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Analysis of Power Costs in the Province of Alberta 1949

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ANALYSIS OF POWER COSTS
in
THE PROVINCE OF ALBERTA
1949

Analysis prepared on behalf of

THE RESEARCH COUNCIL OF ALBERTA

by

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PART A

Introduction

The object of this report is to compare the costs of power generation by the following methods: hydro, coal steam, gas steam, oil steam, gas turbine, and oil and gas diesel.

In the near future additional millions of dollars will be invested in the generation facilities in Alberta to meet an increasing demand for power and to replace worn out and obsolete equipment. It is in the public interest that as full and complete information as possible be available to guide municipalities, companies and individuals who must bear the responsibility of selecting between alternative sources of power.

The report deals only with the costs of generation, and transmission of power from the source to the load centre. Hence the cost per unit, given in the report, is only a portion of the total cost of supply to domestic and other users, in that the distribution charges usually form the larger proportion of the total cost. The cost of delivery will obviously depend on the "use factor" of the distribution network and this will be reflected in rural schemes where the capital cost per consuming point is inherently high and the use factor low.

It is anticipated that this report will present a picture of costs and operating experience which, although not providing categorical answers to all questions that may arise, will present some of the many factors of this intricate problem.

Probable Future Demand for Power

Estimates of the future power requirements of Alberta can be made to some extent by the extrapolation of past consumption curves. For the majority of growth schedules considered, accurate records* cover the

*Dominion Bureau of Statistics, Transportation and Public Utilities Branch, Annual Reports on Central Electric Stations' operations (1932 to 1946).

period 1932 to 1950. This was a period of marked instability, including depression, partial recovery, war, and the abnormal circumstances of a postwar economy. It is obvious that the experience of so unstable a period cannot provide a highly reliable basis for predictions in that the province is only on the threshold of industrial activity.

1. Power Consumed in Domestic Service

The effect of varying economic conditions can be seen in the graph of "Electric Power Consumption by Domestic Services" in Fig. 1. Domestic power consumption remained relatively stable during the depression years up to 1935. Gradual recovery from depression conditions was reflected in a steady increase in the domestic use of power from 1935 to 1940. Wartime restrictions and shortages of household appliances checked expansion, but after 1945 the growth of domestic consumption proceeded at an accelerated pace. The extrapolated line from 1950 to 1955 is based upon the rate of increase in consumption occurring during the period 1947 to 1950. Thus the estimated domestic consumption in 1955 should be over 170 million kilowatt-hours (kwhr.).

Figure 1 is actually the product of two more fundamental schedules: the "Average Consumption of Electricity per Customer" (Fig. 2) and the "Number of Domestic Consumers" (Fig. 3). Continued increase in the average consumption of electricity per customer will depend on the discovery of new uses for electricity and the maintenance of purchasing power to enable customers to buy and use electrical appliances.

In the past, line extensions to new towns have added steadily to the number of domestic customers, but these extensions cannot continue indefinitely. However, there are many hamlets and villages with populations of over 100 that are not at present being served with power. If small diesel units are practicable in such places, considerable extension of service can still be contemplated; and farm electrification will also help to maintain the increase in the number of new outlets. The number of domestic consumers is also influenced by the rural-to-urban shift of population. It is evident that as a family moves from a farm to a city the power company receives a new customer although there may be no increase in total population. Analysis of the trends in the number of customers and in the consumption per customer supports the estimates based on extrapolation of the total consumption.

2. Large and Small Consumers of Industrial Power

The consumption by large and small industrial power users up to 1950 is shown in Fig. 4. The sharp increase in consumption from 1941 to 1943 was caused almost entirely by the operation of the Alberta Nitrogen Plant at Calgary. The extrapolation shown represents a mean expansion based on the 1946-1950 period.

Fig. 5 shows the annual consumption by industrial power consumers excluding the two largest users. Extrapolations based upon the mean rates of expansion between 1946 and 1950 indicate that 400 million kwhr. will be required on this basis in 1955.

The appearance of other large industrial users would add considerably to the total industrial consumption. However, such users must contract for their power in advance, and this may require new power developments. For example, the construction of the Calgary Power Company's Cascade Plant was necessary to meet the demands of the Alberta Nitrogen Plant.

Estimated industrial consumption of 600 million kwhr. in 1955 allows for normal expansion; it does not provide for an increase in demand occasioned by the appearance of new large industrial users.

3. Power Consumed by Commercial Lighting

Electric power consumption by commercial lighting is shown in Fig. 6. Since 1934 there has been a continual increase in the use of power for commercial lighting. There was a marked acceleration in the rate of expansion after 1942 and a further acceleration after 1946. The extrapolation to 1955 is based on the 1946-1950 expansion and the requirements should be about 170 million kwhr. by that time.

4. Power Consumed by Free Service and Street Lighting

This classification includes, in addition to that for street lighting, all power supplied to public projects or institutions and other organizations etc. for which no charge is levied. Electric power consumption by free service and street lighting is shown in Fig. 7. The erratic changes in consumption from 1941 to 1946 were caused by changes in free service consumption. Extrapolation is based on the period 1945 to 1950 and estimates the 1955 consumption as 20.4 million kwhr.

Summary of Estimated Consumption in 1955

The following summary includes the results of the foregoing extrapolations, using the maximum figures obtained in each case:

Estimated consumption by:

1. Domestic services	170	million	kwhr.
2. Large and small power users	600	"	"
3. Commercial lighting	170	"	"
4. Free service and street lighting	20.4	"	"
Estimated total consumption in 1955	960.4		

Estimated Net Generation Required in 1955

In order to arrive at net generation, line losses must be added to the estimated consumption.

Technology of power transmission and distribution has advanced over the past years to give a decreasing percentage loss as shown by the following table which is derived from the Dominion Bureau of Statistics, Transportation and Public Utilities Branch reports on Central Electric Stations' operations.

Year	*Power generated for consumption in Alberta, thousands of kwhr.	Loss, thousands of kwhr.	Loss, % of total
1932	195,467	41,948	21.4
1933	182,963	35,103	19.2
1934	193,002	37,043	19.2
1935	208,054	37,720	18.1
1936	216,770	37,839	17.45
1937	222,755	40,723	18.25
1938	232,451	41,058	17.65
1939	251,806	37,980	15.2
1940	274,121	43,454	15.85
1941	319,743	52,644	16.5
1942	418,704	52,825	12.6
1943	512,985	33,832	6.6
1944	555,034	66,705	12.01
1945	566,744	74,991	13.25
1946	602,048	73,102	12.15
1947	641,331	77,634	12.25
1948	724,498	103,063	14.2
1949	800,729	114,095	14.2
1950	884,117	108,455	12.3

*This excludes a small power import from British Columbia.

Assuming that line losses will not exceed 12% of net generation in 1955, net output in that year should equal approximately 1,090 million kwhr. This estimate, it is to be remembered, does not allow for any new major power using development.

Sources of Electrical Energy

Fig. 8 shows the extent of fuel and hydro generation in Alberta as given by the Dominion Bureau of Statistics, Transportation and Public Utilities Branch reports on Central Electric Stations' operations. The relative importance of fuels is a situation unique to Alberta. Considering the Dominion as a whole, fuel is the source of less than 2% of the total generation.

It does not appear that any conclusion can be reached by studying the graph or extrapolating trend lines of fuel and hydro production. Water conditions vary considerably from year to year and have considerable effect on the ratio of production between fuel and hydro. The years 1943 and 1944, for example, were dry years and hydro output decreased accordingly.

The Transportation and Public Utilities Branch reports do not give a breakdown of generation according to the type of fuel. However, considering that gas and oil engines have a capacity of less than 10% of the steam capacity and that diesel plants have a much lower use factor than steam plants, it is not likely that diesel generation accounts for more than 5% of the total power output.

Development of Power Use Factors

The growth in the output of power does not necessarily depend on increase in the installed capacity of generating equipment. An increased output could be realized by a higher use factor of the existing capacity.

The following table shows the behavior of the over-all use factor for Alberta plants from 1927 to 1949, the use factor in % being:

$$\frac{\text{actual kwhr. output}}{\text{potential kwhr. output}} \times 100$$

(see Appendix No. 1 for calculation of the use factor).

Year	1927	1928	1929	1930	1931	1932	1933	1934	1935
Use Factor,%	25.7	29.3	27.3	23.8	23.6	22.5	21.0	22.2	23.9

Year	1936	1937	1938	1939	1940	1941	1942	1943	1944
Use Factor,%	25.1	26.0	27.3	25.6	28.4	33.3	38.1	45.0	43.6

Year	1945	1946	1947	1948	1949
Use Factor,%	43.4	47.0	47.5	49.0	44.8

A straight line extrapolation would suggest a use factor in 1955 of about 60%, but it is questionable whether such a high figure can be anticipated. Reserve capacity, the irregular daily load pattern for commercial light and domestic service, and single shift work in industrial plants can be expected to put an upward limit on the kwhr. that can be generated. In fact, it is unlikely that the use factor will exceed 50% by 1955.

Accepting this 50% figure, an installed capacity of 249,000 kw. will be required to handle the estimated 1,090 million kwhr. demand in 1955. This output will require the installation of an additional capacity of 103,000 kw. The installed capacity of 146,000 kw. in 1946 is based on a reported 182,500 kva. at 80% power factor.

Electrical Energy Demand by Particular Sizes of Communities

The installed capacity of generation equipment required to supply a particular size of community is rather difficult to predict, particularly in the case of small plants in small community centres. This is due to such factors as the relative numbers of industrial, commercial and domestic users, the degree of acceptance by a newly served area of the service offered which depends, in turn, on the purchasing power of the people, and the merit of service offered with respect to continuity, quality, cost and extensibility. In the case of larger communities and cities, the diversity of industrial and commercial activity and the almost universal demand for domestic utilities service make the per capita demand for electric energy a more nearly fixed quantity in all such communities.

From a consideration of the 1948 consumption by all Alberta communities for which statistics were available, the following schedule of required plant sizes is derived on the basis that all electrical power is generated locally in the community. These statistics, found in Appendix No. 2 to this report, are from the records of the Provincial Statistician.

Population	Average annual consumption, thousands of kwhr.	Estimated average % use factor of generating equipment	Estimated average capacity, kw.	Probable range of capacities found in actual situations, kw.
100	30	25	14	10 - 25
200	60	25	27	15 - 50
300	100	25	46	25 - 75
400	140	30	53	35 - 75
500	180	30	68	50 - 100
750	300	35	100	75 - 200
1,100	450	35	150	100 - 250
2,500	1,650	40	470	300 - 600
5,000	4,000	40	875	600 - 1,200
10,000	10,000	45	2,500	2,000 - 3,500
25,000	30,000	45	7,500	6,000 - 10,000
50,000	60,000	50	14,000	10,000 - 20,000
100,000	125,000	50	30,000	20,000 - 50,000
150,000	200,000	50	46,000	40,000 - 70,000

PART B

Cost of Diesel Generation

Diesel generation is usually considered to be the most expensive method of generating electricity. However, where the load is small and isolated, diesels generally provide the cheapest source of power. As the size of the load increases, steam and hydro become competitive.

Diesel plants are not limited in size as most people imagine. The Saskatchewan Power Commission have a 4,500 kw. plant at Swift Current and a 2,408 kw. natural gas plant at Unity which will probably be expanded. In Alberta, Canadian Utilities operate a 1,380 kw. plant at Grande Prairie. However, the above figures by no means signify the upper limit to diesel plant capacity. In the United States, for example, Reynolds Metals Co. at their Hot Springs, Arkansas plant have gas and spark ignition diesels totalling 123,050 hp. or 78,000 kw. The Aluminum Corporation of America's new Texas plant is planned for 120 (natural gas, spark ignition) units of 1,150 kw. each, totalling 138,000 kw.

A new diesel plant at Tacuboya, Mexico City, is interesting both by virtue of its size (30,900 kw.) and because it uses bunker "C" oil. At 0.5 cents per gallon and at three-quarters load this plant has a guaranteed fuel cost of under 3 mills per kwhr. As the labor cost would be low (compared with steam), and the transmission distance short, this plant is in an advantageous position.

Generally speaking, however, diesels in well-developed load areas in the United States find their principal use for supplying peak loads from what are frequently termed "peaking plants". This is particularly true in high cost hydro grids where the investment per kw. may exceed $600. In such cases the increased cost of the last kwhr. generated on the peak is very high;

in other words, the last thousand kw. of capacity generate relatively few kwhr. and hence the capital cost attributable to this peak power is extremely high. Therefore, it has been found profitable in many cases to build a slightly smaller dam, which will have a much higher use factor, and to install diesel units to supply the peaks of the load.

Production Costs

The six elements of cost of diesel generation are as follows:

(a) Fuel,

(b) Labor,

(c) Lubrication,

(d) Maintenance,

(e) Supplies and miscellaneous expenses, and

(f) Depreciation and interest on investment.

In the following summary of reported costs, it has not been possible to analyze the effect of different engine speeds. Speed is important in that the initial cost and hence the interest charges per kwhr. on low-speed machines are appreciably higher than the corresponding charges for faster engines. On the other hand, some elements of cost for low-speed machines tend to be somewhat less than for the higher-speed machines. This is particularly true for maintenance and, to lesser degrees, for depreciation, fuel and lubrication. However, the conflict between machines of high and low speeds only exists in plants with unit capacities of about 100 kw. and less. Larger machines operate, for the most part, at low speeds.

The costs of American plant operation, obtained from the "ASME Report on Oil Engine Power Cost for 1947" have been referred to and plotted only as supporting evidence. The trend lines and conclusions are based entirely on Canadian plant experience.

(a) Fuel Costs

The fuel costs as reported herein reflect only the over-all efficiencies of the various plants. They are not the actual costs reported by each plant, but are based on arbitrary typical fuel costs of \$0.15 per gallon for fuel oil, \$0.26 per gallon for gasoline, and \$0.20 per thousand cubic feet (Mcf) for natural gas, where each is used. These costs for the three types of fuel are considered to represent typical fuel prices being charged in Alberta.

Fig. 9 shows the reported fuel costs per kwhr., adjusted to allow for the appropriate arbitrary typical fuel cost, as specified above, plotted against annual plant outputs. (See Appendix No. 3a for details of cost adjustment). This graph indicates the range and average trend of fuel costs for any size of generating station. The three high-cost plants are excluded from the envelope curves because of circumstances such as obsolescence, poor maintenance, etc. which remove them from the "typical plant" classification. The two plants which give rise to the "Minimum Cost Curve" are also quite exceptional in their highly efficient operation and indicate what can be done under nearly ideal conditions of machine operation and sizes.

The range of costs depends on many factors: speed, manufacture and design of engine, age, use factors and load conditions. However, despite these variables, it is seen from the curve that most plants operate within a range of about 15% of the average consumption.

The envelope curves show that fuel costs of from 20 to 25 mills should be expected in small plants having peak loads of less than 50 kw. In most examples a load of this type is supplied by a single machine operating continuously. In such an example, the running plant capacity factor is low and fuel consumption is high. In one instance, however, the operator of a small plant has three machines with capacities in the ratio of 1:2:4 to supply his night, day and evening loads respectively. The results of his operation indicate a fuel cost of not more than 13 mills per kwhr., but this is certainly an exceptional instance.

For larger installations with peak loads of from 50 to 200 kw. the above-mentioned combination of machines can be employed more effectively, and fuel costs of 13 to 17 mills may be expected. In still larger plants, where more efficient machines and combination of machines are possible, the fuel cost should fall to between 11 and 12 mills with a possible minimum cost of 9.5 mills per kwhr.

A few United States plants have standard fuel costs of less than 10 mills and, in general, large installations in the United States have lower costs than similar plants in Canada. The reason for this is not entirely clear but, as previously suggested, it may be that the U.S. plants reporting have somewhat newer equipment than is typical in western Canada. Another possible explanation is that in the United States the range of normal air temperatures to which the equipment is subjected may not be as wide as in Alberta, and that elaborate control equipment is more readily available so that machine operating-temperatures are more accurately controlled. It should also be pointed out that the trend for the larger Canadian plants is based on only six stations.

In Fig. 10 are plotted the anticipated fuel costs of several diesel oil and natural gas engines built by different manufactuers, based on the manufacturer's guaranteed minimum performance ratings and fuel oil at $.15 per gallon or natural gas at $.20 per Mcf (see Appendix No. 3b for cost computations). The envelope curves, as drawn, have very little meaning except to indicate the more nearly equal performances of the larger engines. Comparing these curves with those of actual consumption in Fig. 9, it appears that for the smaller machines the actual consumption is just within the limits guaranteed by the builders. However, in the case of the larger machines the guaranteed fuel rate is better than the actual fuel rate. The probable reason for this is that the guaranteed fuel rates apply only to new equipment, whereas in many of the plants considered the large engines are quite old and are now not at their initial efficiency. In general, the smaller engines, which are initially less expensive, are replaced before they reach a state of inefficient operation.

Besides diesel oil, two other types of fuel are available. Firstly, gasoline may be used, but the fuel costs will range from 50 to 100 mills per kwhr. this is, of course, prohibitive except for an isolated small installation set up by an individual to supply his own and perhaps his nearby neighbor's need. Secondly, natural gas may be used.

At the present time there are only a few plants in Alberta using natural gas. From a heat content consideration, diesel fuel at $0.15 per gallon (approximate current price) and Alberta natural gas at $.80 per Mcf are comparable. Hence, when available at less than $.40 per Mcf, as is the case at most points in Alberta where gas is presently available, the use of natural gas results in very low fuel costs.

In the future, as gas transmission lines are developed, it will be possible for most of the larger and some of the smaller stations to obtain gas. However, the costs of transmitting gas are such that small plants which are not located in areas served with gas will be unable to reap the benefits of this resource.

For those stations that may be able to obtain gas having 1,000 BTU per cu. ft. at a price of $.20 Mcf, fuel costs may be reduced to as low as 3.5 mills per kwhr. for the larger units (750 kw.) and to about 5 mills for the smaller units (100 kw.). These costs, which include the cost of pilot oil where used, are based on manufacturers' reports, and the standardized fuel costs of the three such plants considered in this study are consistent with them.

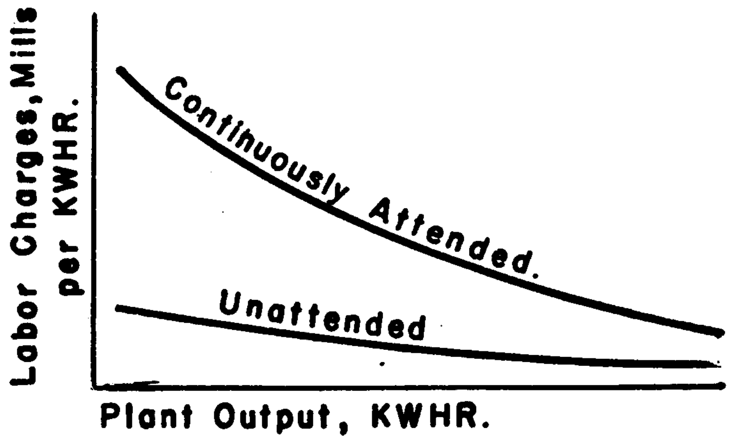
(b) Labor Costs

Fig. 11 shows the reported labor costs of Canadian and United States plants. (See Appendix No. 3c for data on labor costs). There is no simple straight line relationship between output and labor cost. For plants with an output of over 1 million kwhr. per year (approximately 375 kw. capacity) the envelope curves narrow into a fairly obvious pattern, but with plants under 1 million kwhr. the relationship is more difficult to determine.

With regard to attendance and labor, there are two ways in which a power plant can be run. The plant can be left unattended except for fuel handling, lubrication and maintenance which may, on the average, take one hour per day. If there are a number of machines it will be necessary to go to the plant at various times during the day to switch machines on and off as the load conditions vary. This work does not take long, and the small operators that were questioned agreed that not more than one hour per day of their time could be charged to production. Consequently, small diesel plants are usually operated in conjunction with some other business, and the labor charge becomes a nominal 2 to 3 mills per kwhr.

