STATE ELECTRICITY AUTHORITY

ICELAND

REPORT ON

GEOTHERMAL POWER STATION PROJECT

MERZ and McLELLAN,
32, Victoria Street,
London, S.W.1.

MARCH, 1961

MERZ AND McLELLAN

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YOUR REFERENCE ....

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March, 1961

THE DIRECTOR GENERAL,
The State Electricity Authority,
Reykjavik,
Iceland.

Dear Sir,

GEOTHERMAL POWER PROJECT

We have pleasure in submitting herewith our Report on the proposed development of power from geothermal steam at Hveragerdi, prepared in accordance with your letter dated 26th March, 1960. In August, 1960 our Chief Development Engineer visited Iceland to discuss investigation work, to advise on immediate problems, and to collect the information required for the preparation of the report. The object of the report was to appraise the alternative sites at Hveragerdi and Krysuvik, to recommend a scheme for the station which was to have a minimum nett output of 15 MW, and to form the basis for the preparation of tender documents and financing of the project.

In October 1960 you informed us that the results of well drilling at Krysuvik were not promising compared with those at Hveragerdi and accordingly Krysuvik was not to be considered further as a site for the proposed power station.

We submitted a draft report on the 14th December, 1960 based on the prospects of the Hveragerdi steam field as indicated by the yield of five wells, Nos. 1-5, which had been drilled between October 1958 and mid-1960. Since that time we have held up submission of the report pending receipt of the results of further drilling, culminating in the completion of well No. 8 in January this year. This was thought desirable in order to assure ourselves that sufficient data had been obtained to establish the scheme on a firm basis.

The report attached hereto deals with proposals and recommendations for the development of geothermal steam for power production at Hveragerdi. Our findings and conclusions for this purpose may be summarized as follows:-

(1) The total power potential of the steam already proven at Hveragerdi is at least 29 MW. We have proposed that the proven live steam should be approximately double that required to meet full normal output of the station. The additional potential of the hot water associated with the steam is of the order of 11 MW. We recommend that use of the hot water for producing flash steam should not be included in the initial development, but deferred for a possible second stage.

(2) While the evidence of rather rapid fouling of the wells by calcium carbonate deposits is a complication not encountered in such serious degree in any of the other fields so far developed for power, we think that the difficulty is not insuperable since deposits within the well bores can be dealt with by periodic drilling out. We see no reason to expect build up of deposits elsewhere sufficient to interfere seriously with operation. Hence we consider you are adequately covered against falling off of yield by the provision of roughly a 100 per cent proportion of reserve wells and by the allocating of expenditure on drilling tackle and drilling team almost continuously occupied in cleaning out wells or drilling new ones.

(3) We estimate the capital cost of the first stage comprising an installed capacity of 17 MW to be £1,956,000. We think it reasonable from experience elsewhere to assume a 20 year life for the plant and pipework. For the wells a 5 year life has been used in accordance with your wishes, which allows for possible falling off in yield not correctable by cleaning out. On this basis we assess the cost of power at £20.9 per kilowatt year sent out or 0.675 pence per kilowatt hour.

(4) As requested we have considered schemes involving fuel firing, as alternatives to the geothermal power plant, for both an oil-fired condensing station and a back-pressure station, the latter operating in conjunction with the Reykjavik district heating system. These stations, assumed to be located at Ellidaar, near Reykjavik, are estimated to have generation costs in the range 1 to 1.2 pence per kilowatt hour. Costs of diesel generation we estimate to be about 1 penny per kilowatt hour.

We are, Sir,

Yours faithfully,

MERZ and McLELLAN

STATE ELECTRICITY AUTHORITY

ICELAND

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PLATES (continued)

SECTION 1

ELECTRICITY SUPPLY IN SOUTH WEST ICELAND

Existing situation

The total population of the south western region of Iceland is about 121,000 or 70 per cent of the whole population of the country. The region which includes Reykjavik, the capital, Kopavogur, Hafnarfjordur, Keflavik, Akranes and several smaller places shown on the map on Plate 1, receives its electrical supply from an interconnected high voltage network fed by several power stations. (Some outer areas with local smaller power stations are as yet not interconnected). The total installed plant capacity in the region is 90.1 MW as shown in Table 1. It is however planned to extend the transmission network over the whole region within a few years to that shown on Plate 2. The backbone of this network will be the existing Sog system which supplies about 94 per cent of the population in the south west, deriving most of its power from three stations on the Sog River.

These stations, namely Ljosafoss, Irafoss and Steingrimsstod, together with the two transmission lines to Ellidaar, are owned jointly by the State and the Municipality of Reykjavik. The whole available 76.5 metre head of this river is now harnessed. Provision has been made for a further 15.5 MW machine at Irafoss and with this addition the total installed capacity of the Sog stations will reach 87.5 MW and the system 105.6 MW. Nearly the whole of the water will then be used and therefore practically no additional energy can be generated. However, provided the deficit of energy were made up from another source, somewhat greater output in kilowatts could still be obtained from the Sog by reduction of load factor entailing rebuilding or installation of additional machines. The Sog derives much of its flow from underground sources and is stabilized by Lake Thingvalla which covers an area of 83 km^2. However storage is limited by the permissible level variation of 2 metres implying some 400 hours use of the mean flow of 112 m^3/sec which is sufficient to even out variations over some months and to build up a useful reserve for winter but not to cover deficiency in a dry year.

The power from the Sog stations is transmitted about 50 km into Reykjavik at 138 kV by a single circuit steel tower transmission line completed in 1953 following a route indicated in Plate 1 which passes near Hveragerdi. The line has a nominal thermal rating of 96 MW and it will be nearly fully utilized when the final set goes in at Irafoss. There is also a single circuit 66 kV wood pole line, some 25 years old, in parallel taking another route further north. Paralleling of the two lines is possible but not very desirable as the 66 kV line is subject to outages arising from salt deposits on insulators where the route is near the coast. Also ice formation occurs on conductors inland. The load supplied direct from Sog to local networks at 11 and 33 kV is at present 3 to 4 MW and when the Westman Islands are connected into the system, probably in 1961, this load will increase to 5 to 6 MW. The south west system is not interconnected with other parts of the Island.

There is a run of river hydraulic station of 3.16 MW and a 7.5 MW fuel-fired steam station at Ellidaar near Reykjavik. The steam plant is intended for running in emergency to cover outages or for short periods to meet the maximum demand. During the years 1949-53 it ran for longer periods to make up deficiency of energy but this has not been necessary since the Irafoss station came into service in 1953. It could still be required in times of water shortage.

There are other generating sets, viz a 6 MW diesel plant (60 cycles) at the NATO base at Keflavik Airport and a 1,000 hp diesel-alternator at the Reykjavik Hot Water Supply pumping station at Reykir, but these are regarded as private emergency plants and unavailable for public supply.

Growth of maximum demand

The growth of the electrical supply system in the south west, where the installed capacity in 1952 was approximately 30 MW, is attributable to an annual increase in power consumption for domestic, light engineering and commercial premises, referred to as the General Load, supplemented by the introduction of two major industries comprising an artificial fertilizer factory near Reykjavik in 1953 and a cement factory at Akranes in 1958. Recently (1960) the NATO base at Keflavik has been connected to the public supply system through a frequency changer. The relative magnitudes of the maximum non-coincident power requirements for the respective loads during 1959 on the interconnected system were as follows:-

General Load	-	57 MW
Fertilizer factory	-	18 MW
Cement factory	-	4 MW

Although the fertilizer factory takes about 18 MW at full load only 3.1 MW is firm power to which figure the load can be reduced at any time at short notice to enable the General Load to be met. This arrangement has allowed the supply system to be operated without the usual margin of spare plant and to run at an extremely high load factor of the order of 66 per cent. The plant and the 138 kV transmission line have proved very reliable. The loads of the cement factory and Keflavik are both much smaller and load shedding is not applied to them.

The forecast of maximum demand from 1961 to 1970 shown on Plate 3 is based on an average annual increase of 5.7 per cent. The larger increase from 1959 to 1960 is due to the coming into service of the Keflavik supply.

With the commissioning of the machines at Steingrimsstod in late 1959 and early 1960 the system installed capacity is now sufficient to meet the anticipated maximum demands for the winters of 1960/61 and 1961/62. However there will be a likely deficit of plant in 1962 prior to the commissioning of the third machine at Irafoss which is planned for 1962/63. We understand that an additional 8.5 MW unit for peak load duty will probably be installed at the Ljosafoss station in due course to bring the Sog plants to an ultimate capacity of 96 MW but a final decision on when the installation will be made has not been taken.

Energy requirements

Because of the high system load factor it is necessary to discuss not only whether the plant can meet the maximum demand but also whether the flow in the rivers will cover annual energy requirements. Plate 4 shows the energy generated per annum in GWh (gigawatthour = kWh x 10^6), for the years 1952 to 1959 and estimated requirements up to 1970. In the years 1952 and 1953 significant energy had to be produced from fuel to make up requirements beyond what the Sog and other hydro stations generated with the then installed plant. In 1954 and 1955 there was no significant loss of revenue by load shedding but since 1956 load shedding has again reduced the energy sold below what is potentially saleable. For the future the trend shown allows for meeting the demand without load shedding and loss of revenue, i.e. it is assumed that the energy requirements of the fertilizer factory will be fully met.

About 1965 the consumption of energy is expected to exceed that available from the rivers, which on the 'probable' flow amounts to 595 GWh from the Sog and some 25 GWh from other smaller hydro schemes. However it is not possible in the early 1960's to utilize all of the energy and useful output from the Sog might be limited to about 550 GWh as electrical load will not always be available due to seasonal and daily load fluctuations. This involves spillage of water once the storage capacity of Thingvallavatn is fully taken up. Furthermore it is well known that peak load and emergency plant when run take more of the load than should in theory be necessary. This results from such plant having to be run up and synchronised some time before it is really needed and the tendency to keep it running after it could have been dispensed with.

It is necessary to consider the consequences of a dry year since the Sog when fully utilized may yield only about 485 GWh in one year in twenty. In such a year the river may fail to cover requirements as early as 1962 and this could entail some load shedding and the running of steam plant for long periods. A dry year in 1963 or 1964 could require continuous use of fuel-fired plant and some load shedding.

Need for additional generating capacity

The coming into service of the third 15.5 MW unit at Irafoss will allow the expected maximum demand to be met in 1963 but in 1964 the margin of installed capacity over expected demand is very small and it would therefore be prudent to plan for an extension to generating capacity to be available for the winter of 1964/65. It is also apparent from consideration of energy requirements that the new plant should preferably be suited to base-load operation. This is because from 1965 the energy requirements exceed the potential output from the rivers in a normal year. Fuel-fired plant, whilst meeting the kilowatt demand at a moderate price, would be uneconomic for base-load duty. Both the requirements could be met by a geothermal plant of 15 MW nett output coming into service in late 1964. This plant running on base load (7500 h per annum) is assumed to be capable of producing about 110 GWh sent out annually which just enables energy requirements to be met in 1965 in a dry year and up to 1967 in a normal year.

Although there is still a very large untapped hydro-electric potential in Iceland, any new hydraulic station will be somewhat more remote from Reykjavik than Sog. A new transmission line must also be provided. Such development is best undertaken on a large scale to keep down the cost per kilowatt. The initial expenditure is therefore high. A geothermal plant offers a prima facie case for consideration to meet the temporary need until the time comes to develop a large block of hydro power. It can be built on a small scale and entails lower transmission costs than an alternative hydraulic station. This proposal will now be studied in detail.

TABLE 1

PLANT INSTALLED ON SOUTH WEST ICELAND INTERCONNECTED NETWORK

Plant	Type	Date of installation	Units	Total rating MW
Ljosafoss	Hydro	1937-44	3	14.6 +
Irafoss	Hydro	1953	2	31 +
Steingrimsstod	Hydro	1959-60	2	26.4 +
Ellidaar	Hydro	1921-33	4	3.16
Ellidaar	Steam	1948	1	7.5
Andakill	Hydro	1947	2	3.52
*Vestmannaeyjar	Diesel	1949-56	3	2.56
*Rjukandi	Hydro	1954	1	0.84
*Stykkisholmur	Diesel	1946-53	4	0.44
*Vik i Myrdal	Hydro	1938-50	2	0.10
				90.12
Scheduled extensions				
Irafoss	Hydro	1962-3	1	15.5 +
Ljosafoss	Hydro	Undecided	1	8.5 +
				114.12

+ Load transmitted over Sog line, allowing 4 MW local load — 92

* These plants are not yet connected into the main system.

SECTION 2

GEOTHERMAL POWER POSSIBILITIES

Status of geothermal power development elsewhere

The feasibility of making use of natural steam for power production has already been demonstrated in various parts of the world. The following power stations are in operation or in development:-

Plant	Country	MW installed	Commissioning date
Larderello (several stations)	Italy	300	Pre 1939 and 1949-1959
Wairakei 'A'	New Zealand	80	1958-1960
Wairakei 'B'	New Zealand	90	On order
"The Geysers"	California	12.5	1960

Larderello is clearly a very profitable investment and in New Zealand geothermal power is a success and is being extended. Geothermal power there appears competitive in cost with that of hydraulic power though there is some difficulty about applying normal economic comparisons to an asset whose life is not readily ascertainable. Some turbine troubles have occurred at Wairakei but these are not related to geothermal steam but to basic turbine design.

In Iceland natural hot water obtained by drilling has been transmitted some 15 km and used for heating about half of the buildings in Reykjavik since 1943 but no geothermal power has yet been developed. This has not been of interest hitherto because it has been more convenient to utilize the abundant hydraulic power.

In all of the regions mentioned there were originally natural emanations in the form of hot springs, steam vents or geysers. Steam for power has been obtained by the drilling of wells employing the same type of tackle and technique as for oil well drilling. It appears that the steam or hot water is confined by some sort of quasi-impervious barrier somewhat analogous to a cap formation. The steam conditions in the different countries vary - Larderello has slightly superheated steam in most of the field. The pressure there is of the order of 7 kg/cm^2 gauge at the well giving a working pressure at the station of about 4 kg/cm^2 gauge. At "The Geysers" the pressures are somewhat higher, the steam being also superheated. Wairakei on the other hand has much higher pressure, e.g. 14 kg/cm^2 gauge in deep wells but the steam is very wet with a ratio of water to steam of the order of 6 to 1 down to 3 to 1. At Wairakei the water is separated from the steam at the wellhead and in the existing plant only the separated steam is fed to the turbines. The boiling water is at present discarded but the extensions are to rely partly on lower pressure steam produced by flashing of the hot water.

The Iceland conditions seem to resemble those of Wairakei in that the steam is associated with several times its weight of boiling water but the pressure is lower. The pressure in a field depends mainly on the artesian head and the depth of the yielding stratum. The yield is probably dependent on the "openness" of this formation in which water circulates and is raised to boiling point by some means not yet thoroughly understood.

All geothermal steam contains an admixture of gases of which the two preponderant ones are carbon dioxide and hydrogen sulphide, both of which are potentially corrosive to common metals such as iron and copper. The gas content results in the condenser gas extraction equipment being much larger in geothermal stations than in orthodox plants using pure steam. At Larderello there is also hydroboric acid which is not found elsewhere. Originally it was the boric products which were the reason for the development and as a consequence the earlier power plants work on the so-called "indirect" system whereby the raw steam is caused to condense in heat exchangers by evaporating off fairly pure steam from the condensate. The gases are blown off to atmosphere and the boric acid recovered from the enriched blowdown. For power production the "indirect" process is no longer of interest unless the gas content is extremely high because of the sacrifice in output entailed in heat exchange and the high cost of the exchangers. Moreover though the corrosion problem in the turbines is avoided (where it is no longer however regarded as insuperable) it is transferred to the heat exchangers.

