposed by the Federal Fisheries Department. The entire Burrard Inlet area is under severe pressure from increasing population and industrialization, almost all of which tend to reduce the variety and abundance of habitat, and hence aquatic life, in the Inlet. The Fisheries Services personnel are often unable to predict reliably the effects of a particular activity, which means they often must adopt a conservative attitude. For this reason the coal storage area and the consequent filling should be minimized.

10.2.3 SQUAMISH

ADVANTAGES:

a) Coal transport, by unit train, will be over the existing B.C.R. track. Apart from possible track upgrading to handle the greater unit train weight, no extensive construction is required. The projected traffic volume 1.6 trains/day on average, is such that there will be no significant impact on recreation or aesthetics. Noise is likely to be of minor concern provided the trains are scheduled to pass through communities during the day.

b) Operation of a port at Squamish will provide local employment and an expanded tax base for the town.

c) Barge traffic up Howe Sound and into Burrard Inlet will be sheltered, and there will be minimal risk of coal spills into the aquatic environment during coal barging.

d) Squamish is located and sheltered such that barge deliveries will have a high reliability. Coal storage can be transferred from the Burrard Generating Station to the port at Squamish.

e) Resulting from d) above, the amount of filling required for the coal storage area at the Burrard Generating Station can be minimized.

DISADVANTAGES:

a) Squamish appears to be becoming a dormitory suburb for Vancouver. Such residents will oppose increasing industrialization in Squamish.

b) The only viable area in Squamish where port construction is possible, is in the estuary of the Squamish River. This is an important salmon river and further development in this area will be strongly resisted by environmental groups and government departments. A previous study* has ruled against the use of Squamish as a major port. A legacy of that earlier work is the existence of the "Save Howe Sound" Committee.

The gravel pit near Britannia Beach may meet the engineering and economic constraints of a port, and does satisfy many of the environmental objections.

However, the site is alongside the highway and would be opposed on aesthetic and recreational grounds.

In summary, any major development in Howe Sound will meet with strong opposition.

* "An Environmental Perspective on a Squamish Coal Port", Vo. 1-111, Howard Paish and Associates, Dec. 1972. Prepared for the Government of British Columbia.

10.2.4 ROBERTS BANK

ADVANTAGES:

a) Large quantities of coal are already being transported via unit train to Roberts Bank. The additional trains for the Hat Creek coal will have minor impact.

b) Roberts Bank is already the site of a large coal handling port. It is planned to expand the port facilities and coal storage area — regardless of the use of Hat Creek coal at the Burrard Generating Station.

c) The barge route is in sheltered waters and the risk of accidental coal discharge to the marine environment is slight.

d) Roberts Bank is close enough to Burrard Inlet that it could function as the dead coal storage for the Burrard Generating Station.

DISADVANTAGES:

Expansion of the Roberts Bank port may be opposed by environmentalists, and by Federal and Provincial Departments. The opposition would stem from the overall concern over the development of the Fraser River delta, and the loss of valuable salmon and herring habitat.

In mitigation, it should be recognized that expansion will be opposed whether or not Hat Creek coal passes through the port.

10.2.5 NEPTUNE TERMINALS

Neptune Terminals (NT), located in North Vancouver, between the First Narrows and Second Narrows, is a major coal handling facility. The terminal capacity is approximately 5 million tons/year and 500,000 tons of storage is available. The terminal now handles coking coal exports.

Rail access to NT is either by B.C. Railway from the west or by CN Railway from the east. At present, coal enters NT via the CN Railway. We consider that this is the way in which Hat Creek coal should enter NT, because it is believed that coal unit trains, even at only 1.6 trains/day might not be permitted to run on the BCR track through West Vancouver.

Our comparison of the NT alternate considers coal transport via the CNR to the terminal.

ADVANTAGES:

a) Large quantities of coal are already being transported via train to NT. If the terminal were devoted solely to handling Hat Creek coal, there would be no discernible change in operation, and there would be no change in the environmental impact.

b) NT is an existing, major coal handling facility within the Port of Vancouver. No new construction is necessary to handle the Hat Creek coal, providing the terminal can be dedicated solely to B.C. Hydro.

c) Barge traffic would be solely within the Port of Vancouver. The risk of accidental coal discharge through rough weather conditions is minimal.

10.2.6 PORT MOODY

The Port Moody alternate incorporates two possible port alternatives.

The first is a coal storage and handling facility constructed in Burrard Inlet by filling the Inlet. The area to be filled is approximately 1,800' x 750' (Drawing No. F/0036/500/SK3/0). The second alternatives is a coal storage facility constructed south of the Barnet Highway, and coal handling facilities only to be constructed by filling in Burrard Inlet. The area to be filled is approximately 750' x 250' (Drawing No. F/0036/500/SK4/0).

Of these alternatives, we believe that the latter is the more acceptable. There would be greater opposition to the amount of filling in the former case than in the latter, and we believe that the issue of fisheries and loss of aquatic habitat would be paramount factors in the environmental impact of a new facility.

Data collected in 1958 (pre-operational survey for British-American Oil), and in 1961, 1963, and 1969, indicate that there appeared to be changes in the bottom fauna due to refinery discharges. The principal change appeared to be a lower species diversity and a change in polychaeta species dominance. However, in 1969, polychaete worms, clams, snails, and cumacean crustaceans were abundant. Due to the bottom type and depth at the proposed fill area, and based on past observations, it is inferred that an abundant fauna will be present.

For the above reasons we have considered the Port Moody facility as having on-land storage and only a small fill area for loading.

DISADVANTAGES:

a) There will be opposition to any further filling and industrialization of the south shore of Burrard Inlet. Loss of habitat, and hence potential loss of fisheries, will be opposed by Federal and Provincial Fisheries Departments.

b) A new housing development is on the crest of the hill immediately above and behind the proposed dead-coal storage area. Noise, dust and aesthetics will create public opposition to the proposed port installation.

c) Unit-train movements, and the loading and unloading of coal, will be new activities in the area and will generate social antagonism. Increased employment, tax base, etc. are not likely to have a significant positive impact.

d) There will probably be a general objection to a proposed terminal on the grounds that there are already two other terminals (NT and Roberts Bank) which could serve the Burrard Generating Station.

11.0 PLANT MATERIAL BALANCES

11.1

Table 11.1 shows the plant material balances for fuel, air, stack gases and water.

Most of the water flow figures are derived from station records and modified as required. In recent years the station has not operated at full capacity and supply of fresh water from Buntzen Lake has been relatively unlimited and cheap. As a result there is probably a margin for reducing water flows for plant auxiliary cooling.

The last column shows the fresh water return to Burrard Inlet. This is clean water which has been used for coolign purposes only. The disposal of sludge from the water treatment plant, domestic sewage and chemicals from boiler cleaning will not increase except in so far as the load factor increases.

TABLE 11.1
MATERIAL BALANCES — LB/HR

	PULVERIZED COAL MODIFICATION	AIR BLOWN LURGI GAS	O_2 BLOWN LURGI GAS	O_2 BLOWN LURGI GAS WITH SOME CO_2 REMOVAL	FLUIDIZED COMBUSTION
STATION OUTPUT MW	630	630	800	900	900
Fuel Consumption	977,600[1]	2,077,200	1,626,600	414,00	1,117,200[2]
Air Consumption	5,515,900	4,326,400	5,730,000	6,470,400	7,071,700
TOTAL	6,493,500	6,403,600	7,356,600	6,884,400	8,188,900
Gas to Stack	6,249,125	6,403,600	7,356,600	6,884,400	7,839,700
Bottom Ash	48,875	---	---	---	174,600
Dust in Precipitator	195,500		---	---	174,600
TOTAL	6,493,500	6,403,600	7,356,600	6,884,400	8,188,900
Steam Generated	4,410,000	4,410,000	5,607,000	6,300,000	6,300,000
Continuous Blowdown	44,100	44,100	56,070	63,000	63,000
Soot Blowing	44,100	---	---	---	63,000
TOTAL	88,200	44,100	56,050	63,000	126,000
Domestic Water	140	140	140	140	140
Station Services and Auxiliary Cooling	881,660	925,760	1,243,810	1,316,860	1,253,860
Water to Water Treatment and Makeup	88,200	44,100	56,050	63,000	126,000
TOTAL	970,000	970,000	1,300,000	1,380,000	1,380,000
Fresh Water taken from Lake Buntzen	970,000	970,000	1,300,000	1,380,000	1,380,000
Blowdown Water to Ash Slurry[3]	10,750	---	---	---	38,410
Total Fresh Water Returned to Inlet[4]	915,010	969,860	1,299,880	1,379,860	1,278,450

Notes:
(1) Coal as received 20% moist
(2) Dried coal.
(3) Bottom ash retains 22% water.
(4) Station services and auxiliary cooling plus blowdown less blowdown water to ash slurry.

12.0 ACKNOWLEDGEMENTS

12.1

Special acknowledgement is given to the following organizations whose contribution of information assisting in this study is very much appreciated.

Wright Engineers Limited
Interport Consultants Ltd.
TransMountain Pipeline Company
Beak Consultants Limited
Swan Wooster Engineering Co. Ltd.
Alberta Research Council
Ontario Hydro
Alberta Power Limited
Calgary Power
Western Fly Ash Limited
Stock Equipment Company
Upper Lakes Shipping Limited
Interstate Equipment Corporation
British Columbia Railway
Canadian Pacific Railway
Canadian National Railway
Sussman Junk Co.
Neptune Terminals Ltd.
Seaspan International Ltd.
Kaiser Resources
General Metals of Tacoma Inc.
Bickerton Bridge & Steel Erectors Co.
Howden Parsons Ltd.
Combustion Engineering — Superheater Ltd.
Olympic Engineered Sales Inc.
CEGB — U.K.

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APPENDIX I

NOMENCLATURE

A	—	furnace plan area	ft^2
A_E	—	economizer heat transfer surface area	ft^2
A_H	—	air heater heat transfer surface area	ft^2
Cp	—	specific heat of flue gas	
Cpw	—	specific heat of water	
Cpa	—	specific heat of air	
DT_E	—	difference in mean temperatures of heating and heated media in economizer	°F
DT_H	—	difference in mean temperatures of heating and heated media in air heaters	°F
h_g	—	enthalpy of gas at adiabatic flame temperature	Btu/1b
h_E	—	heat transfer coefficient in economizer	Btu/ft^2hrF
H_H	—	heat transfer coefficient in air heater	Btu/ft^2hrF
K_1	—	constant embodying radiation heat transfer coefficient, furnace dimensions, etc.	Btu/hrF^4
K_2	—	gas constant	
K	—	gas constant	
L	—	distance from top burner to furnace exit	ft.
m	—	mass flow of products of combustion	lb/hr
MgE	—	mass flow of flue gas to economizer	lb/hr
Mw	—	mass flow of water to economizer	lb/hr
Ma	—	mass flow of air to air heaters	lb/hr
MgH	—	mass flow of gas to air heaters	lb/hr
M_1	—	**mass flow of gas on alternate fuel** mass flow of gas on N.G. firing at 100% rated capacity	
P	—	pressure of flue gas	psi g.
q	—	heat transfer from products of combustion to furnace wall tubes	Btu
Q_E	—	heat transfer rate in economizer	Btu/hr
Q_H	—	heat transfer rate in air heater	Btu/hr
S	—	height in furnace above top burner	ft
t	—	time	secs.
T	—	absolute temperature of products of combustion in furnace	R
To	—	absolute temperature of furnace wall tubes	R
T_1	=	T adiabatic = adiabatic flame temperature	R
T_2	=	FEGT = furnace exist gas temperature	R
Tao	—	air outlet temperature from air heaters	F

Tain	—	air inlet temperature to air heaters	F
$Tgin_H$	—	gas inlet temperature to air heaters	F
Tgo_H	—	gas outlet temperature from air heaters	F
Tgo_E	—	gas outlet temperature from economizer	F
$Tgin_E$	—	gas inlet temperature to economizer	F
Tw in	—	water inlet temperature to economizer	F
Tw o	—	water outlet temperature from economizer	F
$\frac{d}{dt}$	—	first derivative with respect to time	$\frac{1}{sec}$
$\frac{d}{ds}$	—	first derivative with respect to height in furnace	$\frac{1}{ft}$

APPENDIX 2

COMBUSTION CALCULATIONS

1. STEAM CONDITIONS

For 100% rated capacity,

Steam generated	=	1.05×10^6 pph
Steam reheated	=	0.952×10^6 pph
Reheat inlet temperature	=	695°F
Reheat inlet pressure	=	495 psig
Reheat outlet temperature	=	1010°F
Reheat outlet pressure	=	468 psig
Feed water temperature	=	466°F
Main steam temperature	=	1010°F
Main steam pressure	=	1850 psig

i.e. heat added to steam $= 1038 \times 1.05 \times 10^6 = 1089.9 \times 10^6$ Btu/hr

heat added to reheat steam $= 171 \times 0.952 \times 10^6 = 163 \times 10^6$ Btu/hr

Total heat input $= 1252.9 \times 10^6$ Btu/hr.

2. FUEL ANALYSES & COMBUSTION CALCULATIONS

2.1 COAL

2.1.1 ANALYSIS

CONSTITUENT	LB/LB FUEL	REQ'D FOR COMBUSTION		PRODUCTS OF COMBUSTION					
		O_2	AIR	CO_2	O_2	N_2	H_2O	SO_2	OTHER
C	0.4715	1.2542	5.4364	1.7257	-	4.1775	-	-	-
H_2	0.03675	0.2918	1.262	-	-	0.9706	0.3284	-	-
N_2	0.0115	-	-	-	-	0.0115	-	-	-
Cl	0.00025	-	-	-	-	-	-	-	0.00025
O_2	0.1616	-	-	-	0.1616	-	-	-	-
S	0.0051	0.005	0.022	-	-	0.017	-	0.01	-
Ash	0.3125	-	-	-	-	-	-	-	0.25*
Total		1.551	6.72	1.7257	0.1616	5.1766	0.3284	0.01	0.25025
Subtract for O_2 in coal		0.1616	0.7692	-	0.1616	0.6076	-	-	-
Stoichiometric		1.3894	5.951	1.7257	-	4.569	0.3284	0.01	0.25025

*Note: 20% of ash assumed removed in ash hopper.

The excess air used in several boilers firing coal similar to that being considered is 17% and consequently that value is assumed here, i.e. for 17% excess air 7.0532 lb standard air/lb coal required for combustion.

8.2256 lb/lb coal flue gas is produced.

20% moist coal is assumed and this moisture is included in the above flue gas calculation.

Flue gas moisture content = 8.1%

Higher Heating Value = 6410 Btu/lb coal wet = 8012 Btu/lb coal dry

2.1.2 EFFICIENCY

Stack gas temperature is assumed to be 300°F

$$\text{Dry gas loss} = \frac{8.2256 \times 220 \times 0.24}{8012} = 0.0542$$

$$\text{Moisture loss} = \frac{0.6701 \times 1040}{8012} = 0.0868$$

Unburned combustible	=	0.002
Manufacturers' Margin	=	0.015
Radiation	=	0.002
Total	=	0.16
Efficiency	=	84%

2.1.3 FUEL CONSUMPTION

$$\therefore \text{Coal consumption} = \frac{1252.9 \times 10^6}{0.84 \times 8012} = 0.1862 \times 10^6 \text{ pph}$$

Air consumption	=	1.313×10^6 pph
Flue gas flow	=	1.53×10^6 pph

2.1.4 ADIABATIC FLAME TEMPERATURE

Heat loss in furnace	— radiation	=	0.001
	— manufacturers' margin	=	0.015
	— loss to moisture in products of combustion	=	0.0426
	— loss to unburned combustible	=	0.002
	Total	=	0.0606

Assume air preheated to 530°F then heat available in furnace is

$$0.1862 \times 8012 \times 0.9394 \times 10^6 + 1.313 \times 450 \times 0.24 \times 10^6$$

$$= 1543 \times 10^6$$

$\therefore$ hg adiabatic = 1009 Btu/lb flue gas

$\therefore$ T adiabatic = 3350°F ref 1

2.2 AIR BLOWN LURGI GAS

2.2.1 ANALYSIS

CONSTITUENT	% BY VOL.	LB/LB FUEL	REQ'D FOR COMBUSTION		PRODUCTS OF COMBUSTION		
			O_2	AIR	CO_2	H_2O	N_2
CO_2	12.5	0.237	-	-	0.237	-	-
CO	17.1	0.206	0.1174	0.5088	0.3234	-	0.3914
H_2	23.5	0.02	0.1588	0.6868	-	0.1788	0.5282
CH_4	5.7	0.039	0.1566	0.6735	0.1069	0.0878	0.5179
N_2	41.2	0.497	-	-	-	-	0.497
H_2S	0.04	0.0006	-	-	-	-	-
Stoichiometric			0.4528	1.8691	0.6673	0.2666	1.9345

For 10% excess air — Air required for combustion = 2.0827 lb/lb fuel

Flue gas flow = 3.0827 lb/lb fuel

Flue gas moisture content = 9.5%

Higher Heating Value = 189 Btu/SCF = 3052 Btu/lb.