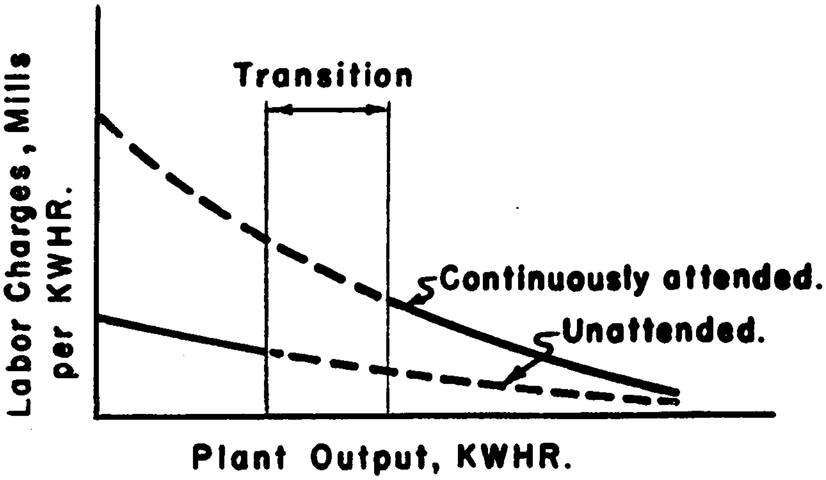
The other method of operating a diesel plant is to have the plant attended 24 hours a day. If the manager works one shift this requires a minimum of 1 manager and 3 other operators, otherwise it requires 1 manager and 4 operators. Such continuous attendance means a minimum annual charge of $9,700 (1 manager at $2500, four operators at $1800 each).

Representing graphically the two possibilities of a continuously attended or an unattended plant, we have the following:



For very small plants the cost of continuous attendance would be prohibitive, and obviously for large plants the value of the machinery is such that to leave the plant unattended would in the long run cause a serious increase in maintenance cost plus, of course, more interruptions in service through breakdowns. At some point between "large" and "small" it will be necessary to switch from the unattended plant to the continuously attended plant. Some transition is possible. For example, some small plants are continuously attended through two day-shifts but are locked up at night. Generally, however, there seems to be quite an abrupt break between plants that employ one operator and plants that employ five or more.

The transition from the unattended to continuously attended plants will result in a labor charge which, when represented graphically, will resemble the following:



The above diagram is of the same form as the preceding graph of reported labor costs.

The following schedule of labor charges has been drawn up on the basis of experience and interviews, and is plotted as the "Scheduled Curve" on Fig. 11.

Annual Output, kwhr.	Approx. peak load, kw.	Labor charged to generation	Labor cost in $ (total)	Labor cost, mills/kwhr.
100,000	25	1 hr./day at $1/hr.	365	3.65
200,000	50	2 hr./day at $1/hr.	730	2.7
800,000	200	1-1/2 man/day at $2000/yr.	3,000	3.75
1,500,000	375	1 manager at $2500/yr., 4 ops. $1800/yr.	9,700	6.5
3,000,000	750	1 manager at $3000/yr., 5 ops. $2100/yr.	13,500	4.5
7,000,000	1,750	1 manager at $3600/yr., 6 ops. $2100/yr.	16,200	2.32

This schedule indicates a much lower labor charge than those reported. However, the reported labor costs show the small plants at a considerable disadvantage because, generally, the full wage of their single operator is shown as a charge to production. This results in production being loaded with the expenses of meter reading, collection, transmission maintenance, small construction, commercial relations, etc. In large plants this work is done by maintenance and construction crews, and by commercial and advertising departments, and does not appear as production expense. Consequently the graph does not provide a valid basis for comparing the production labor expenses of small and large diesel plants.

(c) Lubrication Costs

The lubricating costs in mills per kwhr. of the Canadian plants considered, are plotted in Fig. 12 against the kwhr. output. (See Appendix No. 3d for data on lubrication costs.) Again the trend line indicates a higher cost per unit of output for the small plants. Because of two factors this variation is as might be expected. Firstly, the running plant capacity factor in larger stations is generally higher, while secondly, the lubricating system capacities per kw. bear an inverse relationship to the size of the units. Since the quantity of lubricating oil used is dependent on the operating time and not on the output, both of these factors tend to give lower oil consumption per unit output for the larger engines.

There is considerable scattering of the points away from the trend line in Fig. 12. Such differences in cost can be attributed to variations in the grade of oil used, variations in the cost of the same grade of oil, the age and condition of the equipment, and the number of running hours between changes. The latter factor is relatively more important in the case of the small plants where the operators are not as "schedule-minded" nor as well-equipped to adhere to rigorous schedules. Also, some larger plants do not change oil but simply add oil to replace that which is burned. The age and condition of the machine may be important, but if a plant is reasonably well maintained the oil actually consumed or burned is a relatively small part of the oil used in oil changes.

In determining the costs for American plants, as shown on the graph, the price of oil has been standardized at $0.60 per gallon. This standardization does not, however, eliminate variations due to the other factors mentioned above nor does it permit closer comparison with Canadian plants, since the unit price of oil was not known for many Canadian plants but was definitely more than $0.60 per gallon in most cases.

In addition to the price difference mentioned above, another possible reason for the lower cost of lubrication in the United States is that reclaiming equipment may be in wider use there than in Canada. The only plant within our study which reclaimed oil thereby cut new lubrication oil costs to one-third. In this calculation the costs of reclaiming the used oil were not known and could not be considered, but from figures supplied by one reclaiming plant such costs amount to about $.30 per gallon. Thus, on a bsis of $0.60 per gallon for oil, the saving would be about 33%.

From the graph it appears that lubrication costs vary from 1.5 to 2.5 mills per kwhr. for small plants down to about 0.5 mill per kwhr. for larger installations. A charge of 0.25 mill seems to be the minimum when using oil at $0.60 per gallon.

(d) Maintenance Costs

The envelope curves of Fig. 13 show the range of maintenance costs for Canadian plants in relation to net generation. (See Appendix No. 3e for data on maintenance costs). It is apparent that for the smaller plants the range of costs is wider, and the average somewhat higher, than for the larger stations. This might be expected since small plants with only one or two engines have widely varying annual charges. During a year in which a machine is given a major overhaul, maintenance charges will be high and may constitute a relatively large portion of that year's total costs. On the other hand, there may not be an appreciable maintenance charge for a number of years. In the case of the larger plants, the greater number of units contribute to a diversity of maintenance and it is possible to retain a full-time maintenance staff which, by means of scheduling and preventive checks, is able to decrease the over-all maintenance costs.

As may be seen on the graph, the American plant maintenance charges are lower than those for the Canadian plants. This is explained in part by the lower cost of parts and materials in the United States. Further, it is doubtful whether the United States plants are as true a cross section as the Canadian plants in that they may be weighted toward the more efficient and newer plants.

The trend line approximates the average maintenance cost for the 28 Canadian plants giving only partial weight to plant "A". The charge for plant "A" is exceptional and probably excessive due to a major overhaul and conversion, the cost of which was included in the reported costs.

(e) Supplies and Miscellaneous Expenses

The reported charges for supplies and miscellaneous expenses are shown plotted on Fig. 14. (See Appendix No. 3f for data on supplies and miscellaneous expenses.) The envelope curves, as drawn, indicate quite a wide range of costs for the smaller stations and a narrower range and generally lower cost as the plant output becomes larger. Some of the reasons for the wide variation in costs are as follows:

(1) In small plants in particular, but in all plants to some degree, the accounting procedures are not standard and many expenses associated perhaps

with maintenance (such as rags and cleaning fluid) may be charged to maintenance in some cases and to supplies, etc., in others.

(2) Such items as fuel and lubricating oil for a small engine-driven air compressor may never be separated from the total fuel charge even though, in reality, they are a miscellaneous expense.

(3) The cost of supplies used and expenses incurred in operating the cooling water systems may be vastly different in two plants. One plant may have radiator cooled units while the other may have a circulating water system with a cooling tank, the make-up water for which must be treated to prevent engine scaling, etc.

(4) Many items which would be charged to administration and commercial accounts in the case of small plants are charged to miscellaneous accounts in a larger organization.

(5) Other charges to this account which will vary considerably from one plant to the next are those covering office supplies and expense, advertising, part-time labor, commercial expenses, donations, taxes, etc.

(f) <u>Depreciation and interest on Investment</u>

One of the most difficult problems in costing diesel generation is encountered in determining the charges attributable to depreciation and return on capital. There were only a few diesel plants for which detailed information was available which had been constructed entirely from new equipment. It was, therefore, most difficult to determine an investment cost for different-sized plants. (See Appendix No. 3g for data on investment costs).

In Fig. 15 the costs per kw. of certain high speed diesels are plotted against the kw. ratings of the machines. These units have a per kw. cost ranging from $300 for the very small units (20 kw.) to around

$150 for the larger machines (80-90 kw.). This graph does not, however, accurately indicate the effect of size. Larger plants do not, as a rule, use high-speed engines but rather the more expensive low-speed units. This condition tends to level off the initial costs probably well above the $200 per kw. mark.

In Fig. 16 are shown the 1948 replacement values of 10 plants. To obtain these values historic cost was taken as a base, and price indices were applied to bring them to the 1948 price level. Some of these plants may include second-hand equipment, but the four plants represented by the circled dots do not. (See Appendix No. 3h for data on replacement values.)

There is no indication in the plants studied that the cost per kw. does in fact decrease as the capacity increases. Although the machine cost may drop slightly, the larger plants tend to use more expensive machines, have more auxiliary equipment and, on the whole, are housed in better buildings. For these reasons it is assumed that the cost per kw. for diesel installations is $300 per kw. regardless of size. However, this conclusion does not mean that charges for depreciation and return on capital, per kwhr., will be uniform for all generating stations. The larger plants use more expensive machines that have a considerably longer life expectancy and, further, such plants generally have higher use factors.

Any line drawn between large and small plants is arbitrary, but the following assumptions are fairly close to reality. Two plants are considered, having capacities of 100 kw. and 500 kw. The life expectancies are taken as 15 years and 25 years, the use factors as 25% and 35%, respectively. Depreciation is allowed at a constant rate based on the expected life of the plant, while the interest charged provides a 6% return. The above assumptions result in the following costs:

	Small Plant (100 kw.), mills per kwhr.	Large Plant (500 kw.), mills per kwhr.
Interest on investment (based on 6% return)	8.2	5.9
Depreciation (based on expected plant life)...	9.1	3.9
Total	17.3	9.8

These values are shown in Fig. 17 with the trend line covering a wider range of plants.

Summary of the Costs of Diesel Generation

A summary of the generating costs of diesel installations of different sizes is as follows: (These readings are taken from the trend lines of the foregoing graphs and do not represent the costs of any particular plant).

Plant class	A	B	C	D
Capacity, kw.	40	75	300	2500
Annual net output, kwhr.	0.1 million	0.2 million	1 million	10 million
Approx. population served	200-500	400-800	1300-2500	10,000
Cost in mills per kwhr. for:				
Fuel	21.0	17.5	12.5	10.5
Labor	3.5 *	2.5 *	5.0 **	2.0 **
Lubrication	3.0	2.0	0.5	0.5
Maintenance	6.5	5.5	2.5	1.5
Supplies & misc. expenses	2.0	1.7	0.9	0.3
Total operating expenses	36.0	29.2	21.4	14.8
Interest and depreciation (based on 6% return and expected plant life).	20.0	17.0	10.5	8.0
Total cost, mills per kwhr.	56.0	46.2	31.9	22.8

* unattended plants
** continuously attended plants

Cost of Steam Generation

In this study of steam generation, the number of plants for which information has been available is relatively small. The findings of this section have been based on the records of 20 plants. Of these only four are in Alberta, another five are Canadian plants operating under practically the same circumstances, while the remainder are located in the United States. The records of the American plants are for 1947, from "Statistics of Electric Utilities in the United States - 1947" published by the U.S. Federal Power Commission. Since the detailed operating statements of these American plants were not given, they serve mainly as a general check on the Canadian cost figure.

In order to compare the production costs of various plants on an equal basis, it is necessary to consider the relative amount that the equipment of each plant is used. The use factor of a plant as previously defined, is the ratio, expressed as a per cent, between the kwhr. actually generated and the kwhr. which would have been generated if the plant had been run continuously at its rated load. This factor is usually found to be between 35 and 45%. Plants which have low use factors are generally in one of three situations:

(a) they may be small plants serving limited networks with a poor diversity of load,

(b) they may have a considerable amount of obsolete equipment which seldom run (perhaps only at times of heavy peak demand or in emergency situations), or

(c) they may serve isolated networks on which continuity of service is essential; hence extensive reserve capacity must be provided.

Conversely plants with high use factors are those serving large interconnected networks having highly diverse loads. The interconnections between grids tend to lower the reserve requirements of all plants supplying power to that system.

The fuel charge per kwhr. is one of the elements of generation cost which varies most. To eliminate fluctuations attributed to variations in the price of fuel, and thus be able to investigate the over-all thermal efficiency, fuel prices for the Canadian plants have been reduced to a standard charge based on a cost of $0.15 per million net BTU of energy. It was not possible, however, to standardize the fuel costs of the American plants in this way because their unit fuel costs were not known.

Production Costs

It is possible now, with the above points in mind, to consider the production expense of the various plants. The total cost is considered to be made up of six elements as follows:

(a) Fuel,

(b) Labor,

(c) Maintenance,

(d) Supplies and miscellaneous expenses (including water),

(e) Interest on invested capital,

(f) Depreciation.

(a) Fuel Costs

The graph of standard fuel costs per kwhr. is shown on Fig. 18. (See Appendix No. 4a for details of cost standardization).

As explained above, the standard price of fuel assumed for use in Canadian plants is $0.15 per million net BTU. This charge corresponds to $2.40 per ton for Drumheller slack at 8,000 BTU per pound, or $0.13 per

Mcf for natural gas from the Viking-Kinsella field, or \$0.028 per gallon for bunker "C" oil from the Edmonton refinery.

The 1948 prices of these fuels were as follows:

Drumheller coal delivered to plant in Drumheller - \$1.55 per ton.

Gas delivered in Edmonton - \$0.115 to \$0.12 per Mcf.

Oil at Edmonton refinery - \$0.0675 per gallon.

Fig. 18 shows that as plants decrease in size from an output of about 220 million kwhr. (50,000 kw. capacity), the fuel costs increase from a value of 2.5 mills to 3.5 mills for a plant producing 27 million kwhr. (7,500 kw. capacity), to as high as 6 mills or more for plants producing 9 million kwhr. (2,500 kw. capacity or less). This transition is, of course, due to the inability of the smaller plants to use elaborate and efficient air preheaters, other heat exchangers, or high pressure and high temperature equipment. The cost of such equipment for a small plant would be very high.

(b) Labor Costs

The relation between labor cost per kwhr. and net generation is shown in Fig. 19. (See Appendix No. 4b for data on labor costs). It is apparent from a study of the relationship that labor is one of the factors which limits the use of steam generation to relatively large installations. For large plants (100,000 kw. capacity with 440 million kwhr. output,) a labor charge as low as 0.5 of a mill per kwhr. is probable. Even for plants generating 18 million kwhr. (5000 kw. capacity), the charge will not likely exceed 2 mills per kwhr. However, at lower capacities, the cost rises quite sharply and becomes excessive for plants producing less than 12 million kwhr. (3,000 kw. capacity).

In the case of the plant showing a labor charge of 5.87 mills per kwhr., a heating load is supplied by the exhaust steam. The labor charge for this plant is somewhat higher than it would be without the heating load, hence its exclusion from the envelope curves.

(c) Maintenance Costs

Maintenance charges are plotted in Fig. 20, but no attempt has been made to draw a continuous curve that could be applied to all plants. (See Appendix No. 4c for data on maintenance costs). In the case of smaller plants, maintenance is a very variable item. In a year during which one of the units is given a major overhaul, the maintenance charge will appear very high. Conversely, with no breakdown or major repair item, maintenance will be unusually low. For large plants, with more units, the distribution of maintenance charges over the years becomes more uniform. Since this is so, the larger plants usually retain a full-time maintenance crew who, by following a routine preventive schedule, reduce the cost of repairs and further help to make this charge uniform over the year.

This explains in part the wide spread in maintenance charges of plants with outputs of less than 40 million kwhr. (9,000 kw. capacity) as compared with larger plants having outputs of over 80 million kwhr. (18,000 kw. capacity). For the latter class of plants, not only is the spread less but the average is somewhat lower.

Another factor which affects the maintenance costs is the average age of the equipment. Maintenance on a machine follows an asymmetrical cyclic pattern which increases in magnitude with the machine's age. A plant which has been constructed as a complete unit will not have the uniform charge which will exist in a plant having an equipment turnover, with machines of varying ages in use.

The graph of maintenance indicates that for plants producing more than 80 million kwhr. (over 20,000 kw. capacity), an average maintenance charge of 0.6 mills per kwhr. is reasonable, while for installations generating less than 40 million kwhr. (9,000 kw. capacity or less) the average is

1.1 mills per kwhr. The above costs are equivalent to charges of $2.50 per kw. capacity per year for the larger plants and $5.00 per kw. capacity for the smaller plants.

(d) Supplies and Miscellaneous Expenses

The graph of the cost of supplies and miscellaneous expenses, including supply of boiler and condensing water, is shown in Fig. 21. (See Appendix No. 4d for data on supplies and miscellaneous expenses). For plants producing 12 million kwhr. or less (with capacities of 3,000 kw. and under), the cost is from 1.25 to 1.50 mills per kwhr. which is quite high. As plant capacity increases, the cost drops rapidly until a plant with an output of 40 million kwhr. (9,000 kw. capacity) has a charge of 0.25 mills per kwhr. For larger plants the cost remains nearly constant, with a slight tapering off such that for very large plants (440 million kwhr. output and 100,000 kw. capacity) the charge may drop to as low as 0.10 mill per kwhr.

On the above-mentioned graph there are three definite exceptions to this trend. Two of these are municipal plants in which the condensing water is pumped to the town water supply, and the third supplies a heating load from which there is no condensate return. These circumstances result in considerable variation from the normal water expense. Since water is the principal item in this cost, the shape of the curve would indicate that plants generating more than 45,000 kwhr. (greater than 10,000 kw. capacity) can use the optimum size of pumping units and that their water cost per unit generated is practically independent of both capacity and energy output.

(e) Interest on Invested Capital

Fig. 22 deals with the effect of size on the charge for "return on capital". Because this expense is closely related to the amount of the investment, the figure includes a graph showing the investment per kw. of capacity for each plant, in addition to the graph showing the interest charges for the various plants. (See Appendix No. 4e for data on interest charges).

It is of interest to note that there is no marked correlation between capacity of plant and investment per kw. Therefore, at least within the range considered, plant capacity is not a limiting factor. However, it is very likely that for smaller plants (less than 3,000 kw. capacity), the capital charge per kw. would rise quite sharply.

Although there is no correlation between the investment per kw. of capacity and the output, there is a slight correlation between the interest charge per kwhr. and the capacity. This condition is explained by the higher use factor of the larger plants. Because of their capacities, these plants supply larger areas and more diversified loads than do the smaller plants. The investment charge for plant "A" appears to be excessive. The reason for this is that the plant has a very low use factor, a condition caused not by a poor load factor but rather by some obsolete machinery not in use now. Plants "B" and "C" are in similar situations but to a lesser degree.

The conclusion reached from this graph is that a plant with an output greater than 40 million kwhr. (having a capacity of 9,000 kw. or more) will probably have an interest charge or return on capital charge of about 1.6 mills per kwhr. Plants with smaller outputs, of 12 million kwhr. or less (3,000 kw. or less capacity), will have an increased capital charge approaching 3.5 mills per kwhr. This increase is not so much by reason of their greater expense per kw. of installed capacity but rather by reason of the lower plant use factor which means that each kw. capacity produces fewer kwhr. and therefore each kwhr. must bear a greater portion of the capital expense. The above-mentioned costs are based on the charging of interest to give a 6% return.