A necessary stage in development of geothermal power is the accumulation of sufficient knowledge of prospecting, drilling and measuring techniques to suit the local conditions. In Iceland because of general interest in geothermal possibilities geothermal areas have already been explored and heat flow measurements made over many years. Also drilling has been going on for some considerable time with the result that the technique is established. Thus the initial phases in familiarization and in prospecting may be shortened by virtue of experience already acquired.

Proposed method of utilizing steam in Iceland

The bores so far drilled in Iceland have yielded either hot water or a mixture of boiling water and steam. A yielding bore is generally referred to as a "well". The steam no doubt originates from flashing of the water as it comes up the pipe implying that the source is hot water at depth. Accordingly the same techniques as have proved successful in New Zealand can be applied. At each well the discharge will be put through a separator designed on cyclone principles. The steam separated will be reasonably dry (possibly 0.5 per cent water or less) and this steam will be piped to the station and used in condensing turbines. Initially it is proposed to reject the boiling water though at a later date, if the station is extended, the water might also be piped to the station to be flashed in flash tanks so as to produce additional steam at about atmospheric pressure. This steam could be used in separate low pressure condensing turbines but the most convenient arrangement will probably consist of dual pressure "pass-in" turbines operating partly on live steam and partly on flash steam, as is being done at Wairakei 'B' station now in course of construction.

Any wells showing too low a pressure for operating in parallel at live steam pressure could at this later stage also be coupled in on a pipe system operating at about atmospheric pressure if this were found economically worth while. The techniques to be relied on at the initial stage are already well established, some of the plant at Wairakei having already been in service for 28 months. Experience from New Zealand confirms that from Larderello and shows that mild steel in casings and pipes is satisfactory for use in geothermal steam and does not show severe corrosion. Mild steel separators can also be regarded as having an excellent record, no corrosion trouble having been encountered. Erosion by rock particles can occur in some wells during initial stages but is avoidable by suitable techniques. Certain precautions have to be taken in selecting the types of valves and the metals used in valve trim and in such equipment as traps used for draining the transmission pipes at intervals. At the station the steam will be put through a second separator to remove most of any remaining water, both the bore water which passed the wellhead separator and any additional condensation resulting from heat loss from the pipes. The dilution of the bore water with condensate is advantageous as lowering the chemical content of any residual water remaining after the second stage of separation. Even a very small percentage of water entering with the steam could produce sufficient deposits to interfere with turbine operation in a matter of months because of the very high throughput of steam.

Analyses of the steam and water have shown these to contain the usual chemicals but in lower concentration than elsewhere. Deposit and corrosion aspects are dealt with more fully in Appendix 2 on page A7.

Potentialities of the Hveragerdi region

Recent exploratory drilling has been conducted by the State Electricity Authority at two sites, namely Krysuvik some 30 km SSW of Reykjavik, and near Hveragerdi some 45 km ESE. Three steam wells were drilled at Krysuvik to depths of 350 to 1274 metres in 1960 but none showed a satisfactory yield. It has now been decided to concentrate on Hveragerdi. This is an active geothermal area forming the southern fringe of a large geothermal region known as the Hengill area some 50 km^2 in extent. It reaches into high inaccessible ground further to the north. The heat yield from the whole region has been assessed by Gunnar Bödvarsson as within the limits of 25,000 to 125,000 kcal/sec. This is equivalent to a heat release of the order of 100 to 500 MW.

The area where the drilling has taken place is on a fairly level terrace bounded by geothermal altered rising ground with many natural steam vents immediately to the north and a geyser a little to the south. Lower down in the village of Hveragerdi there are many shallow steam wells drilled for dwelling house and glass house heating.

Four of the bores so far drilled for power purposes are located as shown on Plate 5. The sites of bores 6, 7 and 8 are off the plate, the first two being located some 200 metres and No. 8 some 1100 metres to the north-west of bore 3. Depths vary between 295 and 1200 metres as shown in Table 2. Maximum temperatures of 216°C have been encountered at about 400 metres in No. 3 and 226°C in No. 7 at a similar depth. Yielding horizons lie at various depths down to 640 metres for No. 6. All of the bores have an inner casing of $9\frac{5}{8}$ inch nominal (outside) diameter and are continued into the rock at $8\frac{3}{4}$ inch diameter. The underlying ground below a sedimentary surface layer consists of tuffs and lavas and in view of their solid nature it is not necessary to case to great depth.

Table 2 also shows the yield of six of the wells (No. 5 is regarded as a reference bore to be used for monitoring temperature in the steam field and No. 1 is not included as it had to be abandoned). The satisfactory yielders are wells 2,3,6,7 and 8 and their characteristics are shown in Plate 6. The yields are of very wet steam with a ratio of steam to water in the region of 1 to 4 by weight. The closed valve pressures are in the range 8 to 12.5 kg/cm^2 gauge. The likely working pressure is probably about 5 kg/cm^2 gauge at the wellhead. Analysis of the characteristics shows that if only the steam fraction is utilized, the power output is a maximum at the lowest working pressure (somewhat below 4 kg/cm^2 gauge) but a higher wellhead pressure in the region of 5 to 6 kg/cm^2 gauge yields the maximum output if the heat in the boiling water is assumed to be utilized by production of flash steam at atmospheric pressure. The five wells 2,3,6,7 and 8 together at full flow yield a potential output from condensing turbines of 29 MW using steam alone or 40 MW if both steam and water are used. No. 4 is assumed to cover ejector demand.

Thus the intended output of 17 MW is already covered and one other well of the class of No. 3 would bring the proven steam quantity to more than twice the theoretical requirements. This margin, which has been set arbitrarily, is considered necessary to allow for such eventualities as wells being out of service for maintenance or falling yields from wells.

TABLE 2

LIST OF WELLS

(all with inner casing of $9\frac{5}{8}$ inch outside diameter and drilled $8\frac{3}{4}$ inch diameter in uncased length)

Bore No.	2	3	4	5	6	7	8
Date completed	Oct. 1958	Oct. 1958			Nov. 1960	Jan. 1961	Jan. 1961
Ground level, metres above sea	62	67	69	65			
Drilled depth, m	400	652	687	1200	661	830	295
Casing depth, m	196	196	196	196			
Max. temp, °C	188	219		200		226	213
Yield, steam kg/sec	9.7	18.0	2.0		9.4	8.4	22.5
water kg/sec	90	67	43		56	46	76
Wellhead pressure, kg/cm^2 gauge	5	5	4.5		5	5	5.8
Closed valve pressure, kg/cm^2 gauge	8	12	5.5		10	8	12.5

Total steam proven	70 kg/sec
Equivalent power yield	29 MW
Power required	17 MW
Steam required to provide safe margin	84 kg/sec
Additional steam to be proven (say)	14 kg/sec

SECTION 3

DESIGN OF POWER STATION

Site selected

The site provisionally selected for the power station lies about 1 km north of Hveragerdi which is a village of about 600 population forming the centre of a recently developed horticultural industry based on geothermally heated glass houses. Access is by road, there being no railways in Iceland. The region is subject to earthquakes, the probable maximum intensity of which is defined by magnitude 7 of the Modified Mercalli Scale (this corresponds to accelerations of 80 cm/sec^2). The location is shown in Plate 5. It lies beside the Varma River, a small stream subject to considerable variation of flow which nevertheless offers sufficient advantage to be worth making use of for cooling water. The ground is generally level consisting of a lava terrace some 7 metres above the stream bed to which there is a steep drop. Advantage can be taken of this ground formation in the power station design. There is a fairly flat area on the far side of the river which could be flooded by construction of a dam at small expense. The pond thus formed will serve the dual purpose of ensuring sufficient depth of water at the circulating water pump intakes and also doing duty as a spray pond when the flow in the river does not provide adequate direct cooling.

According to a geological report of Dr Thorleifur Einarsson the formation above described results from the existence of a former raised beach at about 60 metres level having been overlaid with a layer 5 to 10 metres thick of doleritic basalt lava of pleistocene age (5000 to 7000 years old) coming from the west. The river has eroded away the lava leaving a steep bluff and its present bed is on the underlying gravel, sand and clay deposits which are some 40 metres thick. Dr Thorleifur Einarsson regards the lava as a very stable foundation and reports that the danger of a slide towards the river is remote as the dip of the underlying formation is apparently in the other direction. He states also that the gravel and sand deposits with alternate silt and clay layers further north on the east bank of the Varma will not provide as good foundation conditions.

The site is centrally situated with respect to the first wells drilled, Nos. 2, 3 and 4, but more recent drilling for steam has been made in a region to the north-west of No. 3 where Wells 6, 7 and 8 have been put down. Accordingly it might be thought advantageous to select a site nearer these wells to shorten the distance over which the bulk of the steam has to be transmitted. Suitable ground on the lava field on the west bank of the river is available further north but in our opinion there is no site offering equal natural advantages, in particular the elevated terrace above the river, sufficient cooling water from the Varma River (the flow falls off further north) and a location for fairly cheap construction of a cooling pond. Increased civil engineering costs on another site might easily run away with a greater sum than is saved on pipes.

Accordingly we have based our estimates on the assumption that development will proceed on the site selected and we have made provision for the possibility of having to transmit steam some hundreds of metres from possible future wells somewhat to the north.

Cooling water supplies

A steam turbine using saturated steam at about 3 kg/cm^2 gauge inlet pressure with 0.07 kg/cm^2 abs back pressure (2 inch Hg) will reject to the exhaust approximately 1.15 kcal per kW second. Thus a station containing 17 MW of plant will reject about 20,000 kcal/sec and will require in rough terms 1.7 ton/sec of cooling water with 12°C rise. The flow in the River Varma, Plate 7, is very variable reaching 33 ton/sec in flood. It will cover requirements by direct cooling during approximately 45 per cent of the time, but at minimum flow of about 0.25 ton/sec it provides only about one-seventh of the required quantity.

It is proposed to dam the stream so as to raise the water level to say 65 metres above datum and thus provide about 2 metres depth of water at the pump intakes and a reservoir of reasonable capacity. The water will then cover an area roughly 12,000 m^2. The average heat loss from this water surface if raised by 12°C above natural temperature, will be in the region of 1,000 kcal/sec and thus natural cooling is almost negligible, providing for no more than 1 MW even if all the surface were brought into circulation.

At minimum flow in the river if the temperature is raised by 12°C above up-stream temperature, the heat transported away amounts to 250 x 12 = 3,000 kcal/sec which is worth about 2½ MW. A higher rise is presumed to be ruled out by consideration of fishing discussed in Appendix 1.

The greater part of the cooling has accordingly to be covered by some other method when the river is low. The choice lies between natural draught cooling towers, mechanical draught cooling towers, or sprays. In the present case sprays seem to be outstandingly the most suitable since they could readily be accommodated on the dam and the area of water offers sufficient margins to ensure low drift loss. The use of sprays also fits in with the topography and levels. The pumping loss for sprays would be no higher than with cooling towers and no fan power is required. Moreover the estimated capital cost at about £26,000 compares with £55,000 for a mechanical draught cooling tower with ancillary equipment or say £66,000 for a natural draught cooling tower. The reduction in cost together with the saving in fan power is sufficient to outweigh the defect that the performance of a spray pond, being somewhat variable and dependent on the direction and strength of the wind, is not as calculable or as consistent as that of a cooling tower. Sprays have additional advantages in simplicity of construction, the small amount of equipment to be purchased abroad, and in freedom from freezing difficulties. The system would be self-draining and could be brought into service immediately by starting one or more booster pumps without risk of being frozen up. The main spray pipes might be of concrete and the smaller ones of asbestos cement, to save freight on cast iron, and would be supported on precast concrete posts. As velocities in the pond will be very low, even at time of flood, any drifting ice brought down the river is unlikely to damage the supports by impact.

The equipment is thus virtually immune from damage or outage through ice building whereas cooling towers, especially in intermittent use, would require exercise of special care and precautions in cold climate. However the use of cooling towers must be considered as a possibility in the event of future development of the station to say 30 MW as the size of the spray pond selected is adequate only for the 17 MW plant at present under consideration. Increasing the pond area to duplicate the sprays would require considerably more excavation but would probably still be cheaper than cooling towers. However a cooling tower could be operated quite independently of the river and this might be of importance at a later stage.

It is worth mentioning that since silt and gravel brought down by the river in floods may ultimately fill up the dam, it may have to be cleaned out at long intervals. This would not necessarily entail shutting down the station as the material might be shifted by gravel pumps.

<u>Layout</u>

Plate 8 shows a preliminary layout of the power station on the site discussed above. The initial installation provides for a minimum net output of 15 MW from two identical machines each rated at 8.5 MW. Further development on the same general lines is allowed for except that the extension is envisaged as employing pass-in machines to make use of the flash steam produced from hot water yielded by the wells. The buildings are assumed to be of sheeted ferro-concrete construction using largely prefabricated members so as to allow construction to go on in winter. Alternatively if the weather is unlikely to restrict building work, or if local experience in prefabricated construction is somewhat limited, in-situ construction can be adopted at approximately the same cost. The building would be monolithic with the floor slab as would also the machine foundations. The design takes into account horizontal forces arising from seismic accelerations of 0.1g. Heat insulation is by precast lightweight pumice concrete slabs and patent glazing would be used.

The station would preferably be placed on the flat rock shelf at the highest level available and as close to the west bank of the Varma River as permissible, consistent with stability of the ground near the edge of the fairly steep bluff forming the river bank. The precise location is chosen as a compromise to suit the lie of the ground, access, the run of the pipes in the spray pond, and the depth of water at the intake from the pond.

The general nature of the sub-strata is already known from the well borings nearby but trials have not yet been made to determine the load bearing characteristics. However, it is not expected that any difficulties will arise particularly if the ground remains undisturbed by large excavations. The load imposed on the foundation area by the power station building, if regarded as uniformly distributed over the concrete slab 1 to 2 metres thick, will be of the order of $\frac{3}{4}$ ton/ft^2 (8 ton/m^2). The barometric pipes from the condensers can be run above ground to dip down into the river. Steam and circulating water pipes will also be exposed, but on the side of the station away from the road from which it will normally be viewed. The facade is intended to present a pleasing appearance.

<u>Arrangement of the station</u>

The main axis of the station would be parallel to the river. Future extension to the north can take place in an unrestricted manner. The basement level is at 69 metres which is the present general level of the ground in the area, the operating floor level being 12 metres higher. This is necessary as mentioned later in order to provide sufficient height for the barometric legs of the condensers above the level of the river which we have taken to be 65 metres under normal conditions. We have also taken into account in the general design a flood level of 65.5 metres. The machines are placed athwart the turbine house. They are assumed to be approximately 13 metres long and a main span of 17 metres is therefore sufficient. The steam end is towards the river; the alternators will be adjacent to the switchgear annexe and the generator transformer and 138 kV switchgear compound, which will lie on the west side of the station with the existing road intervening. It may be necessary to divert this road if all equipment is to be enclosed within a site boundary fence. We have assumed that only the high voltage switchyard is fenced.

The first bay of the power station will provide space for servicing the outdoor transformers which will be brought into it by a transporter. It will also be used as a setting-down space for plant under overhaul.

The annexe on the west side contains the main switchgear and control room, the latter being at operating floor level with a glass division wall so that the control room staff, while insulated from turbine house noise, will have an oversight of the machines.

The elevated arrangement makes space available under the electrical end of the machine which can be employed for subsidiary switchgear, auxiliaries, battery room, etc.

The whole of the middle floor of the annexe is available for offices and welfare accommodation. A large part of the ground floor is allocated to workshop space.