2.2.2 EFFICIENCY

Stack gas temperature is assumed to be 300°F

$$\text{Dry gas loss} = \frac{3.2721 \times 0.24 \times 220}{3053} = 0.0533$$

$$\text{Moisture in flue gas} = \frac{0.2959 \times 1040}{3053} = 0.0999$$

Radiation and manufacturer's margin = 0.017

Total = 0.1702

Efficiency = 82.98%

2.2.3 FUEL CONSUMPTION

$$\text{Gas consumption} = \frac{1252.9 \times 10^6}{3053 \times 0.8298} = 0.4946 \times 10^6 \text{ pph}$$

Air consumption = 1.0301×10^6 pph

Flue gas flow = 1.5247×10^6 pph

2.2.4 ADIABATIC FLAME TEMPERATURE

Heat loss in furnace:

Loss to radiation & manufacturer's margin	=	0.017
Loss of moisture in products of combustion	=	0.0908
Total	=	0.1078

Assume air preheated to 550°F then heat available in furnace is

$8.8922 \times 0.4946 \times 3053 + 1.0301 \times 0.24 \times 470 = 1463 \times 10^6$ Btu/hr.

∴ hg adiabatic = 960 Btu/lb

T adiabatic = 3195°F ———— ref 1

2.3 O_2 BLOWN LURGI GAS

2.3.1 ANALYSIS

CONSTITUENT	% BY VOL.	LB/LB FUEL	REQ'D FOR COMBUSTION		PRODUCTS OF COMBUSTION		
			O_2	AIR	CO_2	H_2O	N_2
CO_2	35	0.6994	-	-	0.6994	-	-
CO	14	0.178	0.1015	0.4397	0.2795	-	0.3382
H_2	39	0.0354	0.2811	1.2156	-	0.3165	0.9349
CH_4	12	0.0872	0.3479	1.5059	0.2389	0.1962	1.158
N_2	TR.						
Stoichiometric				3.1612	1.2178	0.5127	2.4311

For 10% excess air:

Air required for combustion	=	3.5225 lb/lb fuel
Flue gas flow	=	4.5215 lb/lb fuel
Flue gas moisture content	=	12.34%
Higher Heating Value = 293 Btu/SCF	=	5018 Btu/lb

2.3.2 EFFICIENCY

Stack gas temperature is assumed to be 300°F

$$\text{Dry gas loss} = \frac{4.5225 \times 220 \times 0.24}{5018} = 0.0476$$

$$\text{Loss to moisture} = \frac{0.5579 \times 1040}{5018} = 0.1156$$

Radiation	=	0.002
Manufacturer's margin	=	0.015
Total	=	0.1802

Efficiency = 81.98%

2.3.3 FUEL CONSUMPTION

Gas consumption	=	$\frac{1252.9 \times 10^6}{0.8198 \times 5018}$	=	0.3046×10^6 pph
Air consumption			=	1.073×10^6 pph
Flue gas flow			=	1.3776×10^6 pph

2.3.4 ADIABATIC FLAME TEMPERATURE

Heat loss in furnace:

Loss to radiation & manufacturer's margin	=	0.017
Loss to moisture in products of combustion	=	0.1063
Total	=	0.1233

Assume air preheated to 550°F then heat available to the furnace is $0.8767 \times 0.3046 \times 5018 \times 10^6 + 1.073 \times 470 \times 0.24 \times 10^6$ Btu/hr = 1461×10^6 Btu/hr

∴ hg adiabatic = 1060 Btu/lb

T adiabatic = 3390°F —— —— ref 1

2.4 O_2 BLOWN LURGI GAS WITH SOME CO_2 REMOVAL

2.4.1 ANALYSIS

CONSTITUENT	% BY VOL.	LB/LB FUEL	REQ'D FOR COMBUSTION		PRODUCTS OF COMBUSTION		
			O_2	AIR	CO_2	H_2O	N_2
CO_2	2	0.1156	-	-	0.1156	-	-
CO	7.5	0.2814	0.16	0.6951	0.4418	-	0.5347
H_2	72.7	0.196	1.548	6.7306	-	1.7522	5.1764
CH_4	16.8	0.3568	1.436	6.1619	0.9776	0.8028	4.7383
C_3H_6	0.5	0.0302	0.096	0.4473	0.0948	0.039	0.344
N_2	0.5	0.0201	-	-	-	-	0.0201
Stoichiometric				14.0350	1.6298	2.594	10.8135

For 10% excess air — standard air flow required for combustion	=	15.6384 lb/lb fuel
flue gas flow	=	16.6384 lb/lb fuel
moisture content	=	16.8%

Higher Heating Value = 442 Btu/SCF = 22319 Btu/lb

2.4.2 EFFICIENCY

Stack gas temperature is assumed to be 300°F

Dry gas loss $= \dfrac{16.638 \times 0.24 \times 220}{22319} = 0.0393$

Moisture in flue gas $= \dfrac{2.7897 \times 1040}{22319} = 0.1299$

Radiation and manufacturer's margin = 0.017

Total = 0.1862

Efficiency = 81.38%

2.4.3 FUEL CONSUMPTION

Gas Consumption $= \dfrac{1252.9 \times 10^6}{0.8138 \times 22319} = 0.069 \times 10^6$ pph

Air consumption $= 1.0784 \times 10^6$ pph

Flue gas flow $= 1.1474 \times 10^6$ pph

2.4.4 ADIABATIC FLAME TEMPERATURE

Heat loss in furnace:

Loss to radiation and manufacturer's margin = 0.017

Loss to moisture in products of combustion = 0.1207

Total = 0.1377

Assume air preheated to 550°F then heat available in the furnace is $0.8623 \times 0.069 \times 22319 \times 10^6 + 1.078 \times 0.24 \times 470 \times 10^6 = 1450 \times 10^6$ Btu/hr.

hg adiabatic = 1263 Btu/lb

T adiabatic = 3870°F

APPENDIX 3

FURNACE PERFORMANCE

The radiation heat transfer rate from the products of combustion to the furnace walls is

$$\frac{dq}{dt} = K_1 (T^4 - To^4) \qquad 3.1$$

where: T = flue gas temperature (absolute)

To = furnace wall temperature (absolute)

K_1 = constant embodying radiation heat transfer coefficient, furnace dimensions, etc.

As the gas flows through the furnace its temperature drops from the adiabatic flame temperature to the FEGT and typically these temperatures are of the order of 3500 and 2600°R which compares with the furnace wall temperature of the order of 1000°R. When these temperatures are substituted in equation 3.1 the fourth power involved has the effect that To can be neglected and so

$$\frac{dq}{dt} = K_1 T^4 \qquad 3.2$$

To determine the total heat transfer by radiation in the furnace it is necessary to integrate equation 3.2 from time zero to time t where t is the residence time of gas in the furnace. To do this the variation of temperature must be known.

By assuming the furnace plan area "A" constant at all elevations, the gas laws give the gas velocity in terms of temperature.

i.e. volume of gas $= m K_2 T$ — 3.3. from gas laws

where m = mass flow of gas

K_2 = constant

T = absolute temperature

i.e. the gas velocity $= \dfrac{mK_2T}{A}$

$$\text{i.e.} \quad \frac{dS}{dt} = \frac{mK_2T}{A} \qquad 3.4$$

where S is the distance above the topmost burner.

Combining 3.2 and 3.4 gives

$$\frac{dq}{dS} = \frac{dq}{dt}\frac{dt}{dS} = \frac{K_1 A}{mK_2}T^3 \qquad 3.5$$

Also, since the gas temperature drops by **dT** in travelling distance dS, in time dt,

$$\frac{dq}{dS} = -m\,Cp\,\frac{dT}{dS} \qquad 3.6$$

where Cp = gas specific heat

Combining 3.5 and 3.6 gives

$$\frac{dT}{dS} = \frac{-K_1A}{m^2K_2Cp}\,T^3 \qquad 3.7$$

Integrating equation 3.7 gives

$$\int \frac{dT}{T^3} = \frac{-K_1A}{m^2K_2Cp} \int dS$$

i.e. $$\frac{T^{-2}}{-2} = \frac{-K_1A}{m^2K_2Cp}\,S + C$$

for $S = O$, T = T adiabatic = T_1

$$\therefore\ -\frac{1}{2T_1^2} = C$$

$$\therefore\ \frac{1}{2T^2} = \frac{1}{2T_1^2} + \frac{K_1A\,S}{m^2K_2Cp}$$

i.e. $$T = \frac{T_1}{\left[1 + \left(\frac{2T_1{}^2K_1A}{m^2K_2\,Cp}\right)S\right]^{1/2}} \qquad 3.8$$

for $S = L$ where L = distance from topmost burner to furnace exit = 46 ft.,

$$T = \text{FEGT} = \frac{T_1}{\left(1 + \frac{2T_1{}^2K_1AL}{m^2K_2Cp}\right)^{1/2}} \qquad 3.9$$

The constants of equation 3.9 can be determined from performance data firing NG

i.e. for NG firing,

FEGT = 2680° R

T_1 = 4110° R

m = 1.228×10^6 pph

and substituting these constants in equation 3.10 results in

$$FEGT = \frac{T_1}{\left(1 + \frac{0.08 \times 10^{-6} T_1^2}{M_1^2}\right)^{1/2}} \qquad \text{—} \quad \ldots\ldots\ldots \ 3.10$$

$$\text{where } M_1 = \frac{\text{mass flow of gas on alternate fuel}}{\text{mass flow of gas on NG firing}}$$

By assuming the constants of equation 3.9 corresponding to NG firing to be the same for all fuels, equation 3.10 gives FEGT for a given fuel with its corresponding values for adiabatic flame temperature T_1 and flue gas mass flow ratio M_1. Equation 3.10 is used to determine FEGT corresponding to the firing rate to give 100% rated capacity on the various fuels and the FEGT vs capacity curves are then drawn parallel to that for NG firing in figure 4.1.

APPENDIX 4

FURNACE RESIDENCE TIME

As the flue gas passes through the furnace, its temperature drops from the adiabatic flame temperature at the top burner to FEGT at the furnace exit. The rate at which the temperature drops depends on the rate of heat transfer by radiation which is proportional to the fourth power of the absolute gas temperature.

From Appendix 3 equ. 3.8 gives

$$T = \frac{T_1}{\left[1 + \left(\frac{2T_1{}^2K_1A}{m^2K_2Cp}\right)S\right]^{1/2}} \tag{4.1}$$

For S = L $\quad T = FEGT = T_2$

$$\therefore \quad \frac{2T_1{}^2K_1AL}{m^2K_2Cp} = \frac{T_1{}^2}{T_2} - 1$$

$$\therefore \quad T = \frac{T_1}{\left[1 + \frac{S}{L}\left(\frac{T_1{}^2}{T_2} - 1\right)\right]^{1/2}} \tag{4.2}$$

Using equ. 4.2 and assuming the furnace plan area 'A' to be constant at all elevations, the gas velocity is

$$\frac{dS}{dt} = \frac{mK}{Ap} \frac{T_1}{\left[1 + \frac{S}{L}\left(\frac{T_1{}^2}{T_2} - 1\right)\right]^{1/2}} \tag{4.3}$$

Integrating equ. 4.3 over the height of the furnace gives

$$t = \frac{2ApL}{3mKT_1} \frac{\left[\left(\frac{T_1}{T_2}\right)^3 - 1\right]}{\left[\left(\frac{T_1}{T_2}\right)^2 - 1\right]} \tag{4.4}$$

For B.T.G.S.,

A = 942 ft^2

K = 0.37

p = 14.7 p.s.i.g.

L = 46 ft. so that equ. 4.4. becomes

$$t = \frac{4132 \times 10^6}{mT_1} \frac{\left[\left(\frac{T_1}{T_2}\right)^3 - 1\right]}{\left[\left(\frac{T_1}{T_2}\right)^2 - 1\right]} \qquad 4.5$$

Equ. 4.5 is used to determine the furnace residence times for different fuels at different capacities and these are shown in fig. 4.3.

APPENDIX 5

PERFORMANCE OF EXISTING ECONOMIZER

The economizer is treated as a simple heat exchanger where the quantitiy of heat transferred (Q_E) is given by

$$Q_E = h_E A_E D T_E \qquad \text{5.1}$$

where

h_E = effective heat transfer coefficient

A_E = heat transfer surface area

DT_E = difference in mean temperatures of heating and heated media

A more exact temperature difference is the logarithmic mean temperature difference but the error involved in using the mean temperature difference is small and its use here is justified by the simplicity so afforded.

Two further equations describing the heat transfer which occurs are obtained from consideration of heat balance in both the heating medium and heated medium.

i.e. $$Q_E = Mg_E \, Cp \, (Tgin_E - Tgo_E) \qquad \text{5.2}$$

$$Q_E = Mw \, Cpw \, (Two - Twin) \qquad \text{5.3}$$

where

Mg_E = gas mass flow

Mw = water mass flow

Cp = specific heat gas

Cpw = specific heat water

$Tgin_E$ = gas inlet temperature

Tgo_E = gas outlet temperature

$Twin$ = water inlet temperature

Two = water outlet temperature

from equations 5.2 and 5.3

$$Tgo_E = Tgin_E - \frac{MwCpw}{Mg_E Cp}(Two - Twin) \qquad \text{5.4}$$

$$\text{since } DT_E = \frac{Tgin_E + Tgo_E - Twin - Two}{2} \qquad \text{5.5}$$

substitution of equation 5.4 in equations 5.5 and 5.1 gives

$$Q_E = \frac{h_E A_E(}{2}\left[2\,Tgin_E - \frac{MwCpw}{Mg_ECp}(Two - Twin) - (Twin - Two)\right] \quad 5.6$$

Combining equations 5.6 and 5.3 gives

$$Two = \frac{2Tgin + Twin\left(\frac{2MwCpw}{hA} + \frac{MwCpw}{Mg_ECp} - 1\right)}{\frac{(2MwCpw}{h_EA_E} + \frac{MwCpw)}{Mg_ECp} + 1} \quad 5.7$$

From NG firing
$Tgin_E = 923F$
$Tgo_E = 625F$
$Twin = 466F$
$Two = 545F$
$Mw = 1.05 \times 10^6$ pph
$Mg_E = 1.228 \times 10^6$ pph

$$\text{i.e.}\quad DT_E = \frac{923 + 625 - 545 - 466}{2} = 268F$$

$$\therefore Q_E = h_EA_ED\,T_E = Mw\,Cpw\,(Two - Twin) \quad \text{gives}$$

$$H_EA_E x\, 268 = 1.05 \times 10^6\,(545 - 451)$$

$$h_EA_E = 0.3683 \times 10^6 \quad 5.8$$

Therefore substituting equation 5.8 in equation 5.7 gives

$$Two = \frac{2Tgin_E + Twin\left[\frac{2MwCpw}{0.3683 \times 10^6} + \frac{MwCpw}{Mg_ECp} - 1\right]}{\frac{2MwCpw}{0.3683 \times 10^6} + \frac{MwCpw}{Mg_ECp} + 1} \quad 5.9$$

and equation 5.9 can be used to predict the economizer outlet water temperature for different fuels at different capacities.

To do this it is necessary to know the value of $Tgin_E$ which is applicable. This is determined by reference to Figure 4.1 which shows FEGT vs capacity, the required gas temperature drop over the reheater and superheater can be calculated for the particular capacity of interest from Figure 4.4 and subtraction of this from the value of FEGT obtained from Figure 4.1 allows $Tgin_E$ to the economizer to be determined.

Using equation 5.9 in such a fashion Figure 4.5 was constructed.