(f) Depreciation

In Fig. 23 the per unit depreciation charge and investment per kw. are compared with the output of the installation considered, and the conclusion reached is about the same as that for the capital charge. (See Appendix No. 4f for data on depreciation charges). The depreciation was computed on the assumption of a composite life of plant of 30 years; that is, a constant rate of depreciation of 3-1/3% (slightly higher than 3% normally allowed by the income tax department) was allowed. Hence, a higher use factor for a particular plant means a lower charge per unit of output for that plant. For plants with outputs greater than 40 million kwhr. (9,000 kw. capacity or more) the depreciation charge will be about 0.7 mill per kwhr., while for plants with outputs between 12 and 40 million kwhr. (3,000 to 9,000 kw. capacity) the charge may be as high as 1.75 mills per kwhr.

As mentioned in (e) above, plant "A" has the lowest plant use factor of all those considered, and plants "B" and "C" also have relatively low use factors. Because these plants represent special cases, and since some of the plant equipment in each case violates the used and useful principal, these three points were not given much weight when considering the position of the trend line.

Summary of the Costs of Steam Generation

The following table sets up in summary form the costs that might reasonably be expected from three different-sized plants paying $0.15 per million BTU for their fuel. These costs are not those of particular plants but rather average costs determined from the trend lines.

Plant class	A	B	C
Capacity, kw.	3,000	9,000	50,000
Annual net output, kwhr.	12 million	40 million	220 million
Approx. population served	10,000	25,000	150,000
Cost in mills per kwhr. for:			
Fuel (based on $0.15 per million BTU)	5.0	3.0	2.5
Labor	2.7	1.2	0.7
Maintenance	1.2	1.2	0.6
Supplies and misc. expenses	1.1	0.2	0.2
Total operating expenses	10.0	5.6	4.0
Interest on investment (based on 6% return)	2.3	1.6	1.6
Depreciation (based on rate of 3-1/3%)	1.4	0.7	0.7
Total cost, mills per kwhr.	13.7	7.9	6.3

Cost of Hydro Generation

Hydro plants supply approximately 60% of the electrical energy used in Alberta. As with steam, the number of plants available for study is small. The operating experience of five Alberta stations has been supplemented and substantiated by the summary records of 16 United States companies, each of which operates one or more hydro installations. These records are for 1947 as published in the U.S. Federal Power Commission Report "Statistics of Electric Utilities in the United States - 1947".

The total cost of hydro generation varies considerably and, as may be seen in Fig. 24, there is only a slight correlation between cost and size. (See Appendix No. 5f for data on costs). The dependence of certain elements of cost on station capacity and output tends to give a slightly lower average cost for the larger installations.

The item of cost which probably has the widest range of variation is the interest charge on invested capital. The reasons for this wide variation are twofold. Firstly, the capital investment per kw. of installed capacity is not at all constant due to the vastly different amounts of construction and the varying complexity of such construction for each particular installation. Secondly, the use factors of hydro installations are spread over a much broader range than exists, for example, in the case of steam plants. This is at least partly due to yearly variations in the water flow conditions at each plant. In a situation such as exists in the main power development in Alberta, which is a continuing project, it seems probable that the effect of the use factor may be reduced. As the development becomes more nearly complete the increased control of the flow will result in more efficient use of the water, hence a higher and more consistent annual use factor may be realized.

Production Costs

The production costs of hydro plants may be divided as follows:

(a) Labor,

(b) Maintenance,

(c) Supplies and Expenses,

(d) Interest on Investment,

(e) Depreciation.

(a) Labor Costs

The labor costs reported by the United States plants are shown in Fig. 25, and indicate a labor charge of from 0.5 to 2 mills per kwhr. for plants ofcapacities comparable to those in Alberta. (See Appendix No. 5a for data on labor costs). For very small plants with less than 1,000 kw. installed capacity the charge becomes widely varying and most unpredictable. Where remote and automatic control can be used the labor charge may be reduced to a minimum of about 0.3 mill per kwhr., which also appears to be the minimum for very large plants. However, where small plants must be continuously attended, charges may rise to 4 or 5 mills per kwhr. and, in certain exceptional cases, even higher. While the labor costs for Alberta plants are not available, from the over-all costs reported it is estimated that the charge would be about 0.35 mill per kwhr.

(b) Maintenance Costs

Maintenance charges are shown plotted in Fig. 26. (See Appendix No. 5b for data on maintenance costs). An average charge of 0.4 mill per kwhr. is indicated although this may not be too representative. In many hydro installations, particularly the smaller ones, the capacity is all within a single unit. Hence maintenance becomes irregular, with a heavy charge one year and relatively light charges for several years following.

the plants which show a very high charge (4 mills or more) probably were carrying out major repairs in 1947, the year reported.

(c) Supplies and Miscellaneous Expenses

This also is a highly variable item, as shown by Fig. 27. (See Appendix No. 5c for data on supplies and miscellaneous expenses). No trend can be definitely determined but it is obvious that the average charge is small, generally less than 0.25 mill per kwhr. The cost becomes larger and more erratic in smaller plants probably because some such plants are remotely located and transportation and communication charges are high.

(d) Interest on Investment

This has been computed on the basis of mills per kwhr. and is shown plotted in Fig. 28. (See Appendix No. 5d for data on interest charges). As previously mentioned, this charge generally is the largest single element of the total production cost and varies widely from one plant to another. From the graph it would appear that the normal range of cost is from 1 to 5 mills per kwhr. without regard to plant capacity. The specific charges on the Alberta plants are, as shown, in the lower portion of the span of variation and range from 1 mill (minimum) to 2.1 mills (maximum) per kwhr.

(e) Depreciation

This charge is normally very closely linked with the investment charge and in this case in which the costs have been standardized, they are very nearly directly proportional. On the basis of a constant rate of depreciation on the American plants, as outlined below, a reasonable rate seems to be 0.3 to 1.5 mills per kwhr. as shown by the graph in Fig. 29. (See Appendix No. 5e for data on depreciation costs). Again the Alberta plants have relatively low charges which range from 0.33 to 0.75 mill per kwhr. This charge may be somewhat higher than it should be for the Alberta plants, since it is based on 2% depreciation per year of the investment in the complete production plant which includes all dams, spillways, flumes, penstocks, buildings and equipment associated with the plants. Such an allowance gives, in general, a higher cost than is obtained by depreciating specific items at rates more suitable to their normal useful and expected life.

The breakdown of depreciation rates applied to the American plants is as follows:

(1) On structures and improvements such as roads, buildings, etc. - 2% allowed.

(2) On reservoirs, dams and waterways - 1% allowed.

(3) On equipment such as turbines, generators, pumps, etc. - 4% allowed.

(4) On land and land rights - no depreciation is allowed.

These rates are the constant percentages allowed each year. They are based on a consideration of the expected life of the different types of assets.

The amount allowed under (2) above is actually a nominal amount which compromises two different opinions on the matter. On the one hand, items of that nature are considered to be completely non-depreciable (which they are for all practical purposes, if properly constructed). On the other hand, they are considered to be depreciable in that they may be useful only for the duration of the water-rights lease (which may be 50 or 99 years) or for some limited period due to a natural phenomenon, such as an unexpected recession of glaciers, which might render them useless. Further, it is argued that it should be possible, through write-offs, eventually to return such capital to the investors. Hence the 1% allowed for this depreciation is, to some extent, a compromise between the two lines of opinion.

Summary of the Costs of Hydro Generation

Shown below is a table indicating the average production charges of United States plants as well as those which are representative of the costs of existing installations in Alberta.

	Plants	
Cost in mills per kwhr. for:	United States	Alberta
Labor	1.3	Breakdown
Maintenance	0.4	not
Supplies and expenses	0.2	available
Total operating expenses	1.9	0.5
Interest on investment	3.5	1.6
Depreciation	0.9	0.5
Total cost, mills per kwhr.	6.3	2.6
Approximate rate of investment	$230 per kw. capacity	$150 per kw. capacity

The values shown above for the United States plants are for privately-owned stations which reported to the Federal Power Commission. The costs compare quite closely to figures quoted by the Power Authority of the State of New York in its Seventh Annual Report (1937), at the time of a controversy between private steam generation and government hydro production.

It would seem evident, therefore, that the hydro power development in Alberta to date has been at relatively low cost. Up to the present, about 32% of the estimated ultimate capacity of 500,000 H.P. (320,000 kw.) of the Bow River has been or is being developed. Further development of the presently partially-developed Bow River system will no doubt prove to be slightly more costly because of higher construction charges and the increased complexity of development problems. However, the cost of power generated will be held down by the increased control and more effective use of stream flow, hence the over-all cost of hydro generation will still be relatively low.

Hydro electric power at a cost such as is indicated for Alberta appears to be extremely well-suited to the economical co-ordination of steam power and hydro power in such a way as to reduce the cost of steam generation and to make the best use of the water available. Such co-ordination may become even more desirable than it has been in the past. In fact, it may even become essential should the water supply become a problem for the hydro plants.

In addition to the above-mentioned production charges, there is another element of cost of hydro supply which normally is not present when the generation is by steam. This charge is the cost of transmission from the generation site to the load centre. In general, steam plants are situated very close to the load centre and no transmission is required. A distribution system is, of course, common to both.

Summarizing the reported costs of transmission for the 1947 operations of the 13 American companies, the over-all average is 1.84 mills per kwhr. (See Appendix 6 for data on, and computation of, transmission charges). This is in agreement with a schedule of costs published by the Power Authority of the State of New York in its Seventh Annual Report (1937), which is as follows:

Distance, miles	200	100	50
Transmission cost, mills per kwhr.	1.89	1.43	1.18

Similarly, the over-all average cost indicated by the operation of Alberta lines is 2.6 mills per kwhr. Since the average transmission distance in Alberta is 100 miles, or less, this cost is much higher than the corresponding cost in the United States. This might be expected, however, in view of the more expensive transportation and communication facilities and the lower over-all number of users per unit length of line associated with the Alberta system. The estimated transmission charges for various distances in Alberta are as follows:

Distance, miles	250	200	150	100	50
Transmission cost, mills per kwhr.	3.85	3.45	3.05	2.60	2.15

The cost of installing transmission systems is highly variable. However, from the accounts of American companies, as reported in the Federal Power Commission publications for system voltages of from 11,000 to 132,000 volts and line lengths of 200 to 400 miles, the average cost has been $4,000 per mile which includes transmission substation installations. For low-voltage installations (11,000 volts) charges of about $1,500 might be expected, whereas at the other end of the scale (132,000 volts and higher) costs of $10,000 to $15,000 per mile are encountered.

PART C

Combined Heating and Power Generating Systems

The previous sections of this report have dealt only with plants whose principal, if not sole purpose, is to generate electrical power. There are, however, throughout Alberta several institutional systems for which central heating units are desirable. These units, usually operating on steam, require quite an extensive steam generating plant. In such cases it is very often economical, and sometimes necessary because of isolation, to combine the heating with the generation of electrical power.

In general, in a system such as that mentioned above, the usual procedure is to utilize high pressure steam as the prime mover of the electrical generating plants, and then to pass the exhaust from this unit into the heating system. Of course, the diversity and variation of load on the two systems requires that at times some high pressure steam be drawn for use in the heating system, while at other times the exhaust steam from the engines is more than is required for heating and, hence, must be exhausted to the atmosphere. Under the later conditions the plant operation will definitely be uneconomical. However, in the normal operation of a plant, since the lighting and heating loads coincide to a marked degree, the periods of such uneconomical operating conditions are short and, as suggested, the operation as a whole is economical.

In a combined plant such as described above, the division of labor costs between the heating and electrical generation systems presents a problem in that the systems are operated as one unit by a different class of labor than either would utilize in separate operation. In general, when the two systems are combined a higher class of operators is required. This involves higher wages for the operating superintendent and boiler room attendants than would be required in a straight heating plant, as well as salaries for the engine room operators. Therefore, it seems logical that all of this increased expense should be included in the cost of the electrical power even though in a particular situation, some of it is actually utilized in the operation of the heating system. Consequently, the division is difficult, but in the following example a division is made which is in accord with this contention.

Summary of Costs

The following costs are those obtained from the operating records of a combined heating and generating plant operating at a typical institution:

Installed capacity, kw.	800
Annual output, kwhr.	1,929,220
Plant use factor, %	27.5
Cost in mills per kwhr. for:	
Direct labor cost	5.0
Steam cost (including fuel, labor, steam system maintenance, administration, etc.)	2.4
Other direct generation costs (including general maintenance, water, supplies, administration, etc.)	0.6
Total operating expenses	8.0
Investment interest	2.6
Depreciation	1.4
Total cost, mills per kwhr.	12.0

The cost of 12.0 mills per kwhr. is obtained using the best possible estimates of capital involved in the properties concerned. However, comparing the interest and depreciation charges with those obtained as average in the course of this study, it will be noted that they seem to be somewhat low (compare with Figs. 22 and 23 which show an interest charge of 4.0 mills per kwhr. and a depreciation charge of 1.8 mills per kwhr. for a capacity of 800 kw.). Hence, it would seem advisable to state that the 12.0 mills per kwhr. represents the lower limit of a range from 12.0 to 14.0 mills per kwhr. as the cost of power generated by such a plant.

Comparing this cost with the total cost shown for steam plants of this capacity in Part B of this report, it will be observed that combining the operations of heating and generation results in a reasonably low cost of generation. Such a cost - 12 to 14 mills per kwhr. - would not be possible in an ordinary power generating plant of this size.

PART D

Types of Fuels and their Relative Costs

In Part B of this report, which deals with the cost of generation by steam-driven equipment, the costs of all plants considered have been adjusted so that all fuel costs are based on the standard charge of $0.15 per million BTU net. This treatment eliminates, as far as possible, differences in the fuel costs due to such factors as different moisture contents. It does not, however, eliminate variations in fuel costs that are due to the different characteristics of fuel-burning equipment in individual plants or variations attributable to the different burning qualities and losses which are associated with different types of fuel. The table which follows indicates the standard prices of various fuels, based on $0.15 per million BTU net, together with the current prices being paid by power plants throughout Alberta and other parts of western Canada.

$0.15 per million net BTU is equivalent to a standard price for:		Average 1948 or 1949 price
Edmonton area slack at	$2.36/ton	$2.80/ton at Edmonton
Drumheller area slack at	$2.40/ton	$1.55/ton at Drumheller
		$4.25/ton at Saskatoon
		$4.58/ton at Prince Albert
		$4.35/ton at North Battleford
Lethbridge area slack at	$2.90/ton	$2.71/ton at Lethbridge
Crowsnest area slack at	$3.36/ton	$5.67/ton at Crowsnest
Wabamun area slack at	$2.52/ton	----------------------
Viking-Kinsella gas at	13 ¢ Mcf	12.5¢ to 13.0¢ Mcf
Vermilion gas at	12.0¢ Mcf	----------------------
Bow Island area gas at	13.9¢ Mcf	----------------------
Medicine Hat gas (city-owned) at	12.4¢ Mcf	2.43¢ Mcf
Peace River Area gas at	13.1¢ Mcf (est.)	----------------------
Unity area gas at	12.1¢ Mcf (est.)	12.9¢ Mcf
Athabasca area gas at	13.7¢ Mcf	34¢ Mcf
Bunker 'C' oil at	2.7¢/gal.	6.75¢/gal.
Diesel fuel oil (40° API gravity) at	2.4¢/gal.	16¢/gal.
Propane (liquefied) at	1.5¢/gal.	16¢/gal.
Butane (liquefied) at	1.5¢/gal.	16¢/gal.

The effects of variation of prices, from the standard price, of the basic fuels used in steam generating stations are shown in Fig. 30.

This indicates the fuel cost in mills per kwhr. (for different delivered prices of fuel) which could be expected for plants having capacities of 1,000 to 25,000 kw. or more. At this latter plant capacity, fuel-burning efficiencies tend to level off and show no improvement with further increase in size. Similarly, Fig. 31 shows the variation in cost per kw. due to different prices of diesel fuel oil for plants with capacities of 50 to 3,000 kw. Again it will be noted that plants of larger capacities show very little improvement in fuel performances over that of a 3,000 kw. plant.

In comparing the economics of various types of fuel, many factors besides the unit costs of the fuel must be considered. For a new plant the relative costs of the fuel handling and burning equipment, provision of storage capacity, etc., must all be considered. Also, the possibilities of fuel supply failures, and the short term and long term effects of such failures, must be considered. Further, the amount and degree of skill of the labor required for the various types of installation and the resultant cost of this are important considerations.

For the situation in which a change in the type of fuel is contemplated, probably the greatest single consideration is the saving in the cost of fuel. In general, the cost of conversion from coal to natural gas or bunker "C" oil is not excessive since the conversion can usually be carried out at the time of a major overhaul. Conversion to coal from some other fuel might not be practical and, generally, would be more expensive because of the necessary stoker and ash handling equipment which would probably be required. The saving in labor, resulting from a change from coal to gas or oil, has not been found to be nearly as great as might be expected, particularly in the early stages of the changeover. Operators have found, in general, that the estimates on labor savings rarely materialize because the staff adjustments involved are often affected by local or outside policy pressures.

It is not the purpose of this report to forecast the future of the various types of fuel supply, but some observations regarding the over-all situation seem appropriate. Firstly, the tremendous expansion of the petroleum and natural gas industry in Alberta is making available large quantities of natural gas and fuel oils. As transmission lines and networks develop and refining capacity is increased, large and relatively less expensive supplies of these products will be available at many points at which they are now either unavailable or, if available, are very expensive. There are also developments in coal mining and coal burning techniques which may result in the effective utilization of some of Alberta's presently untouched coal deposits, and of the waste coal production of existing mines which might otherwise lack markets, in the generation of power. Preliminary cost estimates on the possible development of two such possibilities are outlined and discussed in Appendix No. 8.

It has not been possible to obtain information on large gas turbine operation since these units are still in the experimental stages. However, in all probability commercial units will be available within a few years, and their operating costs may be very nearly the same as those of steam turbines.

PART E.

Conclusions

In considering the foregoing data it must be remembered that a local steam plant can be built up as the local load develops, whereas a bulk supply from a hydro station located at a distance may mean the incurring of the major portion of the capital investment before the load can be built up. Thus, the investment charges during the initial stages of development might result in an entirely different cost ratio between the two situations.

It must also be kept in mind that the results include only the cost of generation, and transmission where necessary. They do not include a cost for distribution which will be practically the same, for any locality, whether the power is supplied by a local plant or from a remote station by transmission line.

The cost of distribution is difficult to predict since it depends on so many factors peculiar to the particular locality. These include such things as the density of load on the distribution system, the type of protection required for normal storm conditions, the type of construction and layout chosen, etc. However, it can be said that the total cost of distribution normally runs from 8 to 25 mills per kwhr., with an average value of about 14.5 mills per kwhr. This cost is made up of a charge for supervision, maintenance and operation of from 3.5 to 10.5 mills per kwhr., one on investment in the actual system of from 2.5 to 8.5 mills per kwhr., a charge of from 0.5 to 8.5 mills per kwhr. for line losses, and a commercial charge for sales promotion, billing, etc., of from 0.5 to 2.5 mills per kwhr. (See Appendix No. 7 for data on distribution costs).

The above range of costs was determined from the reported costs of companies whose principal, if not sole function, is the distribution of electric power in the United States, as published in the U.S. Federal Power Commission Report "Statistics of Electric Utilities in the United States - 1947". It is suggested that these costs may be slightly higher than costs for typical systems in Alberta communities, particularly if the Alberta systems are operated as public utilities. This difference is due to lower promotional costs and to the less extensive use of relatively elaborate control and protective equipment to assure continuity of service.

APPENDIX NO. 1

Use Factors of Alberta Generating Plant Equipment

for the Years 1927 to 1948

$$\text{Use factor, \%} = \frac{\text{actual kwhr. output}}{\text{potential kwhr. output}} \times 100$$

Statistics, tabulated below, taken from the Annual Reports on Central Electric Stations' Operations of the Transportation and Public Utilities Branch, Dominion Bureau of Statistics.

