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SECOND SUPPLEMENTARY REPORT

BÚRFELL PROJECT

BY THE

HARZA ENGINEERING COMPANY INTERNATIONAL

PREPARED FOR

THE STATE ELECTRICITY AUTHORITY

GOVERNMENT OF ICELAND

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BURFELL HYDROELECTRIC PROJECT
SECOND SUPPLEMENTARY REPORT

The State Electricity Authority
P. O. Box 40
Reykjavik, Iceland

Subject: Burfell Project
Revised Plan of Development

Gentlemen:

Introduction

This Letter Report summarizes our recent studies of a revised plan of development for the Burfell Project from that presented in the following earlier Project Reports:

A. Project Planning Report - January 1963
B. Supplementary Report to Project Planning Report - April 1963
C. Letter Report on Advanced Planning of Thjorsa Diversion Features - May 1963.
D. Letter Report on Plant with 35 MW Units - May 1963

These four Reports are to be considered complementary to this "Second Supplementary Report". In general, data and information presented in the earlier Reports and appropriate to the newly revised plan of development are not repeated in the current Report.

Report "A", the Project Planning Report in two Volumes, remains as the basic Report for the Burfell Project. The plan of development presented therein was for a Project containing six equal sized units totaling 180 megawatts (MW). Report "C" presented the result of additional planning of those features of the Project designed for diversion of the waters of the Thjorsa to the Power Intake without changes in the power generating facilities or estimated total Project Costs. Report "B" presented a plan involving progressive development of generating capacity to achieve, ultimately, the Project substantially as concieved in Reports "A" and "C". In Report "D" we substituted 35 MW units for the 30 MW units of the plan of staged development presented in Report "B". Other appropriate revisions were made to the Power Features, but no changes were included for the Diversion Features of the Project.

The studies basic to this Letter Report took into consideration the development of the Burfell Project apparently best suited to meet the following criteria:

1. The most recent load growth estimates by SEA for Southwest Iceland and for North Iceland, as presented in Table 1.
2. Service to a one-potline aluminium smelter beginning with 1968.
3. Service to a transmission line extending from Burfell to Akureyri to serve North Iceland loads.
4. Transfer of South Iceland (principally Westmann Islands) service from Burfell to the Sog System.

The plan of development of the Burfell Project which appears best suited to fulfill these criteria would utilize 35 MW units installed in the following Stages:

Stage	Number of Units	Rated capacity - MW incremental	Rated capacity - MW cumulative
I	3	105	105
II	1	35	140
III	1	35	175
IV	1	35	210

The studies basic to these conclusions are discussed below.

Loads and Resources

The load projections of Table 1 are shown graphically on Exhibits I and I A for capacity and on Exhibits II and II A for energy. The values shown are for the generator bus, thus losses are included. The estimated loads for Southwest Iceland represent the totals for the general load, the fertilizer plant and the Nato Base. These load increases are somewhat more conservative than those presented on Exhibit 1 of Report "A", especially so for the fertilizer plant load. The estimated loads proposed to be served on peak only from Burfell in North Iceland are shown as addative to the estimated loads for Southwest Iceland.

The most recent estimate for the aluminium smelter load is for a 30,000 ton per year single potline. The load would be 55 MW of capacity and 470 GWh of annual energy, assuming 6 and 4 percent losses, respectively. This load is added on the graphs to the "normal" load both with and withoüth the inclusion of the North Iceland load.

The resources other than Burfell available to serve the Southwest Iceland load were constdered to have the following rated installed capacities in MW by the beginning of 1968:

Sog Hydro Plants:			
Steingrimsstod	26.4		
Ljosafoss	21.6 (assuming a new 7 MW unit)		
Irafoss	46.5		
Subtotal Sog		94.5	
Andakill Hydro		3.5	
Subtotal			98.0
Other Hydro and Thermal:			
Ellidaar Hydro		3.2	
Ellidaar Thermal		19.0	
Westmann "		3.9	
Nato "		7.5	
Subtotal			33.6
TOTAL			131.6

It is probable that the Sog Hydro Plants could peak at about 7 MW above their total rated installed capacity, but this possible capability was not considered in the current analyses.

It was assumed that the Sog Plants and Andakill would operate in full service after Burfell comes into production in 1968, and that the other Southwest Iceland plants would be placed in a reserve status. All except the Ellidaar Hydro are expensive to operate because of fuel costs, which also requires foreign exchange. Accordingly, only the Sog Plants and Andakill are shown as resources on the load curves of Exhibits I, I A, II and II A.

The energy capability of the Sog Plants presented above has been estimated at 585 GWh in an average year and 470 GWh in a minimum year, based on the flow record for the period 1938-1962, inclusive. However, the Sog flow in the late summer and early fall months of the critical dry year (1951-52) would have produced an energy deficiency of about 10 GWh below the average of the critical year. The winter months of that critical year had flows corresponding to about the average of that year. However, the winter peak energy demands in Southwest Iceland tend to be up about 20 percent over the average for the year. At the same time, summer loads are well below the annual average and the deficiency in those months is not particularly significant from the resources standpoint.

The available energy from the Sog plants during the three high load winter months of an average year is also about 20 percent over that for a critical year. Accordingly, it appears appropriate to evaluate the Sog resources to meet wintertime energy loads on the basis of the critical year production as meeting the requirements during that season for an average year. Winter deficiencies in more critical years might be offset by:

1. Curtailing service to the fertilizer plant
2. Secondary energy from Burfell which is usually available because of hydrologic diversity between the Thjorsa and the Sog and also by utilization of the over-capacity expected from the Burfell turbines.
3. Use of thermal resources
4. Utilization of Thingvallavatn storage

The normally available upper two meters of storage in Thingvallavatn contains about 30 GWh of energy. However, it may be more desirable to consider this storage as a reserve to meet loads during any outages of the Burfell plant.

Sound power resources planning requires provision of capacity and of energy in advance of load by two to four years. This provision makes some energy available in that reserve. The main time for concern with respect to energy deficiencies would be the somewhat improbable coincidence of critical water conditions immediately prior to achieving a substantial resources addition. The thermal plants of Southwest Iceland are herein considered to be the principal reserve for such a contingency. The primary energy available from the Sog plants has been taken at 470 GWh. The annual energy production of Andakill was taken to be 25 GWh. Thus the energy reserves from the Sog plants and Andakill total 495 GWh on the plot of reserves in Exhibits II and II A.

The at-site production of the Burfell Project for the plan of development presented in this Report with 35 MW units has been estimated as follows:

Stage	Peaking Capability-MW	Annual Primary Energy - GWh
I	108	850
II	144	1125
III	178	1385
IV	212	1635

Similarly, the at-site production of Burfell with 30 MW units was estimated as follows:

No. of units	Peaking Capability-MW	Annual Primary Energy - GWh
3	93	745
4	124	980
5	155	1210
6	185	1430

The above values have been used as the Burfell Project resources on Exhibits I and II for the plant with 35 MW units and on Exhibits IA and IIA for the plant with 30 MW units.

Selection of Unit Size and Stages

In order to meet the estimated load requirements, including that of one aluminium smelter potline, the Burfell additions as shown on Exhibits I, IA, II and IIA would be as follows:

35 MW PLANT

Stage	Initial Year: Capacity, Southwest Iceland only	Initial Year: Capacity, With North Iceland Added	Initial Year: Energy, Southwest Iceland only	Initial Year: Energy, With North Iceland Added
I	1968	1968	1968	1968
II	1973	1972	1974	1973
III	1976	1976	1978	1978
IV	1980	1979	1982	1981
New Plant	1982	1981	1985	1984

30 MW PLANT

No. of Units	Initial Year: Capacity, Southwest Iceland only	Initial Year: Capacity, With North Iceland Added	Initial Year: Energy, Southwest Iceland only	Initial Year: Energy, With North Iceland Added
3	1968	1968	1968	1968
4	1971	1971	1972	1971
5	1975	1974	1976	1975
6	1978	1977	1980	1979
New Plant	1980	1979	1982	1981

It is shown by the above that capacity requirements are more critical than those for energy. The latter requirement lags the former by one year in the early stages of unit installation, but becomes three years and two years for the plants with 35 MW and 30 MW unit sizes, respectively, as Burfell becomes fully developed to serve Southwest Iceland loads only. The inclusion of the peaking requirements in North Iceland with relatively small energy requirements increases the lag of energy with respect to capacity slightly further.

This increasing lag of energy with respect to peaking requirements suggests that consideration should be given to the addition of peaking only by the mid or late 1970s, with Burfell additions postponed to meet energy requirements. This can probably best be accomplished by an initial installation of the proposed Vordufell Pumped Storage Project, discussed in our Report of June 1963. By that time the requirement for Reserves, discussed below, might require Vordufell in any event. It is entirely feasible and economical to construct Vordufell for both capacity and reserves.

The above tabulations and aforementioned Exhibits show that the selection of a unit size of either 30 MW or 35 MW will meet feasibily the estimated load requirements of Southwest Iceland either with or without the addition of the North Iceland peaking requirements. Preliminary evaluations have shown that the transmission of Burfell power and energy to North Iceland is feasible and is economical in comparison to new small generating stations in that area. Accordingly, it is considered proper to include the North Iceland future load as served by Burfell. However, the required facilities other than the step-up substation is not included in the Project estimates of this Report.

With either size of unit at Burfell it was assumed that only one unit would be added at a time after an initial installation of 3 units at the beginning of 1968. The additional installation would require on the average about two years construction time each. Increments would need to be installed about every three years on the average with 35 MW units, and slightly less for 30 MW units. The addition of engineering design time would require beginning with the next increment virtually upon completion of the previous one.

There appears to be little difference in fitting Burfell to the capacity growth between 35 MW units and 30 MW units. The same is true generally with respect to energy.

The plant with 35 MW units was selected for proposed construction primarily because our previous studies indicated somewhat greater ultimate economy with the larger units, and because the larger units fitted the load curves slightly better. The planning studies and estimates presented subsequently in this Report are based on a plant with 35 MW units in all Stages of development.