Turbine inlet pressure

The turbine inlet pressure is arrived at by compromise between several factors of which the most important are on the one hand the characteristics of the wells, and the pressure drop to be allowed in transmission to the station, and on the other the variation of turbine steam rate with pressure as illustrated in Plate 9. As mentioned earlier the two earliest good wells 2 and 3 showed a maximum power output on live steam alone at a pressure somewhat below 4 kg/cm^2 gauge at the wellhead. If, however, flash steam is to be made use of, the wellhead pressure for maximum output rises to 5 kg/cm^2. We are of the opinion that no great reliance is to be placed on extrapolation of the measurements below say 4 kg/cm^2. Hence we disregard the apparent advantage of lower pressure. A pressure about 5 kg/cm^2 at the wellhead will allow for say 3 to 3.5 kg/cm^2 at the station and this is a convenient range for the turbine design. A higher pressure would entail too high a wetness at the exhaust and a lower one is inconvenient for use of steam jet ejectors. Hence we propose that the station should be designed for a turbine inlet pressure of 3 kg/cm^2 gauge and that initially provision should be made for using only the steam fraction of the well discharges. We consider that a design based on this concept will enable the station to be commissioned within the required time whereas the use of flash steam would introduce delay and some measure of uncertainty in performance. Operational experience on pilot flash steam plant for Wairakei 'B' will not be available in time for proven techniques to be designed into the plant for Hveragerdi. Hence we recommend that development of power from the water phase be deferred to a possible future extension of plant.

Design of turbine

For the size selected of 8.5 MW and an inlet pressure of 3 kg/cm^2 single cylinder double flow machines are preferred as avoiding a gland at the inlet and providing internal steam thrust balance. However, the number of stages required may favour a somewhat different arrangement, particularly in a reaction machine. An overload valve is not required, rated output being the normal running condition.

The area of exhaust assumed is approximately 2 x 14 ft^2 (2 x 1.3 m^2). The exhaust wetness with a back pressure of 0.07 kg/cm^2 abs will be about 13 per cent. The maximum blade tip speed would be specified not to exceed 900 ft/sec (273 m/sec). This is partly to avoid erosion and partly to ensure that the machine should be designed for a low stress level. The materials of construction are intended to be quite ordinary, viz rotor of mild steel (possibly slightly alloyed), casings of cast iron and blading of 12-14 per cent chrome stainless iron in the fully annealed condition. A drum rotor with reaction construction is preferred (other things being equal) as utilizing rather low stresses and exposing less surface of rotor to corrosive action of the steam. Certain precautions such as avoidance of brazing and of martensitic steel and omission of erosion shields on the blades have to be taken but otherwise the turbines follow orthodox techniques. Evidence elsewhere has shown that this procedure is sound and no large amounts of corrosion resistant steel need be employed. Some erosion of blades and other parts has to be accepted but is considered less dangerous than the risk of cracking which provision of erosion shields or blade hardening would entail. Erosion has not been found to be excessive in other plants. A further important precaution is the exclusion of steam from standing plant and the rapid drying out by circulation of hot air after shut-down. If these are not done serious corrosion is liable to occur through presence of H_2S in company with oxygen.

Arrangement of condenser

For geothermal plants only the jet condenser need be considered since it has the advantages of cheapness, freedom from fouling, and much lower corrosion risk than the surface condenser which is used in plants equipped with boilers primarily because the condensate must be recovered. Jet condensers are built in two forms, namely the high level type with barometric seal and the low level type with extraction pumps. The high level barometric type requires the turbine to be set above the cooling water level by something like 15 metres and hence entails a more expensive turbine foundation and power station building. On the other hand the low level condenser requires extraction pumps to handle the full circulating water quantity against full vacuum. Such pumps have never been built in the sizes required for the present plant though some are in course of design for operation in conjunction with an experimental jet condenser and a dry cooling tower on the Heller principle. These pumps would require to be set some 9 metres below the condenser in order to limit risk of cavitation. They would also be subject in the present instance to risk of corrosion because the condensate would contain corrosive gases. Because of this and the reputation that low level condensers have of being temperamental even in the smaller sizes where they are used, we have decided against that type.

A further possibility was considered, namely the use of outdoor barometric condensers as at "The Geysers" geothermal station in California. That layout allows of setting the turbine somewhat lower than when the condensers are placed immediately under the turbine as in previous geothermal stations at Larderello and Wairakei. Some saving is thereby achieved which may be attractive in the Californian plant which operates with rather high back pressure and is not subject to freezing. In Icelandic conditions we consider an outdoor arrangement less desirable because of the risk of corrosion in the long exhaust duct and of ice building up within the vapour extraction pipes especially in light load conditions. It is supposed that the reason why it is possible to use geothermal steam without incurring severe corrosion of mild steel is that the film of FeS is ordinarily adherent and protective. Below a temperature of about 30°C however it seems that a different corrosion product is formed and this is not protective. Hence low outdoor and vacuum temperatures entail added risk of corrosion. Also we consider that internal corrosion might be serious in the long exhaust duct due to the presence of air with H_2S in the exhaust steam. Small quantities of air will almost inevitably leak through the subatmospheric joints of a turbine.

In "The Geysers" plant advantage is also claimed for the use of a contra-flow condenser. We have looked into this but while there is a theoretical advantage, it does not in practice seem to amount to anything very significant and is insufficient to offset the disadvantage of the longer exhaust duct entailed.

Hence on the whole we have decided to recommend the orthodox arrangement with the jet condensers immediately below the turbine. Because advantage can be taken of the favourable lie of the ground the power station basement is not unduly high and a reasonably high basement has advantages in facilitating accommodation of pipes and equipment and obtaining flexibility in pipe layout.

If a more northerly site is adopted involving cooling towers certain alternative arrangements may be worthy of consideration.

<u>Selection of design back pressure</u>

The appropriate back pressure has to be arrived at by compromise between several factors. In the first place it is clear that the inlet circulating water temperature and the rise allowed (which is dictated by the quantity circulated) fix the lowest vacuum temperature. In practice there is also to be allowed a "depression" between the vacuum temperature and the circulating water outlet temperature. This is dependent on the amount of gas and on the design of the condenser.

If the vacuum temperature can be lowered the turbine can generate more power with a given quantity of steam, but against this must be offset the extra power taken by the circulating water pumps (if the gain is obtained by circulating more water) and there must also be a deduction for the extra power taken by the gas ejectors. Until the gas content of the steam is established with greater certainty the effect of gas extraction power cannot be properly settled. The gas contents so far measured are low but other wells could produce different values and gas content may increase with time.

It should also be mentioned that for a given potential gain in output by lowering of vacuum temperature, the real gain may be significantly reduced by leaving and hood loss and if the leaving loss is to be kept down, a larger last row annulus must be adopted. This will not only result in an increase of turbine price but will also most probably involve a higher tip speed bringing with it higher blade stressing and greater proneness to erosion and fatigue trouble. As mentioned earlier we put an arbitrary limit on tip speed of 900 ft/sec (273 m/sec) but an even lower value might well be advantageous for the sake of ensuring greater reliability.

In the present case the selection of appropriate back pressure is further complicated by the circulating water temperature being variable according to whether the water circulated is at natural river temperature or largely at recooled temperature as when the flow in the river is low. When the temperature is high a large exhaust will not be beneficial. Indeed it may result in additional loss. Conversely a tight exhaust will prevent the turbine benefiting much from low back pressure such as can be attained when there is ample cold water.

In view of these many variables and some uncertainties it is thought that it is unwise to strive for too low a back pressure and better to compromise on a moderate figure of the order of 2 inch Hg (0.07 kg/cm^2 abs) such as will apply with recooled water under average conditions and this will lead to cheaper and more robust turbines and in the output being less sensitive to circulating water inlet temperature. If the flow in the river had been such that adequate water could be counted on in the winter season when maximum power is required, then it would have been worth while to legislate for making use of the lower temperature available. However, the statistics of river flow show that low flows can occur at all seasons of the year so the economic value to be placed on occasional extra output is low.

Gas extractors

Gas content of the steam as so far measured is about 0.1 per cent by weight. This is very low compared with geothermal steam elsewhere, the average figure at Wairakei being some 5 times higher and at Larderello 50 times higher. However, it is necessary to pump out of the condensers not only the gas but also the air which comes in dissolved in the circulating water, air which leaks into the turbine, and also some amount of associated water vapour. Some gas, mainly CO_2, is dissolved in the outlet water. Hence the total quantity of incondensables has to be fixed somewhat arbitrarily. The total quantity is still likely to be vastly higher than that in normal condensing steam turbine plant and hence it is more important than usual to consider means of reducing the power taken by the gas exhausters.

Several methods are available differing in cost, efficiency, and reliability. Of these qualities we attach most importance to reliability. The most efficient method is the mechanical compressor but this is also the dearest and most liable to give trouble and we do not consider the saving in power in the present instance to be enough to justify risk of outage and high maintenance expenditure. Hence we have restricted the choice to the water jet and steam jet ejectors. In principle the water jet is slightly more efficient and in suitable cases the least complicated. However it is not as familiar to some manufacturers as the steam jet ejector. The water jet ejector consumes electric power to drive its pump and this power has to be generated. This power costs more than the equivalent amount of steam and according to preliminary estimates the installation costs of water ejectors are higher than for the steam alternative.

On the other hand the steam jet ejector has certain drawbacks: at the proposed steam pressure at the power station of 3 kg/cm^2 it is operating near to the minimum pressure for two stages. Hence the steam jet is rather vulnerable to possible fall in steam pressure of the wells which cannot be ruled out until there is more experience of the field. A three stage ejector could be used but with additional complication and cost. It would be possible to use the steam output of Well No. 4 for the ejector supply by piping this separately to the station at a pressure of some 4 kg/cm^2 gauge. A cross connection could be made to the main steam manifold for an alternative supply in the event of Well No. 4 losing either steam quantity or pressure.

The inter-condensers would be of the spray type with separate barometric pipe. There is a corrosion problem in all such parts where air and gas occur together but this is not to be regarded as desperately acute. An after-condenser is not essential if it can be accepted that the gases together with something like 1 ton of steam per hour per machine can be blown to atmosphere. If this quantity of steam is regarded as objectionable then it must be condensed in some form of after-condenser, and because of the corrosion risk it would probably be best to make the exhaust pipe in non-metallic composition such as glass fibre and construct a rough spray chamber over the outlet culvert to act as an after-condenser. There is also a possibility of using the available boiling water to actuate the ejectors but this idea is still in the development stage requiring some additional trials before it could be utilized.

For the present it does not seem to be essential to settle the choice and we suggest that alternatives are asked for in the tenders. The best combination may well be a steam jet first stage followed by a water jet second stage. All difficulty about disposing of the corrosive gases is thus avoided. The second stage would be housed in the CW pumphouse. The only drawback is a rather lengthy intermediate vacuum pipe.

It is worth mentioning that consideration has been given to utilizing the heat in the ejector exhausts for space heating in the station. Unfortunately this is not practicable because of the highly corrosive mixture of H_2S, CO_2, air and steam which has to be disposed of. Live steam is therefore a better proposition - or hot water which is abundant.

A further question is to what extent the ejectors should be duplicated. The choice we have settled on is one fully rated ejector per machine plus one additional ejector of the same size. This is not provided primarily for security since we regard the ejector as inherently very reliable. The object is mainly to be able to fit to an unknown amount of gas. Thus it is even possible that the two machines will be able to run on a single ejector under some circumstances (e.g. very tight turbine flanges and poor vacuum) whereas it may be useful to bring in the third ejector under conditions of high inleakage or low steam pressure. The use of a spare ejector takes with it the concept of bussing the vacuum pipes together so that ordinarily the two machines will operate at the same vacuum. A section valve will however permit of separating the systems in case of need. Suitable valves, e.g. of rubber diaphragm type, are available.

Circulating water system

The main circulating pumps and booster pumps are accommodated in a detached unattended pumphouse. All pumps are of vertical spindle type fully immersed so as to be continually ready for starting from the control room without priming or operation of valves. During installation or servicing the pumps are handled by a gantry crane running on the roof and are reached via removable hatches. A bridge spanning from the top of the bluff to the pump-house will provide access for plant. There will be a walkway at lower level giving access for personnel to the building and to the screens. Provision has been made for simple rack screens at the pump inlets and space has been allocated in the turbine room basement for fine screens of the rotating drum type on the pressure side should they be found necessary. It is assumed that the rack screens will suffice to prevent any trash from entering the system and, in the absence of leaves and vegetable matter, self-cleaning screens are not justified. The omission of such inlet screens avoids deep excavations which would be liable to act as sand catchers and generally simplifies the civil works. Isolating valves have been omitted at the circulating water and booster pump suctions. The CW discharge pipe has a non-return valve at the pump and an isolating valve in the turbine room basement. The pumps are intended to work normally on the unit system but the two pump delivery pipes can be bussed together when required. Each pump can be isolated on the discharge side and stop-logs can be inserted in place of the rack screens when pump maintenance is to be carried out. Each circulating water pump will deliver 10,000 Imperial gal/min (760 litres/sec) against a net head of 55 ft (17 metres) and the motor rating will be about 180 kW.

The circulating water will be delivered to the turbine room in two pipes probably in steel, one from each pump, with semi-flexible joints and laid approximately at ground level. The water is sprayed through jets into the condensers and will descend via the barometric tube into a sump which forms a seal. The sump is formed as an open culvert on the inshore side of the pump house. When the flow in the river suffices, the hot water will return to the dam, being prevented from recirculating direct to the intakes by a rough training wall of loose rock. When there is insufficient flow in the river, resort must be had to partial or complete recooling by sprays. Water from the sump is then pumped to the sprays by one or more of three booster pumps. Each booster pump is rated at $\frac{2}{3}$ of a circulating water pump and supplies one section of sprays. The number of booster pumps in operation can be varied according to the flow in the Varma River and the temperature of the water in the pond or to control the downstream temperature.

To prevent icing up at the main CW pump intakes hot water can also be let out through a sluice at the upstream end of the culvert. Portable hoses fed with hot water from the booster pumps could also be used to free any accumulation of ice on screens.

Wells

The present wells drilled primarily for prospecting are all provided with an inner casing of $9\frac{5}{8}$ inch outside diameter. It is usual to fit a master valve on top of the wellhead and the bore of this is the same as that of the casing though it might with advantage be larger. Immediately above the master valve a full bore tee off is necessary. This allows of quenching a well by pumping in cold water or of discharging steam clear of the rig when for instance it is necessary to service a well subsequent to drilling.

Discharge characteristics of the wells have so far been obtained by throttling at the master valve and measuring the discharges of water and steam separately at atmospheric pressure. The yield of flash steam is deduced from that of boiling water and subtracted from the total steam yield to give the yield at wellhead pressure. The characteristics obtained by this indirect method seem to indicate that at least two wells, Nos. 3 and 8, when running at the lowest pressure end of their characteristics (where the power output is the maximum) must be discharging at a velocity approaching sonic velocity in the wet mixture. This does not seem to be advisable as it implies very high pressure drops involving local high stresses and possible risk of erosion. It also seems to indicate that the discharge of the well is being limited by the outlet conditions and hence a larger output could apparently be obtained if the diameter in the upper 20 metres or so were enlarged. Hence for any future production wells it would seem worth while to adopt a larger diameter of inner casing for say the first 20 metres even though the well is continued with $9\frac{5}{8}$ inch casing to normal depth and with $8\frac{3}{4}$ inch in the rock as before. The expectation is that this will result in an augmented discharge for the same wellhead pressure and at little increased cost for the well. Alternatively on the same discharge the velocity will be reduced in the critical part. This seems worth while even though it entails a departure from the standard diameters adopted and hence interferes with interchangeability of valves, pipes, etc.

On the existing wells it would be possible to limit the effects of sonic velocity by fitting a divergent adapter between the master valve and the separator so that the velocity within the separator would be reduced to the order of 150 ft/sec at which we have satisfactory test data. However, in order to keep the size and weight of separator manageable, and for the purpose of interchangeability, it seems that the inlet branch diameter should not exceed 12 inch. Hence for Nos. 3 and 8 wells two such separators might be required in parallel entailing a bifurcation in the pipe.