Year	Generator Capacity		Electrical energy generated, thousands of kwhr.	Use factor, %
	KVA	Computed kw. at 80% Power factor		
1927	86,716	69,400	156,066	25.7
1928	88,360	70,600	181,272	29.3
1929	107,661	86,100	205,351	27.3
1930	122,703	98,100	204,076	23.8
1931	124,007	99,400	205,082	23.6
1932	124,073	99,400	195,467	22.5
1933	124,110	99,400	182,963	21.0
1934	124,296	99,500	193,002	22.2
1935	124,281	99,500	208,054	23.9
1936	123,455	98,800	216,770	25.1
1937	122,491	98,000	222,755	26.0
1938	121,865	97,400	232,451	27.3
1939	140,129	112,000	251,806	25.6
1940	137,930	110,100	274,121	28.4
1941	137,099	109,700	319,743	33.3
1942	156,936	125,300	418,704	38.1
1943	162,797	130,000	512,985	45.0
1944	181,912	145,200	555,034	43.6
1945	186,321	149,000	566,744	43.4
1946	182,516	146,000	602,048	47.0

APPENDIX NO. 2

Consumption of Electrical Energy by Various Alberta Communities for the Year 1948

Statistics, tabulated below, taken from the files of the Provincial Statistician.

Community	Population	Electrical energy consumed, thousands of kwhr.
Cowley	94	48
Paradise Valley	200	27
Edgerton	273	78
Oyen	323	73
Consort	325	103
Spirit River	362	174
McMurray	400	154
Mountain Park	400	93
Cadomin	400	200
Empress	417	108
Luscar	500	146
Lac La Biche	642	120
Barrhead	739	427
Ponoka	1,468	1,169
Edson	1,571	552
Macleod	1,649	979
Blairmore	1,767	1,037
Coleman	1,809	585
Cardston	2,334	2,002
Red Deer	4,042	1,169
Medicine Hat	14,480	26,898
Lethbridge	17,000	18,947
Calgary	110,000	151,872
Edmonton	125,000	149,756

APPENDIX NO. 3a

Computation of Standard Fuel Costs from Reported

Fuel Consumptions of Various Diesel Generating Plants

(Based on diesel fuel oil price of $0.15 per gallon)

Diesel plant No.	Capacity, kw.	Electrical energy generated, kwhr.	Fuel oil consumed, gal.	Fuel cost, mills per kwhr.
1	74	85,000	7,260	12.8
2	130	91,870	13,648	22.4
3	80	98,442	12,223	18.7
4	90	95,301	18,300	28.8
5	---	106,700	14,700	20.8
6	---	110,050	15,520	21.1
7	90	119,053	15,333	19.2
8	90	130,000	18,090	20.8
9	159	223,381	24,628	16.1
10	---	230,460	26,900	17.4
11	165	236,974	27,768	17.6
12	---	280,860	28,450	15.1
13	170	423,154	35,659	12.6
14	293	440,300	42,900	14.6
15	260	453,568	49,972	16.5
16	---	592,500	53,700	13.6
17	700	784,209	63,705	12.2
18	565	829,278	79,866	14.4
19	---	912,600	76,100	12.5
20	692	956,120	66,709	10.5
21	520	1,289,394	126,921	14.7
22	600	1,346,349	98,939	11.0
23	---	2,202,700	220,500	15.0
24	1,664	2,397,467	188,837	11.8
25	880	2,932,766	231,112	11.8
26	1,380	3,102,726	251,376	12.2
27	1,838	6,025,926	485,412	12.1
28	3,138	7,053,500	538,039	11.5

APPENDIX NO. 3b

Computation of Anticipated Fuel Costs of Diesel Engines (Using Fuel Oil and/or Natural Gas) Built by Different Manufacturers

After consideration of the daily load curves (for a yearly period) of one plant which supplied a large urban load, and also of the effects of certain of the elements of the urban loads upon the daily load pattern, it has been assumed that the yearly use factor for a plant, ideally sized to supply an average small community, should be 42%. It is probable that during the summer months the use factor for a short period may be 35% or less, while during the winter months it may be 45% or more. However, a yearly average of 42% appears to be a most reasonable estimate. The ideal size of plant for most communities appears to be such that the average daily peak load during the winter months is approximately 80% of the plant capacity. This size of plant readily handles any normal peak load, and is probably capable of supplying some added load in the community. This, of course, depends entirely on the rate of growth of load within the community.

The following costs are based on diesel fuel oil having a specific gravity of .826 (39.5° A.P.I.) at $0.15 per gallon and natural gas having a heat content of 900 BTU per cubic foot at $0.20 per Mcf.

Approx. generator capacity, kw.	Type of fuel	Fuel consumption: lb./kwhr. (fuel oil) cu.ft./kwhr. (nat.gas) (at 42% use factor)	Standard fuel costs, mills per kwhr.	Annual plant output, kwhr. (at 42% use factor)
25	Nat. gas	41.7 cu.ft.	8.3	92,000
35	Diesel oil	1.24 lb.	22.5	129,000
2,525	" "	1.10 lb.	20.0	92,000
75	" "	0.97 lb.	7.6	275,000
65	" "	1.28 lb.	23.2	239,000
75	" "	0.80 lb.	14.5	275,000
85	Nat. gas with diesel pilot ignition	18.0 cu.ft.& .13 lb.	6.0	312,000
175	" " "	16.5 cu.ft.& 0.12 lb.	5.5	643,000
350	" " "	16.0 cu.ft.& 0.12 lb.	5.4	1,290,000
200	Diesel oil	0.73 lb.	13.3	735,000
195	" "	0.76 lb.	13.8	717,000
345	" "	0.69 lb.	12.5	1,270,000
390	" "	0.72 lb.	13.1	1,430,000
690	" "	0.65 lb.	11.8	2,540,000
550	" "	0.72 lb.	13.1	2,020,000
730	Nat. gas with diesel pilot ignition	11.9 cu.ft.& 0.08 lb.	3.9	2,680,000

APPENDIX NO. 3c

Reported Labor Costs of Various Diesel Generating Plants

Diesel plant No.	Capacity, kw.	Electrical energy generated, kwhr.	Reported labor costs dollars	Reported labor costs mills per kwhr.
1	74	85,000	365	4.1
2	130	91,870	1,513	16.5
3	80	98,442	1,023	10.4
4	90	95,301	1,490	15.6
5	--	106,700	2,460	23.2
6	--	110,050	3,440	31.1
7	90	119,053	1,274	10.7
8	90	130,000	-----	----
9	159	223,381	4,213	18.9
10	--	230,460	2,560	11.2
11	165	236,974	2,744	11.6
12	--	280,860	2,010	7.2
13	170	423,154	2,886	6.8
14	293	440,300	4,350	9.9
15	260	453,568	4,215	9.3
16	--	592,500	6,130	10.4
17	700	784,209	10,248	13.1
18	565	829,278	9,721	11.7
19	--	912,600	4,640	5.1
20	692	956,120	16,500	17.3
21	520	1,289,394	12,316	9.6
22	600	1,346,349	10,159	7.6
23	--	2,202,700	10,720	4.9
24	1,664	2,397,467	13,196	5.5
25	880	2,932,766	11,453	3.9
26	1,380	3,102,726	10,075	3.3
27	1,838	6,025,926	19,553	3.2
28	3,138	7,053,500	23,039	3.3

APPENDIX NO. 3d

Reported Lubrication Costs of Various Diesel Generating Plants

Diesel plant No.	Capacity, kw.	Electrical energy generated, kwhr.	Reported lubrication costs	
			dollars	mills per kwhr.
1	74	85,000	385	4.0
2	130	91,870	251	2.7
3	80	98,442	126	1.3
4	90	95,301	432	4.5
5	--	106,700	270	2.5
6	--	110,050	670	6.1
7	90	119,053	142	1.2
8	90	130,000	108	0.8
9	159	223,381	350	1.6
10	--	230,460	504	2.2
11	165	236,974	468	2.0
12	--	280,860	614	2.2
13	170	423,154	317	0.8
14	293	440,300	539	1.2
15	260	453,568	656	1.5
16	--	592,500	712	1.2
17	700	784,209	1,279	1.6
18	565	829,278	1,155	1.4
19	--	912,600	879	1.0
20	692	956,120	1,469	1.5
21	520	1,289,394	2,834	2.2
22	600	1,346,349	1,127	0.8
23	--	2,202,700	2,745	1.3
24	1,664	2,397,467	5,340	2.2
25	880	2,932,766	1,551	0.5
26	1,380	3,102,726	2,055	0.7
27	1,838	6,025,926	2,649	0.4
28	3,138	7,053,500	7,764	1.1

APPENDIX NO. 3e

Reported Maintenance Costs of Various Diesel Generating Plants

Diesel plant No.	Capacity, kw.	Electrical energy generated, kwhr.	Reported maintenance costs	
			dollars	mills per kwhr.
1	74	85,000	300	3.3
2	130	91,870	244	2.7
3	80	98,442	686	7.0
4	90	95,301	865	9.1
5	--	106,700	1,097	10.3
6	--	110,050	803	7.3
7	90	119,053	451	3.8
8	90	130,000	300	2.2
9	159	223,381	2,103	9.4
10	--	230,460	2,850	12.4
11	165	236,974	589	2.5
12	--	280,860	652	2.3
13	170	423,154	1,273	3.0
14	293	440,300	3,260	7.4
15	260	453,568	1,515	3.3
16	--	592,500	2,670	4.5
17	700	784,209	1,941	2.5
18	565	829,278	1,497	1.8
19	--	912,600	5,100	5.6
20	692	936,120	1,200	1.3
21	520	1,289,394	4,365	3.4
22	600	1,346,349	3,085	2.3
23	--	2,202,700	5,210	2.4
24	1,664	2,397,467	4,140	1.7
25	880	2,932,766	7,573	2.6
26	1,380	3,102,726	4,519	1.5
27	1,838	6,025,926	8,922	1.5
28	3,138	7,053,500	14,947	2.1

APPENDIX NO. 3f

Reported Costs of Supplies and Miscellaneous Expenses

of Various Diesel Generating Plants.

Diesel plant No.	Capacity, kw.	Electrical energy generated, kwhr.	Reported costs of supplies and miscellaneous expenses	
			dollars	mills per kwhr.
1	74	85,000	---	---
2	130	91,870	244	2.7
3	80	98,442	198	2.0
4	90	95,301	108	1.1
5	00	106,700	340	3.2
6	--	110,050	234	2.1
7	90	119,053	205	1.7
8	90	130,000	---	---
9	159	223,381	565	2.5
10	--	230,460	434	1.9
11	165	236,974	449	1.9
12	--	280,860	167	0.6
13	170	423,154	593	1.4
14	293	440,300	452	1.0
15	260	453,568	562	1.2
16	--	592,500	202	0.3
17	700	784,209	1,676	2.1
18	565	829,278	1,352	1.6
19	--	912,600	855	0.9
20	692	956,120	---	---
21	520	1,289,394	968	0.8
22	600	1,346,349	619	0.5
23	---	2,202,700	2,079	0.9
24	1,664	2,397,467	2,899	1.2
25	880	2,932,766	1,503	0.5
26	1,380	3,102,726	1,848	0.6
27	1,838	6,025,926	3,844	0.6
28	3,138	7,053,500	4,137	0.6

APPENDIX NO. 3g

Capital Cost Structure of Ten Particular Diesel Plants

In the case of these costs, the actual historic costs as reported by the proprietors have been adjusted by the application of price indices. The indices used were those published by the Dominion Bureau of Statistics which apply to various classes and types of manufactured goods, equipment and services. In each case, the adjustment applied brings the cost up to a "theoretical replacement cost in 1948". The actual details are shown in the following table. Blanks in the table indicate that the amounts are included under other classifications and were indeterminate.

The amount shown for operating capital is an amount determined arbitrarily as one-eighth of the yearly operating expenses as reported by the various operators. Such an amount, which represents approximately one and one-half months' operating expenses, is often accepted by authorities in the field as the amount required to satisfactorily carry on such business and to meet the normal day-to-day expenses of operation.

Components of Capital Cost of Ten Diesel Plants

Diesel plant	A	B	C	D	E	F	G	H	I	J
Capacity, kw.	80	90	90	90	165	170	293	350	450	1,380
Land	208	160	300	-	200	415	200	350	500	2,110
Structures	2,696	7,834	1,160	-	3,000	3,842	7,730	10,540	14,340	57,036
Fuel holders and accessories	482	-	569	-	230	715	4,240	2,537	1,587	6,059
Oil engines and generators	9,591	8,906	12,263	-	6,680	17,925	71,287	67,500	77,050	192,837
Electrical plant	5,482	-	6,353	-	7,716	7,703	4,406	5,870	6,310	78,986
Misc. equipment	18	237	792	-	345	156	2,820	4,845	5,460	8,553
Subtotal	18,477	17,139	21,437	22,485	18,171	30,756	90,683	91,642	105,247	345,581
Operating capital	717	1,039	943	1,168	1,767	2,613	2,706	3,802	3,836	12,723
Total	19,194	18,178	22,371	23,653	19,938	33,369	93,389	95,344	109,083	358,304
Investment, dollars per kw.	240	202	248	263	121	196	319	272	242	260

APPENDIX NO. 3h

1948 Replacement Value* of Ten Actual Generating Plants in Alberta

Plant capacity, kw.	Replacement cost per kw., dollars
80	240
90	202
90	248
90	263
165	121
170	196
293	319
350	272
450	242
1,380	260

* The value includes machines, equipment, building, and current assets.

APPENDIX NO. 4a

Computation of Standard Fuel Costs per Unit of Net Generation, from Reported Fuel Costs of Nine Canadian Plants

Note: In the following table, the "Actual cost per million BTU" is based on the unit fuel cost reported by the operator and the net BTU content of the particular fuel as reported by provincial authorities on the analysis of that fuel. The "Standard cost" is based on a unit fuel cost of $0.15 per million net BTU.

Steam Plant No.	Actual cost, mills per kwhr.	Actual cost, mills per million BTU	Thermal equivalent, millions of BTU per kwhr.	Standard cost, mills per kwhr.
1	12.99	244	0.0533	8.00
2	2.64	70	0.0377	5.66
3	6.82	257	0.0265	3.98
4	2.97	151	0.0197	2.96
5	0.60	25	0.0240	3.60
6	5.94	258	0.0230	3.45
7	4.44	239	0.0186	2.79
8	4.95	303	0.0163	2.44
9	3.28	178	0.0184	2.76

APPENDICES NOS. 4b, 4c, 4d.

Component costs reported by various steam generating plants for:

(b) Labor, including superintendence and engineering.

(c) Maintenance.

(d) Supplies and miscellaneous expenses, including cost of cooling water.

Note: In the following table, plants 1 to 9 are the Canadian plants corresponding to those listed in Appendix No. 4a. Plants 10 to 20 are American plants having capacities within the same range of capacities as the Canadian plants.

Steam plant No.	4b Labor cost, mills per kwhr.	4c Maintenance cost, mills per kwhr.	4d Supplies and Misc. expenses, mills per kwhr.
1	5.87	1.90	1.98
2	5.10	1.35	1.33
3	1.94	0.95	0.64
4	1.26	0.76	0.51
5	1.17	0.17	0.12
6	1.55	1.11	0.25
7	1.17	0.64	0.15
8	Total 1.75		Division unknown
9	0.79	0.43	0.15
10	1.48	0.51	0.25
11	2.28	1.06	0.67
12	Total 3.42		Division unknown
13	Total 2.71		Division unknown
14	1.35	0.95	0.11
15	1.94	1.39	0.21
16	0.97	0.70	0.41
17	0.45	0.32	0.14
18	Total 0.70		Division unknown
19	Total 1.79		Division unknown
20	Total 1.57		Division unknown

APPENDIX NO. 4e

Computation of Interest Component of Generation Costs

for Various Steam Plants

Steam plant No.	Annual net output, millions of kwhr.	Investment per kw. of capacity, dollars	Total fixed assets, dollars	6% Interest, dollars	Interest charge, mills per kwhr.
1	6.67	127	381,000	22,900	3.43
2	8.70	159	438,000	26,300	3.02
3	20.08	161	946,000	57,800	2.87
4	28.32	116	1,019,000	61,100	2.16
5	29.52	75	1,008,000	60,400	2.05
6	37,87	152	1,518,000	91,000	2.40
7	82.69	99	3,824,000	229,500	2.78
8	98.69	130	5,590,000	335,000	3.39
9	176.49	70	3,085,000	185,000	1.05
10	9.16	104	416,000	24,900	2.72
11	10.93	175	996,000	59,700	5.46
12	14.12	126	504,000	30,200	2.14
13	20.60	98	981,000	58,800	2.85
14	37.68	100	1,055,000	63,300	1.68
15	39.50	95	923,000	55,400	1.40
16	84.50	108	2,160,000	130,000	1.54
17	89.72	75	1,683,000	101,000	1.13
18	181.20	102	5,083,000	305,000	1.68
19	285.25	148	7,096,000	425,000	1.49
20	251.58	153	9,173,000	550,000	2.19

In determining the "Total fixed assets" above, an amount of operating capital equal to 12-1/2% of the yearly operating expenses has been included. This amount, which represents approximately one and one-half months' operating expenses, is often accepted by authorities in the field as the amount required to satisfactorily carry on such business and to meet the normal day-to-day expenses of operation.

APPENDIX NO. 4f

Computation of Depreciation Component of Generation Costs

for Various Steam Plants

Steam plant No.	Annual net output, millions of kwhr.	Investment per kw. of capacity, dollars	Total fixed assets, dollars	3-1/3% Depreciation, dollars	Depreciation charge, mills per, kwhr.
1	6.67	127	381,000	12,100	1.81
2	8.70	159	438,000	14,250	1.64
3	20.09	161	946,000	31,200	1.55
4	28.32	116	1,019,000	33,300	1.18
5	29.52	75	1,008,000	33,300	1.13
6	37.87	152	1,518,000	48,800	1.29
7	92.69	99	3,824,000	125,000	1.51
8	98.69	130	5,590,000	186,000	1.88
9	176.49	70	3,085,000	103,000	0.58
10	9.16	104	416,000	13,500	1.47
11	10.93	175	996,000	32,750	2.99
12	14.12	126	504,000	16,150	1.14
13	20.60	98	981,000	31,800	1.54
14	37.68	100	1,055,000	33,800	0.90
15	39.50	95	923,000	29,000	0.73
16	84.50	108	2,160,000	68,700	0.81
17	89.72	75	1,683,000	54,900	0.61
18	181.20	102	5,083,000	165,000	0.91
19	285.25	148	7,096,000	230,500	0.81
20	251.58	153	9,173,000	298,000	1.19

In determining the "Total fixed assets" above, an amount of operating capital equal to 12-1/2% of the yearly operating expenses has been included. This amount, which represents approximately one and one-half months' operating expenses, is often accepted by authorities in the field as the amount required to satisfactorily carry on such business and to meet the normal day-to-day expenses of operation.

APPENDICES NOS. 5a, 5b, 5c

Component costs reported by various hydro generating plants for:

(a) Labor, including superintendence and engineering.

(b) Maintenance.

(c) Supplies and miscellaneous expenses.

NOTE: In the following table plants 1 to 5 are Canadian plants, while plants 6 to 21 are American plants having capacities within the same range of capacities as the Canadian plants.