The increased load for a second potline of equal size to the first has been plotted on Exhibits I and II. This increment shows that a second potline, if desired, could best be added beginning either in 1971 or 1974, assuming the inclusion of the North Iceland load. With the increment, the need for a new generating plant would occur in 1977 for capacity and in 1978 for energy. Provision of the Vordufell Project could defer the capacity requirement to coincide with the energy requirement. It is very probable that Vordufell would be needed also for Reserves in the event of a Burfell outage.

Reserves

The requirement for Reserves with an aluminium smelter in the event of a Burfell outage was discussed in Report "A" and our Vordufell Report, both referred to above. This requirement has been evaluated on the basis of the loads and resources discussed above and shown on Exhibit I, and also on the general assumptions presented on page 2 of the Vordufell Report. The Reserve capacity required in addition to the 26.1 MW available from the Ellidaar hydro and the thermal stations with a complete temporary outage of Burfell was estimated as follows:

Year	1968	1970	1972	1974	1976	1978	1980
Added Reserve-MW	0	7	20	35	50	70	95

Since these values are based at the generator bus, the requirements would be slightly less if the Reserve station was located at load because of the reduced losses. The availability of over-capacity in the Sog plants, referred to above, could offset the indicated 1970 deficiency.

On the basis of the assumptions it appears that added Reserves would not represent a critical requirement for two or three years after Burfell begins production in 1968. A small gas turbine would probably represent the most economical initial source of reserve capacity and of reactive power. Thereafter by about the mid-1970s it appears appropriate to begin the development of Vordufell as a combined Reserve and Pumped Storage peaking station, particularly in view of the lag between energy and capacity requirements. Of course, operating experience over the years would provide a better basis than now available for selecting reserve and capacity additions.

Power Features

The basic design of the Power Features and the reasons therefore are set forth in Reports "A", "B" and "D". Accordingly, details concerned therewith are not repeated in this Report. Principal changes from the designs presented in the earlier Reports will be discussed briefly. Important data with respect to the Project, when completed to include all of the planned six generating units, is given on Table 2.

The Power Features will be constructed in the four Stages referred to above with three units installed in the first Stage and one unit in each subsequent Stage. The general layout of the Powerstation was rearranged from the plan shown on Exhibit S-18 of Report "B" to the plan shown on Exhibit III, attached. The principal changes included moving the erection by one bay to the right and dimensional changes, discussed in Report "D", required to accommodate the 35 MW units. Changes were made in the Surge Chamber, Draft Tube Extensions and Collecting Tunnel to fit with the transposed third unit.

Each trio of units will now be served by a single Pressure Shaft which will split into individual penstocks in the horizontal run to serve each unit. The Intake was redesigned to accommodate the reduced number of pressure shafts (from three to two). A plan and details of the revised Intake are shown on the attached Exhibits IV and V, respectively.

The moving of the Erection Bay to the right requires a slightly longer Access Tunnel which terminates as before. The Tailrace, Sluiceway, and Sluiceway Dike remain as presented in Report "B", except for the increase in the normal diameter of the Tailtunnel to 8 meters.

The underground excavation will all be accomplished in Stages I and II. The Tailtunnel and Access Tunnel will be completed in Stage I. The Machine Hall will be excavated in Stage I only to a point a few meters to the right of the Erection Bay, then completed in Stage II. The Surge Chamber, Draft Tube Extensions and Collecting Tunnel will be excavated and concreted in Stage I only so far as necessary to provide for the three initial units and the initial provisions for completing this work in Stage II. Each Pressure Shaft and its trio of individual penstocks will be constructed equally in each of the first two Stages. This requires a blind flange in Stage II on the individual penstocks for Units 5 and 6 which would be removed in Stages III and IV, respectively, when the butterfly valves are installed. The Access and Cable Shaft will be completed in Stage I.

The concrete in the machine hall will be placed as required for each Stage. All concrete as far as the right edge of the erection bay will be included in Stage I. Stage II concrete will include the completion of the roof arch and Draft Tube lining plus the concrete required for the fourth unit and for the substructure walls of the last two units. Draft tube bulkhead gates will be required in Stage II for the fifth and sixth units. The remainder of the machine hall concrete will be placed only as required for each additional unit in Stages III and IV, respectively.

The excavation of the Intake Approach Canal will be accomplished fully in Stage I, but only that portion of the Intake required for the first Pressure Shaft will be placed at that time, with completion accomplished in Stage II behind a cofferdam.

The main generating equipment consisting of the turbines, governors, generators and exciters will be installed in each Stage as required. Most of the Accessory Electrical and Miscellaneous Powerplant Equipment is provided in Stage I. The same will be true with respect to the various service systems. Additions in each of the last three Stages will be only as required specifically for each additional unit and will, therefore, be approximately equally divided between these Stages.

Transmission Features

The Transmission Features included in the estimates of this Report consist of the Burfell Step up Substation, the Burfell - Reykjavik Transmission Line and the Reykjavik Receiving Substation. Details are shown on the One-Line Diagram of Exhibit VI, attached. This Diagram was adapted from the one included as Exhibit S-21 of Report "B" with appropriate revisions to reflect the increase in unit size and revisions in the Stages of proposed construction. Exhibit VI shows the requirements for each Stage of development.

Each pair of units will be served by a single three-phase, 138 - 230 kV transformer connected through a power circuit breaker to the main bus of the Burfell Substation. The main and transfer buses will be connected through a transfer and a line breaker.

As mentioned above, the 69 kV service was dropped from further consideration. Instead a 115 kV service intended for connection to the transmission line to North Iceland will be provided by a 15 kVA transformer connected directly to a generator in all Stages. In Stage IV, when the North Iceland load has increased, the 15 kVA transformer will be salvaged and replaced by one of 30 kVA capacity.

The 230 kV wood-pole transmission line will be provided in Stage I and operated always at that voltage. It will be routed to pass adjacent to the proposed Vordufell Pumped Storage Project and the switchyard for the Sog plants. The line will terminate at the proposed new Reykjavik Receiving Substation.

The Receiving Substation will be of a double bus arrangement with three breakers in Stage I, all connected to both the main bus and the transfer bus. There will be one line breaker, one for the service to the special large industry (assumed to be the aluminium smelter in Stage I), and the third for local service in the Reykjavik Area. This service will be through a 70 MVA, 230 - 138 kV autotransformer.

Stage II requires no additional transmission features. The fourth generating unit will be connected to the transformer provided in Stage I for Unit No. 3.

Two bays will be added to the Receiving Substation in Stage III. One will provide a transfer breaker and the other will serve a second autotransformer. The local load in the Reykjavik area is shown by the load growth estimate to require added capacity at that time. A rating of 100 MVA was selected for this second autotransformer which is expected to be adequate until the loads require an additional generating station.

Thjorsa Diversion Features

The proposed Thjorsa Diversion Features are fully described in Reports "B" and "C". The only design changes proposed in this Report deal with the Diversion Inlet and Diversion Canal. The designs basic to the estimates in this Report include two more bays on the right in the ultimate Diversion Inlet and an increase in the final base width of the Diversion Canal. These increases result from the greater turbine capacity with 35 MW rather than with 30 MW units. The design criteria with respect to velocities have been kept the same as before.

The Diversion Inlet and Canal will be constructed in Stage I adequate to serve also Stage II; then both will be completed in Stage III. This procedure requires 8 Inlet bays in Stage I, with 4 added in Stage III. The lengthening of the Inlet reduces slightly the length of the Right Bank Dike, which will be constructed in Stage III.

The base width of the Diversion Canal will be about 82 meters in Stage I immediately downstream of the Inlet. The base width will be gradually narrowed in the next 450 meters to a constant width of 45 meters for its remaining distance. Within this latter reach the right edge will be the same as presented in Report "B". This section will be widened on the left by 25 meters in Stage III, and this addition will decrease gradually upstream to zero at the Inlet.

In Stage III, when the last four bays of the Inlet are provided, the Canal will be widened on the right side a distance of 40 meters immediately downstream of the Inlet. This widening will decrease gradually to zero within the next 450 meters.

Rock excavation from the Stage III canal widening on the right will be used to build the Right Bank Dike, while that from the widening on the left will be used to complete the Bjarnalaekur Dike. The Bjarnalaekur Dike and Outlet will have been constructed in Stage I to the same degree as in the Stage I construction presented in Report "B". The Bjarnalaekur Canal will be constructed in Stage I, with the rock excavation used in the Bjarnalaekur Dike.

The Thjorsa Diversion Weir, including the Sluice Structure at the head of the Bjarnalaekur Canal, will be built in Stage I to the same degree as through Stage II of Report "B". It will then be completed in Stage III, which will also see the construction of the Left Bank Dike.

The Burfell Reservoir will be completed fully in Stage I. That portion of the primary access road, together with required bridges, located on the west side of the Thjorsa and necessary for Stage I construction is planned for construction in 1964 prior to award of the general construction contract. Some additions and improvements, particularly to the east side of the Thjorsa, will be required in the next two Stages.

The Operators Village and General Plant will be provided mostly in Stage I. Small additions will be made in the subsequent Stages.

Construction

The assumptions made with respect to the construction and construction procedures of the Burfell Project are, in general, the same as presented in Reports "A" and "B". It was assumed that each Stage would be contracted separately. It is planned to award the general construction contact in late 1964 with completion and full power generation from the three units scheduled for the end of 1967. The remaining Stages can be accomplished in two calendar years each. However, it would be necessary to accomplish equipment ordering and certain engineering functions a year preceding award of each General Construction Contract for the Stages. Stage I construction would be substantially according to the Schedule presented in Exhibit S-22A in Report "B", except for accomplishment of the primary access in the spring and summer of 1964.

Capital Costs

The assumptions with respect to construction costs for the Staged development are, in general, on the same basis as presented in Reports "A" and "B". However, all costs reflect the recent increase in Icelandic labor rates amounting to an average of about 20 percent.

The estimated capital costs, expressed in United States Dollars for each of the four Stages are summarized on Exhibit VII. The estimate for each Stage is presented to show the Total Investment which includes appropriate amounts for contingencies, engineering, supervision and overhead, and an estimate of net construction interest. All Preliminary Costs to date have been included in the estimated Investment for Stage I, but this amount probably would not require any new financing. On the other hand, a fund for Working Capital may need to be financed and might be equal approximately to that amount.