Separators

No full-scale wellhead separators have yet been used in Iceland. The indirect method of measuring the well characteristics has avoided their use. It is desirable that a separator capable of working at wellhead pressure should now be obtained since this will clear up a number of uncertainties and provide further important experience. The type of cyclone separator as used at Wairakei will require slight adaptation to suit the larger inlet pipe diameter, e.g. 12 inch mentioned above. This is called for by the large volumetric flow consequent on the low operating pressure. Some development work is advisable on this in advance of the power station project since it is necessary to be certain that in extrapolating experience from New Zealand the expected separator efficiency is still achieved. Desirable experience will also be obtained in dealing with the flashing hot water.

Steam pipes

With the standard separator suggested above the outlet steam pipe branch would also be 12 inch. It is suggested that for the high output wells, such as Nos. 3 and 8, two separators would be employed in parallel and these would feed into one 18 inch pipe for transmission to the station. In other cases, e.g. Well No. 2, 14 inch pipe might be run.

It is however not desirable to lay down completely the form of the pipe network until several wells have been drilled and tested and prospecting is well advanced. Basically there is a choice between a radial system with separate pipes from each well to the station or a branched system with several wells feeding into larger mains transmitting the combined yield to the station. The choice depends largely on the location of the wells and it may be appropriate to point out that once the prospecting stage is completed and well drilling is for production only, it will be logical to take account of the pipework layout in the location of new wells. This is particularly necessary if wells are to be frequently out of commission for clearing out of deposits.

Thus it seems almost certain that a good steam yield could be obtained in the vicinity of No. 3 well. The opportunity is afforded of reducing both pipe and drilling costs since a second well in this area could make use of the same steam pipe as No. 3 accepting that the two wells are to be treated largely as alternatives not normally required to be used simultaneously to their full capabilities. In this connection it is to be noted that the small number of wells (possibly four) required to supply the power station will result in necessity for some throttling of yield at times to enable the output of the wells to fit the turbine demand. Only in this way will it be possible to avoid blowing off large quantities of excess steam at the station, the range of variation of yield by making use of the natural characteristics of the wells, that is by throttling at the station, being limited to about 10 per cent.

From point of view of pipe flexibility a radial system has advantages even though two pipes may follow the same route. For a given steam quantity to be transmitted at a given pressure drop, one large pipe costs much less than two smaller pipes. However, a single large pipe would be so stiff that it would require special compensators to provide flexibility whereas it is suggested that these could be largely avoided with the smaller pipes by suitable technique. This entails selection of an indirect route and introduction of deliberate offsets to obtain flexibility. It is also to be mentioned that about 20 inch diameter is the upper limit for solid drawn tube and above that it is necessary to use lap welded tube which is of a slightly lower standard though costing about the same price per ton.

It is proposed to suspend the pipes from concrete posts with hangers so that they are at least one metre clear of the ground and thus out of the way of normal snow and flood water where appropriate. Where convenient two pipes can be suspended from one post with a double cantilever. For a single pipe two posts strapped together to form an A support will ordinarily be used. The pipe hangers will allow a fair amount of flexibility, the only firm restraints being at each wellhead and at the station. Some amount of lagging is desirable in view of the wet and windy climate and to guard against burning of animals or human beings by contact.

Proprietary precast lagging 2 inches thick of, say, calcium silicate covered with aluminium foil will cost very roughly £0.5 per metre per inch of pipe diameter. This includes fixing. Thinner insulation such as would suffice would not cost a great deal less. It should be possible to manage with something cheaper than this, for instance foamed concrete made with pumice dust in precast sections, also covered with aluminium foil, but it would be necessary to interest some local concern and possibly carry out a little development. It is improbable that pumice dust concrete moulded in situ round the pipe would work out economical, because of high labour costs in the field.

Design pressures for pipes and equipment

The highest wellhead pressure so far measured is about 12.5 kg/cm^2 gauge with closed valve. The pressure subsides to much lower values after a well has been closed in for some time. Master valves need therefore to be of at least 250 lb/in^2 (17.6 kg/cm^2) class (steel steam valves). Even a higher class may be chosen according to the maker. The maximum pressure on the wellhead gear and on the pipes in service does not need to be as high as this as it can be limited by two forms of protection. Under normal conditions the pressure at the station would not be allowed to rise above about 4.5 kg/cm^2 at which the safety valves installed on the buspipe would be set. These valves are primarily to protect the turbines. They can be "exercised" from time to time by the station staff to make sure they are free. Safety valves in the field are undesirable and it is proposed therefore to rely on bursting discs installed as emergency protection at each wellhead. This protection is required only against an operating mistake such as shutting the valve at the station before the master valve at the wellhead. Such a mistake could readily be prevented by simple interlocks requiring the key with which the station valve is to be unlocked before closing, to be retrieved from the wellhead valve only when this is in the closed position. If bursting discs are used they may be set to some nominal pressure of the order of $8\frac{1}{2}$ kg/cm^2. This allows all valves except the master valve at the wellheads to be of 150 lb/in^2 (10.6 kg/cm^2) class, this being the lowest design pressure usually adopted for steel steam valves such as are intended.

The pipes and separators would also be designed for 150 lb/in^2 pressure. The hydraulic test pressure to be applied to completed components, viz pipes, separators and valves, would be at least $1\frac{1}{2}$ x design pressure in accordance with relevant design standards. Because of corrosion allowance, and difficulty in making pipes and vessels of thin plates, the wall thickness will be more than what is called for by stress considerations. This allowance is taken account of in assessing the hydraulic test pressure to be applied and on the separators, for example, the pressure will be of the order of 2 x design pressure. Because of this high initial factor of safety separators designed for normal service will also be suitable for testing well characteristics. In such a test, which is not classed as commercial operating service, it will be permissible to exceed the design pressure.

Electrical features

The proposed diagram of electrical connections is as shown in Plate 10. The output of the station will be stepped up to 138 kV for connecting into the existing 138 kV single circuit transmission line, which passes within 3 km of the station. This 138 kV line which has a nominal capacity of 96 MW runs from the Sog River switching station at Ljosafoss to the Ellidaar switching station and will be required to carry about 15 MW output from the geothermal power station. The line is at present running at about 70 MW and will be able to transmit the additional power (see Table 1) also allowing for the scheduled plant extension at Irafoss.

The rupturing capacity of the 138 kV circuit breaker has been put at 1500 MVA. This is well above what the system can require even in the remote future but it is unlikely that any maker will quote a breaker of lower rating at this voltage. A 138 kV breaker with 19 MVA step-up transformer are to be placed in a detached enclosure on the opposite side of the road. This is done to get the bare connections away from the station so that danger of contact is avoided during construction of any future extension. For the same reason it is suggested that the substation feeding into the local 11 kV distribution system should also be sited some distance clear of the power station site in a small kiosk. Connection to both 138 kV and 11 kV substations would be made by underground cables from the main generation switchgear.

Generation voltage

We have to settle the generation voltage which is also that of the main switchgear and could be either

6.3 or 10.5 kV. From the point of view of the alternator the lower voltage is preferred since it results in a simple robust winding. On the other hand 10.5 kV cannot be regarded as an impossible voltage for a rating of 8.5 MW. No question of standardisation on the system arises since the most recent station (Steingrimsstod) has reverted to 6.3 kV whereas 10.5 was adopted at Irafoss. For both switchgear and cables the higher voltage is advantageous. Many switchgear makers would supply for 6.3 kV merely a standard 10 or 11 kV breaker of the same current rating derated in rupturing capacity (and also in normal carrying MVA rating).

As regards cables, some makers would also supply for 6.3 kV an 11 kV cable rated at the same current. Hence at the lower voltage more cables would be required or a larger cross section. This does not however apply to all cable makers.

Fault duty on switchgear

Coming now to the particular conditions, the calculated fault duty on the main switchgear at the first stage of the proposed station, based on all other system extensions at present visualized, is a little under 350 MVA. This is within the range generally available at 6.3 kV being commonly standard 600 MVA 10 kV gear rated down. If the station is doubled in capacity at a later date the rupturing duty can still be held at 350 MVA by duplicating the arrangement, that is by connecting another section of switchgear through another 19 MVA step-up transformer to the single 138 kV breaker and keeping the two sections of main switchgear normally uncoupled. If on the other hand it were desired to work with a single solid busbar, the doubled station will have a fault duty of 600 MVA and provision should be made for this at the first stage. We can see little merit in the solid arrangement, which will cost some £14,000 fob more at Stage I.

The arrangements proposed might be thought somewhat vulnerable to step-up transformer failure since this could immobilize the corresponding amount of plant. If in the light of experience the risk is regarded as significant then in view of the very low spare plant ratio with which the system operates, and the remoteness of Iceland from the manufacturing countries, it would seem a wise precaution to carry a spare step-up transformer of say 20 MVA 138/6.6-11 kV which could be treated as a common spare available for three stations, Hveragerdi, Steingrimsstod and Irafoss. The lower voltage winding would be brought out to six terminals so that it could be connected in either star or delta to fit the appropriate voltage. The use of a star/star transformer does not appear to have any objection since the 11 kV star point could be bonded to the generator neutral and phase relationship is unimportant. The cost of this spare unit (about £20,000 fob) has not been allowed in our estimates since it is regarded as insurance for the system generally.

In our estimates we have allowed for 10.5 kV switchgear rated at 350 MVA. The cost of gear of the same capacity and cabling at 6.3 kV would be some £7,000 fob higher, against which might be offset a possible extra against 11 kV windings for the alternator. This will depend on the maker and no figure has yet been obtained.

A minor point arises in connection with the 11 kV distribution supply. We assume the fault duty on the system is very low probably below 50 MVA. It might be regarded as bad practice to feed this straight from the power station bars with such a high fault duty. The fault duty could be reduced by feeding through a reactor. We are not certain that the phase relationship will be suitable for direct connection and it might be necessary to interpose a 1 to 1 star/delta transformer which would effect the desired reduction of fault duty as well as adjusting the phase relationship.

The main step-up transformer is assumed to be provided with an on-load tap changer. This will enable the 11 kV bars to operate at nearly constant voltage as is desirable for the local 11 kV network and the auxiliaries. However it would be admissible and certainly cheaper to regulate the 11 kV supply and to allow the power station auxiliary voltage to vary.

<u>Supply of auxiliaries</u>

In a geothermal station steam is always available and can be regarded as a more reliable source of power than any alternative. It might appear therefore attractive to drive the auxiliaries by steam in a way analogous with practice in hydraulic stations. It is of course necessary to start auxiliaries such as a circulating water pump so as to raise vacuum before putting the main machine on load. Such auxiliaries must accordingly be driven by non-condensing turbines. On the other hand, since much of the power at the low steam pressure available is developed in the sub-atmospheric stages, it is clear that the auxiliaries should, for economy, be driven by condensing turbines which would require separate jet condensers. Because of these contradictory requirements steam-driven auxiliaries have to be dismissed as too complicated for the size and speeds in question.

We accordingly revert to the usual course of driving auxiliaries by electric motors. The auxiliaries are simple compared with those in a normal fuel-fired station, since there are no boiler feed pumps, extraction pumps or boiler fans. They comprise circulating water and booster pumps, gas removal equipment, lubricating oil pumps and various minor station auxiliaries, i.e. those not associated with each generating unit.

The circulating water pumps, the largest of the auxiliaries, will be of the order of 180 kW and can satisfactorily be supplied at 400 V, hence all auxiliaries can be supplied at this voltage. We have estimated on the basis of contactors with back-up fuses for the circulating water and booster pumps. Each of two 400 V 25 MVA switchboards is supplied from the main busbars through a station auxiliary transformer rated at 2 MVA. When the station is shut down the 400 V supply will be available as a back feed from the 138 kV system or the 11 kV existing supply. The two auxiliary boards can be coupled together and fed from either transformer when necessary (both transformers in parallel involve an excessive fault duty).

It may be mentioned that for starting up the station, in the remote event of no supply for auxiliaries being available, resort could be had to running up the main machines under atmospheric conditions since steam will always be available. An alternative is to provide a small house set of about 1,000 kW rating, or even less. This would however be used only infrequently and special measures (as for the main turbines) would have to be taken to prevent corrosion taking place under standby conditions. A further alternative is a small emergency diesel engine. We have not provided for such a house set which appears to us unnecessary having regard to the conditions.

SECTION 4

ESTIMATE OF COSTS

Capital expenditure - Stage I

Table 3 gives an estimate of capital cost for a station comprising two 8.5 MW turbo-alternators with a minimum net output of 15 MW. The turbine rating provides for various contingencies, such as bad vacuum and high auxiliary power, and the net output will ordinarily be well in excess of 15 MW.

The estimates in so far as they relate to imported material are based primarily on price data collected in Great Britain, the price level being that ruling in 1960. No marked changes are at present taking place and no provision is made for escalation.

The estimate for civil works is based mainly on unit costs in Iceland supplied to us by the State Electricity Authority as applicable to 1960 for the type of construction under consideration. They were adjusted from Steingrimsstod hydro-electric station contracts completed in 1959.

The cost of bores is computed on the basis of £21 per metre on the total depth to be drilled which includes an allowance for field surveying, casing and provision of master valve, testing of boreholes and the use of drilling rig and accessories. The cost of drilling for the additional steam required to cover about double the demand of the station has been assumed at the same rate per ton/h of useful steam yield as the costs incurred on wells drilled up to the end of 1960. This is about £500 per ton/h. Such a procedure may be rather conservative on two counts. First a large margin of safety in yield is covered. Secondly it includes the same ratio of abortive drilling whereas the proportion ought to diminish with experience and could almost certainly be drastically reduced immediately.

Allowance for contingencies and engineering has been put at 10 per cent. Interest during construction is also shown as most contractors would expect progress payments giving them almost full payment at the time of delivery. The figure can only be a token one since it will depend on the terms of payment to be fixed for the various contracts.

The estimates have been tabulated in two columns. The first column shows the fob price of all contract equipment and materials to be imported into Iceland. The second shows the final contract price, which includes the cost of erection and allowances for freight, insurance, import duty, etc. In assessing these allowances we have in some case, e.g. on turbo-alternators, pipework, pumps and transformers, used specific oncosts supplied by the Authority.

TABLE 3

ESTIMATE OF CAPITAL COSTS

	£'s	
	Fob	Total cost in Iceland
Turbo-alternators and auxiliaries, transmission pipework and wellhead equipment	411,000	662,000
Power station building, foundations, circulating water pumphouse and other civil works	53,000	228,000
Wells: drilling and testing		160,000
Drilling rig and accessories		85,000
Electrical equipment including 138 kV transmission line spur	105,000	172,000
Extensions to Ellidaar switching station		90,000
Circulating water system, spray cooling system and cranes	48,000	106,000
Dam on Varma River, acquisition of property and disposal of hot water		83,000
Houses for station operators		30,000
		1,616,000
Contingencies and engineering		162,000
		1,778,000
Interest during construction 1.43 years at 7%		178,000
		1,956,000
Cost per kilowatt installed		£115

Cost of energy production

Using the capital estimate in Table 3 we arrive at the cost of energy production as follows:

	Charges per annum, £'s
Interest on total capital 7% on £1,956,000	137,000
Sinking fund contribution: Basis 20 year life 2.5% on £1,762,000	44,000
Annual cost of well drilling: Basis 5 year life 17.4% on £194,000	34,000
plus cleaning out and maintenance on 8 wells at £5,500 per well	44,000
Maintenance on other equipment: outside labour plus materials	30,000
Operating salaries and wages	15,000
Administration and general expenses	10,000
	314,000

On energy generated 7500 hours use of maximum demand at 15 MW = 112×10^6 kWh,

Generated cost: **0.675 pence/kWh**

Conversions

Costs may be converted to different currencies as follows:

£1 = 106.7 Iceland kronur = \$2.8 US

1d (penny) = £ $\frac{1}{240}$ = 0.44 kronur = 1.16 cent US

The above is computed on an interest rate of 7 per cent and a nominal life in the case of most assets of 20 years. The sinking fund is assumed to earn interest at 7 per cent and in this connection any effect of taxation is disregarded. An exception is the wells where we have used a life allocated by the State Authority of 5 years. We see no reason to distinguish between the lives of other assets. In particular the pipework, according to our experience, will not show any shorter life than, for instance, the turbines and even if it were necessary to drill more remotely in order to continue to provide steam over the life of the station we would not regard this as seriously affecting the calculations which are intended to be on a conservative basis.