Hydro plant No.	5a Labor cost, mills per kwhr.	5b Maintenance cost, mills per kwhr.	5c Supplies & misc. expenses mills per kwhr.
1	Total 0.60	Division unknown	
2	Total 0.53	" "	
3	Total 0.67	" "	
4	Total 0.45	" "	
5	Total 0.42	" "	
6	1.46	0.45	0.65
7	8.54	3.30	0.29
8	5.13	4.49	1.23
9	4.22	0.60	0.14
10	0.38	0.36	0.13
11	2.48	5.21	0.18
12	0.45	0.07	0.04
13	0.91	0.54	0.21
14	0.77	0.68	0.41
15	1.02	0.46	0.97
16	0.46	0.26	0.03
17	0.47	0.21	0.31
18	0.55	0.34	0.10
19	0.32	0.23	0.21
20	0.53	0.28	0.11
21	0.26	0.18	0.03

APPENDIX NO. 5d

Computation of Interest Component of Generation Costs

for Various Hydro Plants

Hydro plant No.	Annual net output, millions of kwhr.	Plant use factor, %	Investment per kw. of capacity, dollars	Total fixed assets, dollars	6% Interest charge, dollars	Interest charge, mills per kwhr.
1	41.9	43.5	136	1,503,000	90,000	2.41
2	71.5	77.7	105	1,098,000	65,800	0.92
3	75.7	61.7	89	1,251,000	75,100	0.99
4	96.9	38.6	175	2,798,000	168,000	1.73
5	143.9	62.0	188	4,980,000	299,000	2.08
6	0.6	26.2	625	165,000	9,900	16.50
7	1.0	11.3	385	381,000	22,800	22.80
8	1.0	15.6	270	203,000	12,200	12.20
9	1.6	71.0	200	50,000	3,000	1.88
10	7.0	72.8	287	31,600	19,000	2.72
11	11.5	65.8	398	797,000	47,800	4.15
12	21.5	20.4	232	2,795,000	168,000	7.81
13	30.6	49.8	136	956,000	57,400	1.88
14	82.2	45.9	203	4,155,000	249,000	3.13
15	92.7	60.0	395	6,953,000	417,000	4.29
16	102.1	54.5	100	2,134,000	128,000	1.25
17	175.0	83.8	159	3,812,000	228,000	1.30
18	196.7	57.1	201	7,912,000	475,000	2.42
19	253.8	60.4	268	12,332,000	740,000	2.92
20	269.2	66.1	276	12,863,000	771,000	2.86
21	311.4	51.8	239	16,416,000	985,000	3.17

In determining the "Total fixed assets" above, an amount of operating capital equal to 12-1/2% of the yearly operating expenses has been included. This amount, which represents approximately one and one-half months' operating expenses, is often accepted by authorities in the field as the amount required to satisfactorily carry on such business and to meet the normal day-to-day expenses of operation.

APPENDIX NO. 5e

Computation of Depreciation Component of Generation Cost for Various Hydro Plants

Hydro plant No.	Annual net output, millions of kwhr.	2% Depreciation on structures & improvements, dollars	1% Depreciation on reservoirs, dams & waterways, dollars	4% Depreciation on equipment, dollars	Total depreciation, dollars	Depreciation charge, mills per kwhr.
1	41.9	Breakdown for Canadian plants unknown; total depreciation taken as 2% of the investment in production plant.			30,000	0.72
2	71.5				21,900	0.31
3	75.7				24,900	0.33
4	96.9				55,800	0.58
5	143.9				99,400	0.69
6	0.6	203	936	2,260	3,399	5.66
7	1.0	494	2,119	1,660	4,273	4.27
8	1.0	445	497	1,430	2,372	2.37
9	1.6	155	275	498	928	0.58
10	7.0	2,409	892	3,750	7,051	1.01
11	11.5	1,872	3,920	7,410	13,202	1.15
12	21.5	3,511	15,973	8,090	27,574	1.28
13	30.6	3,032	1,928	24,200	29,160	0.95
14	82.2	4,776	29,776	22,600	57,152	0.70
15	92.7	17,481	23,105	50,900	91,486	0.99
16	102.1	3,852	9,634	20,970	34,456	0.34
17	175.0	14,492	8,186	32,900	55,578	0.32
18	196.7	23,064	29,458	86,000	138,522	0.70
19	253.8	13,522	23,893	36,900	74,315	0.29
20	269.2	11,807	60,471	108,000	180,278	0.67
21	311.4	35,459	121,777	57,700	214,936	0.69

APPENDIX NO. 5f

Total Cost of Generation for Various Hydro Plants

Hydro plant No.	Annual net output, millions of kwhr.	Sum of variable costs (labor, maintenance, supplies, misc. expenses), mills per kwhr.	Sum of fixed costs (interest & depreciation), mills per kwhr.	Total cost, mills per kwhr.
1	41.9	0.60	2.86	3.40
2.	71.5	0.53	1.23	1.76
3	75.7	0.67	1.32	1.99
4	96.9	0.45	2.31	2.76
5	143.9	0.42	2.77	3.19
6	0.6	2.56	22.16	24.72
7	1.0	11.13	27.07	38.20
8	1.0	10.85	14.57	25.42
9	1.6	4.96	2.46	7.42
10	7.0	0.87	3.73	4.60
11	11.5	7.87	5.30	13.17
12	21.5	0.56	9.09	9.65
13	30.6	1.66	2.83	4.49
14	82.2	1.86	3.83	5.69
15	92.7	2.45	5.28	7.73
16	102.1	0.75	1.59	2.34
17	175.0	0.99	1.62	2.61
18	196.7	0.99	3.12	4.11
19	253.8	0.76	3.21	3.97
20	209.2	0.92	3.53	4.45
21	311.4	0.49	3.86	4.35

APPENDIX NO. 6

Reported Costs of Transmission of American Power Companies

Hydro plant No.	Net plant output for transmission, millions of kwhr.	Transmission plant invest., dollars	Annual cost of operation, dollars	Annual fixed charges (10% on invest.), dollars	Total annual cost, dollars	Cost, mills per kwhr.
8	1.0	76,000	1,659	7,600	9,259	9.26
9			Cost data unavailable			
10	7.0	34,000	404	3,400	3,804	0.54
11	11.5	191,000	6,363	19,100	25,463	2.21
12	21.5	450,000	1,618	45,000	46,618	2.17
13	30.6	632,000	26,197	63,200	89,397	2.92
14	82.2	932,000	24,058	93,200	117,258	1.43
15	92.7	491,000	15,494	49,100	64,594	0.70
16	102.1	292,000	18,423	29,200	47,623	0.47
17	175.0	220,000	940	22,000	22,940	0.13
18	196.7	1,940,000	63,081	194,000	257,018	1.31
19	253.8	759,000	55,780	75,900	131,680	0.52
20			Cost data unavailable			
21	311.4	2,540,000	63,432	254,000	317,432	1.02

Totals .... 1,285.5 (input to transmission lines) 8,557,000 277,386 (3.2% of investment) 1,133,086

Line losses (12%).. 154.0 ...at 6.3 mills/kwhr. the annual cost of line losses amounted to .. 955,000

1,131.5 (output from transmission lines) 2,088,086 1.84 (average transmission cost)

NOTE:

1. In the above table, plant numbers correspond to plant numbers 8 to 21 in Appendix No. 5.

2. The annual fixed charge of 10% on the investment is composed of two components: a depreciation charge of 4% based on a composite transmission plant life of 25 years, and an interest charge of 6%.

3. In determining the over-all average cost of 1.84 mills per kwhr. (which includes line losses), the line losses have been charged for at the average cost of generation for American plants as indicated by Part B of this report - that is, at 6.3 mills per kwhr.

4. From the above table it is seen that the operating costs of these systems represent a charge of approximately 3.2% of the investments in them. For one of the Alberta systems, the reported investment in transmission lines and substation equipment is $6,435,000 and in 1948 the net input to this system for transmission was 429.8 million kwhr. On the basis of these values, the corresponding cost of transmission in Alberta may be compiled as below:

Depreciation: 4% on investment	$257,000
Interest: 6% on investment	386,000
Operating costs: 3.2% on investment	206,000
Line losses: 12% of 429.8 million kwhr. at 2.6 mills per kwhr.	134,000
Total cost of transmission	$983,000

Net output: 88% of 429.8 million kwhr. = 378.3 million kwhr.

Average cost, mills per net kwhr. = 2.6

In the above, the 2.6 mills per kwhr. charged to line losses is the average cost of generation indicated for Alberta plants by Part B of this report.

APPENDIX NO. 7

Reported Distribution Costs of United States Distribution Companies

System No.	Millions of kwhr. sold	Investment in distribution plant in thousands of $	Fixed costs (10% on invest.) in thousands of $	Distribution expenses in thousands of $	Cost of distribution losses in thousands of $	Commercial costs of distribution in thousands of $	Fixed costs, mills per kwhr.	Distribution expenses, mills per kwhr.	Cost of losses mills per kwhr.	Commercial costs, mills per kwhr.	Total cost, mills per kwhr.
1	9.4	548	54.8	99	20.2	27	5.7	10.5	2.1	2.9	21.2
2	18.6	1,091	109.1	125	30.4	40	5.9	6.7	1.6	2.1	16.3
3	20.5	922	92.2	72	13.8	8.8	4.5	3.5	0.7	0.4	9.1
4	34.2	944	94.4	129	30.5	30.4	2.8	3.8	0.9	0.9	8.4
5	35.0	1,877	187.7	181	27.2	71.5	5.3	5.2	0.8	2.0	13.3
6	35.9	2,981	298.1	209	65.4	41.6	8.3	5.8	1.8	1.2	17.1
7	35.9	2,233	223.3	300	57.5	74.6	6.2	8.4	1.6	2.1	18.3
8	38.9	3,294	329.4	439	80.6	98.2	8.5	11.3	2.1	2.5	24.4
9	40.1	1,298	129.8	145	14.1	30.1	3.2	3.6	0.4	0.7	7.9
10	41.7	2,943	294.3	414	49.3	108.2	7.1	9.9	1.2	2.6	20.8
11	42.1	1,622	162.2	237	22.3	39.7	3.9	5.6	0.5	0.9	10.9
12	51.4	2,168	216.8	282	57.4	81.9	4.2	5.5	1.1	1.6	12.4
13	60.3	2,267	226.7	300	67.2	101.0	3.8	5.0	1.1	1.7	11.6
14	80.2	3,100	310.0	518	68.3	159.0	3.9	6.5	8.5	2.0	20.9
15	130.2	7,141	714.1	911	180.0	249.2	6.5	7.0	1.4	1.9	16.8
	647.4		3,442.9	4,361	784.2	1,161.2	5.1	6.5	1.2	1.7	14.5
	Total		Total	Total	Total	Total	Average	Average	Average	Average	Average

NOTE:

1. In the above table, the "Cost of distribution losses" includes the cost of the losses plus the cost of energy used by the distributing company and not included as sales. The latter item represents approximately 0.3% of the total sales while the losses represent approximately 9% of the input to the distribution systems. This percentage is in contrast to the 12% loss encountered in transmission systems. The difference is principally due to the lower use factors usually typical of distribution systems.

2. The fixed costs again include a charge of 6% on investment allowed as a fair interest charge and a depreciation charge of 4% which is based on a composite life of plant of 25 years.

APPENDIX NO. 8

Possibilities of Power Production at Mine Site

In a location about 50 miles from Edmonton there are large reserves of coal consisting of 15-foot seams under a maximum of 30 feet of surface overburden. These are located adjacent to a large lake which offers a supply of water adequate for quite a large steam plant power development. It is estimated that, by the use of mechanized equipment and strip-mining techniques on a reasonably large scale, coal could be delivered to a nearby plant at a cost of not more than $1.00 per ton. The coal from this area has a net BTU rating of 8,400 BTU per lb. This would result in a fuel cost of approximately 1.3 mills per kwhr. Considering an initial development of 10,000 kw. capacity, the total cost of power generation might be expected to be 6.6 mills per kilowatt-hour. If the plant capacity was later increased to an ultimate of 50,000 kw. or more, the cost of generation could probably be reduced to about 4.7 mills per kwhr. Since such a plant would probably supply a load, centred and alternately supplied by a further plant at Edmonton, a transmission charge must be added to the generation costs as stated. The charge indicated by this report for a 50-mile distance is 2.2 mills per kwhr. Therefore, the cost of this power delivered to the load centre would be 6.9 mills per kwhr. These charges are based on average values (as determined previously in this report) and hence it seems probable that, when the most is made of the natural advantages of such a plant location, the total cost for generation and transmission would be comparable with the present cost of generation at the Edmonton plant. This cost, based on actual fuel costs, rather than on the standardized costs previously discussed, is 6.9 mills per kwhr. It is also possible that when the relative costs of insurance, taxes, and other elements which depend entirely on local conditions are considered for the two locations, the comparison would be even more favorable toward the proposed plant location.

APPENDIX NO. 9

Waste Coal Production and the Possibility of its Utilization in Power Generation

At present the coal industry in Alberta is producing two types of waste fuels.

1. Sludge or Slurry Coal produced from the washing of railroad coal. This is a very fine powdered coal which, according to analysis, yields about 25% ash and 10,000 to 11,000 BTU/lb. It is so fine that it is difficult to store, and blows easily. It is also hard to handle in the hopper since it will not feed properly. To cause it to burn in the fire box requires excess draft which blows part of it up the stacks, and it has been found that a normal 70,000 lb./hr. stoker fed boiler could not produce more than about 35,000 lb./hr. of steam when burning this coal. There seems, in general, to be an excess of earth material in this slurry coal. This detracts from its usefulness for steam generation in that a greater capital expenditure than normal would be required for boiler and fuel burning equipment.

2. Slack and Screenings Coal produced at the mine mouth from the screens. Quantities amounting to about 30% of the production of some mines are in this form and have been continuously stockpiled until at present stocks of several hundred thousands, or in some cases even millions of tons, are at hand. The estimated ash content of this coal is about 30% with considerable earth material included. It is estimated that its heat content is 10,000 BTU per lb. The only markets at present for this coal are the very limited local domestic markets.

It has been suggested, with regard to the latter type of waste production, that it might be utilized in large base load generating plants. The afore-mentioned stockpiles would serve as standby stocks while current production of this type, if insufficient in quantity, would be appropriately blended with higher quality coal to supply the requirements of these plants. Should the market demand for higher quality coal drop off, this would serve a further purpose of helping to maintain mine production. Assuming then that such set-ups are possible with plants capable of burning pulverized coal and also of handling the relatively high ash content, consideration must be given to the cost structure and other factors involved in such production.

The costs of fuel for such proposed plants are quite difficult to ascertain or estimate. To pick up and deliver coal to a plant hopper from the above-mentioned stockpiles might cost approximately up to $1.50 per ton, although this would depend on the proximity of the plant to the stockpile and the handling equipment provided. This can be taken as the price of the coal only if the coal company concerned releases the stockpile without compensation. At the same time any high quality coal (15% ash) supplied for blending would probably cost $6.00 per ton before blending, but including the cost of the blending process and delivery to the hopper. At these rates and with fuel values as estimated, the fuel cost per million BTU would be:

(a) For unblended coal .... $.075

(b) For blended coal* .... $.132

(c) Standard costs used in this report .... $.150/million BTU.

---

* Blended in the ratio 2 parts slack to 1 part high quality - slack 10,000 BTU/lb., high quality 12,000 BTU/lb.

In addition to the initial cost of fuel as outlined above, the cost of ash handling must be considered. In such cases there is a relatively higher percentage of ash than is normal. Estimating the maximum cost of ash removal to be \$.75 per ton and including it as a coal cost, we have the following net cost of fuel:

For unblended coal (30% ash) .... \$ 1.73/ton or
\$ 0.087/million BTU

For blended coal (25% ash) .... \$ 3.18/ton or
\$0.149/million BTU

It is unlikely that there would be an outlet for ash to municipal works projects as is the case in so many of the plants considered in arriving at the cost estimates of this report. However, it is possible that in some locations the ash might be used in a secondary industry such as the casting of concrete blocks in various forms. In this way the cost of ash handling might be recovered, thereby effecting a saving of from 0.10 to 0.15 mill per kwhr.

Another major consideration is the supply of cooling water for such plants as those suggested above. Probable sources of such water would be nearby lakes or rivers. A plant of 15,000 to 20,000 kw. would probably require a minimum stream flow of 10 million gallons per day. Larger plants would require correspondingly larger amounts of cooling water. An alternative to the pumping of water from a flowing stream would be the creation of a reservoir to serve as a cooling pond. In the case of very large installations with capacities of near 100,000 kw., a cooling tower would probably be the best method of handling the cooling load. The cost of a cooling tower installation and operation on a per kwhr. basis varies only slightly over a wide range of plant capacities and is about 0.1 mill per kwhr. This cost is in addition to the normal charge for the pumping of cooling water, and minor expenses for supplies associated with it. The costs of "Water and supplies" as shown in the table below include a flat charge of 0.1 mill per kwhr. for cooling tower operation.

If due consideration is given to the over-all power supply situation in Alberta, it is clear that plants as suggested above would supply power to networks and, in all probability, would function as "base load supplies". This combination would, of course, reduce the per unit generation costs because of the higher plant use factor. Countering this effect is the fact that the output would have to be transmitted, generally an average of 150 miles to the load centre. Hence, with due consideration given to the facts outlined above as regards fuel price, base load conditions, etc., the costs of generating electrical power in stations of different capacities could be expected to be as shown below.

Installed plant capacity, kw.	Estimated annual output, millions kwhr.	Estimated use factor, %	Cost, mills per kwhr.						
			Labor	Fuel*	Maintenance	Water & supplies	Depreciation**	Interest***	Total
10,000	70	80	0.9	2.7	0.6	.3	0.5	0.9	5.9
25,000	153	70	0.8	2.5	0.6	.3	0.5	1.0	5.7
50,000	262	60	0.7	2.5	0.6	.3	0.6	1.1	5.8
100,000	436	50	0.6	2.5	0.6	.3	0.8	1.4	6.4

* The fuel cost assumes a ratio of unblended to blended coal of 2:1, giving $0.15 per million BTU (i.e. the standard cost).

** Depreciation at 3-1/3% allowed.

*** Interest on investment of 6% allowed.

Each of the above percentages is allowed on an investment rate of $100 per kw. of installed capacity.

In addition to the production costs there is, of course, the charge for transmitting this power to the load centre which is assumed to be 150 miles distant. Considering the relatively high use factor of the transmission line, it is probable that this cost would not exceed 3 mills per kwhr. The inclusion of this charge gives a final cost of power at the load centre of:

10,000 kw. plant at 80% use factor - 8.9 mills/kwhr.
25,000 kw. plant at 70% use factor - 8.7 mills/kwhr.
50,000 kw. plant at 60% use factor - 8.8 mills/kwhr.
100,000 kw. plant at 50% use factor - 9.2 mills/kwhr.

Comparing the above costs with those determined previously in this report as being average values, it is noted that the generating costs would be somewhat lower than average for comparable steam plants, although this advantage is not so pronounced for the larger plants unless higher use factors can be developed. Also, the total costs, including the transmission charges, are no doubt less than the cost would be if the fuel in question were transported to a plant at the load centre. They are, however, higher than the corresponding cost of hydro generated power which, including transmission, would be about 7.8 mills per kwhr. As mentioned above, these might be reduced slightly (by 0.2 mill per kwhr.) if a cooling tower installation is unnecessary and if the cost of ash removal can be recovered through some by-product revenue.