The estimates for each subsequent Stage include an allowance for extra costs inherent with Staged Construction as compared to the initial complete construction presented in the Report "A". The various allowances for Indirect Costs are on the same general bases as presented in our earlier Reports.

The Costs for Thorisvatn Initial Storage amounting to $ 2,000,000 are considered as included with Stage III in the same manner as presented in Report "D".

None of the estimates for the four Stages include any allowance for one year of interest reserve, or for import duties and taxes.

An exchange rate of 43 Icelandic Kronur to one United States Dollar was used where appropriate in the detail that is back of each summary estimate of Exhibit VII. The foreign exchange requirements in the Stage I construction are estimated to be about 65 and 80 percent of the Construction Cost for the production and transmission plants, respectively, for an overall average of about 67,5 percent. The corresponding overall average for the last three Stages would be about 70 percent.

Annual Costs

Estimates were made for annual costs not controlled by financing terms. These items include operation and maintenance costs, and reserves to provide for extraordinary replacement costs not included in normal maintenance or covered by insurance. These reserves would be required primarily for equipment rather than for more durable features such as the civil engineering structures. Stage I has a lesser percentage of construction cost represented by equipment than do the subsequent Stages. Accordingly, the reserves were taken at about 0.9, 1.1, 1,1 and 1.9 percent, of the estimated Total Construction Cost for Stages I to IV, respectively.

A value of Water Rights has been included in previous economic analyses for the Burfell Project. However, there has developed no firm basis for evaluating water rights and they have now been excluded from consideration in the economic analyses which follow. Of course, it would be normal to include some such value within a rate base.

The annual costs other than debt service were estimated to be as follows in thousand United States Dollars:

Item	Stage			
	I	II	III	IV
O & M	300	130	85	70
Reserves	205	40	65	25
Total	505	170	150	95
Cumulative Total		675	825	920

Primary Energy Costs

The delivered average annual primary energy in million kilowatthours, computed on the same general basis as in Reports "A" and "B", was estimated as follows:

Stage	Energy	Cumulative Energy
I	820	820
II	265	1085
III	250	1335
IV	240	1575

The above energy estimates for Stages III and IV do not include any allowance of firming energy from Thorisvatn Initial Storage. It is expected that some increment, however, would be available and that not all of the water would be required for ice sluicing. Thus, the energy estimates for these last two Stages may be somewhat conservative.

The unit cost of primary energy for each Stage and as each Stage is completed was estimated on the same general basis as utilized in Report "D". The unit cost of energy was determined for annual debt service expressed as five, seven, and nine percent of estimated Total Investment. Thorisvatn Initial Storage was included with Stage III. The computations are shown on Table 3, and presented graphically on Exhibit VIII, both attached.

Summary And Conclusions

The studies summarized in this Second Supplementary Report have shown that the Staged construction of the Burfell Project to fit the estimated power and energy load growth in Southwest Iceland, including the load of one aluminium potline and with or without the peaking load of North Iceland, is feasible technically and presents no unusual construction problems. Reserve allowances for temporary emergency outages by Burfell provided by existing stations appear adequate for the Southwest Iceland load until about 1970. At that time a decision may be required between a small gas turbine plant and initiation of Vordufell Pumped Storage. The latter would also provide economic capacity but no energy. Further system operating experience by 1970 may more clearly establish actual Reserve requirements. It is expected that any operational ice problems in winter at Burfell may be largely solved in detailed design or by subsequent operational procedure changes. A complete outage at Burfell because of ice problems appears very unlikely.

The Staged construction proposed in this Report is attractive economically when considered with respect to the estimated load. The estimated unit costs of delivered energy, assuming that all energy is sold, on the assumption of a 25 year level debt service amortization period and a six percent effective interest rate (7.8 percent of Total Investment) would be as follows:

Stage	Unit energy Cost (US mills per kWh)		Initial year (2)
	by Stage	Cumulative	
I	3. 1	3. 1	1968
II	1. 9	2. 8	1972
III (1)	2. 8	2. 8	1976
IV	0. 9	2. 5	1979

(1) Includes Thorisvatn Initial Storage

(2) Based on Capacity Requirements

The above unit cost does not reflect any import duties and taxes within the Total Investment. Also the value of Water Rights has not been considered, but would have a relatively small effect. However, unit energy costs in the range presented above must always be considered as low cost energy.

The Burfell Stages have been fitted to the capacity and energy load curves in advance of load. This advanced construction, normal and essential in public utility practice, shows that each increment will exceed requirements immediately upon installation by about three years of load growth. This means that load, and therefore sales and revenue, will not exist for all of the energy added by each increment of new Burfell capability until finally absorbed; at which time a new addition will be made creating a new surplus approximately equal to that which existed at the time of the last previous addition. The net effect is, of course, an increase in the unit energy costs from the values presented above because of income deficiency in about the first three years of each incremental installation.

The first Stage of Burfell construction has the highest estimated unit energy Cost. This results principally from the inclusion in that Stage of the burden resulting from the initial construction of the Access Tunnel, Tailtunnel and main Transmission Line adequate for the full development purposed herein. Accordingly, it may be necessany or desirable to lighten the financial burden during the first few load development years. The following may represent feasible means of accomplishing this initial reduction:

1. Deferring the beginning of amortization
2. Capitalization of some portion of the interest for the load development period

3. Deferring the establishment of Reserves
4. Reducing the level of accumulated Reserves

Careful analyses may reveal other financial means of lightening the financial burden during the development period.

Deferring amortization and establishment of Reserves for renewals and replacements for the first three years of Stage I operation, for example, would reduce the above estimated unit cost of Burfell energy from 3.1 mills to 2.3 mills. However, the true unit cost of energy during those three years would be somewhat greater, or about 2.9 mills, because of the unsold energy which is surplus to load.

The unit energy costs discussed above and shown graphically on Exhibit VIII for the presently proposed Staged development of the Burfell Project appears to us to be favorable economically either on an actual or relative basis. This situation is true for each individual Stage or appropriate combination thereof. The reduction in unit energy cost below that for the first Stage as Burfell becomes more fully developed is unusual for hydroelectric power development which provides resources for expected system load for such a long term of years. Even the inclusion of Thorisvatn Initial Storage in Stage III has no serious adverse cost effect.

The Stage I unit costs are favorable in comparison with any other source of hydroelectric power which we have appraised in Southwest Iceland. This relationship applies with respect to either large or small potentials in the area which would fit in to proper water reserves development. We are certain that we have not overlooked any site which might possibly be as favorable as Burfell. Further, we know of no small hydroelectric potential in the north portion of Iceland which could produce power and energy at a cost as low as Burfell Stage I, probably even with the inclusion of the transmission burden from Burfell to North Iceland.

The unit cost of energy for Stage II and, particularly, Stage IV is remarkably low. However, it shouldbe borne in mind that the last three Stages should properly be charged further for their respective fair share of the common costs, referred to above, provided originally with Stage I.

The estimated unit energy costs as shown on Exhibit VII represent average costs only. The various selling prices of the energy should include a further allowance to the owner for reserves needed during the first few years of load development, for bad business years, and possibly for cash funds for expansion studies and other system betterments.

It is normal for utilities to sell power and energy on the basis of both a capacity and an energy charge, whereas the above analyses have been based solely on energy costs. When both charges are included in the rate base the average kilowatthour return increases with decreasing load factor. The loads assumed in the load growth analyses of Exhibits, I and II include the following:

1. A high load factor load, the aluminium smelter, for which the income per unit of energy is usually relatively low.
2. A normally high load factor load which is subject to sudden, complete and even long term dropping, the fertilizer plant, for which the income per unit of energy is also relatively low.
3. The medium load factor normal load, such as that for Southwest Iceland, for which the income per unit of energy is relatively much higher than that from large industrial loads.
4. Peaking loads, such as that for North Iceland, for which the income per unit of energy is relatively high.

The overall average increase from these various types of loads as related to the average unit cost of energy is important to system resources planning. However, such a detailed analysis has been beyond the scope of this Report.

We conclude on the basis of our engineering studies presented in this Second Supplementary Report and based largely on the studies summarized in our previous Reports that the Burfell Project constructed substantially in the Stages outlined above represents the next logical development of the hydroelectric power rewources of Iceland to serve the loads presented in the forecasts.

Very truly yours,
HARZA ENGINEERING COMPANY
INTERNATIONAL

C. K. Willey
Vice President

Encl.: Table 1 to 3, incl.
Exhibits I to VIII, incl.

TABLE 1

ICELAND LOAD ESTIMATES

Year	SOUTHWEST ICELAND Energy General Load GWH	Fertilizer (1) GWH	Nato Base (2) GWH	Total - GWH	Power General Load MW	Fertilizer MW	Nato Base MW	Total - MW	Total (3) with Smelter Energy GWH	Total (3) with Smelter Power MW	NORTH ICELAND Energy GWH	NORTH ICELAND Power MW	Totals without smelter Energy GWH	Totals without smelter Power MW	Totals with smelter Energy GWH	Totals with smelter Power MW
1967	436	142	56	634	97	6	8	111	1104	166	5	4	639	115	1109	170
1968	467	142	59	668	103	6	8	117	1138	172	7	5	675	122	1145	177
1969	500	142	63	705	109	6	9	124	1175	179	10	6	715	130	1185	185
1970	535	166	66	767	115	10	9	134	1237	189	13	7	780	141	1250	196
1971	572	166	70	808	122	10	10	142	1278	197	18	9	826	151	1296	206
1972	612	166	74	852	129	10	11	150	1327	205	22	10	874	160	1344	215
1973	655	166	78	899	137	10	11	158	1369	213	25	11	924	169	1394	224
1974	701	166	84	951	145	10	12	167	1421	222	29	12	980	179	1450	234
1975	750	190	84	1024	153	14	12	179	1494	234	35	14	1059	193	1529	248
1976	803	190	84	1077	162	14	12	188	1547	243	40	15	1117	203	1587	258
1977	859	190	84	1133	172	14	12	198	1603	253	47	17	1180	215	1650	270
1978	919	190	84	1193	184	14	12	210	1663	265	55	19	1248	229	1718	284
1979	983	190	84	1257	197	14	12	223	1727	278	63	21	1320	244	1790	299
1980	1052	214	84	1350	211	18	12	241	1820	296	71	23	1421	264	1891	319
1981	1126	214	84	1424	225	18	12	255	1894	310	80	25	1504	280	1974	335
1982	1205	214	84	1503	241	18	12	271	1973	326	89	27	1592	298	2062	353
1983	1289	214	84	1587	258	18	12	288	2057	343	99	30	1686	318	2156	373
1984	1379	214	84	1677	276	18	12	306	2147	361	109	32	1786	338	2256	393
1985	1476	238	84	1798	295	22	12	329	2268	384	120	35	1918	364	2388	419