APPENDIX 6

PERFORMANCE OF EXISTING AIR HEATERS

The air heaters may be considered as simple heat exchangers where the heat transfer (Q_H) between the flue gas and combustion air is given by

$$Q_H = h_H A_H DT_H \qquad 6.1$$

where h_H = effective heat transfer coefficient

A_H = heating surface area

DT_H = difference in mean temperatures of gas and air

Performing a heat balance in the gas and air over the heater yields two further equations

$$Q_H = MaCpa\,(Tao - Tain) \qquad 6.2$$

$$Q_H = Mg_H Cp\,(Tgin_H - Tgo_H) \qquad 6.3$$

where Ma = Mass flow of air

Mg_H = Mass flow of gas

Cpa = Specific heat air

Cp_H = specific heat gas

Tao = air outlet temperature

Tain = air inlet temperature

$Tgin_H$ = gas inlet temperature

Tgo_H = gas outlet temperature

Mean temperature difference $$DT_H = \frac{Tgin_H + Tgo_H - Tain - Tao}{2} \qquad 6.4$$

From equations 6.2 and 6.3

$$Tgin_H - Tgo_H = \frac{MaCpa}{Mg_H Cp}(Tao\text{-}Tain)$$

i.e. $$Tgo_H = Tgin_H - \frac{MaCpa}{Mg_H Cp}(Tao - Tain) \qquad 6.5$$

Substituting equation 6.5 in equation 6.4 gives

$$DT_H = \frac{Tgin_H + Tgin_H - \frac{MaCpa}{Mg_H Cp}(Tao\text{-}Tain) - Tain - Tao}{2} \qquad 6.6$$

Substituting equation 6.6 in equation 6.1 gives

$$Q_H = \frac{h_H A_H}{2}\left[2Tgin_H - Tao \left(\frac{MaCpa}{Mg_H Cp} + 1\right) + Tain\left(\frac{MaCpa}{Mg_H Cp} - 1\right)\right] \quad \text{——— 6.7}$$

Combining equations 6.7 and 6.2 gives

$$Tao\text{-}Tain = \frac{h_H A_H}{2MaCpa}\left[2Tgin_H - Tao\left(\frac{MaCpa}{Mg_H Cp} + 1\right) + Tain\left(\frac{MaCpa}{Mg_H Cp} - 1\right)\right]$$

$$\text{i.e. } Tao\left[1 + \frac{h_H A_H}{2MaCpa}\left(\frac{MaCpa}{Mg_H Cp} + 1\right)\right] = \frac{h_H A_H}{MaCpa} Tgin_H + \left[\frac{h_H A_H}{2MaCpa}\left(\frac{MaCpa}{Mg_H Cp} - 1\right) + 1\right] Tain$$

$$\text{i.e } Tao = \frac{\dfrac{h_H A_H}{MaCpa} Tgin_H + \left[\dfrac{h_H A_H}{2MaCpa}\left(\dfrac{MaCpa}{Mg_H Cp} - 1\right) + 1\right] Tain}{1 + \dfrac{hA}{2MaCpa}\left[\dfrac{MaCpa}{Mg_H Cp} + 1\right]} \quad \text{——— 6.8}$$

The constant ($h_H A_H$) can be determined from the performance on NG firing i.e. for NG firing at 100% capacity

Mg_H	=	0.614×10^6 pph to each heater
Ma	=	0.583×10^6 pph to each heater
$Tgin_H$	=	625F
Tao	=	530F
Cpa	=	0.24
Cp	=	0.27
Tain	=	80

∴ from equation 6.8

$$530 = \frac{\dfrac{h_H A_H \times 625}{0.583 \times 10^6 \times 0.24} + \left[\dfrac{h_H A_H}{2 \times 0.583 \times 10^6 \times 0.24}\left(\dfrac{0.583 \times 0.24}{0.614 \times 0.27} - 1\right) + 1\right] 80}{1 + \dfrac{h_H A_H}{2 \times 0.583 \times 10^6 \times 0.24}\left(\dfrac{0.583 \times 0.24}{0.614 \times 0.27} + 1\right)}$$

$$= \frac{4467\dfrac{h_H A_H}{10^6} - 44.6\dfrac{h_H A_H}{10^6} + 80}{1 + 6.59\dfrac{h_H A_H}{10^6}}$$

$$\frac{h_H A_H}{10^6} = 0.494 \quad \text{——— 6.9}$$

Substituting equation 6.9 in equation 6.8 gives

$$\mathrm{Tao} = \frac{\dfrac{0.494}{\mathrm{MaCpa}} \times 10^6\,\mathrm{Tgin_H} + \left[\dfrac{0.494}{2\mathrm{MaCpa}} \times 10^6\left(\dfrac{\mathrm{MaCpa}}{\mathrm{Mg_HCp}} - 1\right) + 1\right]\mathrm{Tain}}{1 + \dfrac{0.494}{2\mathrm{MaCpa}} \times 10^6\left(\dfrac{\mathrm{MaCpa}}{\mathrm{Mg_HCp}} + 1\right)} \qquad 6.10$$

Equation 6.10 can be used to predict the performance of the existing air heaters on gas fuels.

PERFORMANCE ON COAL FIRING

For the performance with coal firing the heat transfer coefficient must be downrated by 10% to account for the effects of dust, etc.

i.e. for coal firing $h_H A_H = 0.494 \times 0.9 \times 10^6$

$= 0.4446 \times 10^6$

Substituting in equation 6.8 gives

$$\mathrm{Tao} = \frac{\dfrac{0.4446 \times 10^6}{\mathrm{MaCpa}}\mathrm{Tgin} + \left[\dfrac{0.4446 \times 10^6}{2\mathrm{MaCpa}}\left(\dfrac{\mathrm{MaCpa}}{\mathrm{Mg_HCp}} - 1\right) + 1\right]\mathrm{Tain}}{1 + \dfrac{0.4446 \times 10^6}{2\,\mathrm{MaCpa}}\left(\dfrac{\mathrm{MaCpa}}{\mathrm{Mg_HCp}} + 1\right)} \qquad 6.11$$

Equation 6.11 can be used to predict the performance of the existing air heaters on coal firing.

A further complication with coal firing is that the combustion air comprises primary and secondary air which are fed to the coal pulverizers and windbox respectively at different pressures. To satisfy this requirement, one of each of the two existing air heaters will be used for primary air and secondary air respectively.

The required amount of gas passed to each heater must be determined and this can be done as follows.

At 70% capacity the FEGT on coal firing is 2180F (fig. 4.1). The superheater and reheater load at 70% capacity is $525 \times 0.7 \times 10^6$ Btu/hr.

$= 367.5 \times 10^6$ Btu/hr.

So that the gas temperature entering the economizer is 950°F.

The required feed water enthalpy at the economizer outlet is 560 Btu/lb so that the gas temperature leaving the replacement economizer will be 690°F.

i.e. the gas inlet temperature to the air heaters will be 690°F.

The ratio of primary to secondary air is taken as 1:2 so that at 70% capacity,

primary air flow $= 0.3064 \times 10^6$ pph

secondary air flow $= 0.6128 \times 10^6$ pph

Assume M pph gas is passed to the primary air heater and (1.071-M)pph gas is passed to the secondary air heater.

From equation 6.11 for the primary air heater

$$\text{Tao} = \frac{4172 + \left[3.023\left(\frac{\text{MaCpa}}{\text{MCp}} \cdot 1\right) + 1\right] 80}{1 + 3.023\left(\frac{\text{MaCpa}}{\text{MCp}} + 1\right)} \qquad \text{6.12}$$

Using Equations 6.10 and 6.12 the air outlet temperatures for the different fuels can be calculated and by using Equation 6.5 the corresponding gas outlet temperatures can be obtained.

This has been done for the different fuels considered, at the capacities which can be obtained, and the results are summarized in the table below:

	AIR BLOWN LURGI GAS	O_2 BLOWN LURGI GAS	COAL
Capacity	70%	89%	70%
Gas temp. to air heaters	630°F	650°F	690°F
Gas flow to air heaters	1.067 x 10^6 pph	1.2261 x 10^6 pph	1.071 x 10^6 pph
Primary	—	—	0.361 x 10^6 pph
Secondary	—	—	0.71 x 10^6 pph
Air flow to air heaters	0.7211 x 10^6 pph	0.955 x 10^6 pph	0.9192 x 10^6 pph
Primary	—	—	0.3064 x 10^6 pph
Secondary	—	—	0.6128 x 10^6 pph
Air outlet temperature	558°F	515°F	—
Primary	—	—	650°F
Secondary	—	—	585°F
Gas outlet temp.	342°F	349°F	281°F
Primary	—	—	242°F
Secondary	—	—	300°F

CAPITAL COST ESTIMATES — COAL TRANSPORTATION

Unit Train — SQUAMISH — Barge

LOCATION	ITEM	COST $\$ \times 10^3$	TOTAL PLANT COST $\$ \times 10^3$
Hat Creek	Mine Head Coal Storage and Unit Train		
	— loading plant		
	— site preparation	250	
	— bucket wheel stacker-reclaimer 140 ft. boom	3,500	
	— conveyors, 3000 ft., 2000 TPH, $475/ft.	1,425	
	— primary crushers, samplers	1,500	
	— transfer points	200	
	— electrical installation, lighting	500	
	— 1000 ft. x 2, rails for machines	150	
	— loading sites, two-5,000 tons each	2,500	
	Sub-Total:		10,175
Hat Creek	Rail Spur Line to BCR $8,125,000 given by BCH + 30% for unit train operation		10,560
Squamish	Unit Train Coal Unloading, Storage of 500,000 tons and barge loading (combined references, Wright Engineers, Swan Wooster, Neptune Terminals, Car & Associates)		22,000
Squamish — BTGS	Three Barges, 8,000 DWT each, self-unloading (Reference Interport Consultants Ltd.)		12,000
BTGS	Coal Receiving, Storage & Reclaiming Plant		
	— site preparation, excavation 73,000 cu. yd. fill 171,000 cu. yd.	1,200	
	— docking guides	300	
	— receiving hopper	150	
	— conveyors, 300 ft., 1000 TPH @	112	
	$375/ft., 1400 ft., 2000 TPH @ $475/ft.	665	
	— elevating steelwork to powerhouse	70	
	— transfer points	12	
	— bucket wheel stacker reclaimer, 150 ft. boom	3,700	
	— rails, 1400 ft., 2 rails	210	
	Sub-Total:		6,419
ESTIMATED CAPITAL COSTS:			61,154

CAPITAL COST ESTIMATES — COAL TRANSPORTATION

Unit Train—ROBERTS BANK—Barge

LOCATION	ITEM	TOTAL PLANT COST $ x 10^3
Hat Creek	Mine Head Coal Storage and Unit Train — loading plant (same as)	10,175
Hat Creek	Rail Spur Line to CNR (or CPR)	22,000
Roberts Bank to BTGS	Three Barges, 8,000 DWT each self-unloading	12,000
BTGS	Coal Receiving, Storage & Reclaiming Plant (same as)	6,419
ESTIMATED CAPITAL COSTS:		50,594

BCR Unit Train — NEPTUNE — Barge

LOCATION	ITEM	TOTAL PLANT COST $ x 10^3
Hat Creek	Mine Head Coal Storage (Unit Train — loading plant	10,175
Hat Creek	Rail Spur Line to BCR	10,560
Neptune to BTGS	Two Barges, 4,000 DWT each, self-unloading	4,000
BTGS	Coal Receiving, Storage & Reclaiming Plant	6,419
ESTIMATED CAPITAL COST:		31,154

CPR (or CNR) Unit Train — NEPTUNE — Barge

Hat Creek	Mine Head Coal Storage & Unit Train — loading plant	10,175
Hat Creek	Rail Spur Line to CPR (or CNR)	22,000
Neptune to BTGS	Two Barges, 4,000 DWT each, self-unloading	4,000
BTGS	Coal Receiving, Storage & Reclaiming Plant	6,419
ESTIMATED CAPITAL COST:		42,594

CPR Unit Train — PORT MOODY — Barge

LOCATION	ITEM	TOTAL PLANT COST $ x 10^3
Hat Creek	Mine Head Coal Storage & Unit Train — loading plant	10,175
Hat Creek	Rail Spur Line to CPR	22,000
Port Moody	Unit Train Coal Unloading, Storage of 400,000 to 500,000 tons & barge loading	25,000
Port Moody to BTGS	Two Barges, 4,000 DWT each, self-unloading	4,000
BTGS	Coal Receiving, Storage, & Reclaiming Plant	6,419
ESTIMATED CAPITAL COST:		67,594

CALCULATION OF TOTAL EFFECTIVE CAPITAL COST COAL TRANSPORTATION ALTERNATIVES

SLURRY

ITEM	$\$ \times 10^3$	$\$ \times 10^3$
Estimated capital cost		99,369
Contingency @ 15%	14,905	
Adjusted capital cost		114,274
Engineering cost including construction supervision @ 8%	9,142	
Corporate overhead @ 5%	5,714	
Effective capital cost		129,130
Interest during construction		
1st year, @ 40% complete, 10% interest	2,583	
2nd year, @ 100% complete, 10% interest	9,040	
TOTAL EFFECTIVE CAPITAL COST:		140,753

Unit Train — SQUAMISH — Barge

ITEM	$\$ \times 10^3$	$\$ \times 10^3$
Estimated capital cost		61,154
Contingency @ 15%	9,173	
Adjusted capital cost		70,327
Engineering cost including construction supervision, 8%	5,626	
Corporate overhead, 5%	3,516	
Effective capital cost		79,469
Interest during Construction		
1st year @ 40% complete, 10% interest	1,589	
2nd year @ 100%, 10% interest	5,562	
TOTAL EFFECTIVE CAPITAL COST:		86,620

Unit Train — ROBERTS BANK — Barge

ITEM	$\$ \times 10^3$	$\$ \times 10^3$
Estimated capital cost		50,594
Contingency @ 15%	7,589	
Adjusted capital cost		58,183
Engineering cost including construction supervision, 8%	4,654	
Corporate overhead, 5%	2,909	
Effective capital cost		65,746
Interest during construction		
1st year @ 40% complete, 10% interest	1,314	
2nd year @ 100% complete, 10% interest	4,602	
TOTAL EFFECTIVE CAPITAL COST:		71,662

CALCULATION OF TOTAL EFFECTIVE CAPITAL COST
COAL TRANSPORTATION ALTERNATIVES

BCR Unit Train — NEPTUNE — Barge

ITEM	$ x 10^3	$ x 10^3
Estimated capital cost		31,154
Contingency @ 15%	4,673	
Adjusted capital cost		35,827
Engineering cost including construction supervision, 8%	2,866	
Corporate overhead, 5%	1,791	
Effective capital cost		40,484
Interest During Construction		
1st year @ 40% complete, 10% interest	809	
2nd year @ 100% complete, 10% interest	2,833	
TOTAL EFFECTIVE CAPITAL COST:		44,126

CPR Unit Train — NEPTUNE — Barge

Estimated capital cost		42,594
Contingency @ 15%	6,389	
Adjusted capital cost		48,983
Engineering cost including construction supervision, 8%	3,918	
Corporate overhead, 5%	2,449	
Effective capital cost		55,350
Interest during construction		
1st year @ 40% complete, 10% interest	1,107	
2nd year @ 100% complete, 10% interest	3,874	
TOTAL EFFECTIVE CAPITAL COST:		60,331

CPR Unit Train — PORT MOODY — Barge

ITEM	$ x 10^3	$ x 10^3
Estimated capital cost		67,594
Contingency @ 15%	10,139	
Adjusted capital cost		77,733
Engineering cost including construction supervision, 8%	6,218	
Corporate overhead, 5%	3,886	
Effective capital cost		87,837
Interest During Construction		
1st year @ 40% complete, 10% interest	1,756	
2nd year @ 100% complete, 10% interest	6,148	
TOTAL EFFECTIVE CAPITAL COST:		95,741

FUEL COST CALCULATION
COAL TRANSPORTATION ALTERNATIVES

SLURRY 900 MW @ 70% Cap. Factor, 4.05 x 10^6 tons/yr. *

ITEM	UNIT COST $/TON	¢/Btu × 10^6
Annual charge on capital of $140,753,000 @ 12.33%	4.32	34.59
Minehead coal cost	3.00	24.04
Slurry preparation plant operation	.61	4.92
Pumping stations operation	.20	1.66
Dewatering plant operation	.21	1.67
TOTAL FUEL TRANSPORTATION COST	8.34	66.88

* Since the slurry alternative does not provide for a large reserve stock pile, it must have carrying capacity for the 100% MCR condition of 16,000 TPD.

Unit Train — SQUAMISH — Barge 900 MW @ 70% cap. factor, 4.05 x 10^6 tons/yr.

ITEM	UNIT COST $/TON	¢/Btu × 10^6
Annual charge on capital of $86,620,000 @ 12.33%*	2.65	21.13
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	.96
Unit Train to Squamish 140 Miles x 1.75¢/ton mile	2.45	19.63
Squamish unloading, storage, reclaiming and barge loading	.18	1.44
Barge towing	.54	4.33
BTGS Unloading, stacking, storage and reclaiming	.13	1.04
TOTAL FUEL COST:	9.07	72.57

*Includes:		
	Interest	10.00%
	Administration & General	.36%
	Insurance	.25%
	Interim replacement	.35%
	Taxes	1.00%
	Depreciation	.37%
	TOTAL	12.33%

Maintenance is included individually in operating costs.

Unit Train — ROBERTS BANK — Barge 900 MW @ 70% cap. factor, 4.05 x 10^6 tons/yr.