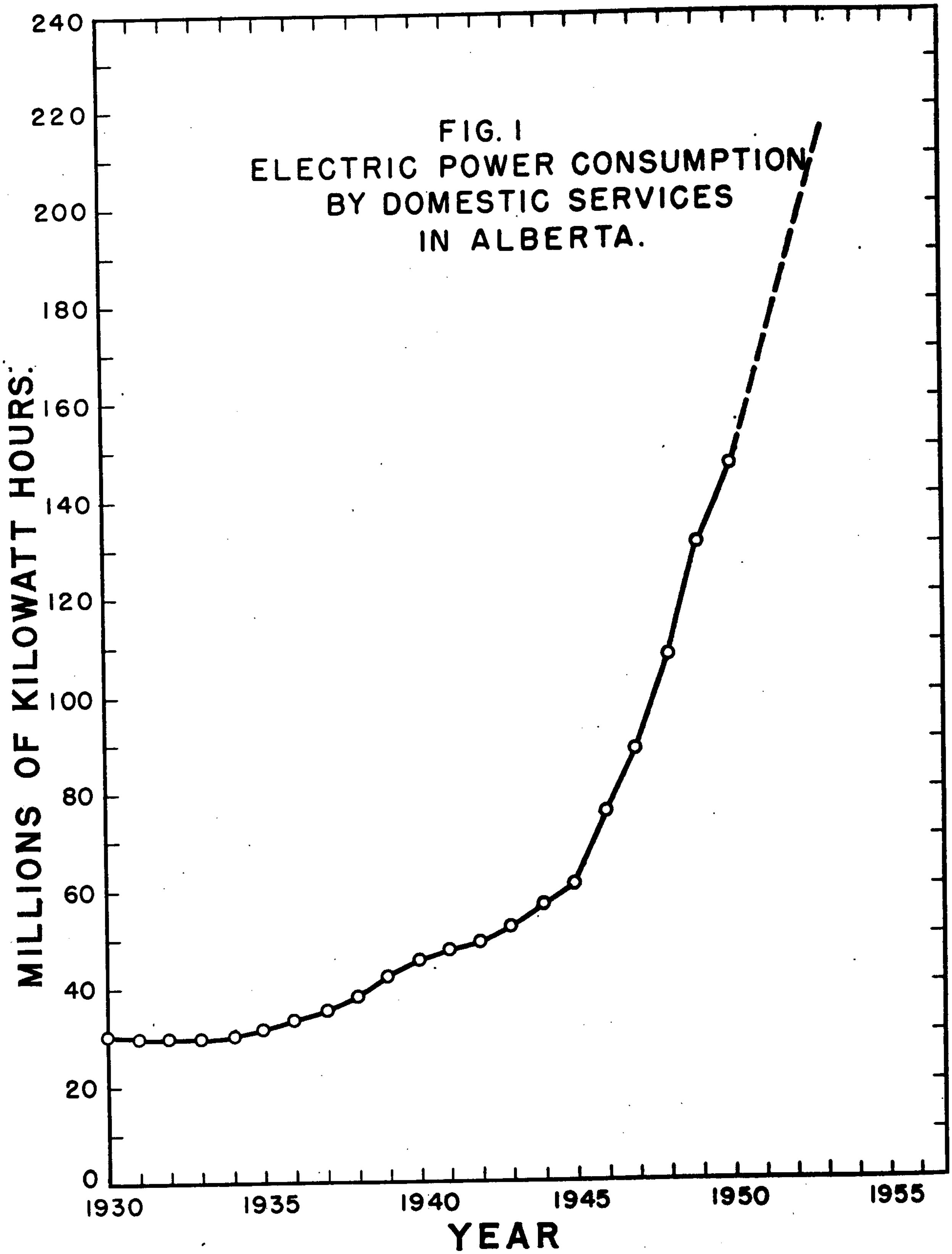


FIG. I
ELECTRIC POWER CONSUMPTION
BY DOMESTIC SERVICES
IN ALBERTA.
MILLIONS OF KILOWATT HOURS.
240
220
200
180
160
140
120
100
80
60
40
20
0
1930
1935
1940
1945
1950
1955
YEAR

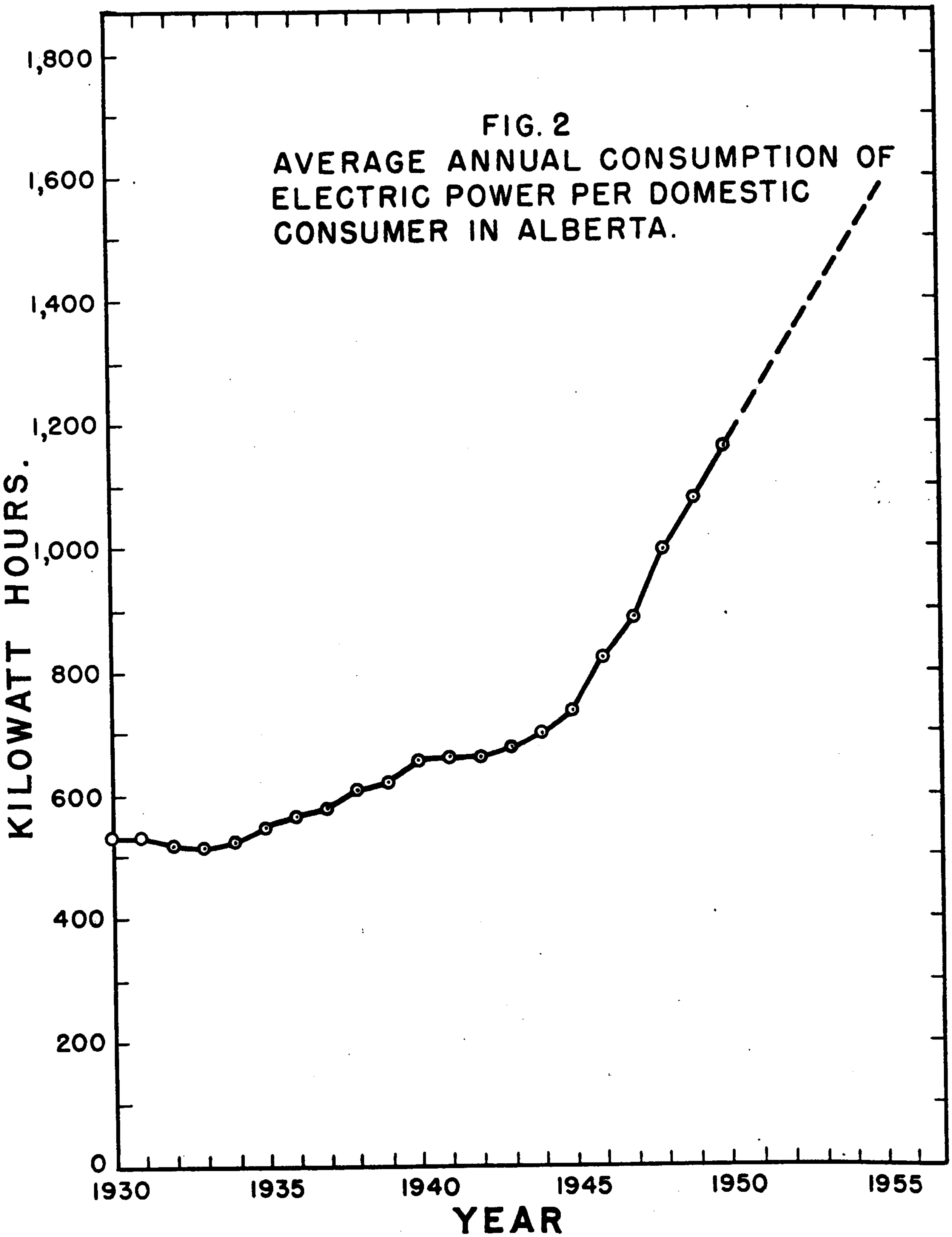


FIG. 2
AVERAGE ANNUAL CONSUMPTION OF ELECTRIC POWER PER DOMESTIC CONSUMER IN ALBERTA.

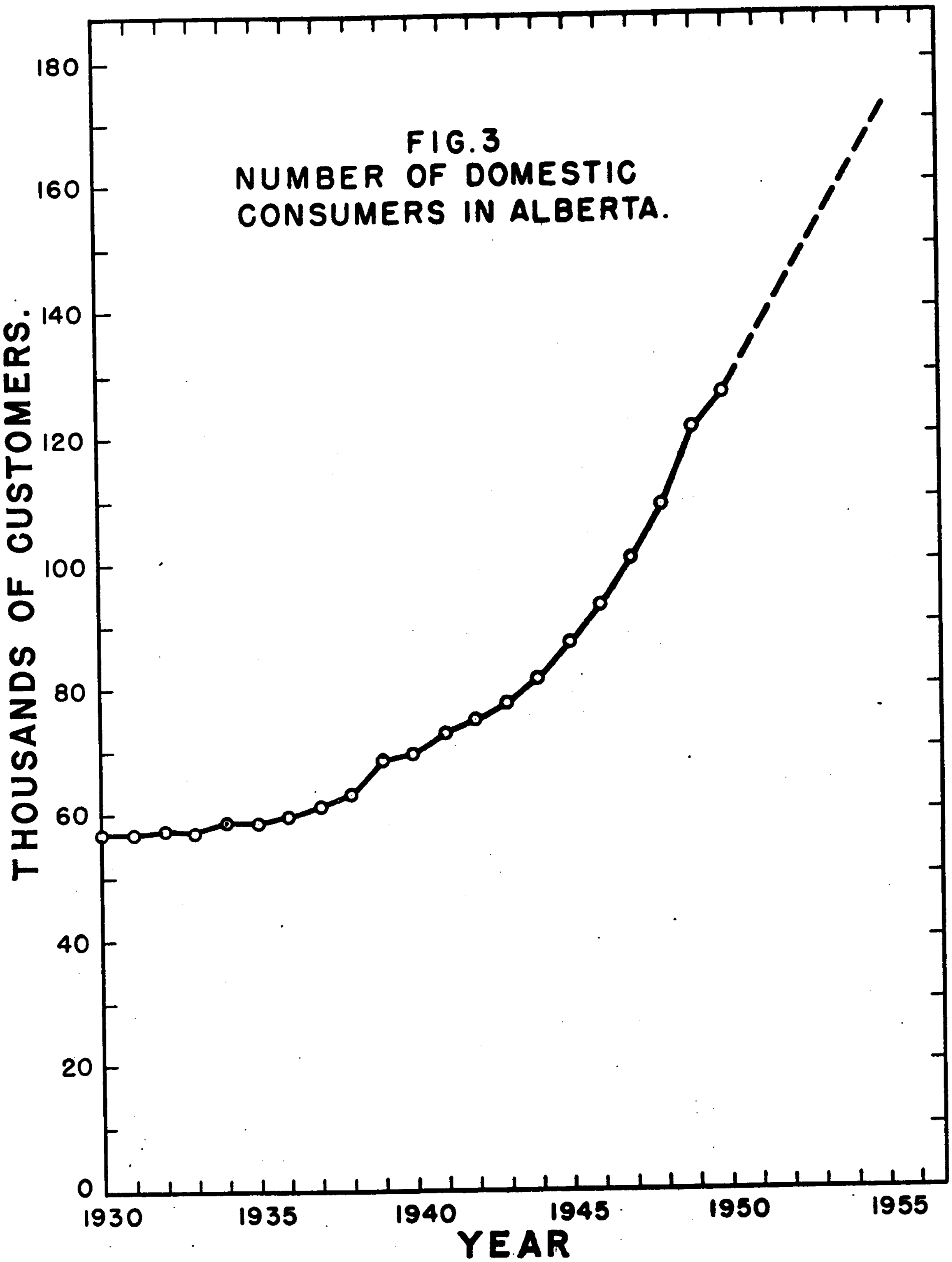


FIG. 3
NUMBER OF DOMESTIC
CONSUMERS IN ALBERTA.
THOUSANDS OF CUSTOMERS.
0
20
40
60
80
100
120
140
160
180
1930
1935
1940
1945
1950
1955
YEAR

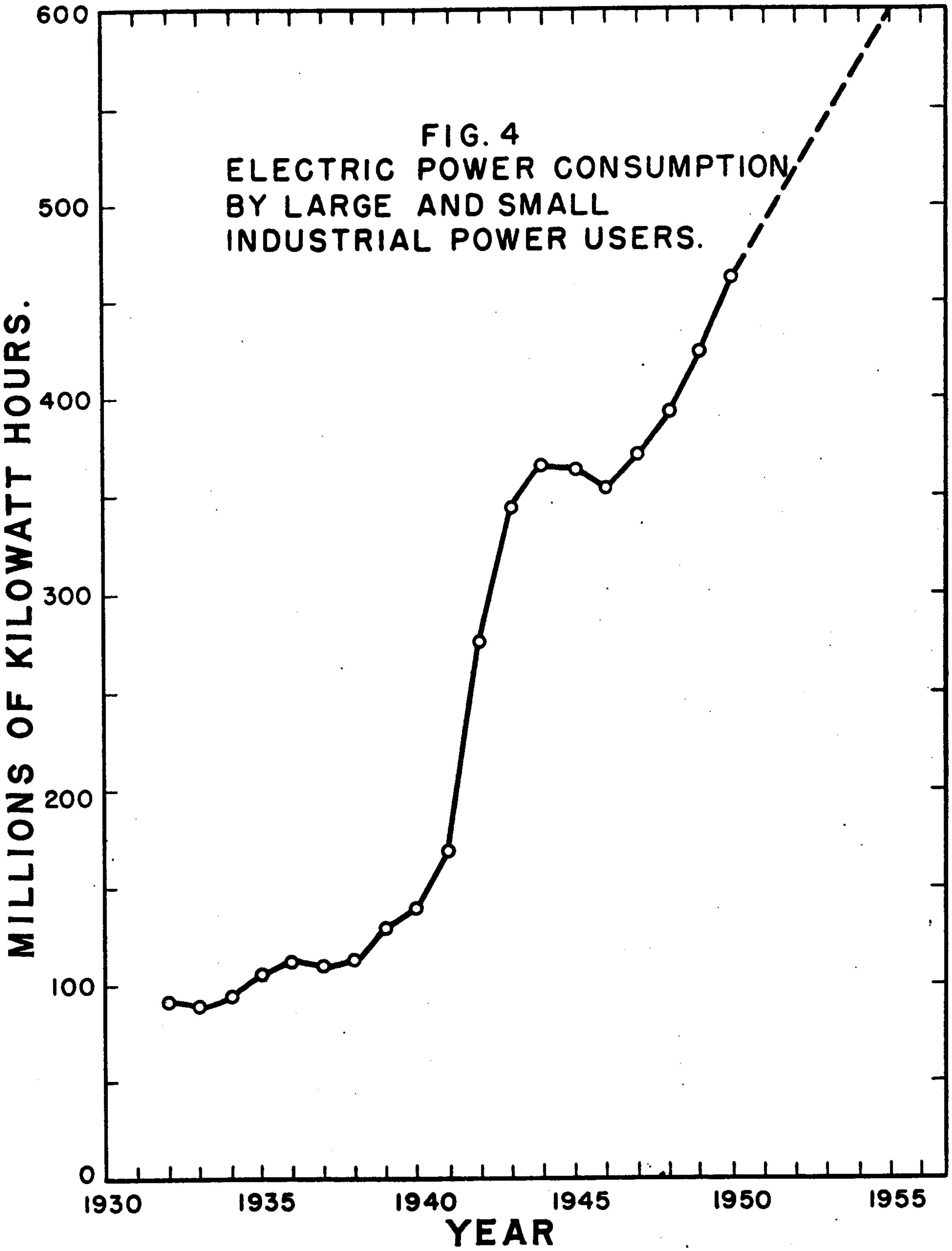


FIG. 4
ELECTRIC POWER CONSUMPTION
BY LARGE AND SMALL
INDUSTRIAL POWER USERS.
MILLIONS OF KILOWATT HOURS.
600
500
400
300
200
100
0
1930
1935
1940
1945
1950
1955
YEAR

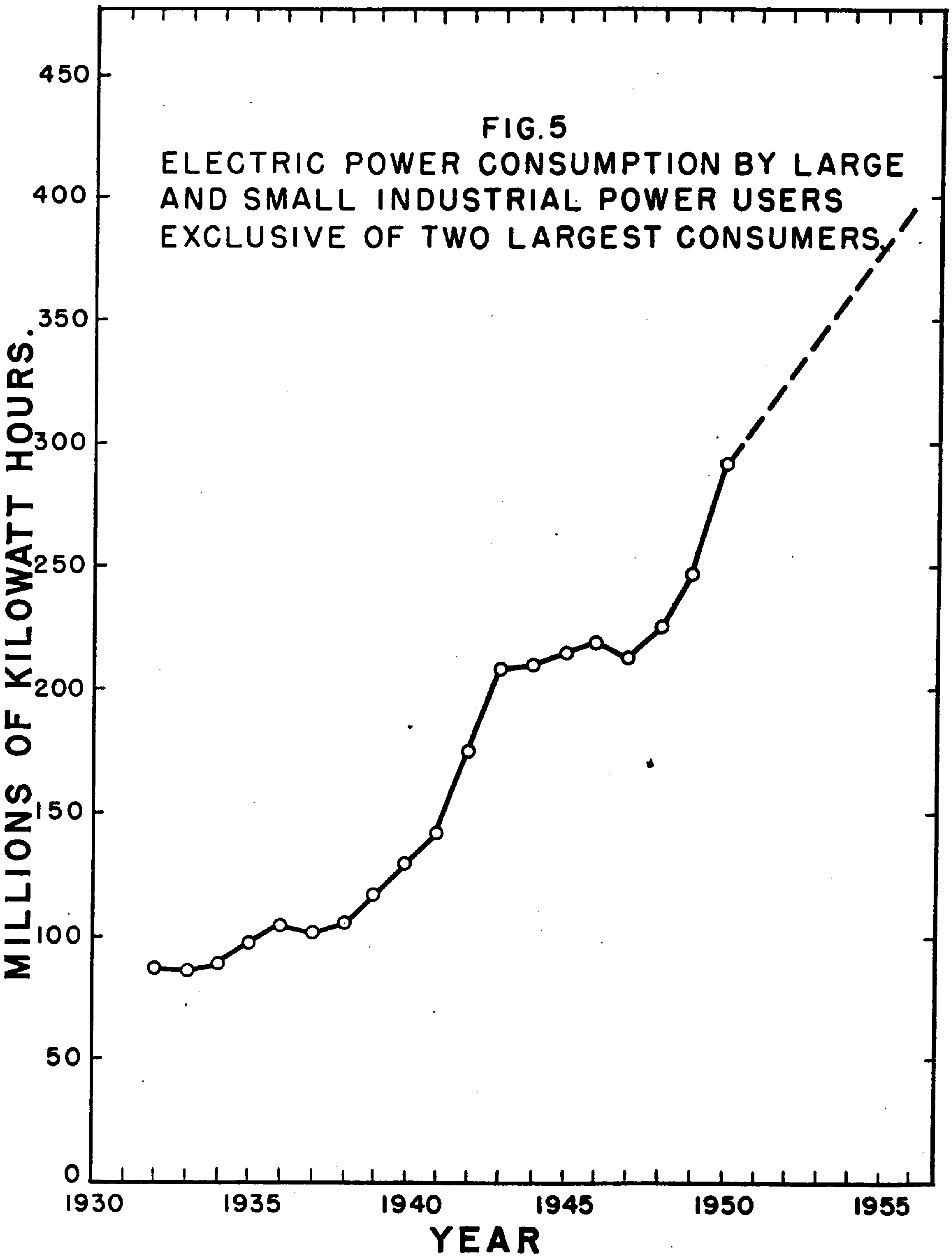


FIG. 5
ELECTRIC POWER CONSUMPTION BY LARGE AND SMALL INDUSTRIAL POWER USERS EXCLUSIVE OF TWO LARGEST CONSUMERS.
MILLIONS OF KILOWATT HOURS.
0
50
100
150
200
250
300
350
400
450
1930
1935
1940
1945
1950
1955
YEAR