(1) Assumed that Fertilizer based primarily on fuel in the future

(2) New frequency converter assumed

(3) Assumed at 55 MW of Capacity and 470 GWh of Energy

TABLE 2

BURFELL HYDROELECTRIC PROJECT

SIX - 35 MW. UNITS INSTALLED

TABULATION OF SIGNIFICANT DATA

Drainage area - square kilometers	6380
Discharge - cubic meters per second	
Maximum design flood	7750
Maximum historical	2000
Average	338
Minimum historical	72
Headwater elevation - meters above sea level	
Maximum (at maximum design flood)	248
Normal	244.5
Minimum	243.5
Tailwater elevation - meters above sea level	
Maximum with ice jam in Thjorsa	130 ±
Normal maximum (flood in Fossa)	126.5
Normal	125.5
Minimum	125 ±
Minimum after assumed degradation in Fossa	123 ±
Diversion dam	
Crest elevation of overflow section - meters above sea level	243.75
Crest elevation of gated section - meters above sea level	242.5
Height of overflow section from foundations - meters	5.5
Dikes	
Total length - meters	5000
Maximum height from foundations - meters	30
Total volume of fill - cubic meters	880,000
Canals	
Total length - meters	3,200
Total volume of excavation - cubic meters	1,100,000
Penstocks	
Type	steel lined vertical shafts
Diameters - meters	5.0
Length for 3 units - meters	215
Powerstation	
Type	underground
Length - meters	118
Width - meters	16.5
Height - meters	34

TABLE 2

(continued)

Tailrace tunnel	
Type	horseshoe, concrete lined
Diameter - meters	8
Length - meters	1560
Turbines	
Number	six
Type	Francis
Rating at 115 meters net head - metric horsepower	51.600
Discharge at rated head, full gate - cubic meters per second	38
Speed - revolutions per minute	300
Generators	
Number	six
Type	vertical shaft, hydraulic turbine driven
Rating - kilovolt-amperes	38.889
Power factor	0.9
Voltage - kilovolts	13.8
Phases	three
Cycles per second	50
Speed - revolutions per minute	300
Transformers	
Number	three
Type	outdoor, three-phase, OA/FA/FOA
Rating - megavolts-amperes	43-43-86
Voltage - kilovolts	13.8-230
Main transmission line	
Length - kilometers	110
Voltage - kilovolts	230
Construction	wood poles