Extension to Stage II

The extension of the station to 30 MW by a second stage consisting of two similar machines (except that they would make use in part of pass-in flash steam from the hot water) is estimated to cost about £79 per kilowatt. The completed station would then cost £97 per kW installed. The estimates are not shown in detail because the parts which would differ markedly from the first stage, namely the transmission pipes for hot water depend on the locations of supplementary steam wells. These and the flash tanks can only be given token prices at the present stage. A cooling tower is assumed placed on the flat area on the far side of the river. No allocation has been made for any additional transmission line or for electrical extensions at the receiving end since this will depend on the timing of the further extension in relation to general system development.

The operating costs would be roughly 10 per cent lower on the doubled output primarily because of the lower financial charges but also because the staff would need little augmentation. Experience by that time may well show that a smaller ratio of spare bores will suffice on the greater number.

Staffing

The operating staff required for a geothermal station may be taken as about the same as that in a hydraulic station containing the same number of generators. Hydraulic stations are a better guide in this respect than fuel-fired steam stations in which the staff is largely occupied on the boilers and their associated coal handling and ash disposal plant, which do not arise in this case. In line with the State Electricity Authority's practice we visualize that the operating staff will consist of the following:

Station superintendent

Shift staff, 3 shifts each consisting of shift charge engineer and assistant charge engineer

Electrician

In addition there will be a day staff consisting of maintenance crew, including drillers, mechanics and general labourer: **Total 16 men**

The drilling crew of five men will normally be engaged on the redrilling of wells every other week, doing maintenance work on the wellhead and other equipment when they are not engaged on drilling. It is difficult to visualize exactly how much work the wells will entail, but since a crew capable of using the drill must be kept together they should preferably be capable of this dual function of drilling and routine maintenance to keep down operating costs.

There will not ordinarily be sufficient work to keep a workshop staff occupied in this station, and it will be found more economical to form a central overhaul and breakdown group available to all stations, hydraulic and steam, provided of course that staff is sufficiently adaptable to work on both types of plant. We do not think that this should create difficulty unless it is contrary to trade union practices.

We have not seriously considered remote control since we consider the technology is not yet sufficiently established.

We have not visualized that the circulating water pumphouse should be manned since the pumps will be started from the station and normally there will be no valves to operate. There will of course have to be a daily visit to inspect the condition of the intake screens and to check over the lubrication of the pumps, and less frequently, valves should be operated to keep them free.

Once a year each pump will have to be overhauled and for any major work we consider they would be removed to the workshop.

As there will ordinarily be no high voltage switching to be done at Hveragerdi we think that the whole control including 138 kV gear can be done by the shift charge engineer or his assistant who will presumably be in telephone communication with the switching stations at Ljosafoss and Ellidaar.

The wellhead equipment and pipelines require no constant attention but periodic inspections not less than once per week are to be recommended when gauges and other instrumentation are to be read. Less frequently all valves need to be operated to avoid seizure. Instrumentation both in the field and in the station can advantageously be kept to a minimum. The most important pressure is that of the steam received and this can be read on a mercury manometer. Vacuum pressure measurement would also be by an absolute mercury gauge. Temperatures are within the range of mercury thermometers. Thus basic instruments of the simplest type are adequate.

Time of construction

We have scheduled the first machine to be put into service in just under four years from the date of the decision to proceed with the work. This allows seven months for preparing specifications, receiving and adjudicating tenders and placing of contracts. The manufacturing period allowed for the turbo-alternators is thirty months plus eight months for delivery and erection. The controlling factor is clearly the time required for the turbine maker's delivery for plant which is in some degree non-standard. We have had assurance from some manufacturers that they could achieve deliveries of this order. All other contracts could we consider be fitted into the same period.

SECTION 5

ALTERNATIVE SCHEMES INVOLVING FUEL FIRING

Geothermal plant combined with fuel-fired superheating

The thermal efficiency of the geothermal steam cycle is inherently low, about 16 per cent. It could be substantially improved or in other words the output from a given steam flow could be increased by raising the steam temperature in a fuel-fired superheater. The increase in output obtainable and the efficiency of utilization of the fuel depend on the superheat temperature adopted. As a practical example a temperature of 700°F (371°C) will yield an extra output of 42 per cent at an efficiency of utilization of fuel around 35 per cent. This efficiency is distinctly better than could be obtained in separate plant using most modern steam conditions appropriate to the size of the machine. The incremental capital cost of the plant to give this extra output is also lower than that of an orthodox power station of the same order of capacity. A further advantage offered is that superheating the steam allows the turbine to operate over the greater part of the expansion in the dry region and hence the erosion and corrosion troubles associated with wet steam are largely eliminated.

Though all these advantages are genuine it is necessary to mention certain limitations and to view the comparison against the existing background. First, if the fuel-fired plant is only to be used for peak load the efficiency is not of first order account. On the other hand with fuel at £8 per ton even with 35 per cent efficiency the fuel cost per kWh is 0.46 pence so it cannot compete on base load with the basic geothermal plant. The site is not well placed for fuel deliveries and road transport charges would add somewhat to fuel costs so offsetting part of the better efficiency.

Secondly as regards capital cost it is not expected to show any saving as compared with a 10 MW extension at Ellidaar utilizing the existing excess boiler capacity. Moreover the Ellidaar plant, being near Reykjavik, is better placed for relieving the system of both kilowatts and kilovars and such plant might be worth having for running even as a synchronous condenser.

Thirdly the full benefits mentioned are obtainable only in plant designed for the conditions. If the turbines are designed for use at 700°F then the staging will not be exactly suited to running with saturated steam and there will be some sacrifice in performance. The turbines must in any case be specified to be suitable for the higher temperature from the beginning though this is not expected to entail any significant extra price. There are two ways of dealing with the 60 per cent increased volumetric flow consequent on superheating. One is to bring in a third additional turbine so as to increase the swallowing capacity by 50 per cent. Raising pressure within normal limits will take care of the margin. The other way is to specify the turbine to be capable of operating at 50 per cent increased pressure as well as higher temperature and with alternators also 50 per cent oversize. The system pressure would then be raised coincident with the change in temperature. This would entail a two-cylinder design of turbine but might be expected to cost less than the other method. The raising of the pressure would of course affect the whole system and cause the well yields to fall back along their characteristics but it is assumed that additional spare wells could be brought into service to make up the deficiency. The two schemes are thus slightly different basically in that part of the augmented output by raising pressure comes from the wells and not from fuel so the fuel consumption is rather less. It has to be assumed that the raised pressure on the system generally is permissible. This is true for the system as provisionally outlined but might not be true in a general case.

A further matter which would need to be investigated, and on which there is at present no data, is whether a superheater handling geothermal steam would show significantly increased corrosion from the steam side. It is thought that this is unlikely. However there is very little modern experience with separately fired superheaters and none known of with the conditions which would apply in this case, in that there would be no economiser. This affects mainly the outlet temperature to which the stack gases can be reduced and for this reason the efficiency has been put at under 80 per cent.

To summarise, it would be possible to obtain some 40 per cent extra output by fuel-fired superheating at a high efficiency and low price per kilowatt but it is unlikely that this would fit general requirements of the system any better than an extension at Ellidaar designed for peak load service. Moreover so long as steam can be obtained cheaply and in sufficient quantity, an extension of the station relying on saturated steam would be a cheaper proposition for base load duty.

Condensing oil-fired station at Ellidaar

We have been considering an extension of generating capacity at Ellidaar to be used for peak load service only. It is also of interest to compare the cost of geothermal power with that produced by a base load oil-fired condensing plant located at Ellidaar. It is estimated that such a plant could be built at a cost of about £100 per kW. The annual efficiency sent out is assumed to be 25 per cent and the cost of fuel oil is taken at £8 per ton (approximately 850 kr per ton).

The cost of generation then works out as follows:-

	pence/kWh sent out
Capital charges, 9.5% on £100/kW calculated on 7500 kWh/kW per annum	0.30
Fuel	0.63
Operating wages, maintenance, management, etc, say	0.10
	1.03

The generation cost is so much higher than the 0.675 pence/kWh for the geothermal station, shown on page 56, that the comparison will not be seriously affected by likely variations in capital cost from the £100 per kW assumed. Even if the capital charges are reduced by as much as 30 per cent the generation cost will not fall below 0.9 pence/kWh.

Non-condensing oil-fired station at Ellidaar operating in conjunction with the Reykjavik district heating scheme

As a further alternative we consider an oil-fired steam plant with back pressure turbines designed to reject their exhaust heat into water which could augment the natural hot water supplies, from wells at Reykir and Reykjavik, used for district heating in the capital. It is understood that the price which the district heating authority would pay for such heat is 22.5 pence/million Btu (10 kr per million Btu).

The amount of power that can be derived depends on the initial steam conditions adopted, but assuming the same size of plant as in the geothermal station, namely two 8.5 MW turbo-alternators, steam conditions of approximately 500 lb/in^2, 800^oF, as used in the existing Ellidaar plant, are about appropriate.

The cost of such an extension is rather lower than that of a condensing plant because of the omission of condensers and the more expensive condensing end of the turbine, but this is partly offset by the increased boiler capacity required. A figure of £80 per kW has been taken.

We estimate that for every 1 million Btu in fuel supplied to the boiler, the heat account will be as follows:-

Heat realized in steam	850,000 Btu
Heat utilized by the turbine	200,000 Btu
Heat rejected	650,000 Btu

The heat utilized in the turbine will produce 56 kWh and the fuel cost is derived as follows:-

	pence
Cost of fuel per million Btu	46.5
Value of heat rejected	14.7
Fuel cost for 56 kWh	31.8
Fuel cost per kWh	0.57

The overall generation cost can then be estimated:

	pence/kWh sent out
Capital charges, 9.5% on £80/kW calculated on 3750 kWh/kW per annum	0.49
Fuel	0.57
Wages, maintenance, management, etc, say	0.10
	1.16

Hence a non-condensing oil-fired station operating in conjunction with the district heating scheme is not competitive with geothermal power.

In the above calculation we have assumed that augmentation of the natural heat for district heating would be required for six months in the year and electrical output would be limited by the requirements of the district heating system. A plant of 15 MW nett output will reject 185 million Btu/h, sufficient to heat 144 litres/sec of water from 10°C to 100°C. This is to be compared with the existing system in which the hot water wells supply some 360 litres/sec which is augmented on peak heating load by 60 litres/sec at the Ellidaar steam station.

It is to be noted that even if the district heating requirements were such as to enable the plant to run at the equivalent of full output for 7500 hours per annum, the generation cost is not likely to fall below 0.9 pence/kWh.

Diesel generation

It is also necessary to consider diesel generation to complete the study. Diesel plant could be located near the load centres and is assumed to cost approximately £60 per kW installed. The annual efficiency sent out is taken to be 35 per cent and the fuel price assumed for diesel oil is £11.25 per ton (1200 kr per ton). The cost of power then works out as follows:-

	pence/kWh sent out
Capital charges at 9.5% on £60/kW calculated on 7500 kWh/kW per annum	0.18
Fuel	0.65
Wages, maintenance, lubricating oil, say	0.15
	0.98

The capital cost of a diesel station may vary rather widely in accordance with the size and speed of the engine selected and whether supercharged or naturally aspirated, also with the standard of building adopted. In some degree the various factors compensate one another, for instance high speed usually implies high maintenance costs. There is in fact no diesel generating station in the UK returning generation costs lower than taken above. Therefore there is no prospect of diesel generation competing with the geothermal scheme on base load.

APPENDIX I

DISPOSAL OF HOT WATER

The hot water produced by the wells in association with steam is potentially an asset particularly in a cold country though if it cannot be usefully disposed of it becomes an embarrassment.

The quantities yielded at present are as follows:

Well No.	Wellhead pressure kg/cm^2g	Water yield kg/sec
2	5	90
3	5	67
4	4.5	43
6	5	56
7	5	46
8	5.8	76
	Total	378

By the time the station is constructed the total water yield might be of the order of 450-500 kg/sec but as all the wells will not be in use at the same time the water to be disposed of will ordinarily be about 300 kg/sec.

We have recommended that in the initial development of geothermal power at Hveragerdi the hot water should be discarded. There is no immediate use for it locally as the village of Hveragerdi is adequately supplied with steam and hot water from its own wells which have been in use for several years. Transmission of the hot water to Reykjavik to supplement the existing district heating system is another possibility but it would involve an expenditure of the order of £2 million and would hardly show to advantage compared with drilling for hot water somewhere nearer to Reykjavik or Hafnarfjordur. Its use for salt production is considered later but this also is of doubtful economic merit. Flash steam produced from this water may at some future stage of development be used for power generation. However, this would not greatly affect the quantity of hot water to be disposed of since it would utilize only the flash energy above 100°C.

Disposal to river

The simplest course would be to let the hot water go into the Varma River. This would be tolerable under high river flow conditions but at low flow it would be lethal to the fish since 300 l/sec at 100°C would result in a rise of about 43°C at minimum river flow of 250 l/sec. This is additional to any rise put in by the heat rejected by the power station which has been discussed in the main body of the Report. The cost of compensating the fishing interests and any other riparian owners downstream sets an upper limit on the amount to be spent on provision of any alternative cooling arrangement designed to recool the water to a low temperature before its discharge to the river. If fishing interest were disregarded the cooling of the boiling water to a temperature unobjectionable to cattle or human beings is relatively simple since the heat in excess of 100°C can be flashed to atmosphere while a small cascade will readily cool the water to the order of 50°C. The further stage of cooling down to 25°C requires much more expenditure. The simplest way of reducing the temperature of the water is to discharge the flashing mixture from the wellhead separator across an area of open ground some distance from the station and allow the water to drain back into the river. This might be done on either side of the river according to convenience. There are some defects in such a scheme and the first is that the cooling cannot be calculated with any certainty. It might also lead to ground erosion and in winter ice build-up would bring problems. Silica deposition might kill vegetation but, on the other hand, the heat released might be expected to improve the general climate in the vicinity and so promote growth of vegetation outside the range of silica or excess heat. Vapour carryover and noise are both problems, though we think they could be dealt with by suitable directing of the jet. Complaint due to carryover of scale-forming substances onto distant greenhouses such as has occurred with vertical discharge is not likely. A period of trial would in any case be essential before devising any remedial measures.

It is apparent that any more elaborate alternative to such a simple scheme must involve higher costs. The ultimate development is to use cooling towers, though not of conventional design. Boiling water can be cooled very rapidly. We visualise a contraflow tower taking boiling water under sufficient pressure to cause it to discharge up into a tower without pumping. The air would be heated sufficiently to produce a strong draught without the use of an unduly high chimney. An unusually deep contraflow fill is required. Normal evaporative cooling to a reasonable approach to air temperature would take place in the lower part. A fill of material able to withstand the high temperature would be required and this might be plain or reinforced glass on concrete bearers or possibly concrete or asbestos cement. A scaling problem can be foreseen but no solution can be offered until practical experience is obtained. There could be a tower at each wellhead, one tower to two wells, or a central tower serving a number of wells. The cooling equipment will clearly cost less if it is concentrated into one unit but this entails piping the hot water from the various wells to a central point. The cost of piping could hardly be justified unless it were treated as ante-dated expenditure belonging to Stage II when the hot water is to be used for producing power from flash steam.