ITEM	UNIT COST $/TON	¢/Btu × 10^6
Annual charge on capital of $71,662,000 @ 12.33%	2.20	17.61
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	.96
Unit Train to Roberts Bank 205 miles x 1.75 ¢/ton mile	3.58	28.68
Roberts Bank unloading, storage, reclaiming & barge loading	1.00	8.01
Barge towing	.54	4.33
BTGS Unloading, stacking, storage & reclaiming	.13	1.04
TOTAL FUEL COST:	10.57	84.68

FUEL COST CALCULATION
COAL TRANSPORTATION ALTERNATIVES

BCR Unit Train — NEPTUNE — Barge

900 MW @ 70% cap. factor, 4.05 x 10^6 tons/yr.

ITEM	UNIT COST S/TON	¢/Btu × 10^6
Annual charge on capital of 44,126,000 @ 12.33%	1.35	10.84
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	.96
BCR Unit Train to Neptune 180 miles x 1.75c/ton mile	3.15	25.24
Neptune unloading, storage, reclaiming & barge loading	1.25	10.02
Barge towing	.31	2.48
BTGS Unloading, stacking, storage & reclaiming	.13	1.04
TOTAL FUEL COST:	9.41	74.66

CPR Unit Train — NEPTUNE — Barge

900 MW @ 70% cap. factor, 4.05 x 10^6 tons/yr.

ITEM	UNIT COST S/TON	¢/Btu × 10^6
Annual charge on capital of $60,331,000 @ 12.33%	1.85	14.82
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	.96
CPR Unit Train to Neptune 207 miles x 1.75¢/ton mile	3.62	29.03
Neptune unloading, stacking, storage, reclaiming & barge loading	1.25	10.02
Barge towing	.25	2.48
BTGS Unloadings, stacking, storage & reclaiming	.13	1.04
TOTAL FUEL COST:	10.22	82.39

CPR Unit Train — PORT MOODY — Barge

900 MW @ 70% cap. factor, 4.05 x 10^6 tons/yr.

ITEM	UNIT COST $/TON	¢/Btu × 10^6
Annual charge on capital of $95,741,000 @ 12.33%	2.94	23.53
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	.96
CPR Unit Train to Port Moody 200 miles x 1.75c/ton mile	3.50	28.04
Port Moody unloading, storage, reclaiming & barge loading	.18	1.44
Barge towing	.20	1.60
BTGS Unloadings, stacking, storage & reclaiming	.13	1.04
TOTAL FUEL COST:	10.07	80.48

FUEL COST CALCULATION
COAL TRANSPORTATION ALTERNATIVES

SLURRY **630 MW @ 79% cap. factor, 2.83 x 10^6 Tons/year ***

ITEM	UNIT COST $/TON	UNIT COST ¢/Btu x 10^6
Annual charge on capital of $119,640,000 @ 12.33%	5.25	42.07
Minehead coal cost	3.00	24.04
Slurry preparation plant, operation	.55	4.41
Pumping stations, operation	.16	1.28
Dewatering plant, operation	.17	1.36
TOTAL FUEL TRANSPORTATION COST:	9.13	73.16

* Carrying capacity 11,200 TPD

Unit Train — SQUAMISH — Barge 630 MW @ 70% cap. factor, 2.83 x 10^6 tons/yr.

ITEM	UNIT COST $/TON	UNIT COST ¢/Btu x 10^6
Annual charge on capital of $77,958 @ 12.33% *	3.42	27.41
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.14	1.12
Unit Train to Squamish 140 miles x 2¢/ton mile	2.80	22.44
Squamish unloading, storage, reclaiming & barge loading	.20	1.60
Barge towing	.78	6.25
BTGS Unloading, stacking, storage & reclaiming	.15	1.20
TOTAL FUEL COST:	10.49	84.05

* Capital costs reduced 10% from 900 MW estimates

Unit Train — ROBERTS BANK — Barge 630 MW x 70% cap. factor, 2.83 x 10^6 Tons/yr.

ITEM	UNIT COST $/TON	UNIT COST ¢/Btu x 10^6
Annual charge on capital of $64,495,800 @ 12.33%	2.83	22.68
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	
Unit Train to Roberts Bank 205 miles x 2¢/ton mile	4.10	32.85
Roberts Bank unloading, storage, reclaiming & barge loading	1.00	8.01
Barge towing	.78	6.25
BTGS Unloadings, stacking, storage & reclaiming	.15	1.20
TOTAL FUEL COST:	12.00	96.15

CPR Unit Train — PORT MOODY — Barge 630 MW @ 70% cap. factor, 2.83 x 10^6 Tons/yr.

ITEM	UNIT COST $/TON	UNIT COST ¢/Btu x 10^6
Annual charge on capital of $86,166,900 @ 12.33%	3.78	30.30
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	
CPR Unit Train to Port Moody 200 miles x 2¢/ton mile	4.00	32.05
Port Moody unloading, storage, reclaiming & barge loading	.20	1.60
Barge towing	.30	2.40
BTGS Unloadings, stacking, storage & reclaiming	.15	1.20
TOTAL FUEL COST:	11.57	92.71

FUEL COST CALCULATION
COAL TRANSPORTATION ALTERNATIVES

CPR Unit Train — NEPTUNE — Barge 630 MW x 70% cap. factor, 2.83 x 10^6 tons/yr.

ITEM	UNIT COST $/TON	¢/Btu × 10^6
Annual charge on capital of $54,297,900 @ 12.33%	2.38	19.09
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	1.12
CPR Unit Train to Neptune 207 miles x 2¢/ton mile	4.14	33.17
Neptune unloading, stacking, storage, reclaiming & barge loading	1.25	10.02
Barge towing	.45	3.61
BTGS Unloadings, stacking, storage & reclaiming	.15	1.20
TOTAL FUEL COST:	11.51	92.15

BCR Unit Train — NEPTUNE — Barge 630 MW x 70% cap. factor, 2.83 x 10^6 tons/yr.

ITEM	UNIT COST $ /TON	¢/Btu × 10^6
Annual charge on capital of $39,713,400 @ 12.33%	1.74	13.97
Mine Head Coal Cost	3.00	24.04
Hat Creek Loading	.12	1.12
BCR Unit Train for Neptune 180 miles x 2¢/ton mile	3.60	28.85
Neptune unloading, storage, reclaiming & barge loading	1.25	10.02
Barge towing	.45	3.61
BTGS Unloadings, stacking, storage & reclaiming	.15	1.20
TOTAL FUEL COST:	10.33	82.81

ASH TRANSPORTATION ALTERNATIVES

CAPITAL COSTS

Barge-Reclamation Site 900 MW

Reclamation site assumed to be within 40 nautical miles.

ITEM	COST ($ x 10^3)
2-400 Ton dry storage silos, pneumatic systems, bottom ash crusher, 200 Ton dewatering bin.	2,900
2-4000 Ton self unloading barges with retractable 150-foot discharge boom.	5,200
TOTAL CAPITAL COST	8,100

Barge—TERMINAL—Trains 900 MW

ITEM	COST ($ x 10^3)
2-400 Ton dry storage silos, pneumatic systems, bottom ash crusher, 2000 Ton dewatering bin.	2,900
Provision for larger barges to accommodate increased cycle time for ash loading and unloading.	4,500
Terminal unloading hopper, conveyors and two 200,000 ton unit train loading silos.	1,850
Hat Creek car tipper and hoppers.	1,900
Provision for conveyers or water slurry to nearby lagoon.	1,000
TOTAL CAPITAL COST	12,150

CALCULATION OF TOTAL EFFECTIVE CAPITAL COST

ASH TRANSPORTATION ALTERNATIVES

Barge—Reclamation Site

ITEM	($ x 10^3)	($ x 10^3)
Estimated capital cost		8,100
Contingency, 15%	1,215	
Adjusted capital cost		9,315
Engineering cost including construction, supervision, 8%	745	
Corporate overhead	465	
Effective capital cost		10,525
Interest during construction		
1st year @ 40% complete, 10% interest	210	
2nd year @ 100% complete, 10% interest	737	
TOTAL EFFECTIVE CAPITAL COST		11,472

Barge—TERMINAL—Unit Train

ITEM	$ x 10^3	$ x 10^3
Estimated capital cost		12,150
Contingency, 15%	1,822	
Adjusted capital cost		13,972
Engineering cost including construction, supervision, 8%	1,117	
Corporate overhead, 5%	698	
Effective capital cost		15,787
Interest during construction		
1st year @ 40% complete, 10% interest	315	
2nd year @ 100% complete, 10% interest	1,104	
TOTAL EFFECTIVE CAPITAL COST		17,206

Barge—Reclamation Site
900 MW @ 70% cap. factor, 1.05 x 10^6 tons/yr.

Reclamation site assumed to be within 40 nautical miles of BTGS

ITEM	$/TON
Annual charge on capital of $11,472,000 @ 12.33%	1.35
B.T.G.S. barge loading	.15
Barge to reclamation site, return	.74
TOTAL ASH DISPOSAL COST	2.24

Barge—SQUAMISH—Unit Train 900 MW @ 70% cap. factor 1.05 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $17,206,000 @ 12.33%	2.02
B.T.G.S. Barge loading	.15
Barge back-haul to Squamish	.32
Unloading, Silo storage and loading	.18
Unit train back-haul to Hat Creek 140 miles @ 1.10 ¢/ton mile.	1.54
Hat Creek unloading and lagoon disposal	.12
TOTAL ASH CAPITAL COST	4.33

TOTAL ASH DISPOSAL COST CALCULATION

ASH TRANSPORTATION ALTERNATIVES

Barge — ROBERTS BANK — Unit Train

900 MW @ 70% cap. factor, 1.05 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $17,206,000 @ 12.33%	2.02
B.T.G.S. barge loading	.15
Barge back-haul to ROBERTS BANK	.32
Unloading, silo storage and loading	.18
Unit train back-haul to Hat Creek	
205 miles @ 1.10 ¢/ton mile	2.25
Hat Creek loading and lagoon disposal	.12
TOTAL ASH DISPOSAL COST	5.04

Barge—NEPTUNE—BCR Unit Train

900 MW @ 70% cap. factor, 1.05 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $17,206,000 @ 12.33%*	2.02
B.T.G.S. Barge loading	.15
Barge back-haul to NEPTUNE	.17
NEPTUNE unloading, silo storage and unit train loading.	.18
Unit train back-haul to Hat Creek 180 miles @ 1.10 ¢/ton mile.	1.98
Hat Creek unloading and lagoon disposal	.12
TOTAL ASH DISPOSAL COST	4.62

* Includes:	Depreciation	.37%
	Administration & general	.36%
	Insurance	.25%
	Interim replacement	.35%
	Taxes	1.00%
	Interest	10.00%
		12.33%

Maintenance is included in individual operating costs.

Barge—NEPTUNE—CPR Unit Train

900 MW @ 70% cap. factor, 1.05 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $17,206,00 @ 12.33%	2.02
B.T.G.S. barge loading	.15
Barge back-haul to NEPTUNE	.17
Unloading, silo storage and loading	.18
CPR unit train back-haul to Hat Creek	
207 miles @ 1.10 ¢/ton mile	2.28
Hat Creek unloading and lagoon disposal	.12
TOTAL ASH DISPOSAL COST	4.92

TOTAL ASH DISPOSAL COST CALCULATION

ASH TRANSPORTATION ALTERNATIVES

Barge—PORT MOODY—Unit Train 900 MW @ 70% cap. factor 1.05 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $17,206,000 @ 12.33%	2.02
B.T.G.S. barge loading	.15
Barge back-haul to PORT MOODY	.11
PORT MOODY unloading, silo storage and unit train loading	.18
Unit Train back-haul to Hat Creek 200 miles @ 1.10 c/ton mile	2.20
Hat Creek unloading and lagoon disposal	.12
TOTAL ASH DISPOSAL COST	4.78

Barge—Reclamation Site 630 MW @ 70% cap. factor .84 x 10^6 tons/yr.

Reclamation site assumed to be within 40 nautical miles of B.T.G.S.

ITEM	$/TON
Annual charge on capital of $10,325,000 @ 12.33%	1.52
B.T.G.S. barge loading	.17
Barge to reclamation site, return	.74
TOTAL ASH DISPOSAL COST	2.43

Barge—SQUAMISH—Unit Train 630 MW @ 70% cap. factor .84 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $15,485,000 @ 12.33%	2.27
B.T.G.S. barge loading	.17
Barge back-haul to SQUAMISH	.34
Unloading, silo storage and loading	.18
Unit train back-haul to Hat Creek 140 miles @ 1.35 ¢/ton mile	1.89
Hat Creek unloading & lagoon disposal	.13
TOTAL ASH DISPOSAL COST	4.98

Barge—ROBERTS BANK—Unit Train 630 MW @ 70% cap. factor .84 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $15,485,000 @ 12.33%	2.27
B.T.G.S. barge loading	.17
Barge back-haul to ROBERTS BANK	.34
Unloading, silo storage and loading	.19
Unit train back-haul to Hat Creek 205 miles @ 1.35 ¢/ton mile	2.75
Hat Creek unloading and lagoon disposal	.13
TOTAL ASH DISPOSAL COST	5.86

TOTAL ASH DISPOSAL COST CALCULATION

ASH TRANSPORTATION ALTERNATIVES

Barge—NEPTUNE—BCR Unit Train
630 MW @ 70% cap. factor .84 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $15,485,000 @ 12.33%	2.27
B.T.G.S. Barge loading	.17
Barge back-haul to NEPTUNE	.17
NEPTUNE unloading, silo storage and unit train loading.	.19
B.C.R. unit train back-haul to Hat Creek 180 miles @ 1.35 ¢/ton mile.	2.43
Hat Creek unloading and lagoon disposal	.13
TOTAL ASH DISPOSAL COST	5.36

Barge—NEPTUNE—CPR Unit Train
630 MW @ 70% cap. factor .84 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $15,485,000 @ 12.33%	2.27
B.T.G.S. barge loading	.17
Barge back-haul to NEPTUNE	.17
Unloading, silo storage and unit train loading	.18
CPR unit train back-haul to Hat Creek 207 miles @ 1.35 ¢/ton mile	2.79
Hat Creek unloading and lagoon disposal	.13
TOTAL ASH DISPOSAL COST	5.71

Barge—PORT MOODY—Unit Train
630 MW @ 70% cap. factor .84 x 10^6 tons/yr.

ITEM	$/TON
Annual charge on capital of $15,485,000 @ 12.33%	2.27
B.T.G.S. barge loading	.17
Barge back-haul to Port Moody	.13
Unloading, silo storage and unit train loading	.19
Unit train back-haul to Hat Creek 200 miles @ 1.35 ¢/ton mile	2.70
Hat Creek unloading and lagoon disposal	.13
TOTAL ASH DISPOSAL COST	5.59

COAL/WATER SLURRY EVALUATION

COAL SLURRY PIPELINE PRELIMINARY NOTES & CALCULATIONS

INTRODUCTION

A slurry system breaks down into three distinct process plant sections as follows:

a) Slurry preparation at mine site & water supply

b) Pumping stations & pipeline

c) Dewatering & coal handling at power station site.

Each of these plant areas requires an analysis of capital costs, labour costs and power requirements.

BASIS FOR DESIGN

A continuous power demand of 900 MW = 5,770,000 tons/year

Coal demand @ 80% annual load factor = 4,600,000 tons/year.

Initial costing of system is based on a pipeline capable of a nominal 6,000,000 tons/year.

Yearly pipeline capacity can be reduced by speed control of pumping stations or loading the line with water.

SLURRY PREPARATION

DESIGN ASSUMPTIONS

The coal washing plant at the mine site will provide an adequate storage of dry coal to supply the slurry preparation plant at all times including provision for twelve hour mine shutdown periods.

Slurries from the coal washing plant are free of oversize coal, excessive slime fraction and trash, and need no further screening.

POWER IS AVAILABLE

The necessary water rights are obtainable for the required plant consumption.

GENERAL PROCESS DESCRIPTION

Two basic products are received from the coal washing plant at the mine. These are flotation fines in the minus 28 mesh to zero range and a minus ¾" main coal product. The main coal product is conveyed to a surge bin from where it is conveyed to the rod mills. Classification is achieved by a single deck vibrating screen from which the plus 14 mesh oversize goes back to grinding and the screen undersize, depending on the percentage solids content, either goes to thickening or one of the five agitated holding tanks.

In the holding tanks the two product streams join to make up the pipeline product, i.e. the screen undersize materials and the thickened flotation fines. In these holding tanks, final adjustment for the correct pipeline density takes place as well as measurement of the product screen analysis. Densities are measured on a continuous basis and adjustments can be made automatically by the addition of water or thickened underflow product.