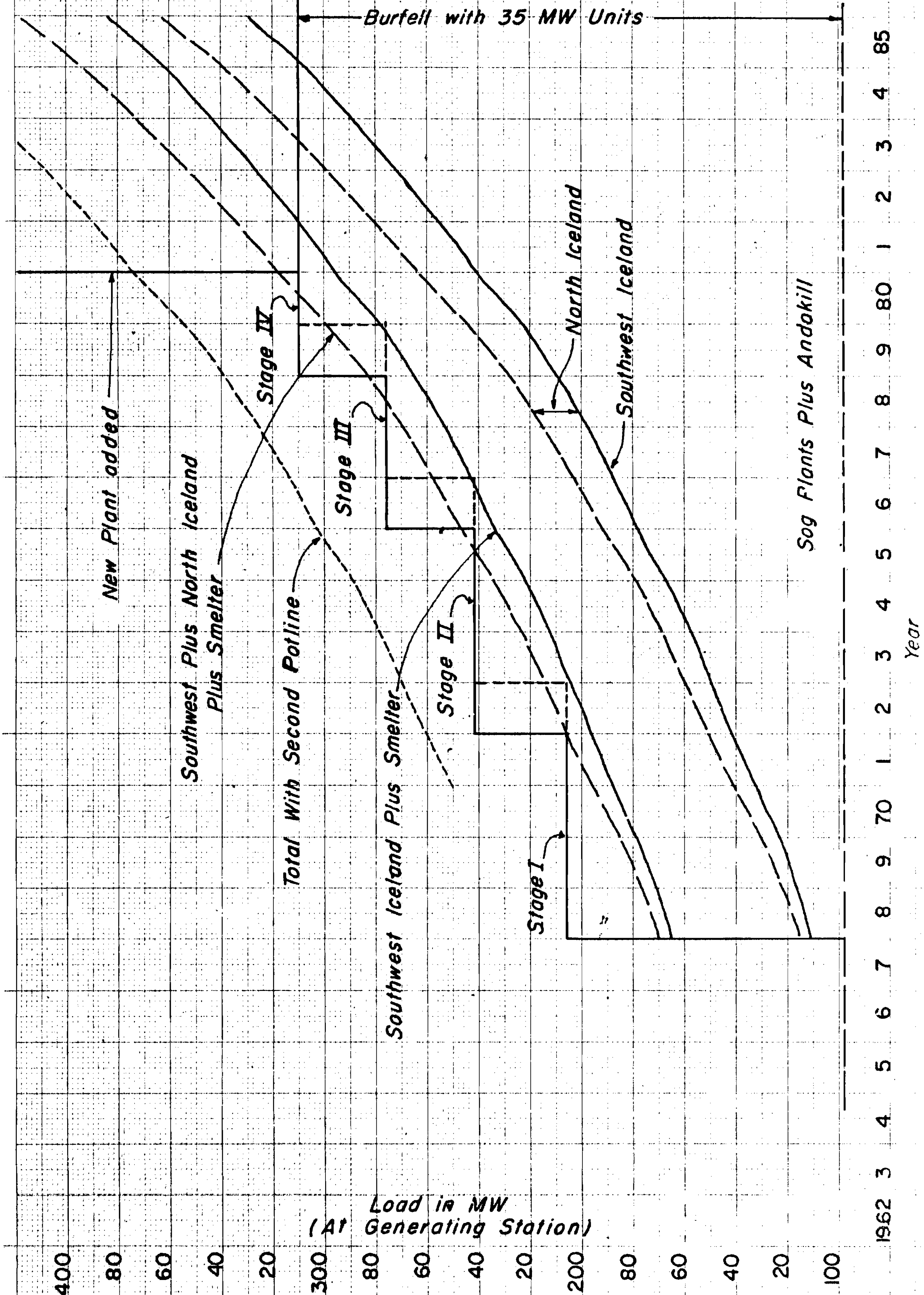
Revised November 26, 1963

TABLE 3

BURFELL HYDROELECTRIC PROJECT
STAGED DEVELOPMENT
PLANT WITH 35 MW UNITS
ESTIMATED UNIT COST OF ENERGY

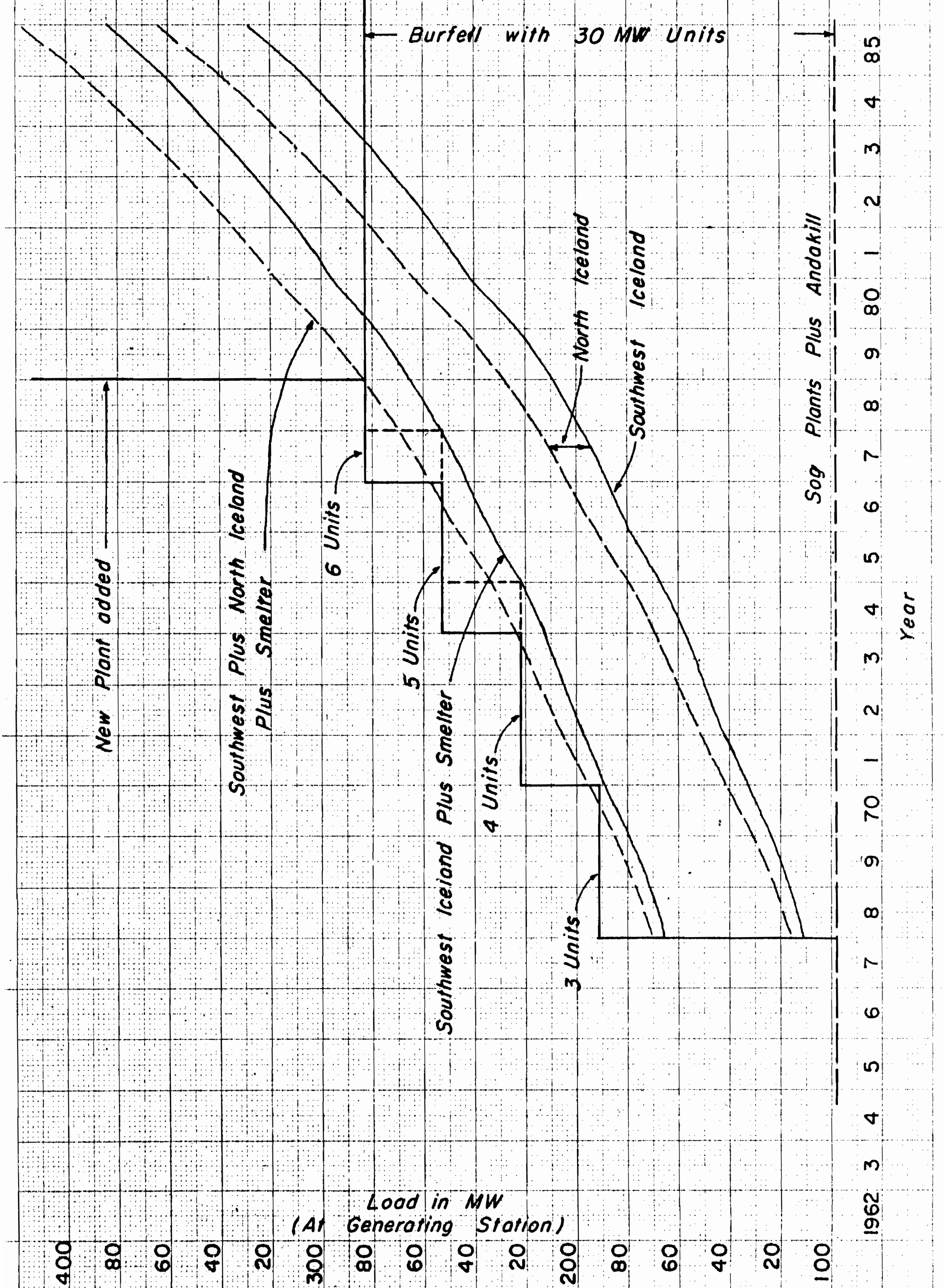
		Percent of Debt Service		
		5	7	9
STAGE I				
O & M, Reserves, etc.	$1000	505	505	505
Debt Service	$1000	1300	1820	2340
Total	$1000	1805	2325	2845
Annual Energy	MkWh	820	820	820
Cost of Energy	US Mills/Kwh	2.20	2.84	3.47
STAGE II (Incremental)				
O & M, Reserves, etc.	$1000	170	170	170
Debt Service	$1000	205	287	369
Total	$1000	375	457	539
Annual Energy	MkWh	265	265	265
Cost of Energy	US Mills/Kwh	1.41	1.72	2.03
STAGES I + II				
O & M, Reserves, etc.	$1000	675	675	675
Debt Service	$1000	1505	2107	2709
Total	$1000	2180	2782	3384
Annual Energy	MkWh	1085	1085	1085
Cost of Energy	US Mills/Kwh	2.01	2.56	3.12
STAGE III (Incremental)				
O & M, Reserves, etc.	$1000	150	150	150
Debt Service	$1000	355	497	639
Total	$1000	505	647	789
Annual Energy	MkWh	250	250	250
Cost of Energy	US Mills/Kwh	2.02	2.59	3.16
STAGES I + II + III				
O & M, Reserves, etc.	$1000	825	825	825
Debt Service	$1000	1860	2604	3348
Total	$1000	2685	3429	4173
Annual Energy	MkWh	1335	1335	1335
Cost of Energy	US Mills/Kwh	2.01	2.57	3.13
STAGE IV (Incremental)				
O & M, Reserves, etc.	$1000	95	95	95
Debt Service	$1000	78	109	139
Total	$1000	173	204	234
Annual Energy	MkWh	240	240	240
Cost of Energy	US Mills/Kwh	0.72	0.85	0.98
STAGES I + II + III + IV				
O & M, Reserves, etc.	$1000	920	920	920
Debt Service	$1000	1938	2713	3487
Total	$1000	2858	3633	4407
Annual Energy	MkWh	1575	1575	1575
Cost of Energy	US Mills/Kwh	1.81	2.30	2.80

EXHIBIT I



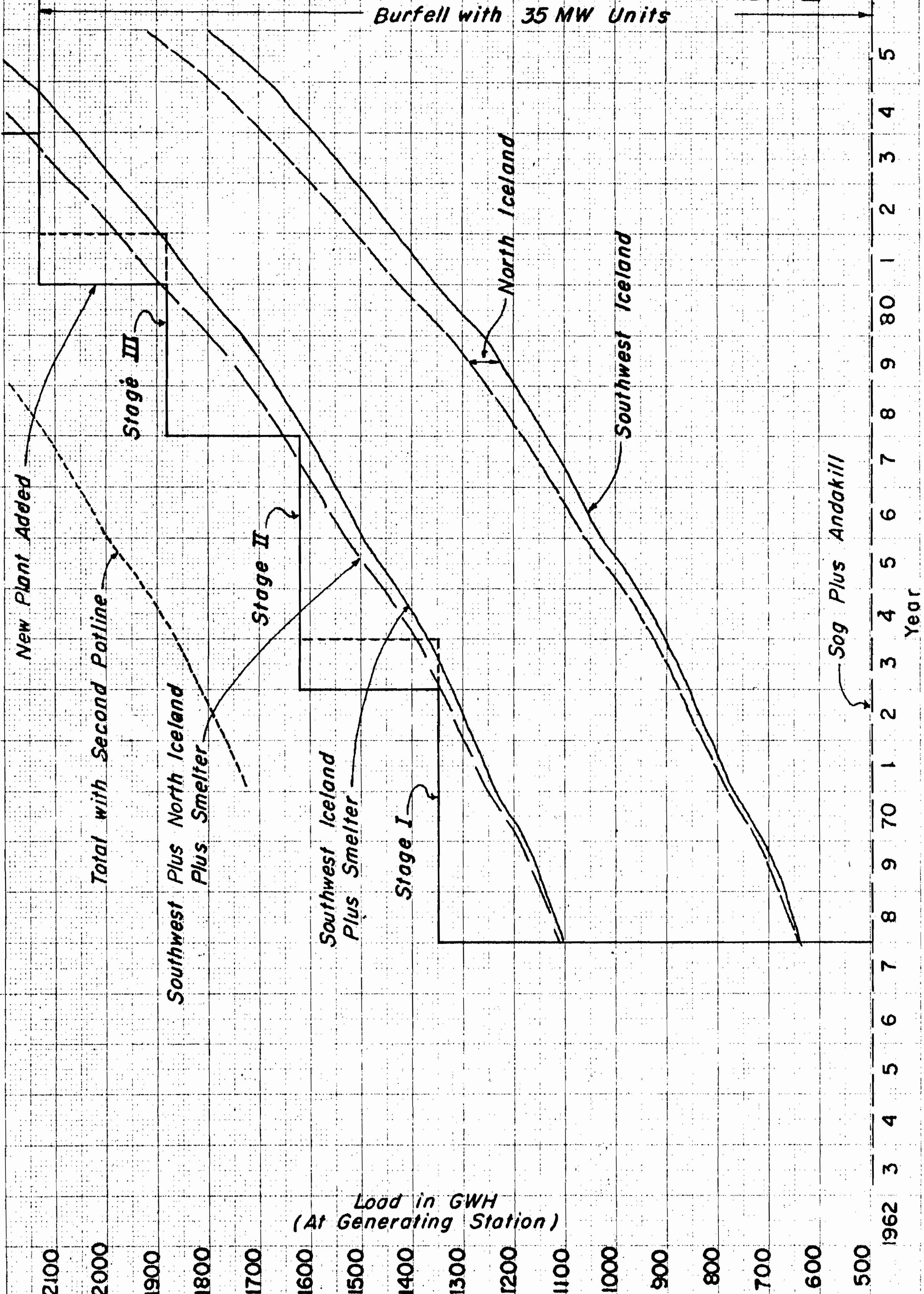
HARZA ENGINEERING COMPANY INTERNATIONAL	Estimated Loads and Resources Southwest and North Iceland Burfell Project with 35 MW Units	OCT. 6. 1963 290 P 90

EXHIBIT I A



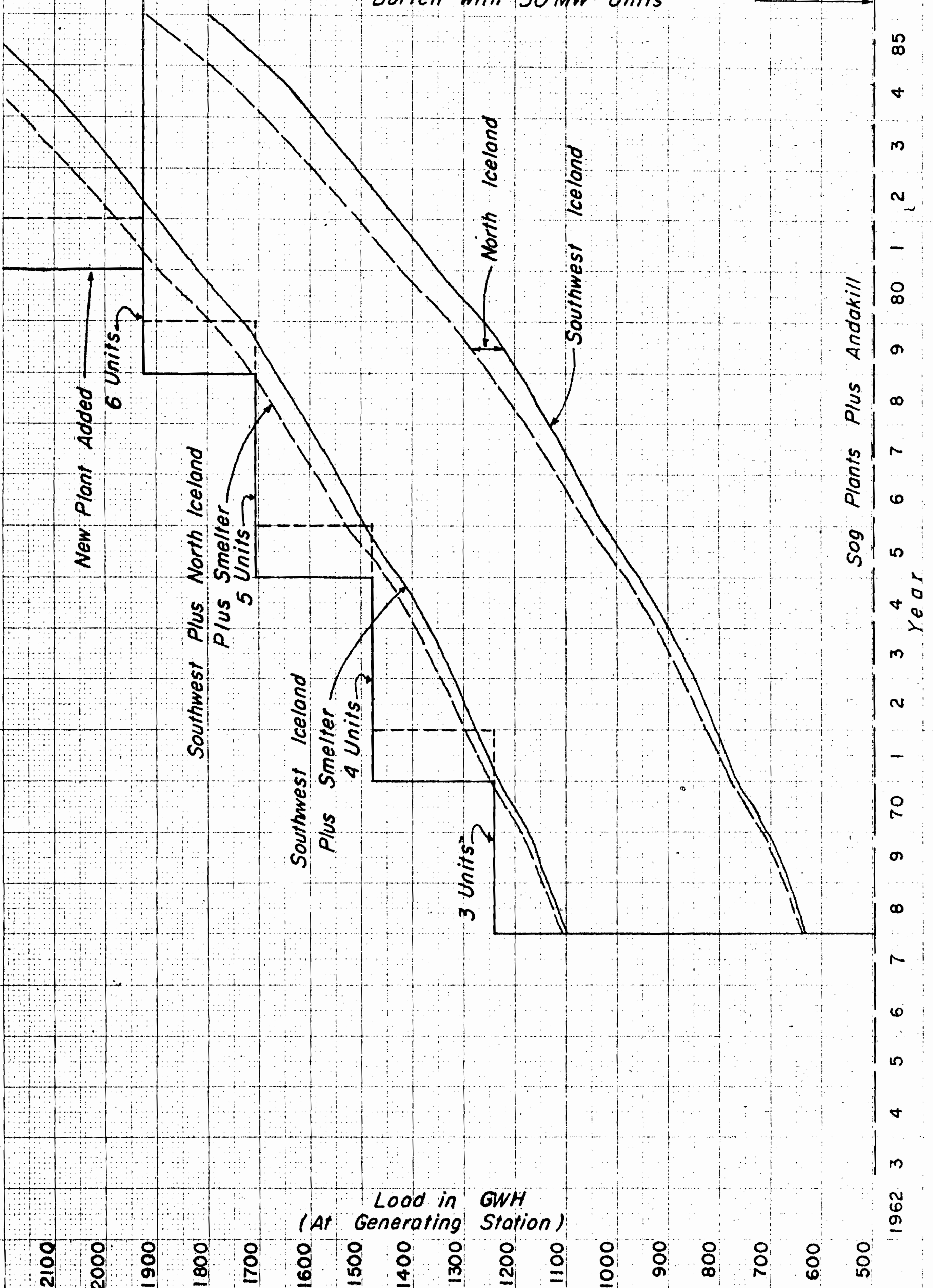
HARZA ENGINEERING COMPANY INTERNATIONAL	Estimated Loads and Resources Southwest and North Iceland Burfell Project with 30 MW Units	OCT. 6 1963 290 P 91