There are many variations of such a scheme which can be developed at a later stage, but we conclude that something on the lines of what we have discussed is feasible. A certain amount of trial and development will be required since such high temperatures are not usual in existing cooling tower technology. However we foresee no serious design difficulties as the size of tower required is modest. In our opinion it will be possible at reasonable cost by one or other of the above methods to keep the temperature of the Varma River to say 25°C except possibly in a combination of very unfavourable circumstances such as high atmospheric temperature, high natural river temperature and low river flow. A token sum has been allowed in the estimates.

Alternative methods of disposal

Piping the hot water down to the Olfusa River, a distance of some 8 km, appears too costly to be considered seriously (order £250,000). The possibility of pumping hot water back into the ground has often been suggested though it has not been tried, so far as we are aware, in a geothermal region. Oil companies regularly pump water into depleted fields to maintain the pressure that forces oil to the surface after natural pressure begins to subside. We have not given any serious consideration to this possibility. We do not preclude it entirely but consider that experiments would have to be carried out in the site area to determine the feasibility, consequences and power requirements of such a scheme. It is possible that unstable ground conditions could arise and the effect on the hydro-thermal system would require long-term observation.

The only potential use we have thought of for the large quantities of hot water at 100°C is in salt production by evaporation of sea water. A scheme has already been put forward in a preliminary way by which sea water could be evaporated in ponds heated by passage of hot water through tubes or under sheets of polythene. We have suggested that a pilot pond on these lines should be constructed for preliminary testing.

The 300 kg/sec of boiling water we mention above as having to be discarded by the power station would be almost sufficient to produce 20,000 tons of salt per annum. It would involve converting a flat area of some 10 hectares into polders so that sea water could readily be pumped into them. The bottom would have to be made impervious by use of puddled clay unless the site were already on clay. The flat region to the south of Hveragerdi appears to be quite well suited though it is unfortunate that the water in the estuary of the nearby Olfusa River will be too diluted with fresh water to be economic as a source of salt water. A pipeline would have to be constructed to convey full strength sea water from some suitable point on the coast. The distance of 14 km is not intolerable. On the other hand the cost of the hot water pipe delivering by gravity over a distance of say 5 km might amount to some £100,000 and therefore though the hot water is free at the source above Hveragerdi it may not prove cheaper at point of use than hot water available elsewhere, e.g. at Krysuvik which is within 7 km of the sea.

APPENDIX 2

CORROSION AND DEPOSITS

Provisional analyses of the impurities in the steam and of the water delivered by Well No. 3 are given in Table 4. The main contaminants in the steam are the gases carbon dioxide and hydrogen sulphide which are regularly found in geothermal steam in other parts of the world, the contents in the present case being distinctly lower than experienced elsewhere. The water contains common salt and scale-forming substances. This is also usual but the salt concentration is much lower than met with in New Zealand while the calcium carbonate is higher.

All geothermal waters are liable to be saturated with some scale-forming constituents from the rocks. The most important of these are silica and calcium carbonate. Calcium sulphate seems to be less common and hydroboric acid in large concentration is uncommon though it occurs at Larderello.

The gases CO_2 and H_2S are both potentially corrosive in the presence of water which is unavoidable in the plant as resulting from condensation of the steam. Corrosion tests were started at Hveragerdi in October 1960 to obtain data on the suitability of a range of construction materials likely to be used in a power plant.

Preliminary results show the same sort of pattern of attack as experienced elsewhere. Some of the specimens show very violent attack in oxygenated steam. However this is normal experience and ample practical evidence obtained elsewhere, confirmed by inspection of equipment used in tests so far in Iceland, shows that general corrosion of common materials of construction such as mild steel and cast iron is not serious either in the turbine or in the pipework so long as there is no oxygen present. It appears to be generally true that geothermal steam does not contain oxygen, presumably because this has been used up in reacting with other substances underground.

The H_2S does initially attack steel even without oxygen, but the reaction product FeS, which is a black scale, is adherent and forms a protective coating. This coating inhibits further attack so long as it is not disturbed. Continued attack therefore is concentrated where the scale is removed by water erosion, e.g. on the turbine stator, and precautions have to be taken to protect, or make renewable, any areas so affected. Injection of amines intended to counteract H_2S has been tried but found undesirable as it removed the protective FeS film.

There is a more violent corrosion environment in the exhaust duct and gas extraction parts of the condenser where oxygen is present, through having leaked in or been released from the circulating water. However this affects mainly parts which are static, not very expensive and also can be protected by coatings.

Experience confirmed by tests shows that various films such as graphite (Apexior No. 1) and oil offer some protection even in the presence of oxygen and make possible the exposure of bright parts, such as valve spindles, without serious attack at least for several months before renewal of protection is necessary. Both austenitic stainless steel of 18/8 chromium nickel type (and its variants) and in lesser degree ferritic 12 per cent chromium iron are reasonably resistant to H_2S. They also acquire a black film of FeS. However 12 per cent chromium steel in martensitic state and probably all hardened steels are subject to stress corrosion cracking. Hence it is inadvisable to employ any such alloy in hardened state since this is likely to contain martensite and its behaviour will be unreliable.

As H_2S also attacks copper violently and some of its alloys, it is advisable to exclude brazing compounds which consist largely of copper. Nickel is also attacked.

The selection of materials is somewhat complicated by the possible presence of chlorides in the form of sodium chloride. This cannot be carried in the steam phase but only in the water. However it is not practicable entirely to eliminate water by separators. Unfortunately some of the best materials for resisting H_2S are prone to chloride attack. This is so both with 12 per cent chromium and austenitics such as 18/8/3 chromium nickel molybdenum. However practical experience with 12 per cent chrome iron at Wairakei so far seems to show that this is not a serious problem when using live steam. It may become more serious when using flash steam where there is less opportunity to eliminate carryover of water but there is an amelioration in that the Hveragerdi bore water is not very high in salt content.

Scaling

The scale-forming substances silica and calcium carbonate (commonly described as "calcite" though more properly aragonite) are liable to occur in saturation or even supersaturation in the bore water. Saturation concentration of silica (quartz) at a temperature of 200°C is quoted as about 250 ppm and of calcium carbonate (in the presence of CO_2) the order of 2000 ppm. The presence of one substance may affect the solubility of another. Silica can also be carried in steam in very small concentration, possibly 0.05 ppm, and as a colloid in excess of saturation in the water. Silica tends to be thrown down by drop in temperature of water but because of the colloidal state shows a time lag. Calcite on the other hand is not soluble in steam and hence is mainly thrown down by evaporation or by release of CO_2 from solution (e.g. by flashing of steam) when it then occurs in excess of saturation in the remaining water. Deposition then seems to occur without time lag. Hence silica deposits can be expected to form deep down in the bores where the pressure is lowered in relation to the lithostatic pressure at which the silica was initially in equilibrium. They may possibly occur also in the passages in the rock feeding the bores. In either case a slow falling off in yield will take place. In the first case the well can be restored to its initial output by putting the drill down at intervals. In the second case no remedy is known but it is not certain that the trouble occurs.

With calcite the deposits occur about where the steam flashes, i.e. generally high up in the bore, and can be of much greater magnitude. Hence falling off of output is much more rapid. The No. 2 well at Hveragerdi showed significant falling off in a period of two months continuous operation and this was ascertained to be caused by calcite. The output was restored by putting the drill down and this may be required every few months.

It appears that calcite is not likely to cause deposits beyond the wellhead since in service flashing will cease there and the reverse process of slight condensation will occur. However all droplets may be expected to contain saturation concentration of calcite and hence a very small percentage of carryover of water could in a matter of months represent a sufficient weight of scale to be troublesome if it deposits within the turbine. Silica and calcium sulphate can also cause trouble in the turbines but may be expected to be in lesser quantity. The process of reducing the effects of carryover is helped by the formation of condensate in the steam transmission pipe due to heat loss from the pipe surface. This condensate will reduce the salt concentration in the bore water carried over from the separator and some of the mixture will be discharged through traps in the pipelines. We propose installing a set of water eliminators at the station and it is even possible that "Knitmesh" screens, to catch any small droplets, may have to be installed behind these. In this way the salt concentration of droplets carried into the turbine, and also the total quantity of salts associated with the steam, will be considerably reduced. The evidence so far obtained is insufficient to enable a final decision to be reached as to the seriousness of the problem, however it is possible that the high pH (9.5) of the water indicates that it contains dissolved salts such as sodium carbonate which may be beneficial as counteracting the acid gases.

Corrosion of concrete and cement

In geothermal regions the content of sulphates in the ground water is often sufficient to cause rapid deterioration of concrete made with ordinary Portland cement. This is now recognised to be caused by reaction between the sulphates and the tricalcium-aluminate which is a constituent of most Portland cement. The reaction involves a conversion to calcium sulphate which is accompanied by a considerable increase in volume. This causes disruption of the concrete and ultimately complete loss of strength. Remedies consist in selection of the raw materials to produce a cement having a low content of tricalcium-aluminate or alternatively volcanic trass may be incorporated in the concrete mix. It is possible that the cement made in Iceland using some volcanic materials may be naturally resistant. Tests have been suggested to establish whether this is so.

Asbestos cement goods for use in geothermal waters must also be made of sulphate resisting cement, otherwise their decay is likely to be rather rapid.

Corrosion in river water

Corrosion tests on selected materials are being made in the river water and since this consists partly of discharges from geothermal ground, it is likely, at least under low flow conditions, to be somewhat corrosive to copper base alloys which are commonly used for tubes of generator coolers, oil coolers, etc. It is expected that by testing a variety of alloys, one or more will be found which show adequate resistance. Possibly stainless steel might have to be used. This is no great drawback for the quantities of tubular materials required are small and the cost is not seriously higher than of cuprous material.

General corrosion from atmosphere

The H_2S content of the air in and around the power station and bores is unlikely to be high enough to require any special precautions against corrosion other than of the parts mentioned above. Copper in electrical conductors and the like exposed to rain or condensation may be expected to form a purple patina after which the speed of attack is reduced. A bright appearance can be preserved by lacquering or greasing. In the case of very thin wires of copper alloys such as constantan (especially if not carrying current) the surface to volume ratio may be so high that attack will reduce the cross section seriously within a short time so the resistance is not constant and the wires ultimately disappear. This trouble is known in highly contaminated industrial atmospheres and the remedy is to use nickel chrome wires which are more resistant to attack. Pure aluminium is not significantly attacked.

Bore water may contain some fluorides and if it is allowed to concentrate on glass by evaporation, the surface may show roughening and loss of transparency. The calcium carbonate, silica and other soluble salts may also be left as deposits when geothermal water evaporates and, though these do not corrode, they may cause inconvenience in that they will have to be cleaned off.

TABLE 4

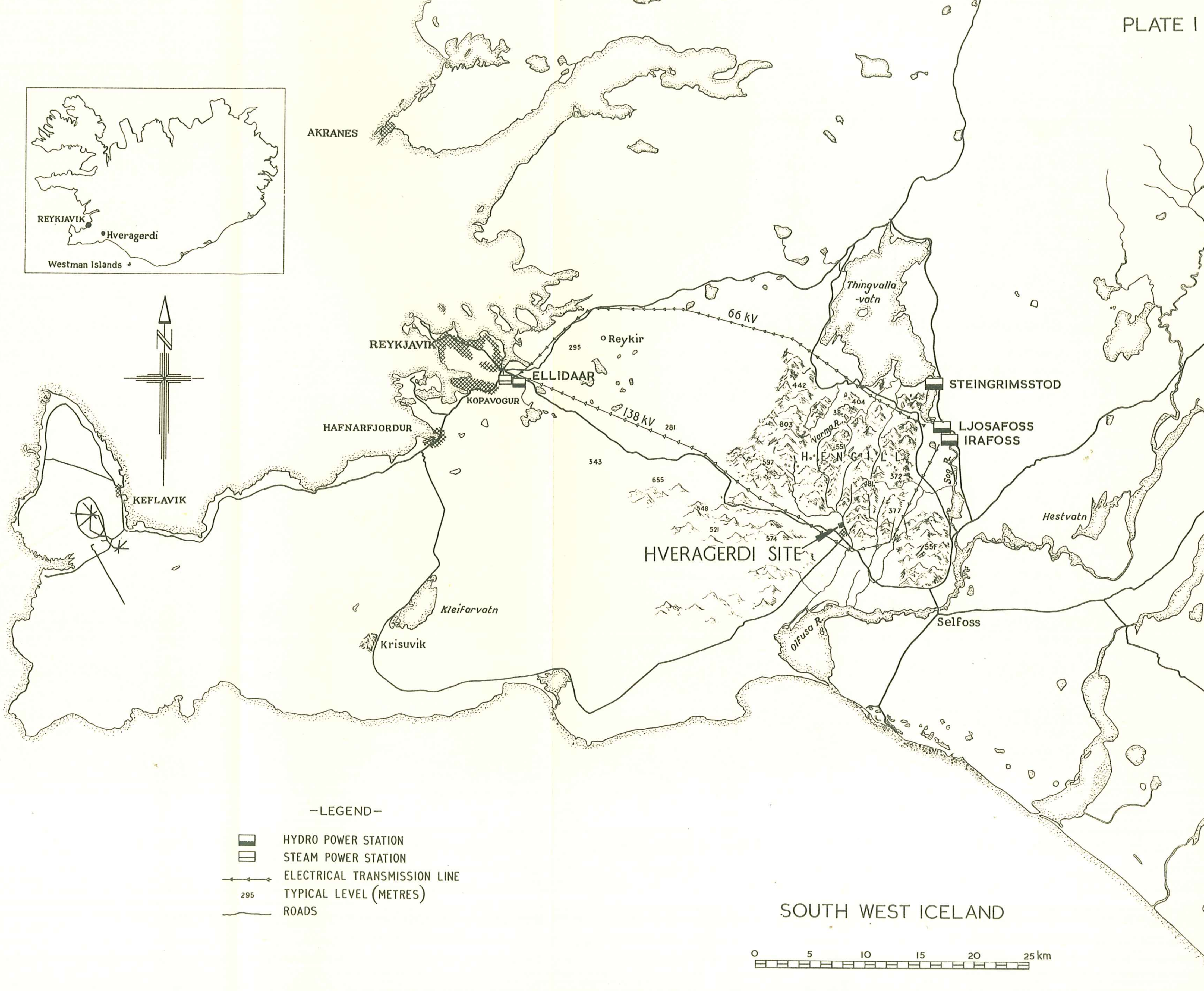
GAS CONTENT OF STEAM
(measured at atmospheric pressure)