Five tanks are supplied for prepared coal slurry. One is being filled from production at all times, one is being tested prior to being pumped, one is being pumped to the pipeline pumphouse and the remaining two are full of prepared slurry as stored reserves.

POWER SUPPLY

POWER AVAILABILITY

It has been assumed that major power supplies will be available to the slurry preparation plant from a sub-station built to supply the overall needs of the mine site.

POWER DISTRIBUTION

A suitably located electrical room will contain the starters and excitation units for the mill drive motors, and 4160/480V transformers to reduce voltage for supplying the 480V motor control centres.

EQUIPMENT ENCLOSURES

Equipment enclosures, in the general plant area, will comply with the requirements of Class II, Group F hazardous locations (for atmospheres containing coal dust) as designated in Part V of the Canadian Electrical Code.

DESIGN CRITERIA

Motors over 250 horsepower	—4000 volts, 3 phase
Motors ½ to 250 horsepower and reversing duty motors of all sizes	—460 volts, 3 phase
Motors under ½ horsepower	—120 volts, single phase
High bay lighting	—480 volts, 3 phase
General lighting	—120 volts, single phase
Motor control	—120 volts.

Emergency lighting will consist of self-contained relay/battery sealed beam units placed at strategic locations.

WATER SUPPLY

The total water quantity required for the slurry preparation plant is 3,000 USgpm for six million tons per year. All water supply facilities would be designed for 3,000 USgpm supplied 365 days per year 24 hours per day.

The major water source in the area of the coal deposits is the Fraser River. A detailed study of local conditions has not been made, but reference to the Department of Lands official survey map of the Ashcroft district suggests a pumping station could be sited southwest of Pavilion where access to the river is easier.

The extreme variations in daily discharge flow range from 289,000 cubic feet per second to 4,000 cubic feet per second. Ice conditions prevail on the river between late November and the end of March. Levels vary from a minimum of 2.5 feet to a maximum of 43 feet.

Water will be drawn through a field of horizontal perforated pipes buried in a gravel filter below the river bed. This arrangement provides water during ice-up conditions and during periods of low river flow.

From the intake pit a vertical turbine pump would lift the water to a second pump suction chamber fitted with baffles to settle out the remaining silt material. From this second suction chamber a high lift centrifugal pump would supply the pipeline. Standby pumps would be provided at both stages and pump operation would be fully automatic with indications supplied to the slurry preparation plant control room. Power supplies for the water supply pumping station are available via the existing local distribution network.

The pipeline distance between the proposed river pumping station and the mine site is approximately 16 miles and the pipeline route would follow the power distribution line connecting Pavilion to the mine area.

SLURRY PIPELINE

PIPELINE ROUTING

The route was selected on a preliminary basis from Survey and Mapping Branch, British Columbia Contour Interval, 100 feet; scale 1:50,000 maps. No field inspections were made.

Route description is as follows (see Drawing A-0036-500-Sk. 10).

APPROXIMATE MILE POST	PIPE LINE MILE	LOCATION
0	0	Hat Creek
6.5	7.2	Fountain Range Summit
19.0	21.0	Lillooet
32.0	35.4	Shalath
50.0	55.4	D'Arcy
58.5	64.8	Berkin
72.5	80.3	Pemberton
90.0	99.6	Alta Lake
99.0	109.6	Brandywine Falls
104.0	115.0	Garibaldi
116.0	128.4	Cheekeye
122.0	135.0	Mamquam River
151.0	167.0	Buntzen Aquaduct
155.0	171.6	Ioco — Burrard Steam Plant

The profile of the pipe line is shown on Drawing A-0036-500-Sk. 9.

SITE PREPARATION

The land area required for receiving, dewatering, and water treatment is approximately 700' x 1400', on 22.5 acres. To provide this area via reclamation of the BTGS waterfront, making maximum use of existing available space will require 1.3 million cubic yards of rock fill. At $7.50 per cubic yard and including granular surfacing, site preparation cost will be approximately $9.88 million.

The alternative to a dewatering complex at the BTGS waterfront is the area to the north, northwest of the power house. Aerial reconnaissance and examination of topographical maps showed that such an area would be a minimum of 2300' from the power house, and would require a rock cut and fill operation of approximately 700 cubic yards. Total levelling cost will be approximately $5.25 million. Additional slurry line and coal conveyor costs for such a site 2300 feet from the power house will be $2.125 million and $2.40 million. The total estimated cost for a remote dewatering site is therefore approximately $9.78 million.

BASIS FOR COST ESTIMATION

The pipeline cost estimates include the following:

a) 20" O.D. pipe 0.375 wall Grade X 60
b) Casing pipe
c) Coating materials
d) Rock shield
e) Gunniting
f) River and swamp weights
g) Casing seals and insulators
h) Main line valves
i) Fencing, valve boxes, ROW markers
j) Scraper traps (sending and receiving)
k) Cathodic protection.

The total material cost has been increased by 10% to allow for contingencies.

Cost of pipe is taken at $528/ton delivered to site; other materials at current market prices.

CONSTRUCTION COSTS

The construction costs cover:

a) Pipe stringing, laying, ditching, welding, cleaning, lowering in, back-filling and clean-up.
b) ROW clearing, grading and grubbing
c) Rock removal (on ROW)
d) Rock removal (in ditch)
e) Extra coating at crossings
f) Padding and rock shielding
g) Installing river and swamp weights
h) Test welds
i) Installation of block valves
j) Costs for boring and casing of crossings
k) Installation of scraper traps
l) X-raying
m) Individual costs for major river crossings
n) Contract extras based on a per footage
o) 100% hydrostatic testing
p) Freight charges

ROW COSTS

The costs directly associated with the right-of-way include the following:

a) Survey costs (old and new ROW)
b) Working room allowance
c) General considerations
d) Damages.

NOTE: No allowances have been made for right-of-way acquisition.

DEWATERING

Two alternate types of dewatering equipment are available for pipeline slurries. One is the vacuum disc filter and the other the centrifuge. Owing to the higher operating and maintenance costs of the centrifuges, our preferred design includes vacuum disc filters.

The dewatering system is shown schematically on Dwg. 500 SK8. The pipeline coal is diverted via a pressurized splitter into the holding tanks through automatically controlled valves. The slurry is pumped from the holding tanks by soft-rubber lined pumps to a pulp splitter which distributes the slurry to the disc filters.

To maintain availability of the system, spare pumps have been allowed for wherever excessive pump wear is a likely problem, and where pump failure would lead to a plant shutdown.

To obtain maximum service life from the connecting pipework, all pipe runs up to the filters are fully rubber lined.

The dewatered coal, at a moisture content in the range 25-35% is conveyed directly to the main coal bunkers. The exact range of moisture for satisfactory flow characteristics within the bunker-coal feeder — pulverizer downspout system for a given size and geometry of bunker is unknown and a large scale test programme would be necessary to determine the optimum parameters.

INCIDENTALS

The incidentals cover the following:

a) Environmental impact study
b) Timber cruising reports
c) Stumpage fees for timbered areas
d) Aerial photography and mapping
e) Rip rapping, sandbagging and corduroying
f) ROW access roads
g) Aerial markers
h) Revegetation
i) Field and administration, inspection, testing of materials and other materials and other miscellaneous outside services

Where at all possible up-to-date costs have been obtained.

Comparison of final cost figures have been made with recent construction work and costs as indicated are reasonably compared.

COAL SLURRY PROCESS PLANT
CAPITAL COSTS

ITEM	$ x 10^3
Equipment	
Mechanical	3,663
Electrical	368
Instrumental	326
Service Structures	3,880
Installation	
Mechanical	1,170
Electrical	159
Instrumental	91
Spares	307
ESTIMATED CAPITAL COST:	9,964

ESTIMATED TOTAL CAPITAL COST
SLURRY

ITEM	UNIT $ x 10^3	$ x 10^3
Pipeline 20" dia.		
Material including pipe	19,300	
Construction	40,460	
		59,760
Slurry preparation plant		9,964
Slurry pump stations		6,250
Slurry dewatering, BTGS		13,125
BTGS coal handling apparatus to power house (conveyors, transfer points, support structures)		390
Site preparation at BTGS		9,880
ESTIMATED TOTAL CAPITAL COST:		99,369

CALCULATIONS & NOTES

Density of coal slurry:

50:50 by weight

$$\text{Specific gravity} = \frac{100}{\frac{50}{1.4} + \frac{50}{1.0}} = \frac{100}{35.7 + 50} = \underline{\underline{1.168}}$$

Fuel requirement = 15,800 tons/day

A 50:50 (by weight) slurry will comprise 15,800 tons/day coal + 15,800 tons/day water

$$\text{15,800 tons water/day} = \frac{15{,}800 \times 2240 \times 7.5}{24 \times 60 \times 62.4} \text{ USgpm}$$

$$\text{Water flow} = 2{,}960 \text{ USgpm}$$

$$\text{31,600 tons slurry/day} = \frac{31{,}600 \times 2240 \times 7.5}{24 \times 60 \times 62.4 \times 1.168}$$

Slurry flow = 5,070 USgpm

Slurry velocity (20" O.D. line 0.375" wall) $= \dfrac{5070}{7.5 \times 2.02 \times 60}$ ft./sec.

Slurry velocity = 5.57 ft./sec.

Assume two pumping stations, the first at Hat Creek and the second at Pemberton.

Assume 25 psi pressure drop/mile friction loss for 20" ϕ pipe.

Assume factor of 1.1 for actual pipe miles/route miles.

Assume 3 pump operating and 1 standby/pumping station (see performance curve for positive displacement pumps).

Discharge pressure at this flow (1700 USgpm) = 1400 psi

Assume second pump station at Pemberton — 72.5 miles from Hat Creek.

(Pa = pressure at Pemberton)

$$1400 + \frac{1350 \times 1.168}{2.31} = Pa + 72.5 \times 25 \times 1.1$$

$$Pa = 1400 + 682 - 2000 = \underline{\underline{82 \text{ psi}}}$$

(Pb = pressure at Burrard)

$$1400 + \frac{2000 \times 1.168}{2.31} = Pb + 82.5 \times 25 \times 1.1$$

$$Pb = 1400 + 1010 - 2260 = \underline{\underline{150 \text{ psi}}}$$

(Pc = pressure at Fountain Range peak)

$$Pc = 1400 - 1010 - 5 \times 25 \times 1.1 = \underline{\underline{250 \text{ psi}}}$$

(Pd = pressure at Coast Range peak)

$$Pd = 1400 + \frac{150 \times 1.168}{2.31} - 53.5 \times 25 \times 1.1$$

$$Pd = 1476 - 1470 = \underline{\underline{6 \text{ psi}}}$$

$$\text{BHP for pumps} = \frac{1700}{1.2} \times \frac{1.168 \times 1400 \times 2.31}{3960 \times 0.85 \text{ (overall } \eta)} \quad \text{per pump}$$

$$\text{Pump BHP} = \underline{\underline{1590 \text{ HP}}}$$

Total no. of pumps = $\underline{\underline{8}}$ (6 operating — 2 standby).

Estimated prices from J. Rybak U.S. Steel (Wilson-Snyder), August 11, 1975 11" piston x 18" stroke 1750 HP pump/motor combination.

Pump	$225,000	
Gear reducer	25,000	
Fluid drive	50,000	
Motor	35,000	
'Unitization' connections, instrumentation, etc.	40,000	
Pulsation dampeners	12,500	
TOTAL	$387,500	per pump

Total supply cost for 8 pumps = $3,100,000

CONTACTS

Wilson-Snyder Pumps

Gerald Thompson — Sales Seattle (206) 622-1972

R.J. (Bob) Prudhomme — Director (Sales) Dallas based

Joe Rybak — Design (Pump & Pipelines)
Dallas (214) 747-8921 Loc. 308 (3 hours ahead)

FAULT CONDITIONS:

a) Assume pipeline breaks down at minesite end or intermediate pumping station for loss or power supply to pumps — the pipeline remains full. Thus, slurry storage is required for time it takes to restore power and flow. This is the most common failure.

b) If a fault occurs that requires the Hat Creek-Pemberton section to be drained and flushed (24 hrs.), required 24 hours for repair and a further 24 hours for restoration of flow at the power plant end — this suggests a tank storage capacity of 3 days supply.

c) A shutdown requiring a complete flush of the 172 miles would require 2 days to flush the line, 2 days to restore slurry flow plus time for repair — say 5 days total tank storage at the power station end.

Obviously c) is worst case.

Based on following:

Approx. velocity of slurry = 5.5 ft./sec.
Distance = 172 miles

Travelling time $= \dfrac{172 \times 5280}{5.5 \times 3600}$ hrs. = <u>46 hours</u>

Black Mesa Pipeline — John C. Montfort — Inc. Manager (602) 774-6949

Mojave GS, Arizona — Mr. Fraser — (702) 298-2553 — Superintendent
Walt Forbes — Maintenance Engineer

In addition to the cost of the pumps, additional costs are incurred at the pumping stations for the following:

Buildings to house pumps, electrical equipment, stores, workshops, offices, etc.

Slurry storage pond or tanks for emergency emptying of pipeline section.

Water storage ponds or tanks for emergency flushing of pipeline section.

Costs are also incurred for automatic control facilities for pumps, valves, etc., from a central location at the mine-site end of the pipeline.

Total estimated **installed** cost of two complete pumping stations with above facilities:

<u>$6,250,000</u>

SLURRY STORAGE

(See Hydro transport 3 — Paper on storage & agitators Section B4-43).

Assuming 3 storage tanks with 2 normally 85% full and the third held partially empty with adequate capacity to absorb a full pipeline.

Vol. of 172 miles of 20" ϕ pipeline

$$= \frac{\eta \times 19.25 \times 19.25 \times 172 \times 5280}{4 \times 144} = 1{,}840{,}000 \text{ ft.}^3$$

$$1{,}840{,}000 \text{ ft.}^3 = \frac{1{,}840{,}000 \times 7.5 \times 9.72}{2 \times 2240} \text{ tons coal}$$

$$= 30{,}800 \text{ tons coal.}$$

This suggests tanks are capable of holding 24,000 tons coal, so that if necessary the 30,800 tons contained in the line could be drained into the three tanks in the approximate ratio 4,000 tons/4,000 tons/24,000 tons.

With a total storage of 72,000 tons a five day shutdown could be supported at 91% load factor:

i.e. 72,000 = 15,800 x 5 x Load Factor = 91%.

Single tank capacity = 24,000 tons coal

$$= \frac{\eta D^3}{4} \times \frac{7.5 \times 9.72}{2 \times 2240}$$

$$D^3 = \frac{24{,}000 \times 4 \times 2 \times 2240}{\eta \times 7.5 \times 9.72} = 1{,}880{,}000$$

$$D = 123' \text{ (H = D:- see Hydro transport 3-B4-43)}$$

Say 125' x 125' tanks.

Tanks of 125' diameter are installed at the Mojave power plant with additional emergency storage provided by 500' diameter ponds where the coal is dried out by natural evaporation.

Slurry storage tanks of the above capacity (3 x 24,000 tons) would provide a 9-day storage at 50% load factor, 6 days at 75% and 5 days at 90%.

Neither 5 nor 9 days can be considered adequate emergency storage to cover for labour disputes or force majeure conditions.

Consideration should, therefore, be given to an additional conventional coal storage system to increase the emergency storage capacity and increase the flexibility and reliability of the overall system.

Coal from local Vancouver terminals could be brought to the site by barge, off-loaded and compacted for supply to a simple reclaim system which would connect to the disc filter conveyors.

A reduction in the annual coal demand would have a significant effect on costs. For this reason it is essential to determine, based on the provincial system demand characteristics, the optimum fuel delivery rate.

A reduced coal demand could mean a smaller pipeline diameter, one rod mill instead of two, a simpler water supply system, fewer pipeline pumps and a smaller and simpler dewatering plant.

TYPICAL LABOUR COSTS FOR SLURRY PREPARATION PLANT

DUTY	GROSS LABOUR RATE $/HR.*	$/YR.	NO. PER SHIFT	TOTAL NO.	COST PER YEAR $
Engineer		26,500	1	4	106,000
Operators	14.15	24,800	2	8	198,400
Sampler	13.85	24,100	1	4	96,400
Mechanic	14.35	25,100	1	4	100,400
Foreman		26,500	1	4	106,000
Labourer	12.05	21,100	1	4	84,400
				28	
Clerk-Timekeeper	4.80	8,400		1	8,400
Instrument Technician	12.60	22,050		3	66,150
Mechanics	12.60	22,050		3	66,150
Electrician	12.60	22,050		3	66,150
				10	
Total Direct Labour Cost:					898,450

Rates based on 1750 hrs./yr.
Gross labour rate includes all fringe benefits.

*Shift work allowance averaged at $1.75/hr. for all shifts.