EXHIBIT II



HARZA ENGINEERING COMPANY INTERNATIONAL	Estimated Loads and Resources Southwest and North Iceland Burfell Project with 35 MW Units	OCT. 6. 1963 290 P 92

EXHIBIT II A



HARZA ENGINEERING COMPANY INTERNATIONAL	Estimated Loads and Resources Southwest and North Iceland Burfell Project with 30 MW Units	OCT. 6. 1963 290 P 93

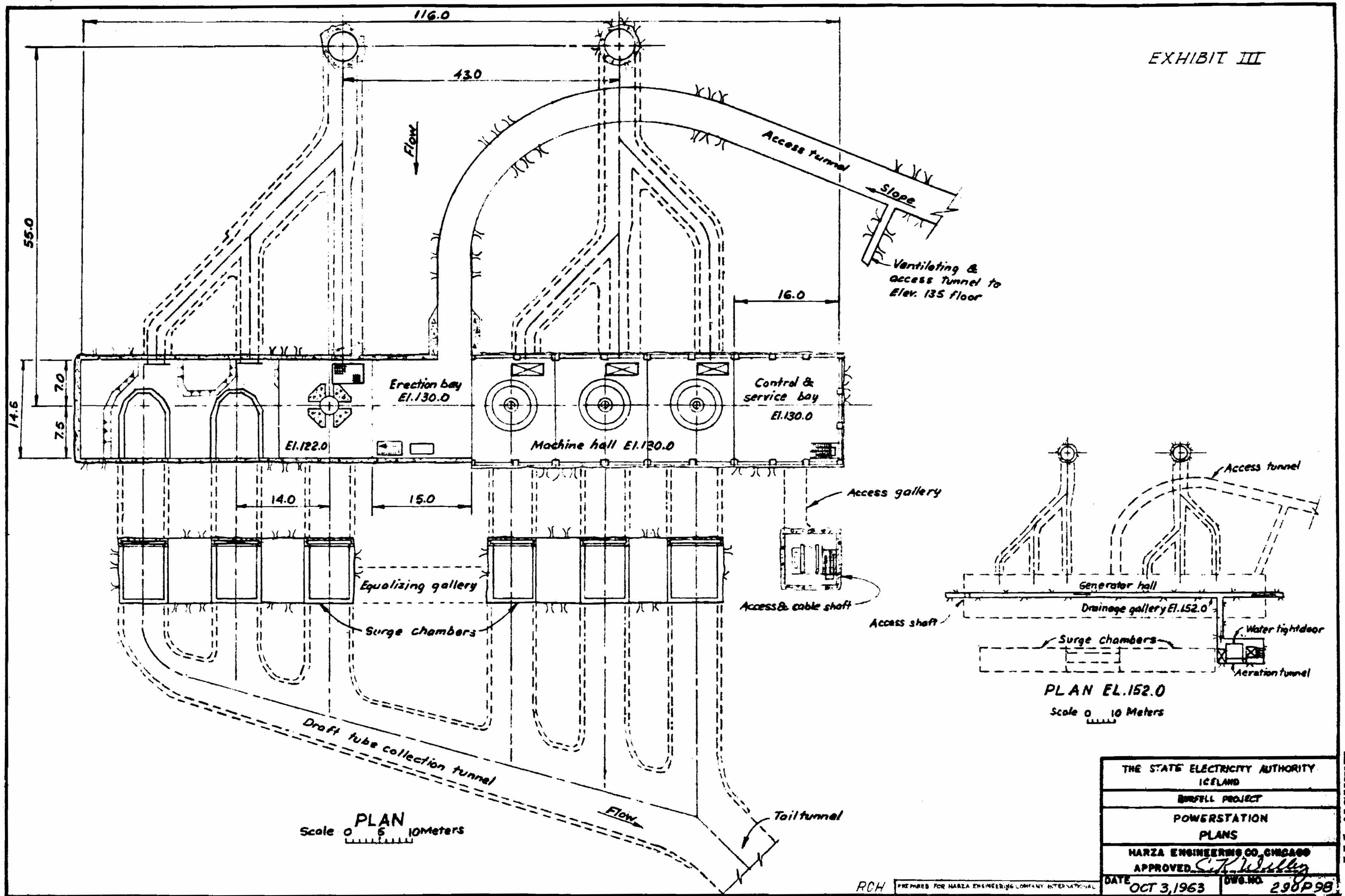
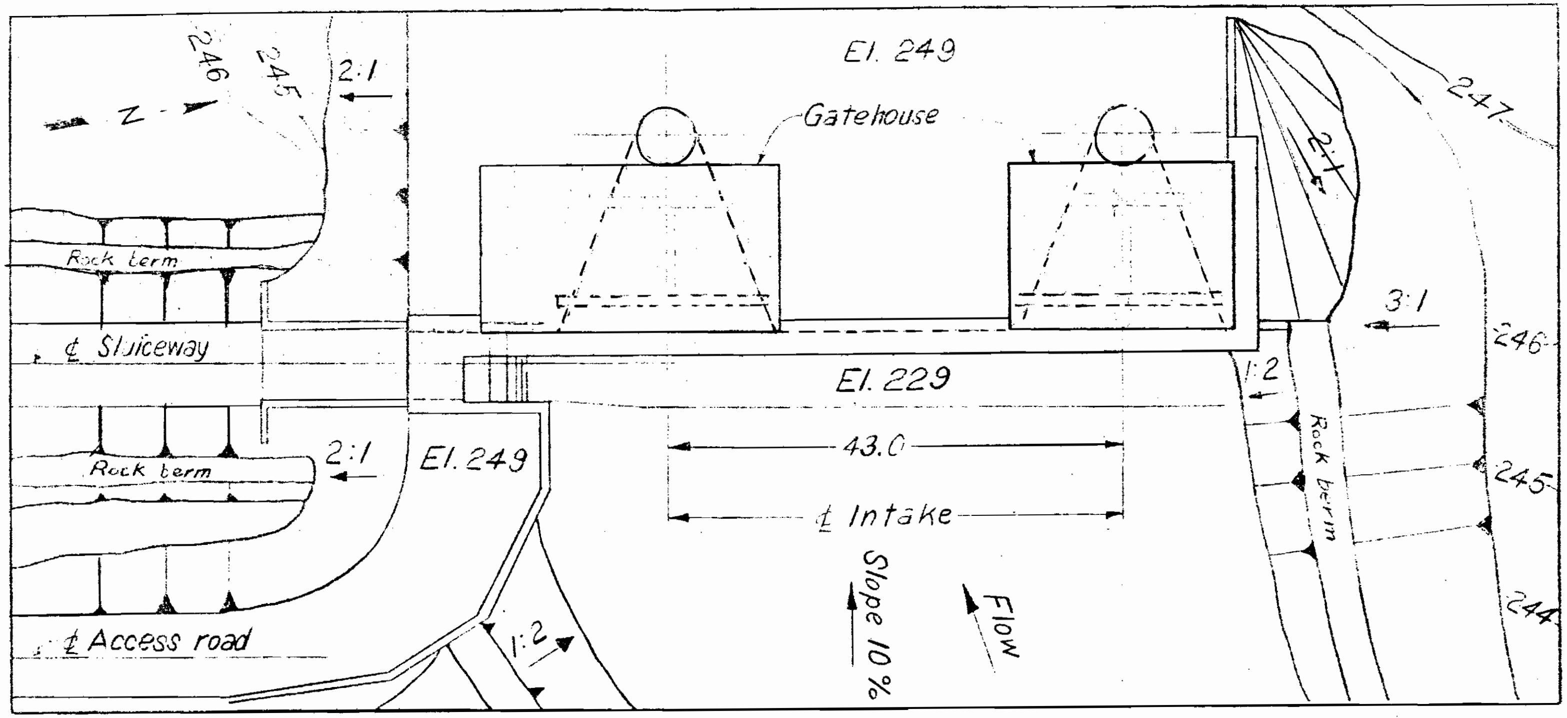