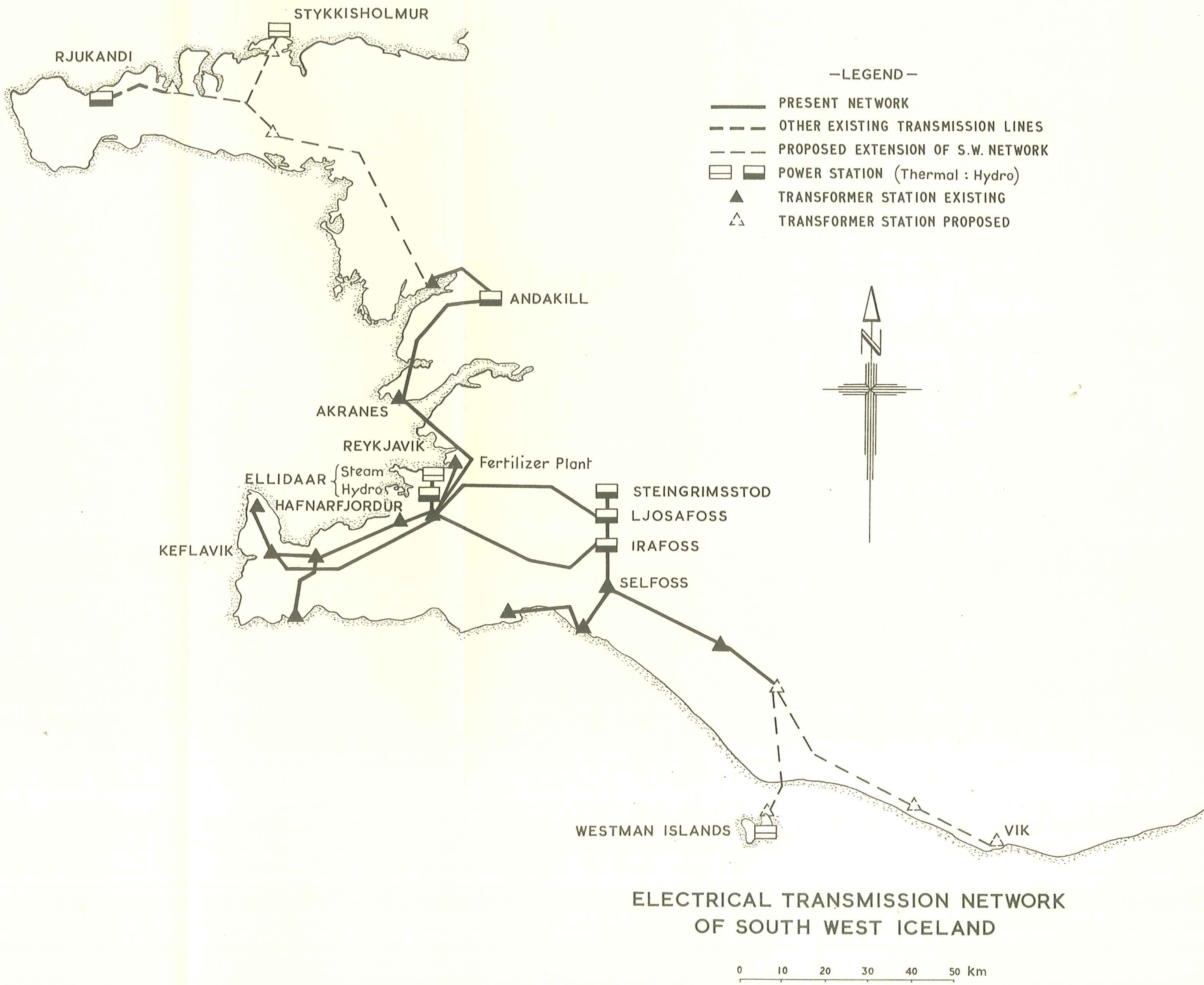
	parts per million by weight
Carbon dioxide (CO_2)	590 - 790
Hydrogen sulphide (H_2S)	76 - 106
Hydrogen	1 - 2
Balance, mostly nitrogen (N_2)	25 - 25
Total	692 - 923

DISSOLVED SOLIDS CONTENT OF BORE WATER

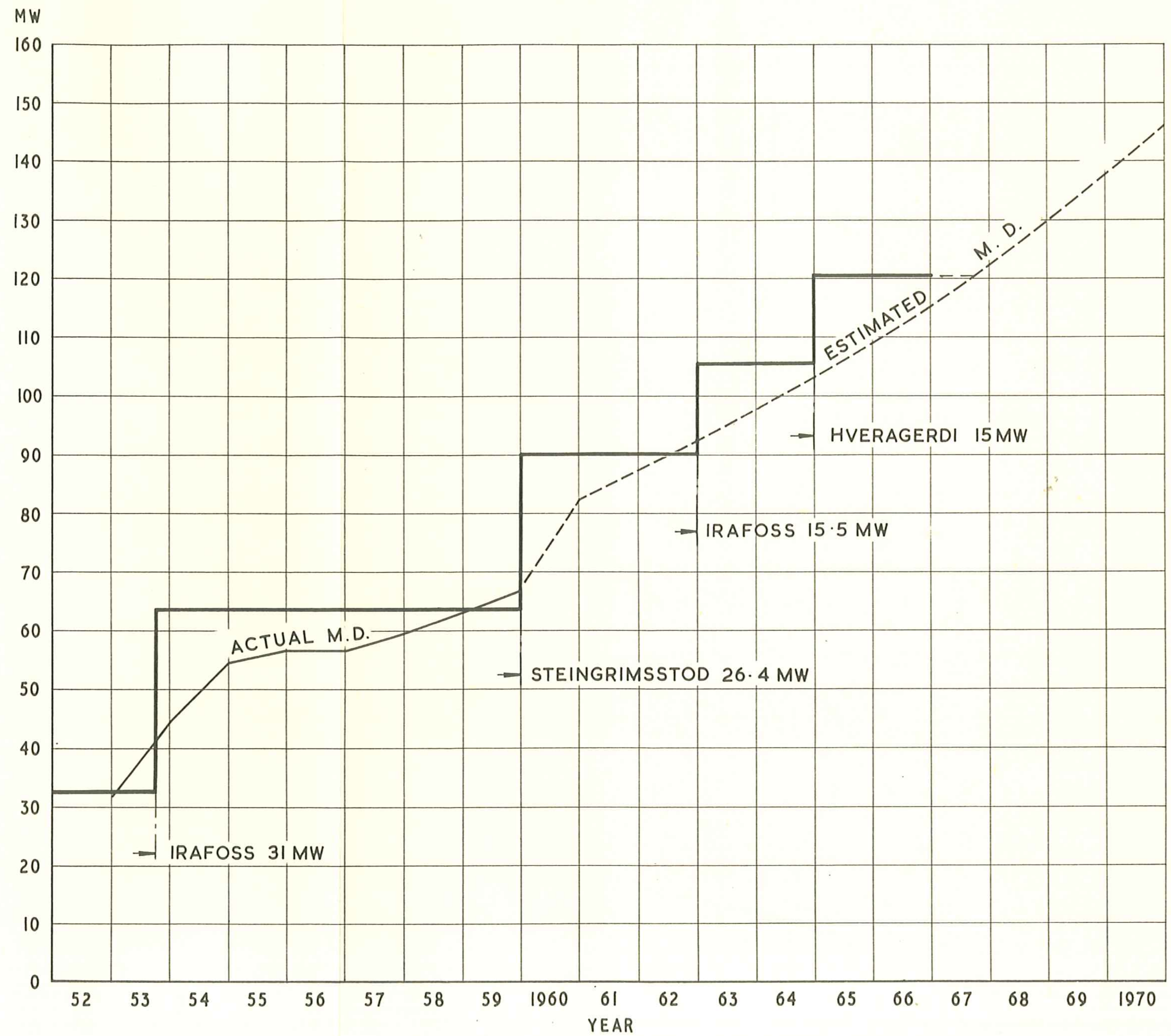
	parts per million by weight
Chloride (Cl)	167
Silicic acid (Si02)	341.2
Sulphate (SO_4)	61.2
Fluoride (F)	2.3
Minerals	904
Hardness ($CaCO_3$)	9.5

pH	9.56

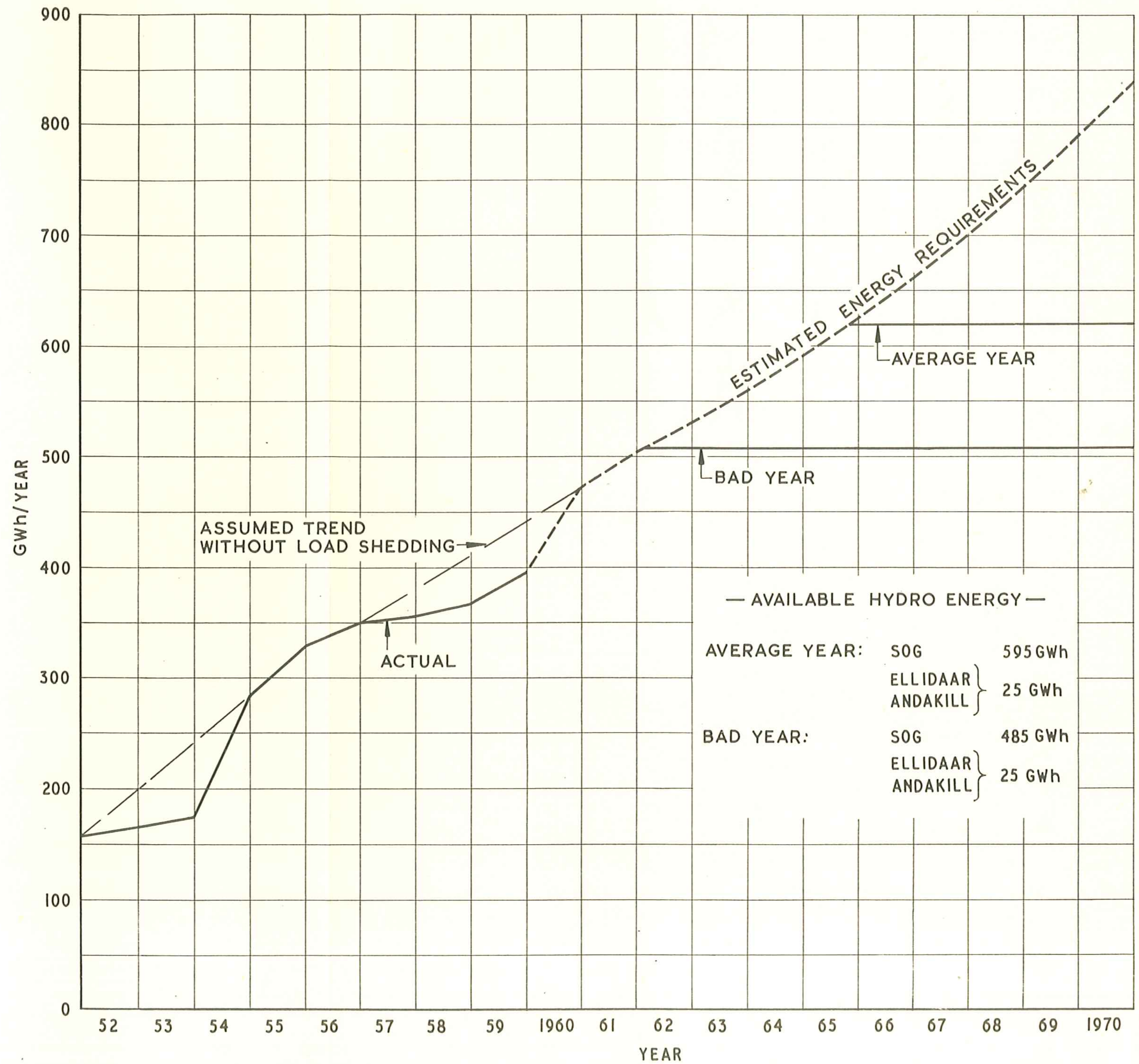

REYKJAVIK
Hveragerdi
Westman Islands
N
AKRANES
REYKJAVIK
ELLIDAAR
KOPAVOGUR
HAFNARFJORDUR
KEFLAVIK
Reykir
66 kV
138 kV
Thingvalla-vatn
STEINGRIMSSTOD
LJOSAFOSS
IRAFOSS
HENGILL
Varma R.
Sog R.
Hestvatn
HVERAGERDI SITE
Selfoss
Olfusa R.
Kleifarvatn
Krisuvik
-LEGEND-
HYDRO POWER STATION
STEAM POWER STATION
ELECTRICAL TRANSMISSION LINE
295
TYPICAL LEVEL (METRES)
ROADS
SOUTH WEST ICELAND
0 5 10 15 20 25 km