OPERATING COSTS — SLURRY PREPARATION PLANT
THROUGHPUT 5,000,000 LT/YR.

		YEARLY OPERATING COST $
Labour	(Operating and minor maintenance)*	898,450
Maintenance	(Additional labour plus rental and material at 6% of equipment cost)**	261,408
Consumables	Screens 30 day life 35,000 Rods 1.2 lbs/ton 80,000 Lime 0.5 lbs/ton 35,000 #1 Inhibitor .02 lbs/ton 35,000 #2 Inhibitor .02 lbs/ton 35,000	950,000
Power	(6150 HP @ incremental energy cost of 10 mills/ kWhr)***	367,700
Insurance	@ 0.25% of equipment cost**	10,892
TOTAL:		2,488,450
Operating cost/ton @ 5 x 10^6 LT/YR.		0.50/LT

*Major maintenance included in Maintenance Costs.
**Equipment costs — $4,356,800
***Power consumption is considered equivalent to 8000 hours at full load.

TYPICAL LABOUR COSTS FOR PIPELINE PUMPING STATIONS
Day Staff Only — 2 Stations

DUTY	RATE \$/HR.	\$/YR.	TOTAL NO.	COST PER YEAR \$
Mechanic	12.60	22,000	4	88,000
Operator	12.10	21,200	2	42,400
Labourer	10.30	18,000	2	36,000
TOTAL DIRECT LABOUR COST:				166,400

Rates based on 1750 hours/year.

Gross pay rate includes all fringe benefits.

OPERATING COSTS FOR TWO PUMPING STATIONS
SLURRY THROUGHPUT 5,000,000 LT/YR

		YEARLY OPERATING COST \$
Labour	(Operating and minor maintenance)*	166,400
Maintenance	(Additional labour plus rentals and material at 3% of equipment cost)**	
Major Spares	Liners Pistons Piston Rods & Packing Piston Rubbers Valve Inserts Valves & Seals	93,000
Power	(9600 HP @ incremental energy cost of 10 mills/ kWhr)***	572,000
Insurance	@ 0.25% of equipment cost**	7,750
TOTAL:		839,150
Operating Cost/Ton @ 5 x 10^6 LT/YR.		0.17/LT

*Major maintenance included in Maintenance Costs.

**Equipment Costs — \$3,100,000

***Power consumption is considered equivalent to 8000 hours at full load.

TYPICAL LABOUR COSTS FOR COAL DEWATERING PLANT
5,000,000 LT/YR

DUTY	GROSS LABOUR RATE $/HR.*	$/YR.	NO. PER SHIFT	TOTAL NO.	COST PER YEAR $
Operators	14.15	24,800	3	12	297,600
Mechanic	14.35	25,100	1	4	100,400
Foreman	-	26,500	1	4	106,000
				20	
Engineer		26,500		1	26,500
Mechanics	12.60	22,050		2	44,100
Labourer	10.30	18,000		1	18,000
				4	
TOTAL DIRECT LABOUR COST:				24	
TOTAL:					592,600

Rates based on 1750 hours/year.

Gross labour rate includes all fringe benefits.

*Shift work allowance averaged at $1.75/hour for all shifts.

OPERATING COSTS — COAL DEWATERING PLANT
THROUGHPUT 5,000,000 LT/YR

		YEARLY OPERATING COST $
Labour	(Operating and minor maintenance)*	592,600
Maintenance	(Labour plus material at 3% of equipment cost)**	180,000
Power	(1000 HP @ incremental energy cost of 10 mills/kWhr)***	59,600
Insurance	@ 0.25% of equipment cost**	15,000
TOTAL:		847,200
Operating Cost/Ton @ 5 x 10^6 LT/YR.		0.17/LT

*Major maintenance included in Maintenance Costs.

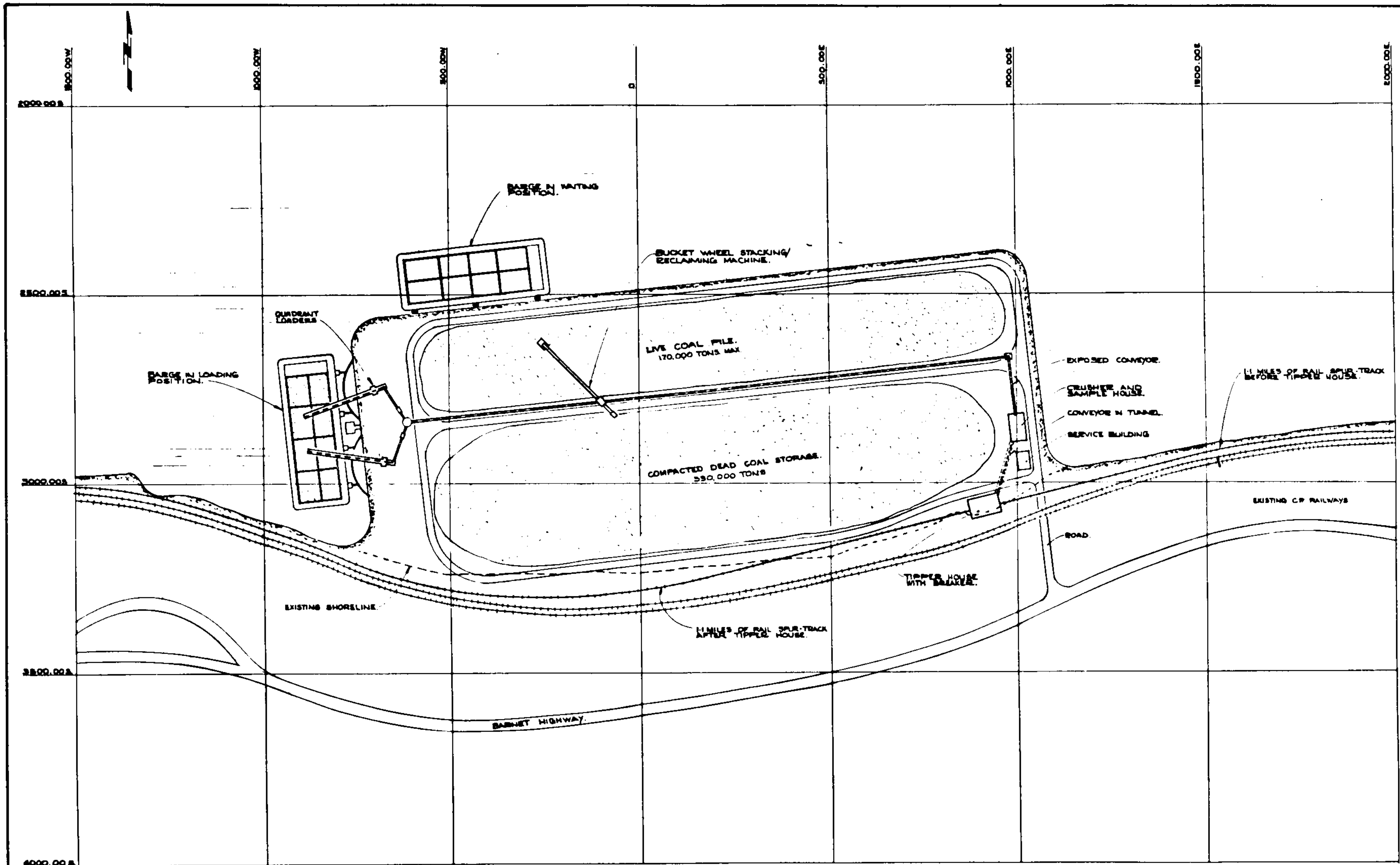
**Equipment costs — $6,000,000

***Power consumption is considered equivalent to 8000 hours at full load.

LIST OF ABBREVIATIONS

BTGS	Burrard Thermal Generating Station
Btu	British Thermal Unit
°C	Degrees Centigrade
CEGB	Central Electricity Generating Board (U.K.)
CF	Capacity Factor
cfs	Cubic Feet per Second
CO_2	Carbon Dioxide
COP	Coefficient of Performance
CSL	Combustion Systems Limited
EPA	Environmental Protection Agency
EPDC	Engineering & Power Development Consultants Limited
ERDA	Energy Research Development Administration
°F	Degrees Fahrenheit
FB	Fluidized Bed
FBC	Fluidized Bed Combustion
FPC	Federal Power Commission
GE	General Electric
gpm	Gallons per Minute
GS	Generating Station
HHV	Higher Heating Value
HP	Horse Power
HP piping	High Pressure Piping
Hz	Hertz
IDC	Interest During Construction
IEA	International Electrical Association
IGT	Institute of Gas Technology
Ins. Hg abs	Inches of Mercury (Absolute)
ISO	International Standards Organization
kV	Kilo volts
kW	Kilowatt
kWh	Kilowatt Hours
LHV	Lower Heating Value
LP piping	Low Pressure Piping
LPG	Liquid Propane Gas
mill	0.1 Cent
MIT	Massachusetts Institute of Technology
mm	Millimeter
MVA	Megavolt Amperes
MW	Megawatt
NEMA	National Electrical Manufacturer's Association
NO_x	Oxides of Nitrogen
NRC	National Research Council
PF	Pulverized Fuel

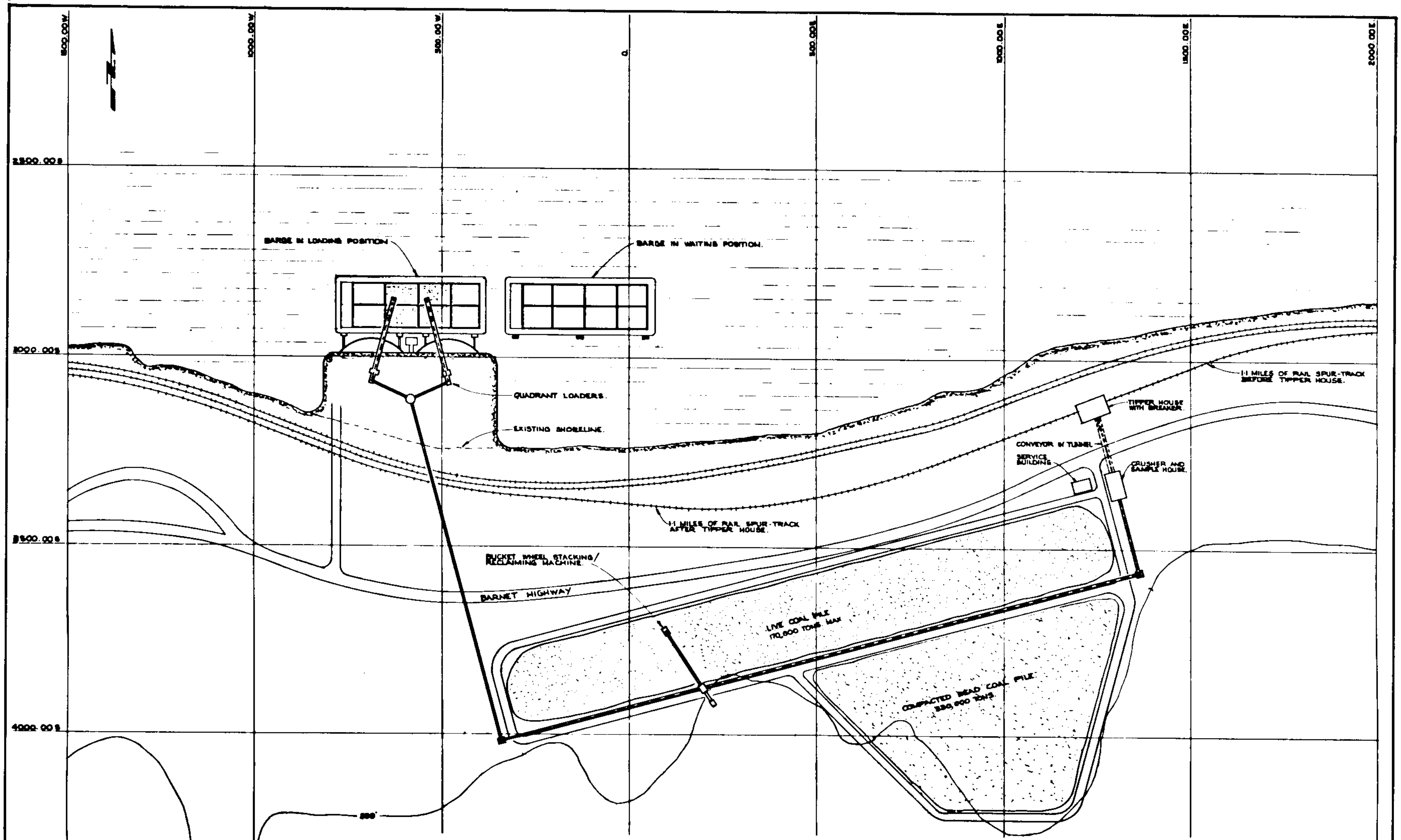
ppm	Parts per Million
psig	Pounds per Square Inch (gauge)
rpm	Revolutions per Minute
RWE	West German Electric Power Utility
SASOL	South African petrochemical complex near Johannesburg
scf	Standard Cubic Foot
scfd	Standard Cubic Feet per Day
SNG	Synthetic Natural Gas
SO_2	Sulphur Dioxide
STAG	Steam and Gas (General Electric Combined Cycle trade name)
STEAG	West German Electric Power Utility
Ton	short ton (2000 lb.)
UACL	United Aircraft of Canada Ltd.
U.S. Dept. of H.E.W.	Health, Education and Welfare
USgpm	U.S. Gallons per Minute



F 0036 500 SK3 BURRARD THERMAL GENERATING STATION STUDY "D" COAL STORAGE & LOADING FACILITIES SITE "B"

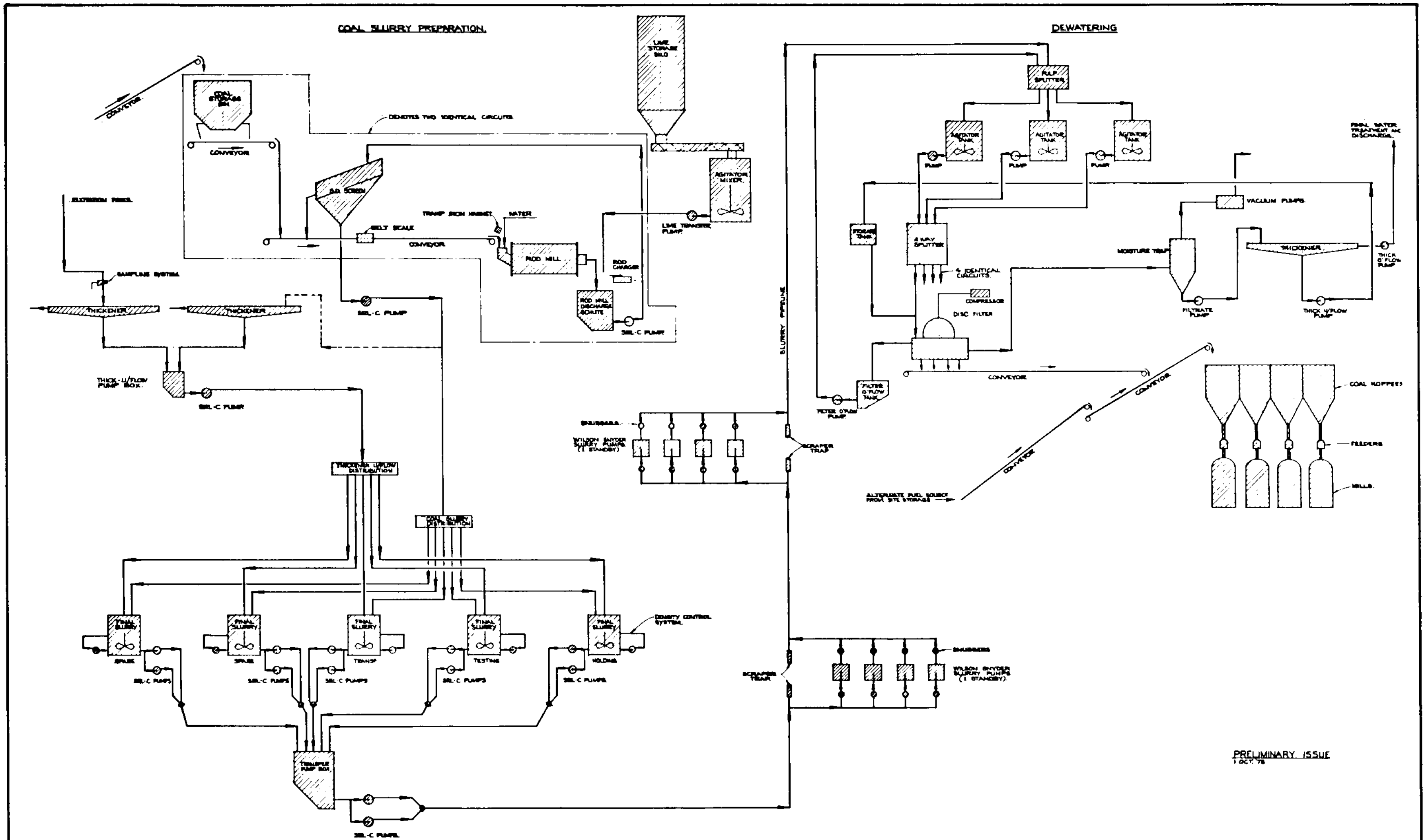
B.C. HYDRO & POWER AUTHORITY

integ
Intercontinental Engineering Limited
Vancouver Canada London England



F 0036 500 SK4
BURRARD THERMAL GENERATING STATION STUDY "D" COAL STORAGE & LOADING FACILITIES SITE "A"