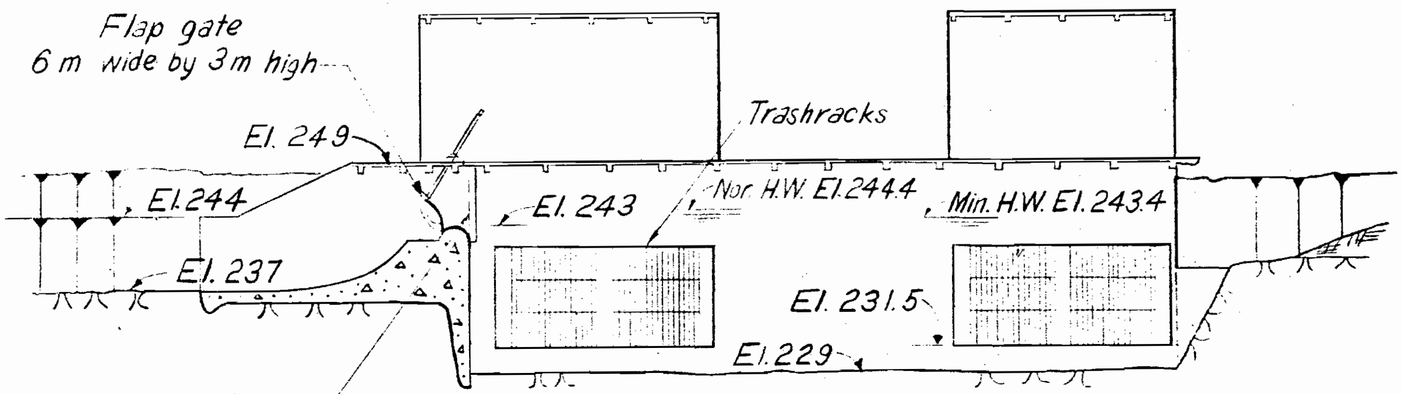
EXHIBIT III
116.0
43.0
55.0
Flow
Access tunnel
Slope
Ventilating & access tunnel to Elev. 135 floor
16.0
Erection bay El.130.0
Control & service bay El.130.0
El.122.0
Machine hall El.130.0
7.0
7.5
14.6
14.0
15.0
Access gallery
Equalizing gallery
Access & cable shaft
Surge chambers
Draft tube collection tunnel
Flow
Tailtunnel
PLAN
Scale 0 5 10 Meters
Access tunnel
Generator hall
Drainage gallery El.152.0
Access shaft
Water tight door
Surge chambers
Aeration tunnel
PLAN EL.152.0
Scale 0 10 Meters
THE STATE ELECTRICITY AUTHORITY
ICELAND
BURFELL PROJECT
POWERSTATION
PLANS
HARZA ENGINEERING CO. CHICAGO
APPROVED
DATE OCT 3, 1963
DWG. NO. 290P98
RCH
PREPARED FOR HARZA ENGINEERING COMPANY INTERNATIONAL

Exhibit III

EXHIBIT IV



PLAN – INTAKES AND SLUICEWAY



ELEVATION

Scale 0 10 20 30 Meters

THE STATE ELECTRICITY AUTHORITY ICELAND
BURFELL PROJECT
INTAKES – I
HARZA ENGINEERING COMPANY INTERNATIONAL
PREPARED BY HARZA ENGINEERING COMPANY APPROVED C. K. Willey
CHICAGO ILLINOIS / DATE OCT 1963 / DWG NO. 90F85

Exhibit V

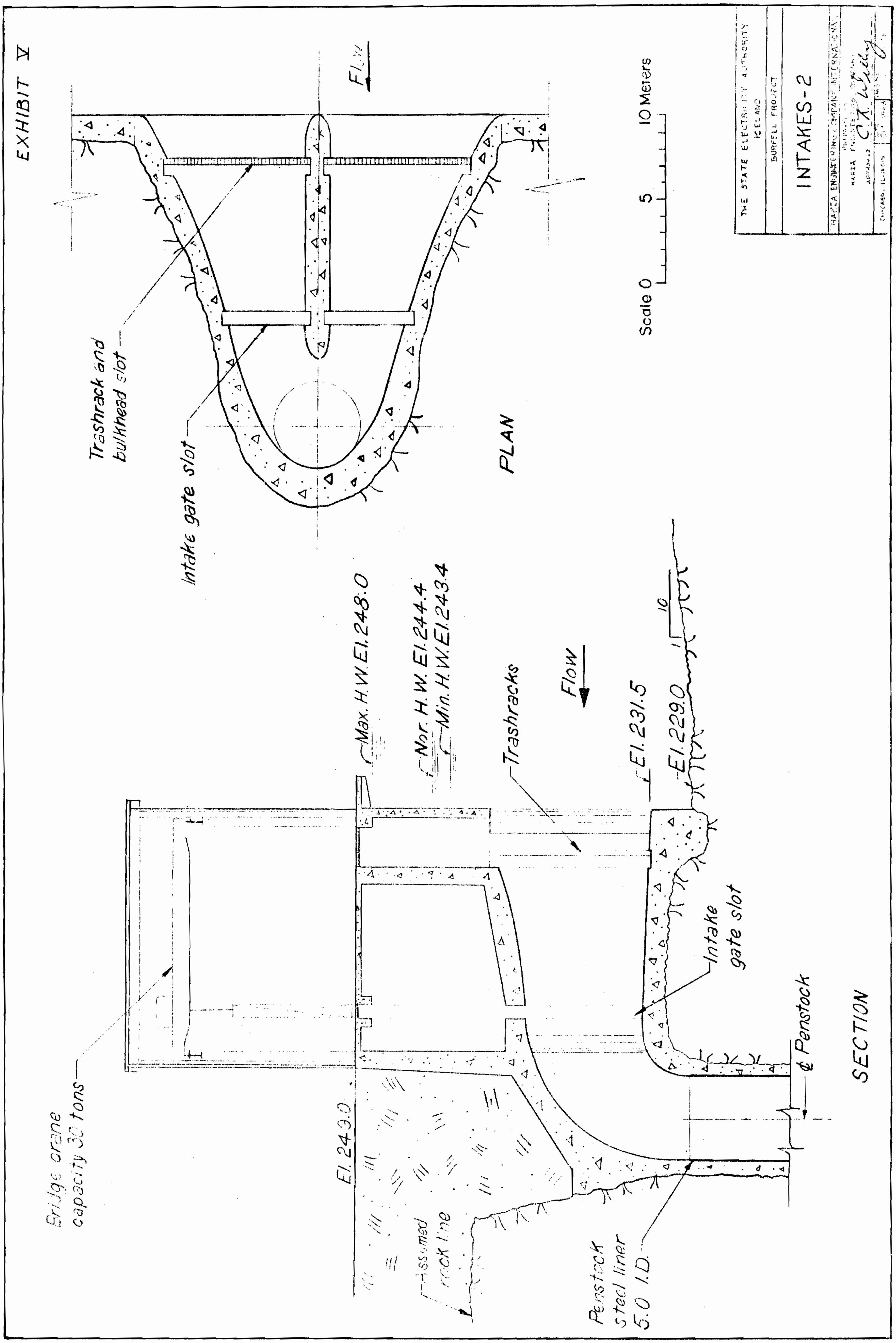
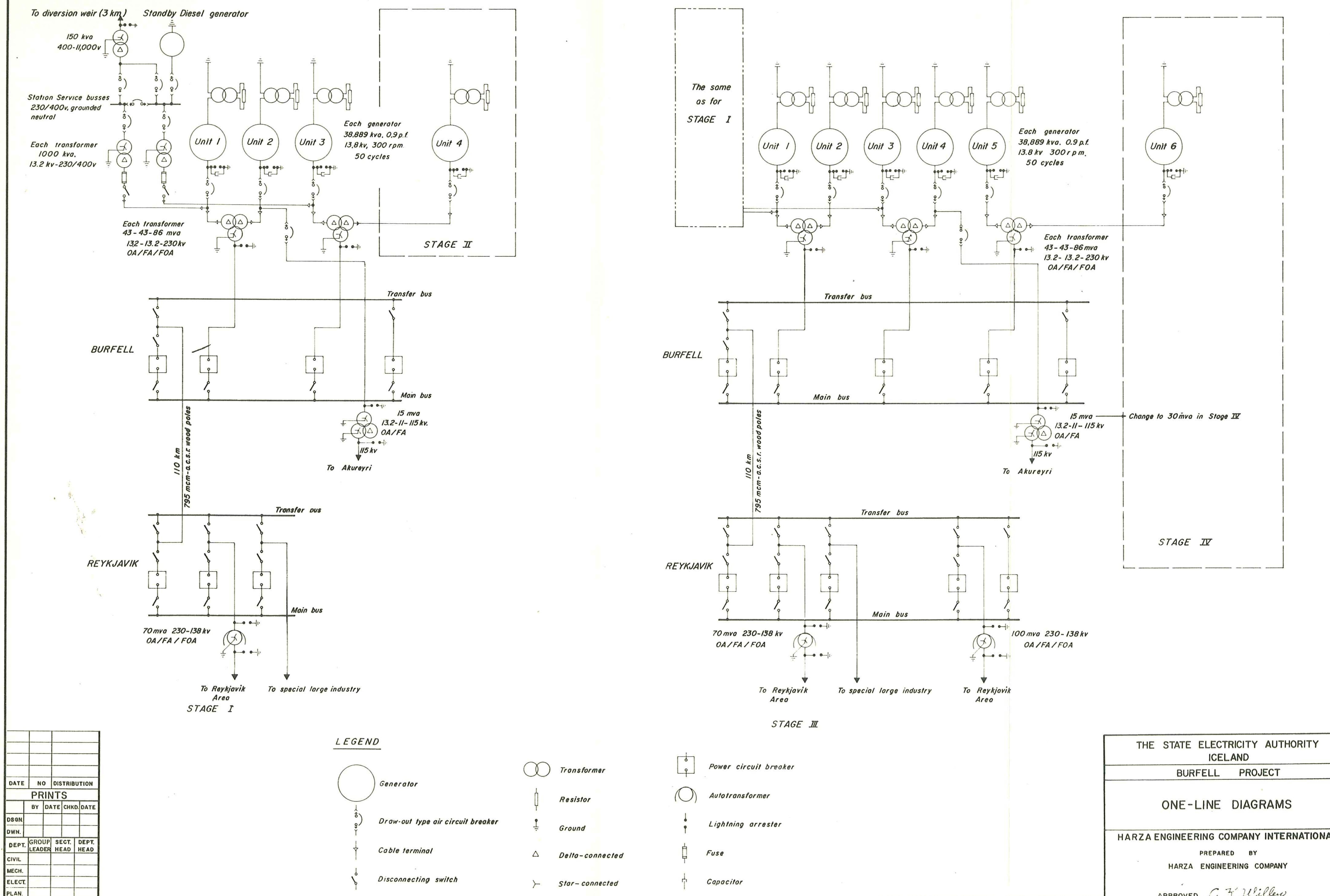


EXHIBIT V
Flow
Trashrack and bulkhead slot
Intake gate slot
PLAN
Scale 0 5 10 Meters
THE STATE ELECTRICITY AUTHORITY ICELAND
BURFELL PROJECT
INTAKES-2
HARZA ENGINEERING COMPANY INTERNATIONAL
Max. H.W. El. 248.0
Nor. H.W. El. 244.4
Min. H.W. El. 243.4
Trashracks
Flow
El. 231.5
El. 229.0
10
1
Intake gate slot
℄ Penstock
SECTION
Bridge crane capacity 30 tons
El. 243.0
Assumed rock line
Penstock steel liner 5.0 I.D.