ELECTRICAL TRANSMISSION NETWORK OF SOUTH WEST ICELAND

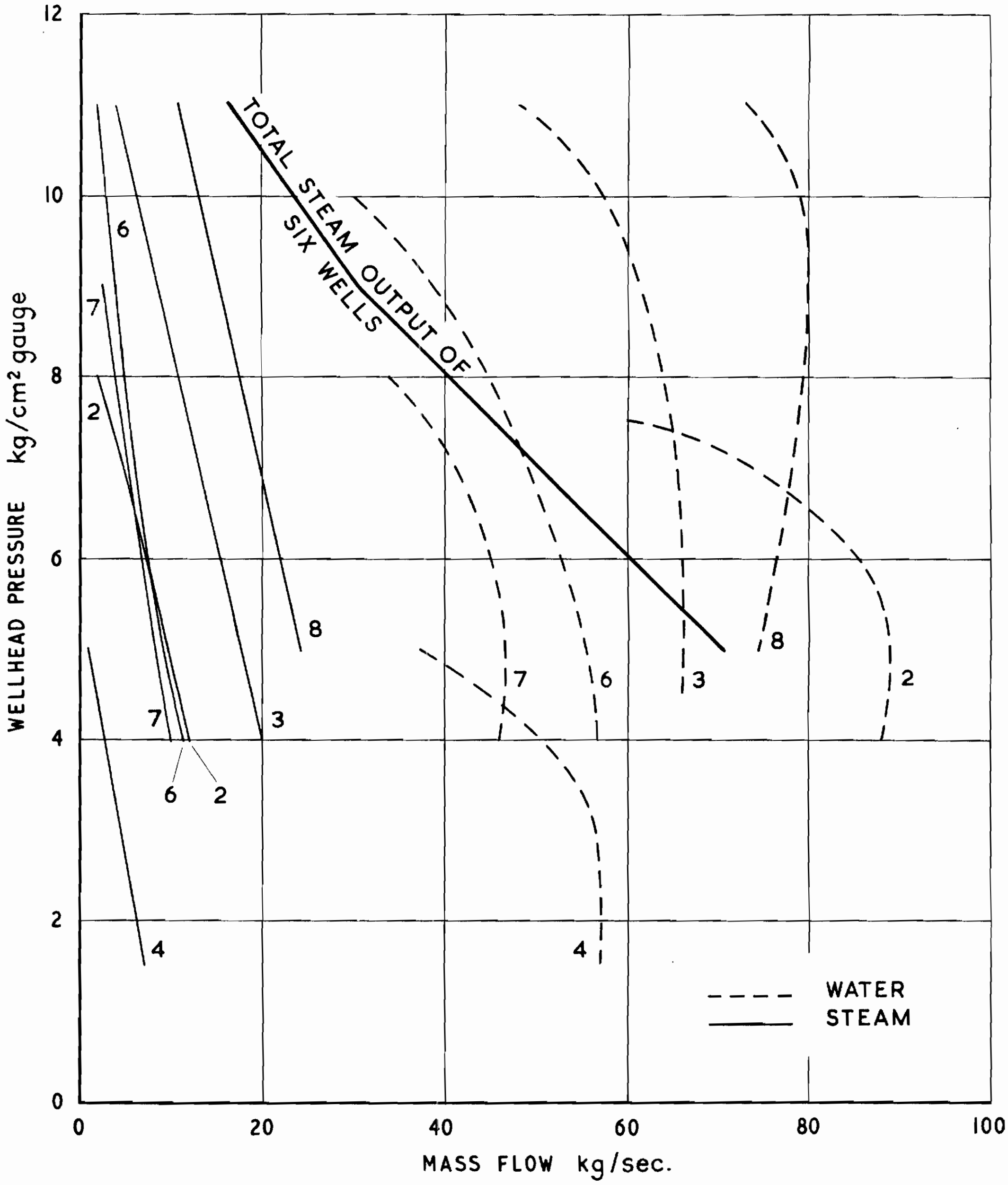


PLANT INSTALLATION PROGRAMME
AND COINCIDENT MAXIMUM DEMAND (½ HOUR)
IN SOUTH WEST REGION

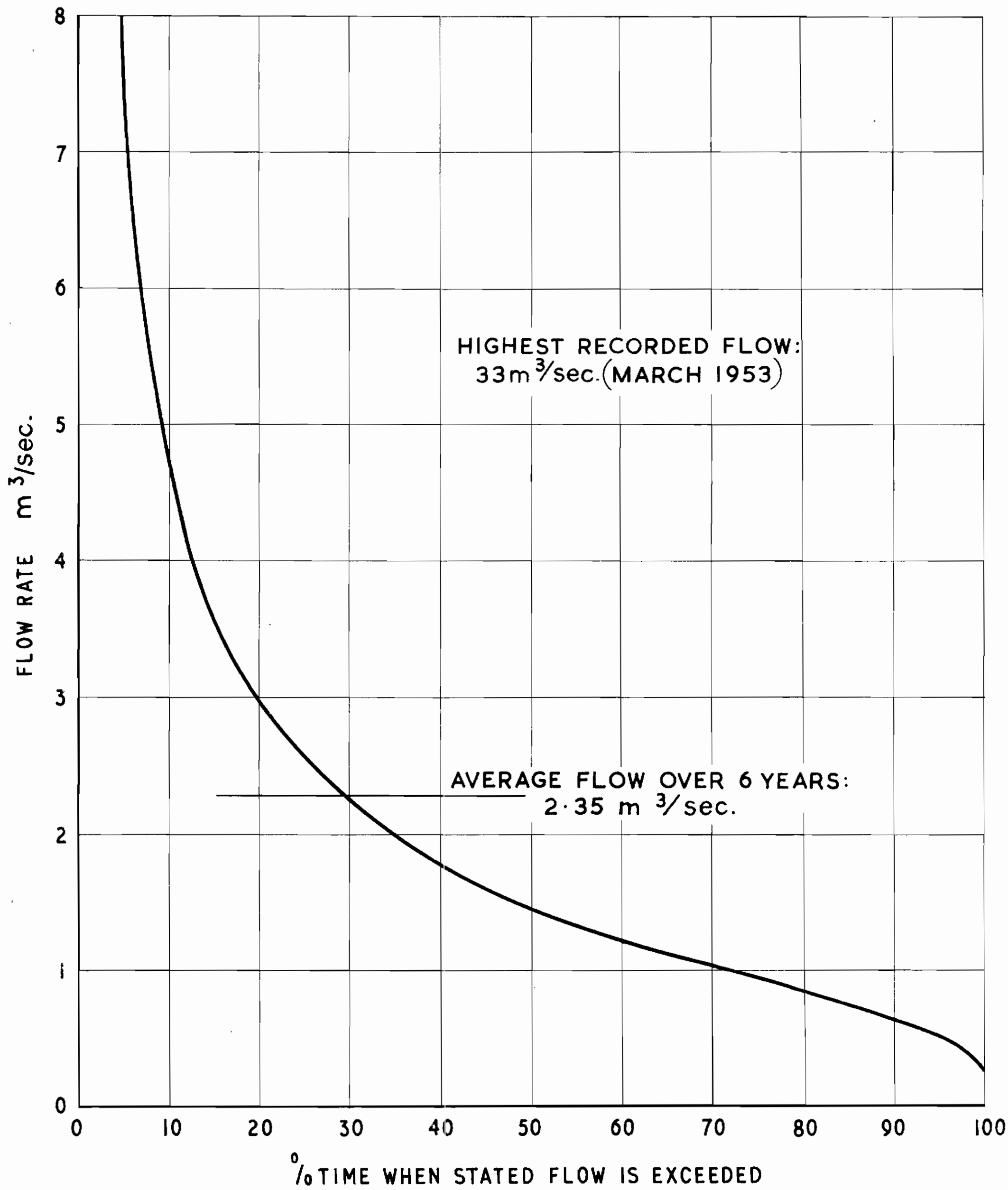


ANNUAL ENERGY REQUIREMENTS IN
SOUTH WEST REGION

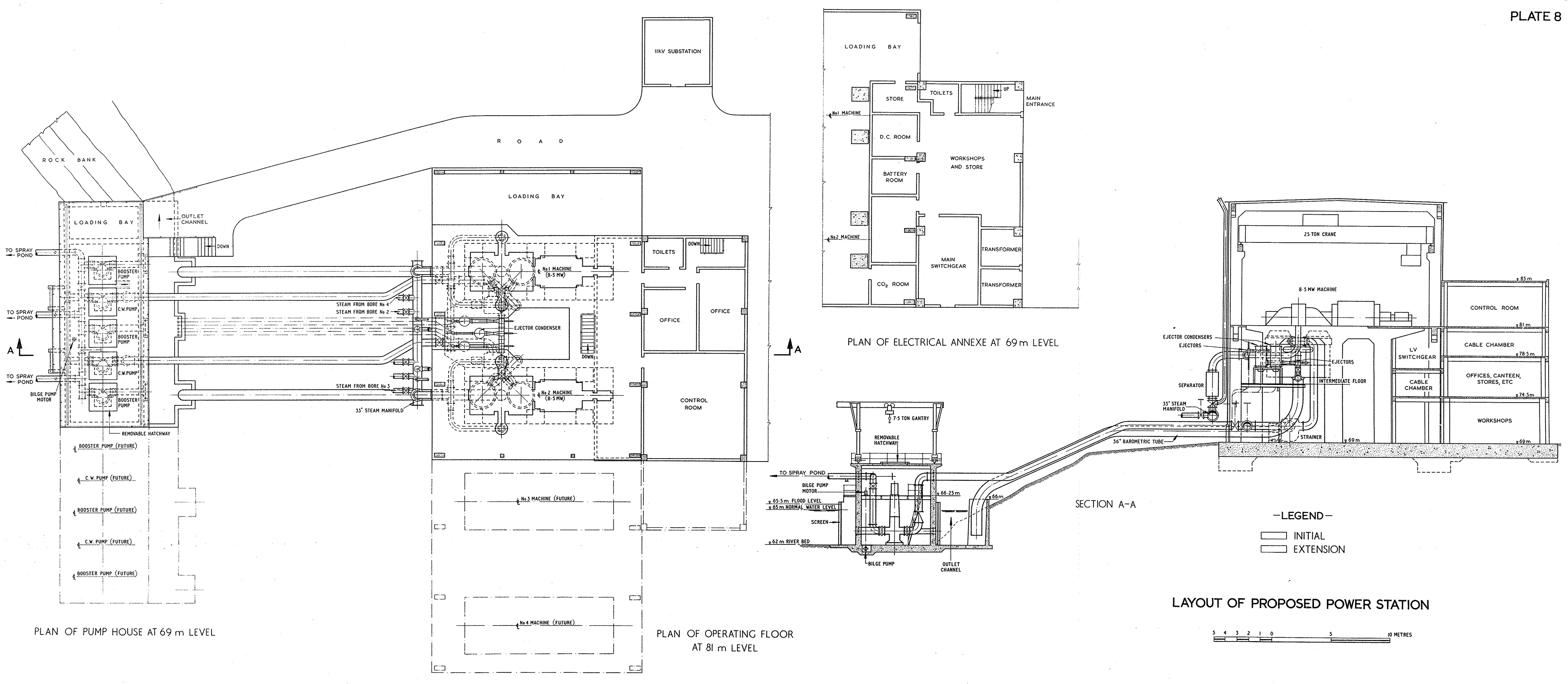
PLAN SHOWING LOCATION OF
PROPOSED POWER STATION AT HVERAGERDI



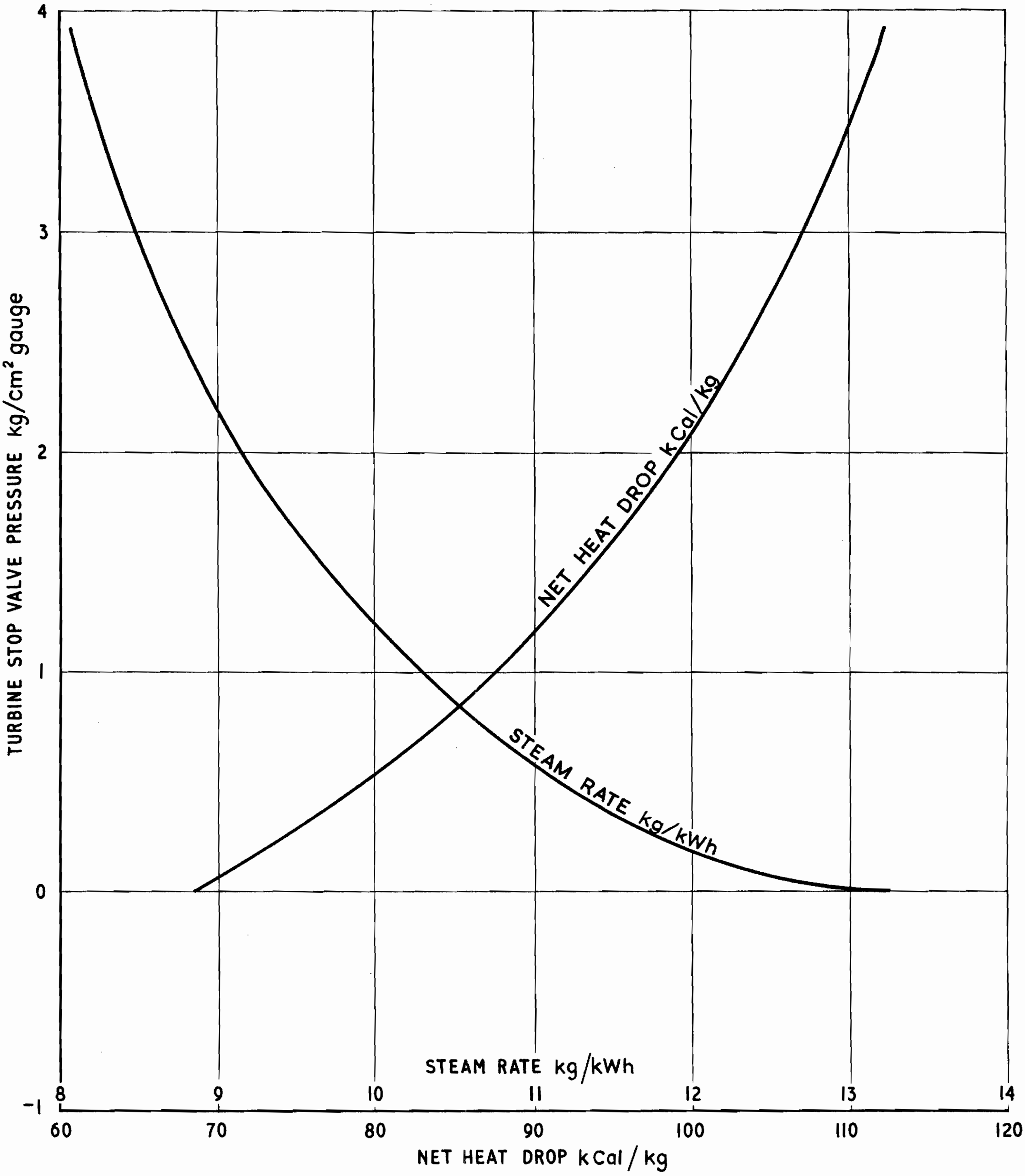
CHARACTERISTICS OF WELLS



FLOW IN VARMA RIVER
(1949 - 1955)



LAYOUT OF PROPOSED POWER STATION



HEAT DROP AND STEAM RATE WITH EXPANSION OF SATURATED STEAM

ASSUMPTIONS:

(a) BACK PRESSURE 0·069 atm. abs (2" Hg)
(b) 5% PRESSURE DROP IN THROTTLE VALVE
(c) STEAM 1% WET AT TURBINE INLET
(d) LEAVING LOSS OF 5·55 kCal/kg
(e) POLYTROPIC EFFICIENCY 0·85
(f) BAUMANN WETNESS CORRECTION APPLIED

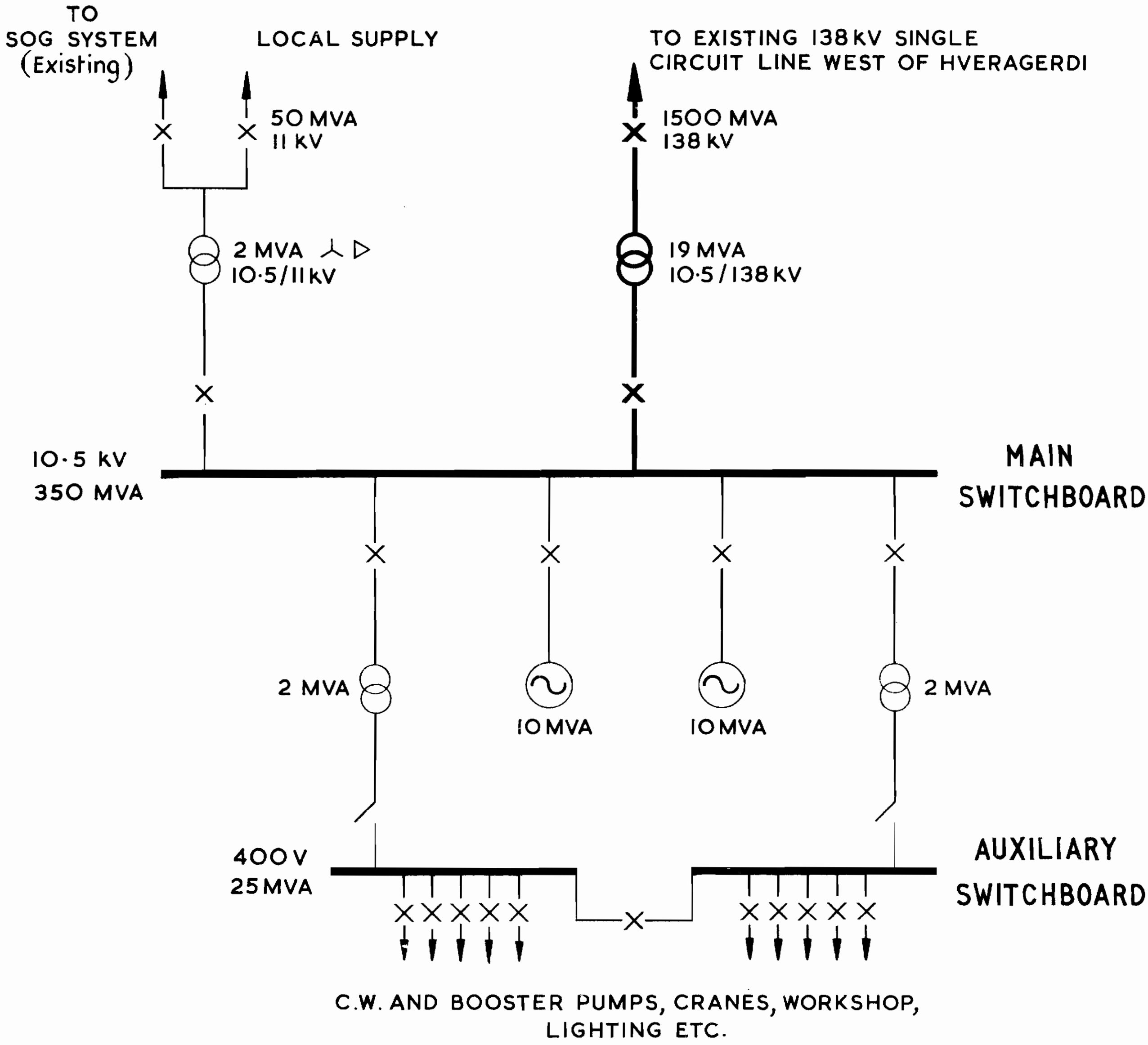


DIAGRAM OF ELECTRICAL CONNECTIONS