B.C. HYDRO & POWER AUTHORITY
integ
Intercontinental Engineering Limited
Vancouver Canada London England

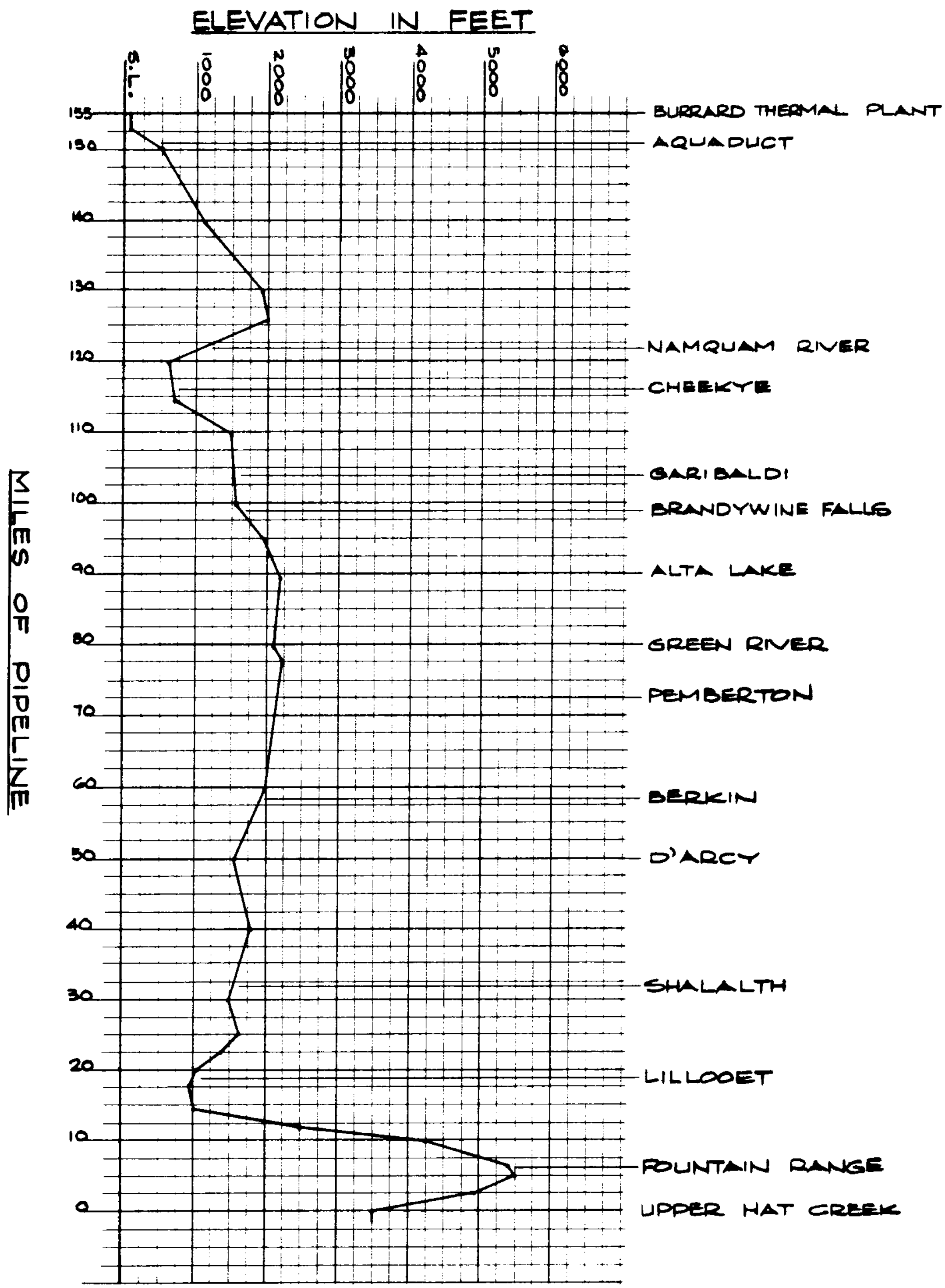


F 0036 500 SK8

BURRARD THERMAL GENERATING STATION STUDY "D" COAL SLURRY PIPELINE
FLOW DIAGRAM

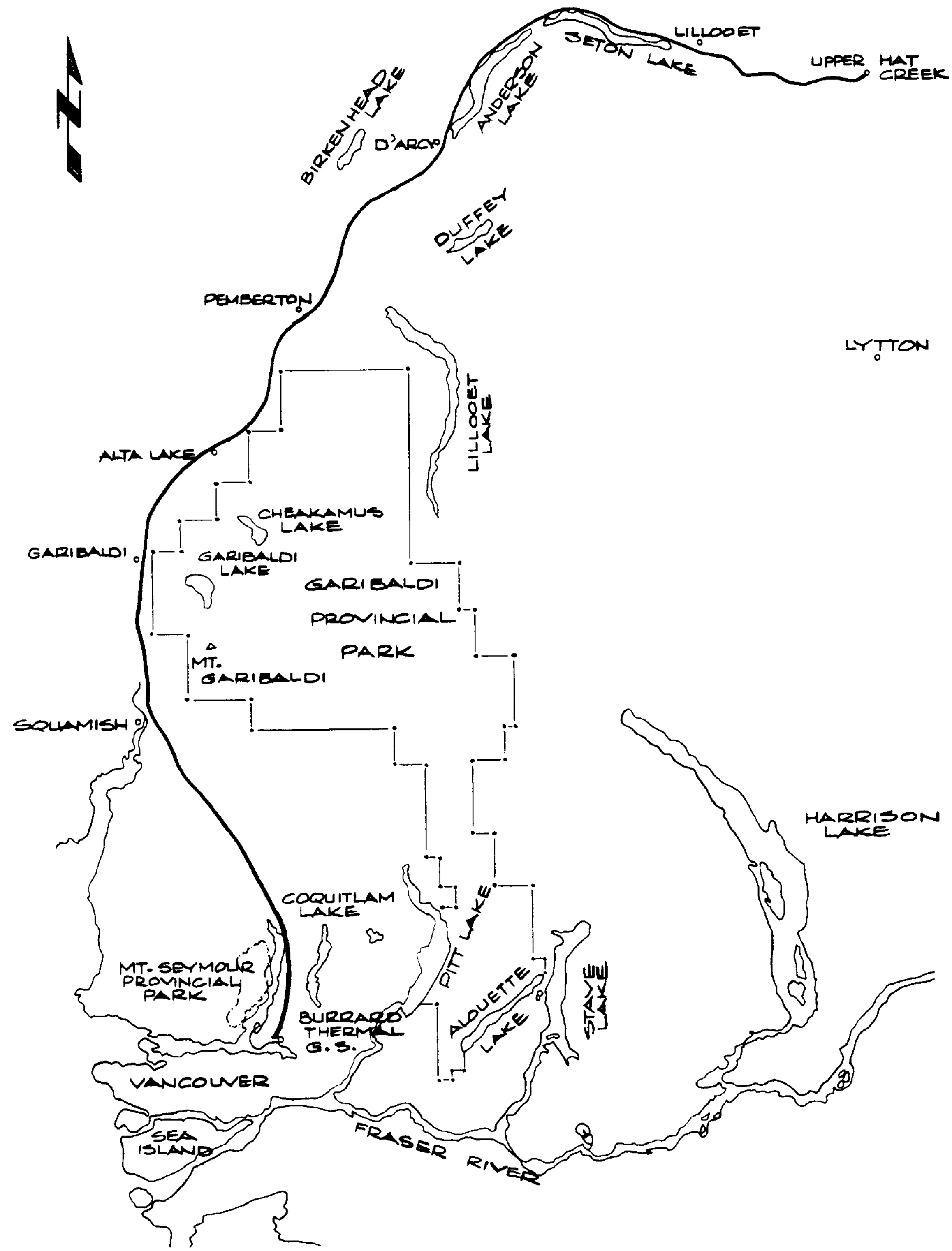
B.C. HYDRO & POWER AUTHORITY

integ
Intercontinental Engineering Limited



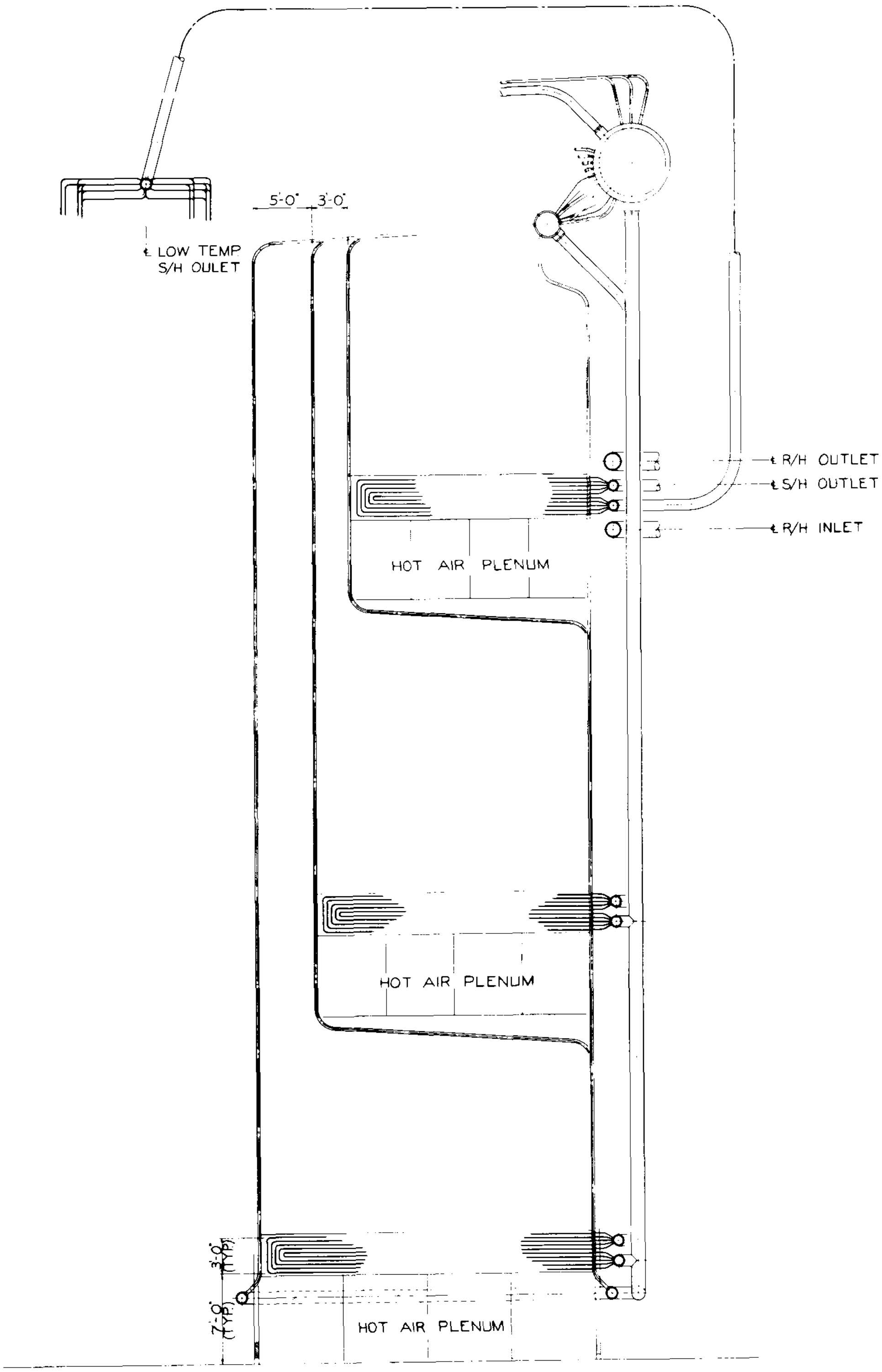
A 0036 500 SK9
BURRARD THERMAL GENERATING STATION
STUDY "D" SLURRY PIPELINE PROFILE

B.C. HYDRO & POWER AUTHORITY
integ
Intercontinental Engineering Limited



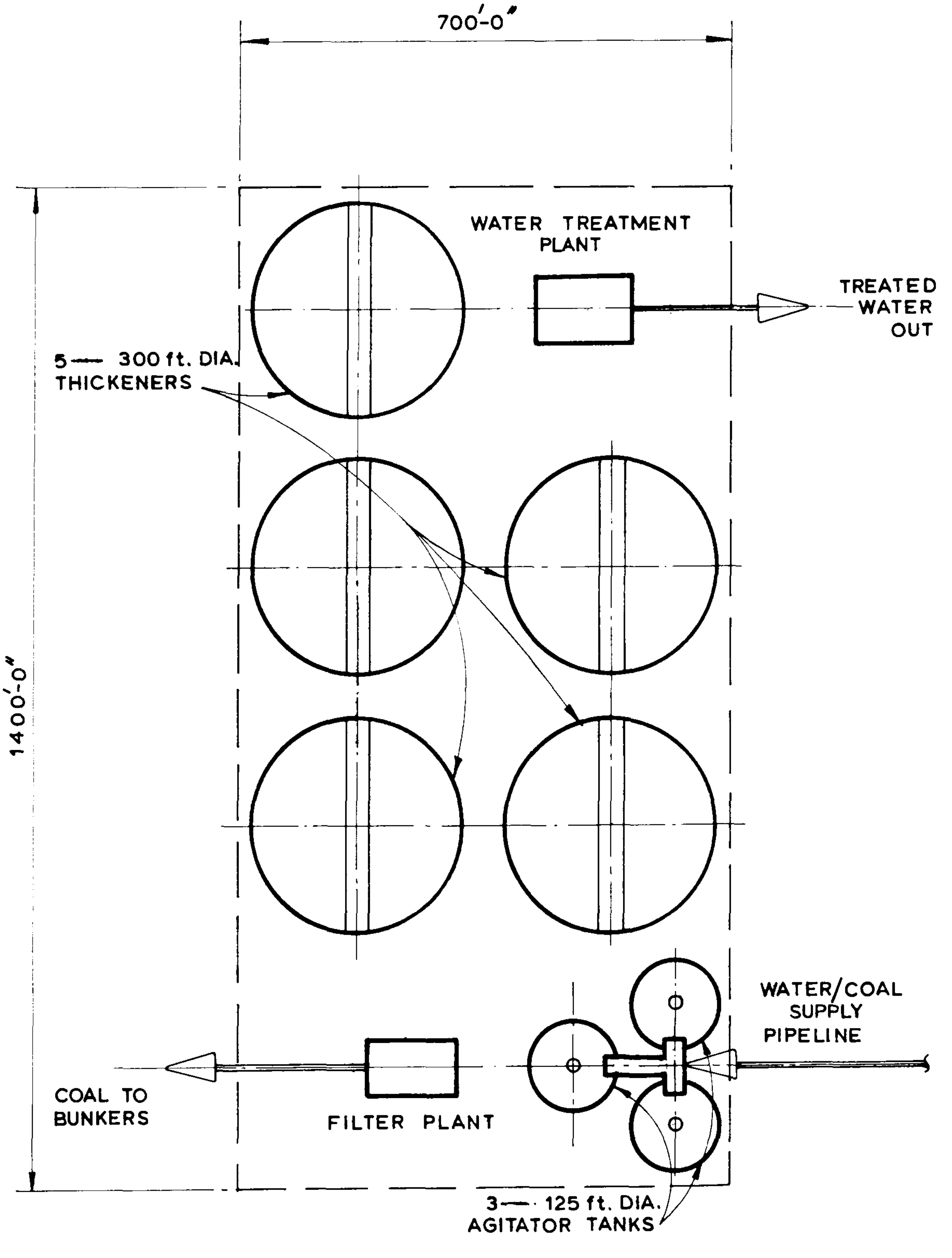
A 0036 500 SK10
BURRARD THERMAL GENERATING STATION
STUDY "D" SLURRY PIPELINE ROUTE