EXHIBIT VI



DATE	NO	DISTRIBUTION

PRINTS

	BY	DATE	CHKD	DATE
DSGN.				
DWN.				
DEPT.	GROUP LEADER	SECT. HEAD	DEPT. HEAD	
CIVIL				
MECH.				
ELECT.				
PLAN.				
STAFF			CH.ENGR.	

REV. NO	DATE	NATURE OF REVISION	BY	CHKD.	APPD.

THE STATE ELECTRICITY AUTHORITY
ICELAND

BURFELL PROJECT

ONE-LINE DIAGRAMS

HARZA ENGINEERING COMPANY INTERNATIONAL

PREPARED BY
HARZA ENGINEERING COMPANY

APPROVED C. K. Willey

CHICAGO, ILLINOIS | DATE OCT. 1963 | DWG. NO. 290 P 97

BURFELL - 210 MW PLANT

6x35 MW UNITS IN 4 STAGES

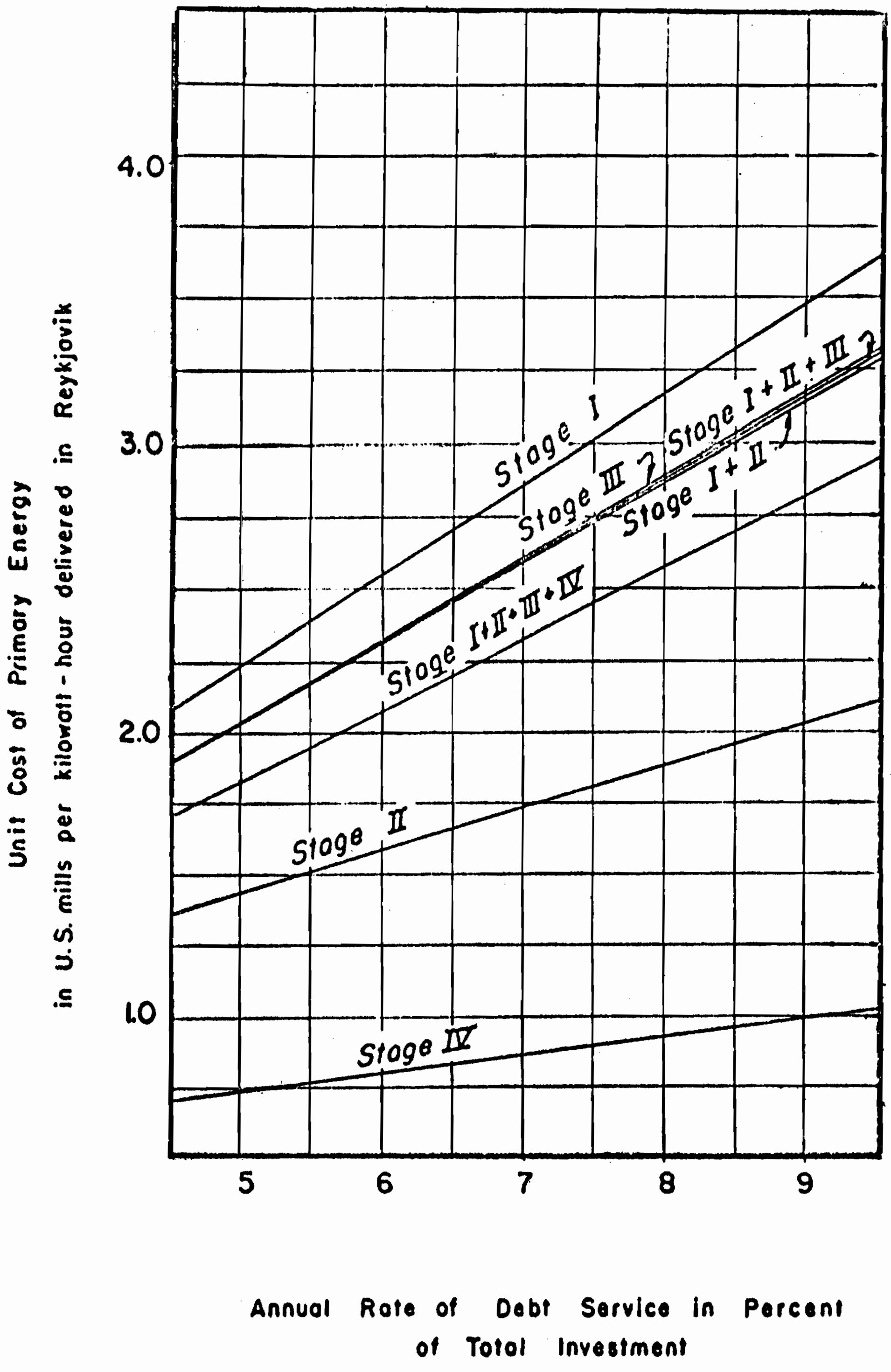
ITEM	STAGE I INITIAL 105 MW $ US	STAGE II INCREM. 35 MW $ US	STAGE III INCREM. 35 MW $ US	STAGE IV INCREM. 35 MW $ US	TOTAL 210 MW $ US
POWER PLANT STRUCTURES					
Powerstation	2 037 483	590 908	128 125	128 025	2 884 541
Access Tunnel	1 050 920	0	0	0	1 050 920
Subtotal	3 088 403	590 908	128 125	128 025	3 935 461
RESERVOIR, DAM AND WATERWAYS					
Burfell Reservoir	75 000	-	-	-	75 000
Bjarnalaekur Dike	1 039 000	-	167 000	-	1 206 000
Right Bank Dike	-	-	133 000	-	133 000
Left Bank Dike	-	-	553 000	-	553 000
Diversion Canal	536 000	-	381 000	-	917 000
Bjarnalaekur Canal	453 000	-		-	453 000
Diversion Weir and Inlet	1 454 000	-	660 900	-	2 114 700
Approach Canal	151 900	0	0	0	151 900
Sluiceway	248 800	0	0	0	248 800
Dike of Sluiceway	94 480	0	0	0	94 480
Intake	446 250	432 905	0	0	879 155
Penstocks	568 950	568 950	0	0	1 137 900
Tailrace Surge Chamber	574 875	348 400	0	0	923 275
Tailrace Tunnel	3 405 700	0	0	0	3 405 700
Tailrace Canal	233 000	0	0	0	233 000
Subtotal	9 280 955	1 350 255	1 894 700	0	12 525 910
TURBINES AND GENERATORS	2 145 000	715 000	715 000	715 000	4 290 000
ACCESSORY ELECTRICAL EQUIPMENT	470 000	156 000	159 000	163 000	948 000
MISCEL. POWER PLANT EQUIPMENT	504 000	82 000	82 000	82 000	750 000
ACESS ROADS	410 000	90 000	90 000		590 000
OPERATORS VILLAGE AND GEN. PLANT	235 000	44 000	21 000	24 000	324 000
SUBTOTAL PRODUCTION PLANT	16 133 358	3 028 163	3 089 825	1 112 025	23 363 371
TRANSMISSION PLANT					
Burfell Step-Up Substation	718 000	-	237 000	65 000	1 020 000
Transmission Line - Burfell-Reykjavik	1 650 000	-	-	-	1 650 000
Reykjavik Receiving Substation	444 000	-	374 000	-	818 000
SUBTOTAL TRANSMISSION PLANT	2 812 000	-	611 000	65 000	3 488 000

BURFELL - 210 MW PLANT

6x35 MW UNITS IN 4 STAGES

	STAGE I INITIAL 105 MW $ US	STAGE II INCREM. 35 MW $ US	STAGE III INCREM. 35 MW $ US	STAGE IV INCREM. 35 MW $ US	TOTAL 210 MW $ US
SUBTOTAL DIRECT COSTS	18 945 358	3 028 163	3 700 825	1 177 025	26 851 371
Contingencies	2 554 642	361 837	459 175	82 975	
TOTAL DIRECT COSTS	21 500 000	3 390 000	4 160 000	1 260 000	
Eng., Superv. O.H.	1 800 000	260 000	290 000	90 000	
Total Construction Cost	23 300 000	3 650 000	4 450 000	1 350 000	
Interest	2 200 000	250 000	300 000	100 000	
Thorisvatn Initial Storage			2 000 000		
Subtotal	25 500 000	3 900 000	6 750 000	1 450 000	
Preliminary Costs	500 000				
Extra Cost for Increm. Costs		200 000	350 000	100 000	
STAGE INVESTMENT COST	26 000 000	4 100 000	7 100 000	1 550 000	
Rated Installed Capacity MW	105	35	35	35	
Unit Cost - Dollar per Rated Installed kW	247	117	203	44	
CUMULATIVE PROJECT INVESTMENT					
Stages I + II		30 100 000			
Stages I + II + III			37 200 000		
Stages I + II + III + IV				38 750 000	
CUMULATIVE RATED INSTALLED CAPACITY - MW		140	175	210	
CUMULATIVE UNIT COST-DOLLARS					
Stages I + II		215			
Stages I + II + III			212		
Stages I + II + III + IV				184	

EXHIBIT VIII
Revised November 26, 1963



NOTES:

No allowance made for income from sales of secondary energy.

Import duties and taxes not included.

Stage III includes Thorisvatn Initial Storage, but no allowance for any increase in firm energy.

THE STATE ELECTRICTY AUTHORITY
ICELAND

BURFELL PROJECT

UNIT COST OF ENERGY

HARZA ENGINEERING COMPANY INTERNATIONAL

PREPARED BY
HARZA ENGINEERINC CO, CHICAGO
APPROVED C. K. Willey

DATE Nov, 1963	DWG NO. 290 P 99R1