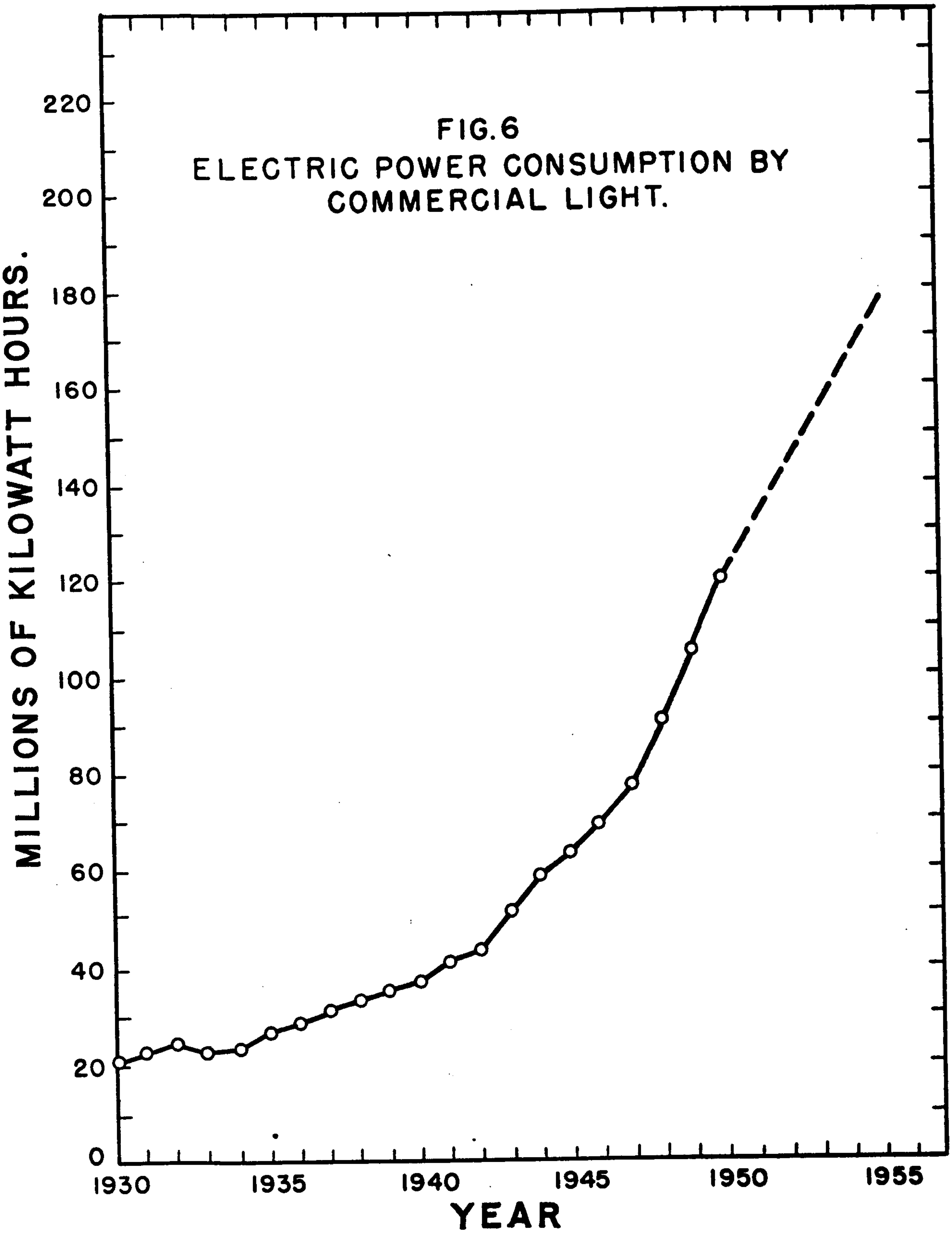


FIG. 6
ELECTRIC POWER CONSUMPTION BY
COMMERCIAL LIGHT.
MILLIONS OF KILOWATT HOURS.
0
20
40
60
80
100
120
140
160
180
200
220
1930
1935
1940
1945
1950
1955
YEAR

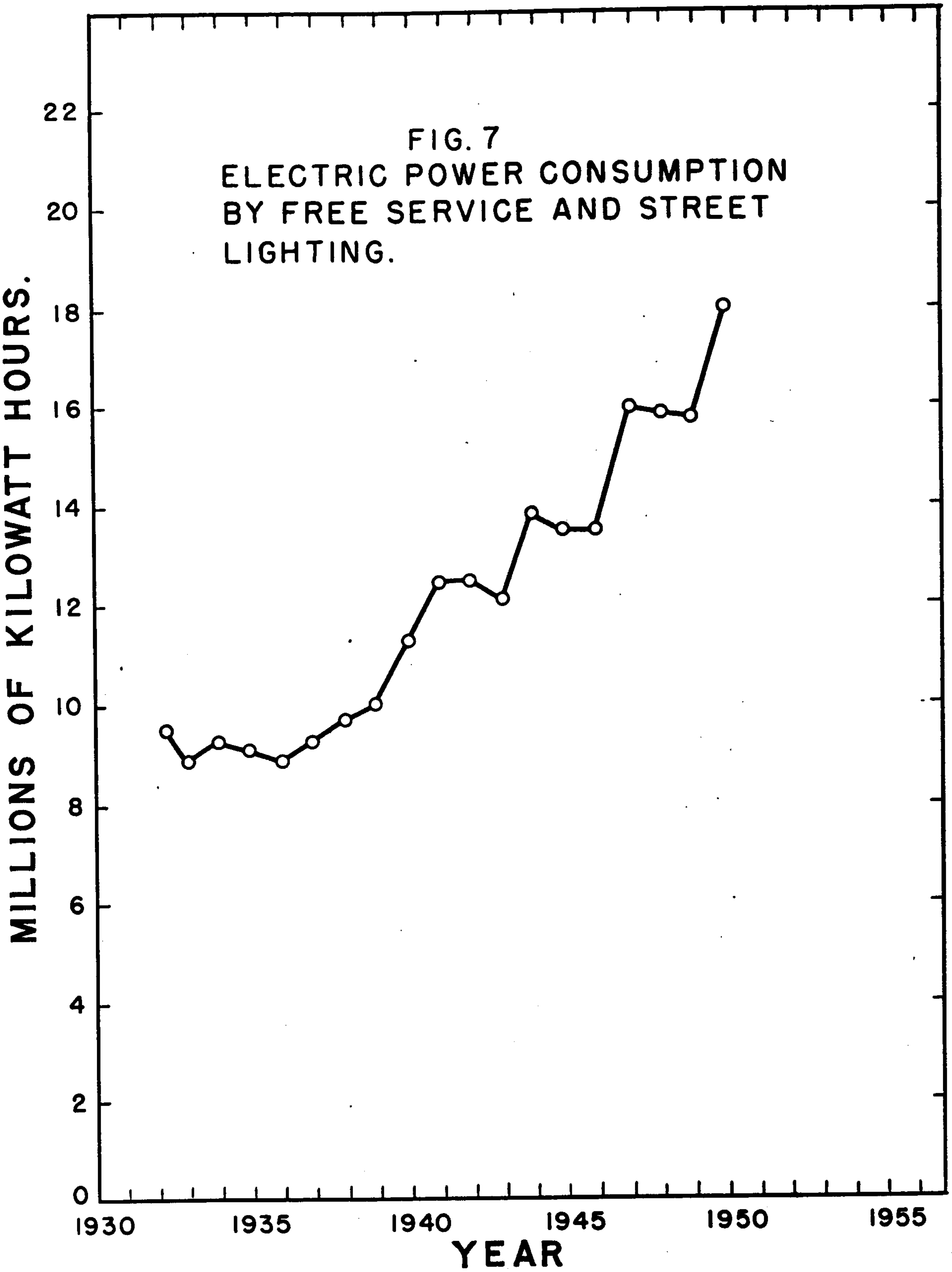


FIG. 7
ELECTRIC POWER CONSUMPTION BY FREE SERVICE AND STREET LIGHTING.

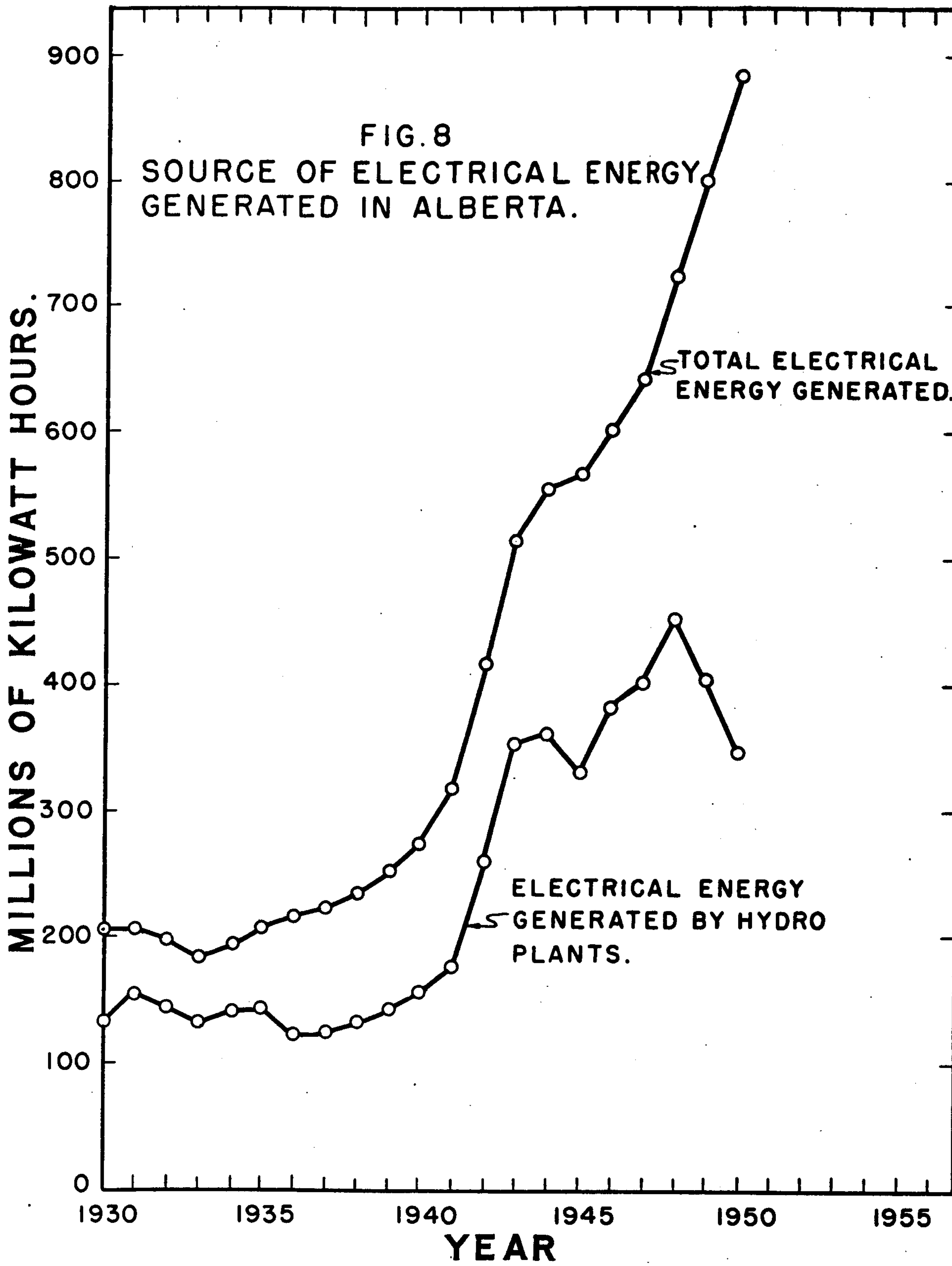


FIG. 8
SOURCE OF ELECTRICAL ENERGY
GENERATED IN ALBERTA.
MILLIONS OF KILOWATT HOURS.
900
800
700
600
500
400
300
200
100
0
TOTAL ELECTRICAL
ENERGY GENERATED.
ELECTRICAL ENERGY
GENERATED BY HYDRO
PLANTS.
1930
1935
1940
1945
1950
1955
YEAR

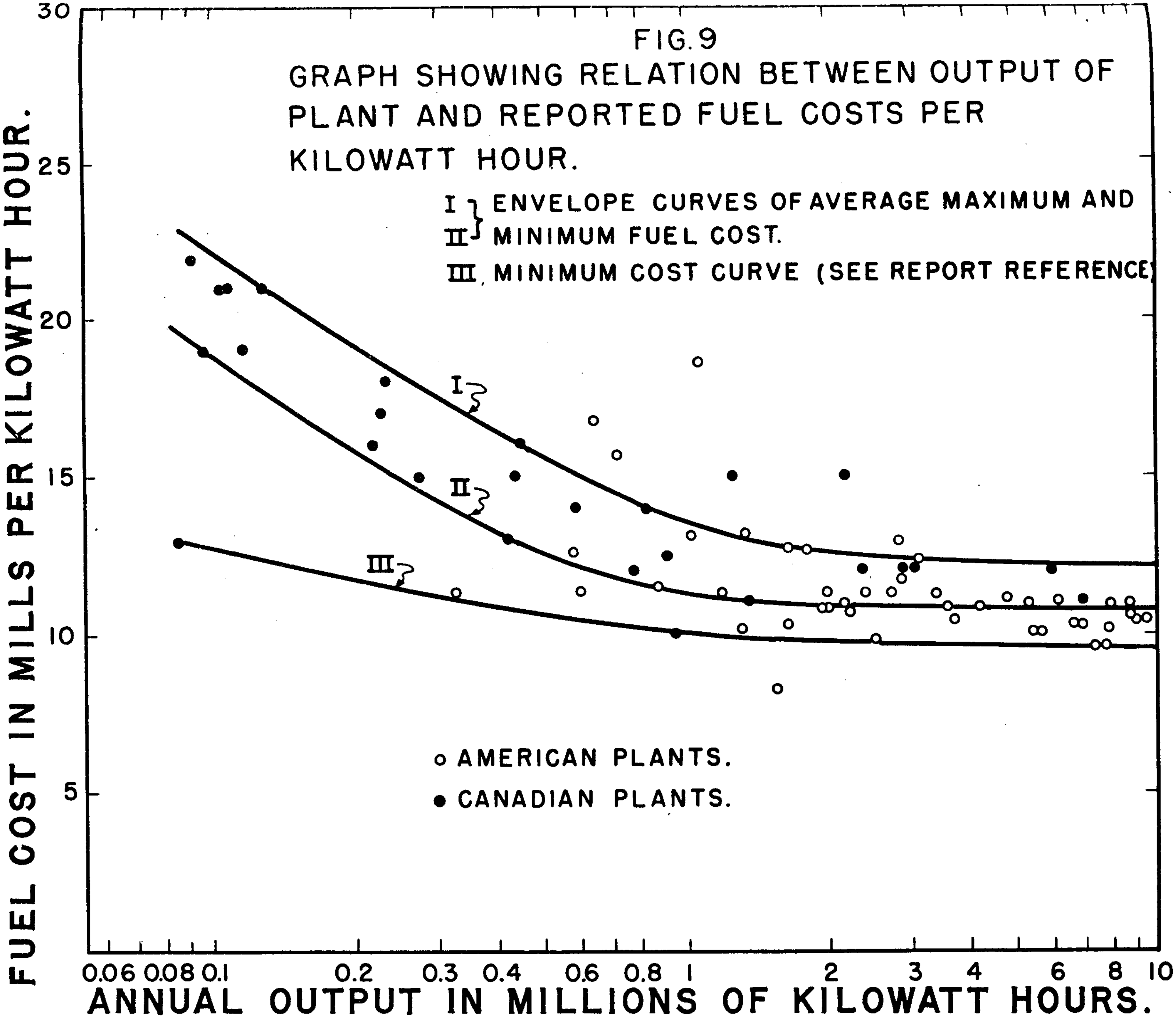


FIG. 9
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND REPORTED FUEL COSTS PER KILOWATT HOUR.
I } ENVELOPE CURVES OF AVERAGE MAXIMUM AND
II } MINIMUM FUEL COST.
III. MINIMUM COST CURVE (SEE REPORT REFERENCE)
I
II
III
○ AMERICAN PLANTS.
● CANADIAN PLANTS.
FUEL COST IN MILLS PER KILOWATT HOUR.
30
25
20
15
10
5
0.06
0.08
0.1
0.2
0.3
0.4
0.6
0.8
1
2
3
4
6
8
10
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

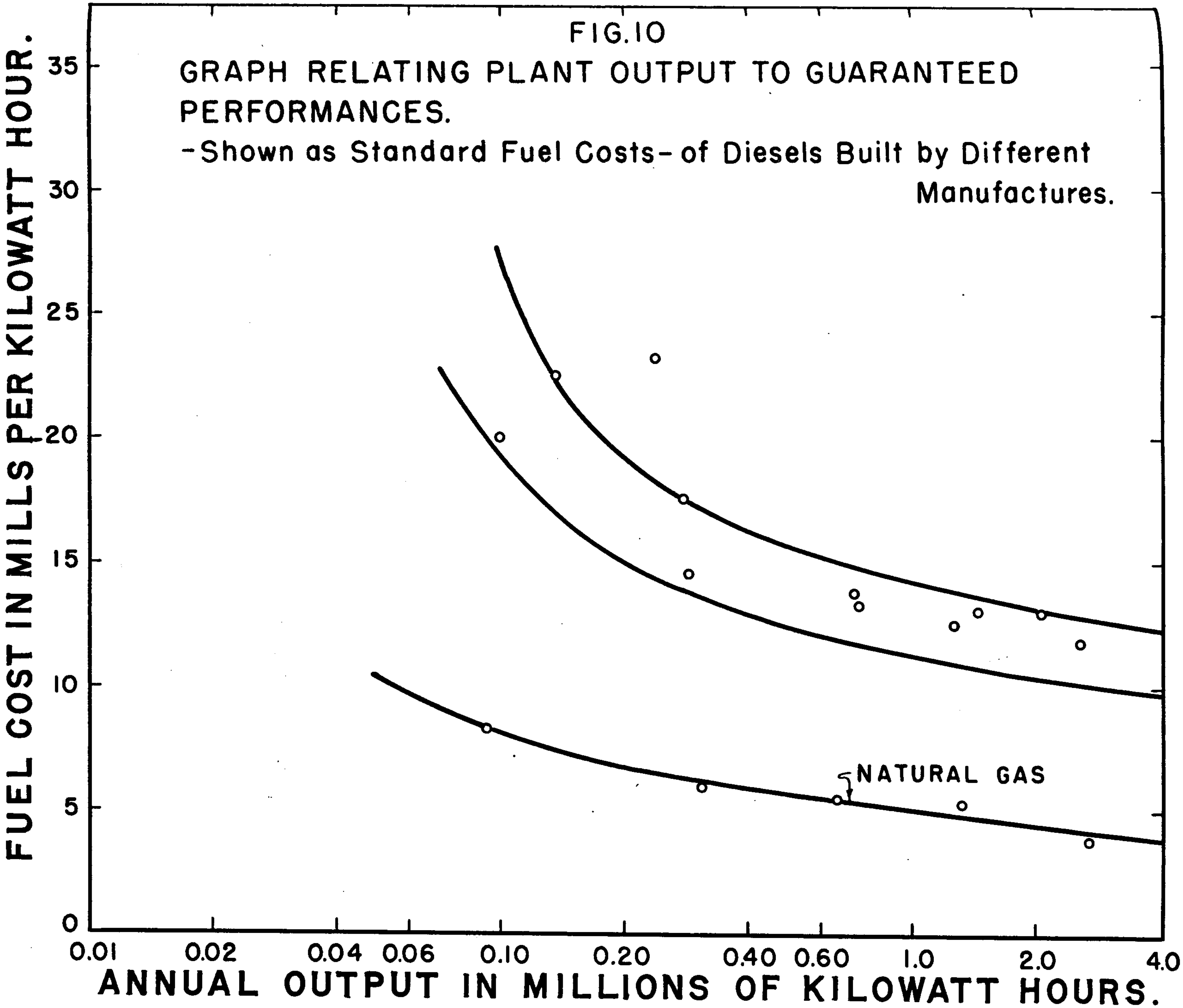


FIG. 10
GRAPH RELATING PLANT OUTPUT TO GUARANTEED PERFORMANCES.
-Shown as Standard Fuel Costs- of Diesels Built by Different Manufactures.
FUEL COST IN MILLS PER KILOWATT HOUR.
35
30
25
20
15
10
5
0
NATURAL GAS
0.01
0.02
0.04
0.06
0.10
0.20
0.40
0.60
1.0
2.0
4.0
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