B.C. HYDRO & POWER AUTHORITY
integ



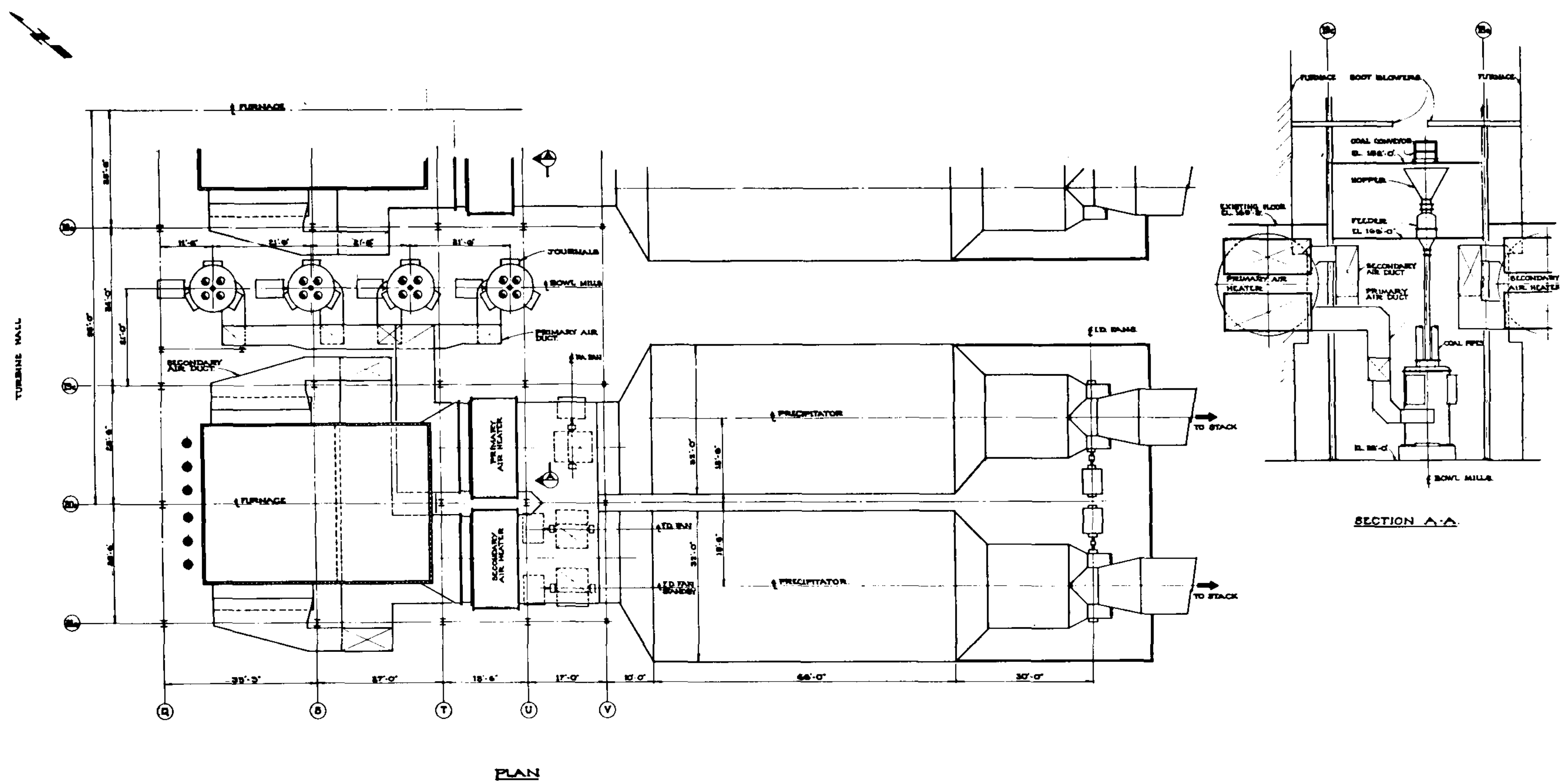
F 0036 500 SK11
BURRARD THERMAL GENERATING STATION
STUDY "D" CONVERSION TO FLUIDIZED COMBUSTION
PROVISIONAL GENERAL ARRANGEMENT

B.C. HYDRO & POWER AUTHORITY
integ
Intercontinental Engineering Limited



A 0036 500 SK13
BURRARD THERMAL GENERATING STATION
STUDY "D" SLURRY SYSTEM
TYPICAL DEWATERING PLANT LAYOUT

B.C. HYDRO & POWER AUTHORITY
integ



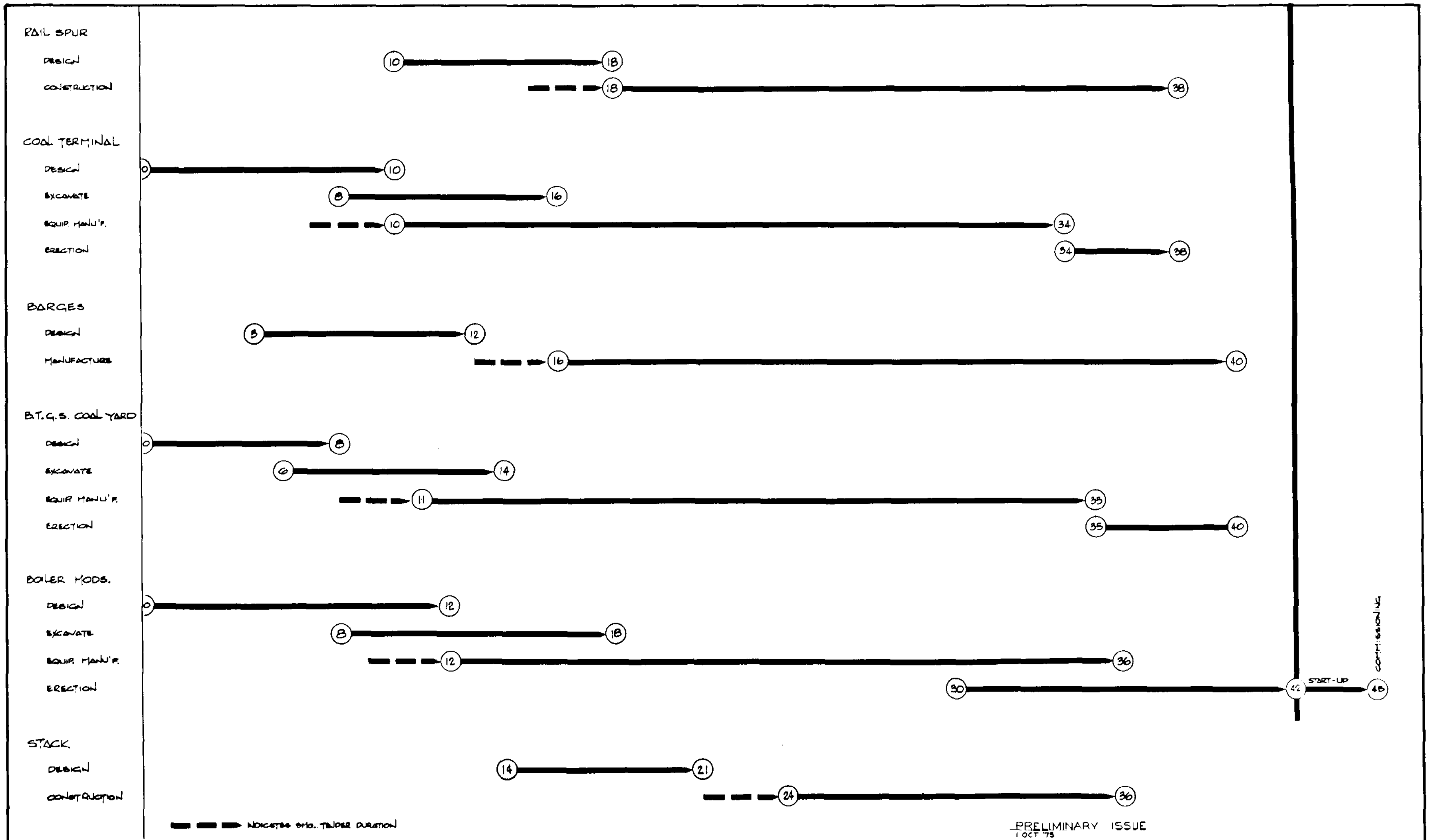
F 0036 500 SK15

BURRARD THERMAL GENERATING STATION STUDY "D" MODIFICATION OF EXISTING PLANT FOR PULVERIZED FUEL

B.C. HYDRO & POWER AUTHORITY

integ

Intercontinental Engineering Limited



D 0036 500 SK18

BURRARD THERMAL GENERATING STATION STUDY "D" CONSTRUCTION SCHEDULE

B.C. HYDRO & POWER AUTHORITY

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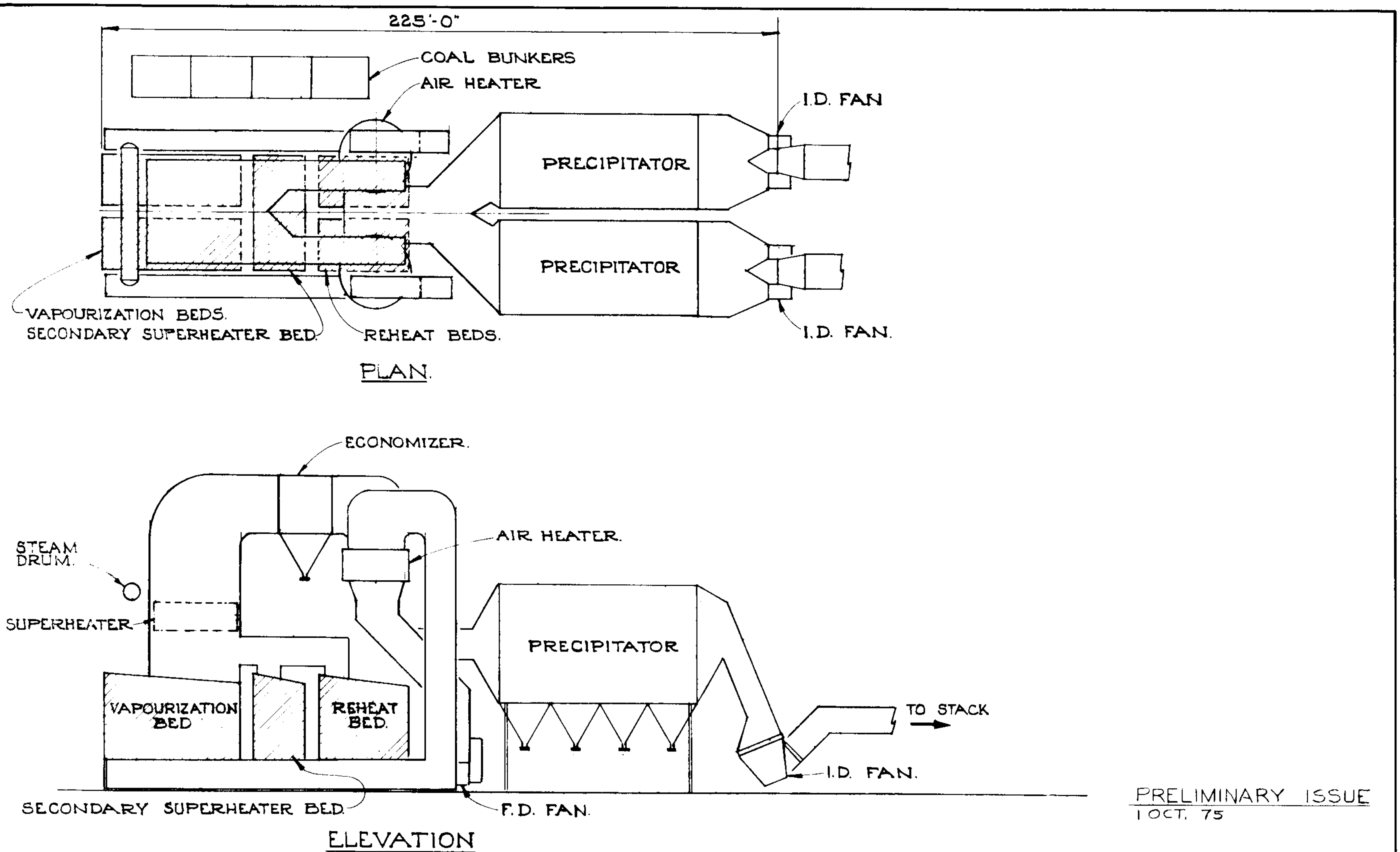

B 0036 500 SK20
BURRARD THERMAL GENERATING STATION STUDY "D" 150 MW FLUIDIZED COMBUSTION BOILER PRELIMINARY ARRANGEMENT

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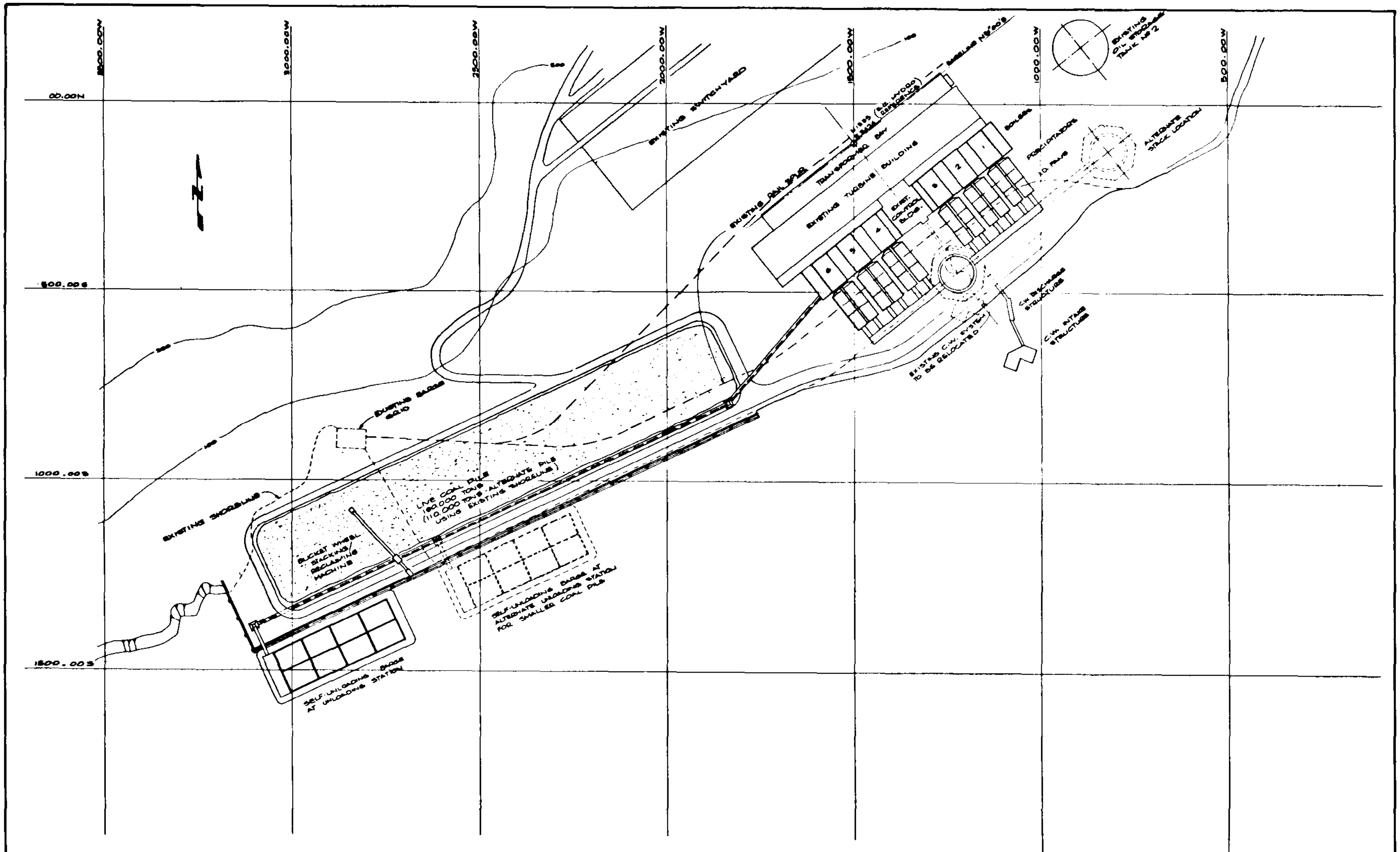

F 0036 500 SK21

BURRARD THERMAL GENERATING STATION STUDY "D" MODIFICATION OF EXISTING PLANT FOR PULVERIZED FUEL — SITE LAYOUT

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