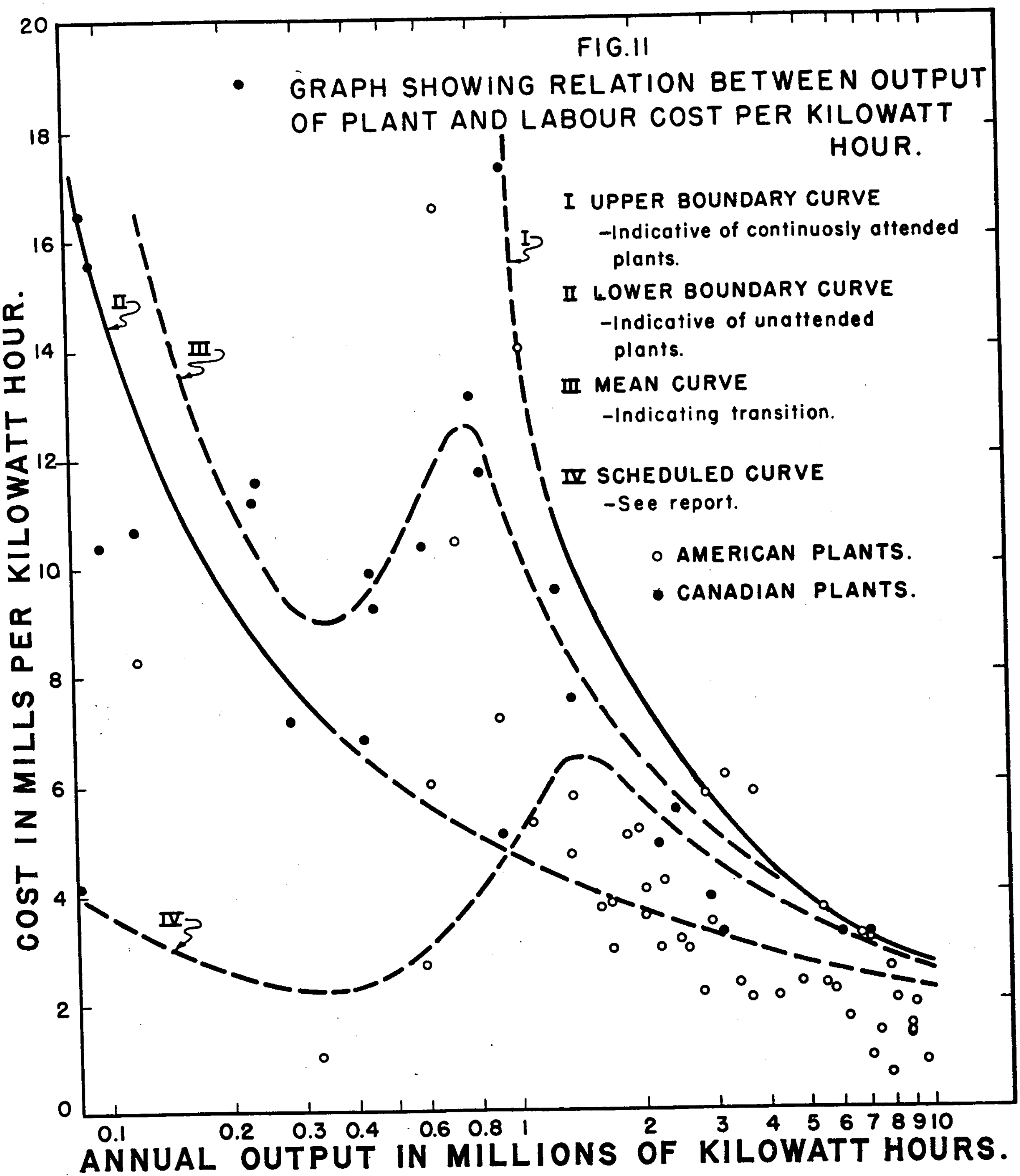
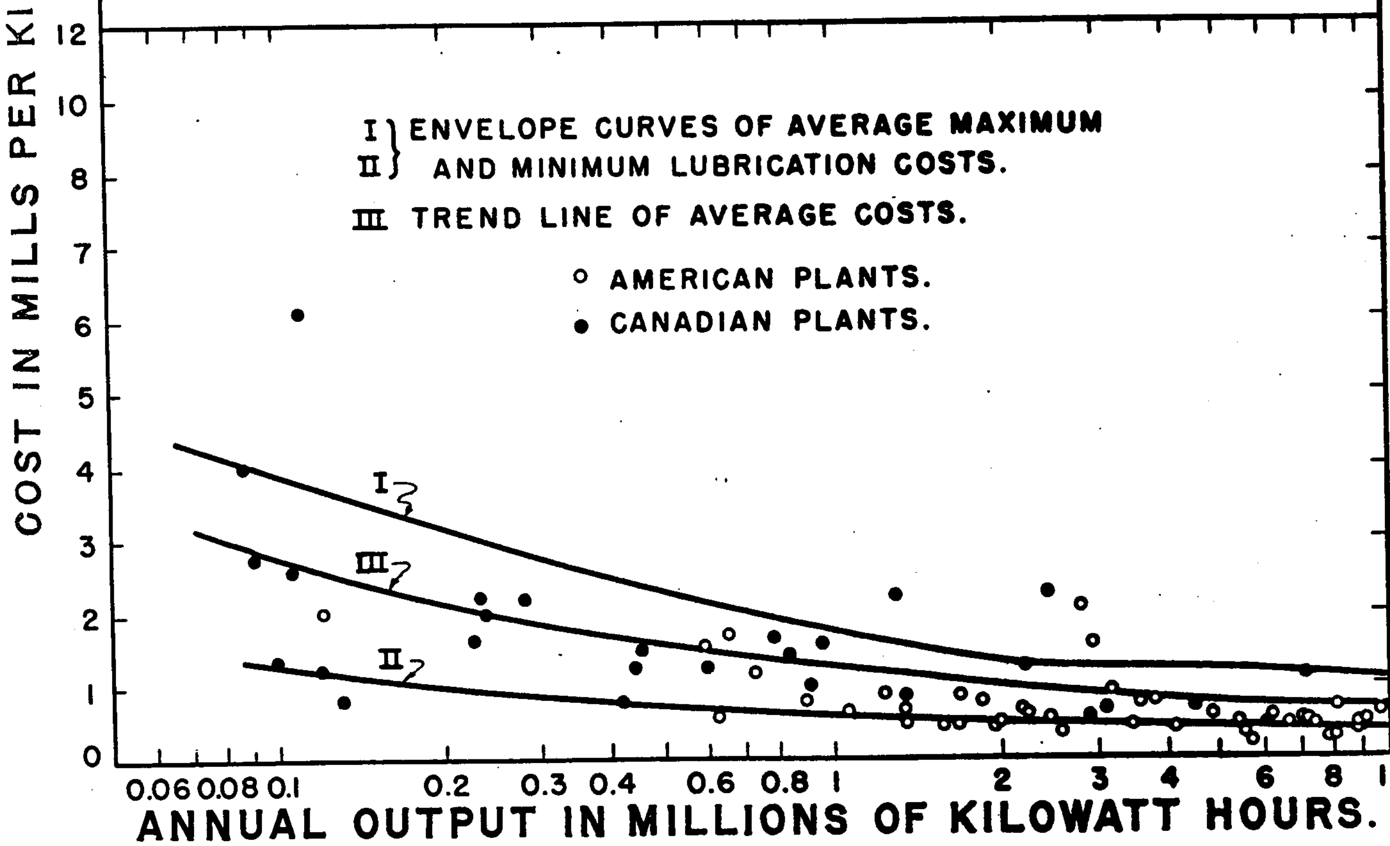


FIG.11
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND LABOUR COST PER KILOWATT HOUR.
I UPPER BOUNDARY CURVE
-Indicative of continuosly attended plants.
II LOWER BOUNDARY CURVE
-Indicative of unattended plants.
III MEAN CURVE
-Indicating transition.
IV SCHEDULED CURVE
-See report.
AMERICAN PLANTS.
CANADIAN PLANTS.
I
II
III
IV
COST IN MILLS PER KILOWATT HOUR.
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.
0
2
4
6
8
10
12
14
16
18
20
0.1
0.2
0.3
0.4
0.6
0.8
1
2
3
4
5
6
7
8
9
10

FIG.12

GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND LUBRICATION CHARGE PER KILOWATT HOUR.



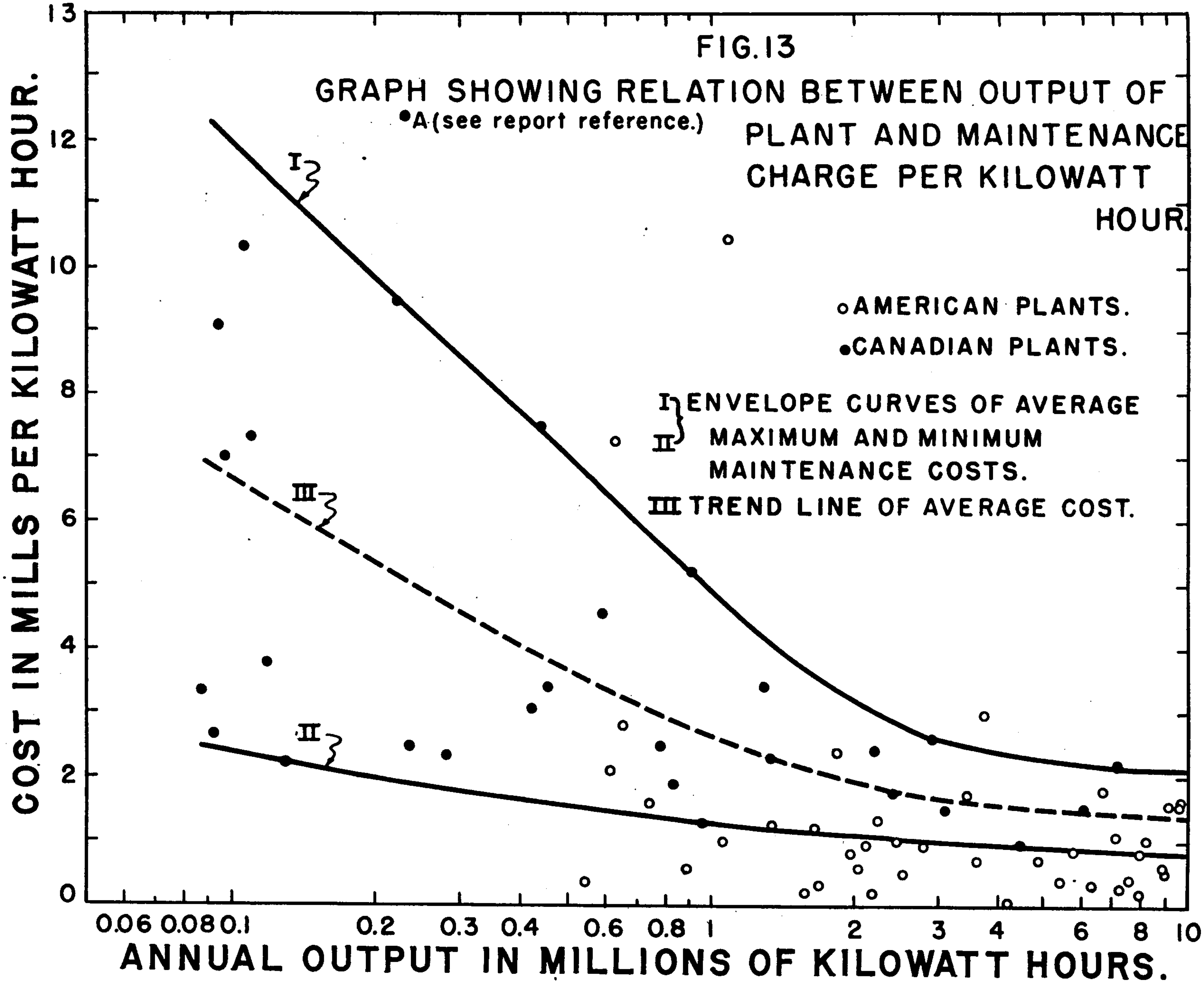


FIG. 13
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND MAINTENANCE CHARGE PER KILOWATT HOUR.
•A (see report reference.)
I
II
III
○ AMERICAN PLANTS.
● CANADIAN PLANTS.
I } ENVELOPE CURVES OF AVERAGE
II } MAXIMUM AND MINIMUM MAINTENANCE COSTS.
III TREND LINE OF AVERAGE COST.
COST IN MILLS PER KILOWATT HOUR.
0
2
4
6
8
10
12
13
0.06 0.08 0.1 0.2 0.3 0.4 0.6 0.8 1 2 3 4 6 8 10
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

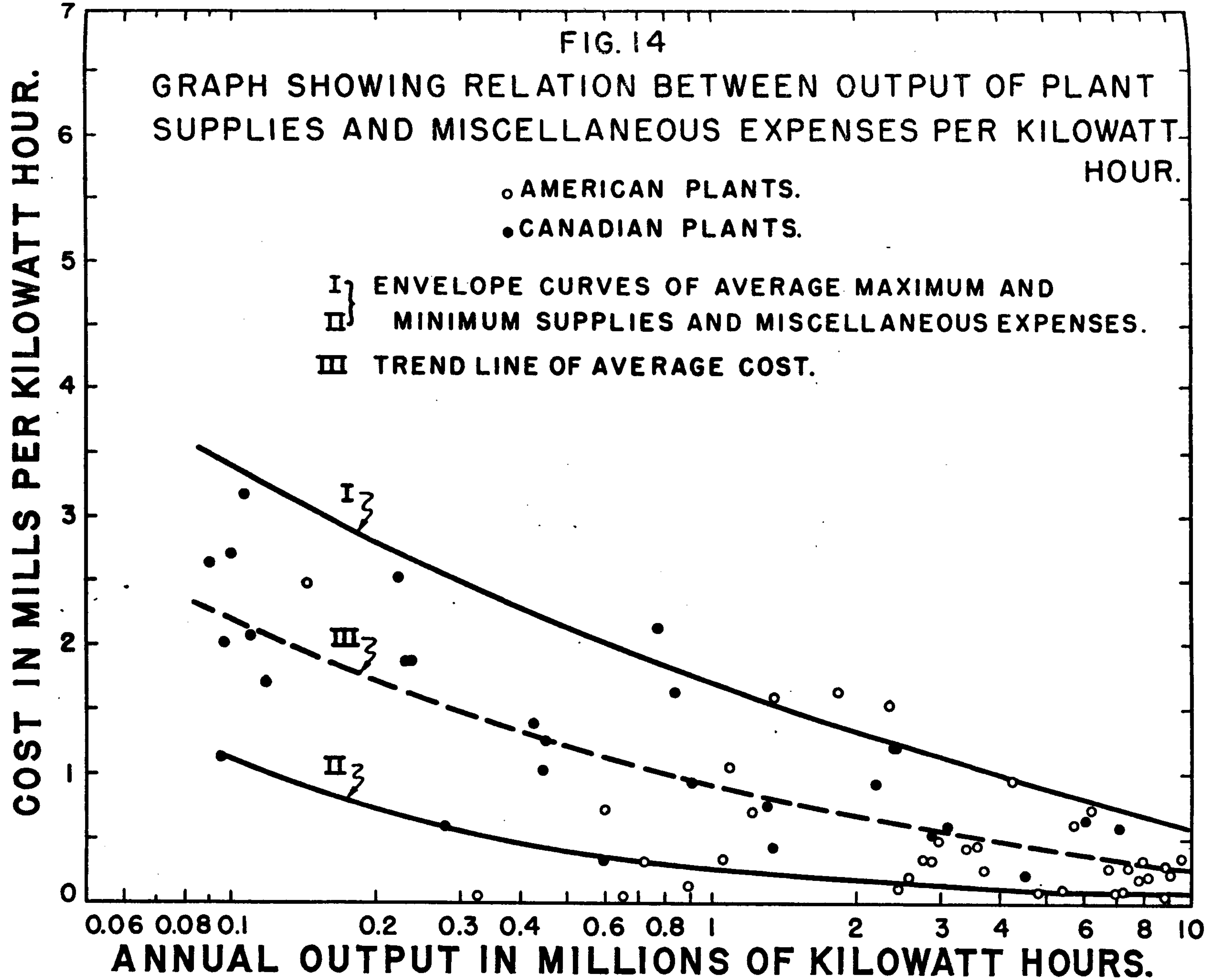


FIG. 14
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT SUPPLIES AND MISCELLANEOUS EXPENSES PER KILOWATT HOUR.
AMERICAN PLANTS.
CANADIAN PLANTS.
I } ENVELOPE CURVES OF AVERAGE MAXIMUM AND
II } MINIMUM SUPPLIES AND MISCELLANEOUS EXPENSES.
III TREND LINE OF AVERAGE COST.
I
II
III
COST IN MILLS PER KILOWATT HOUR.
0
1
2
3
4
5
6
7
0.06
0.08
0.1
0.2
0.3
0.4
0.6
0.8
1
2
3
4
6
8
10
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

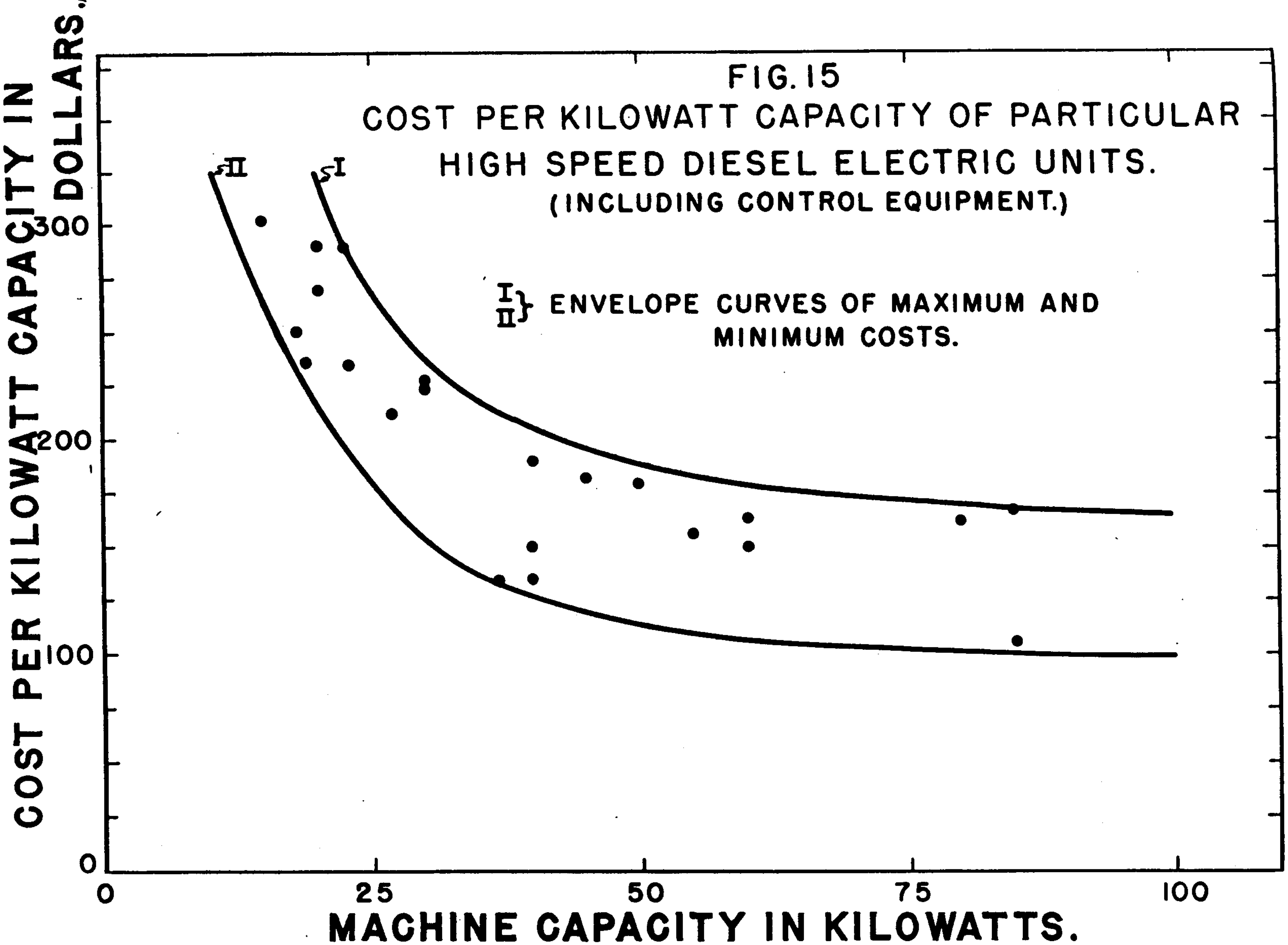


FIG. 15
COST PER KILOWATT CAPACITY OF PARTICULAR
HIGH SPEED DIESEL ELECTRIC UNITS.
(INCLUDING CONTROL EQUIPMENT.)
I
II
ENVELOPE CURVES OF MAXIMUM AND MINIMUM COSTS.
COST PER KILOWATT CAPACITY IN DOLLARS.
MACHINE CAPACITY IN KILOWATTS.
0
100
200
300
25
50
75
100

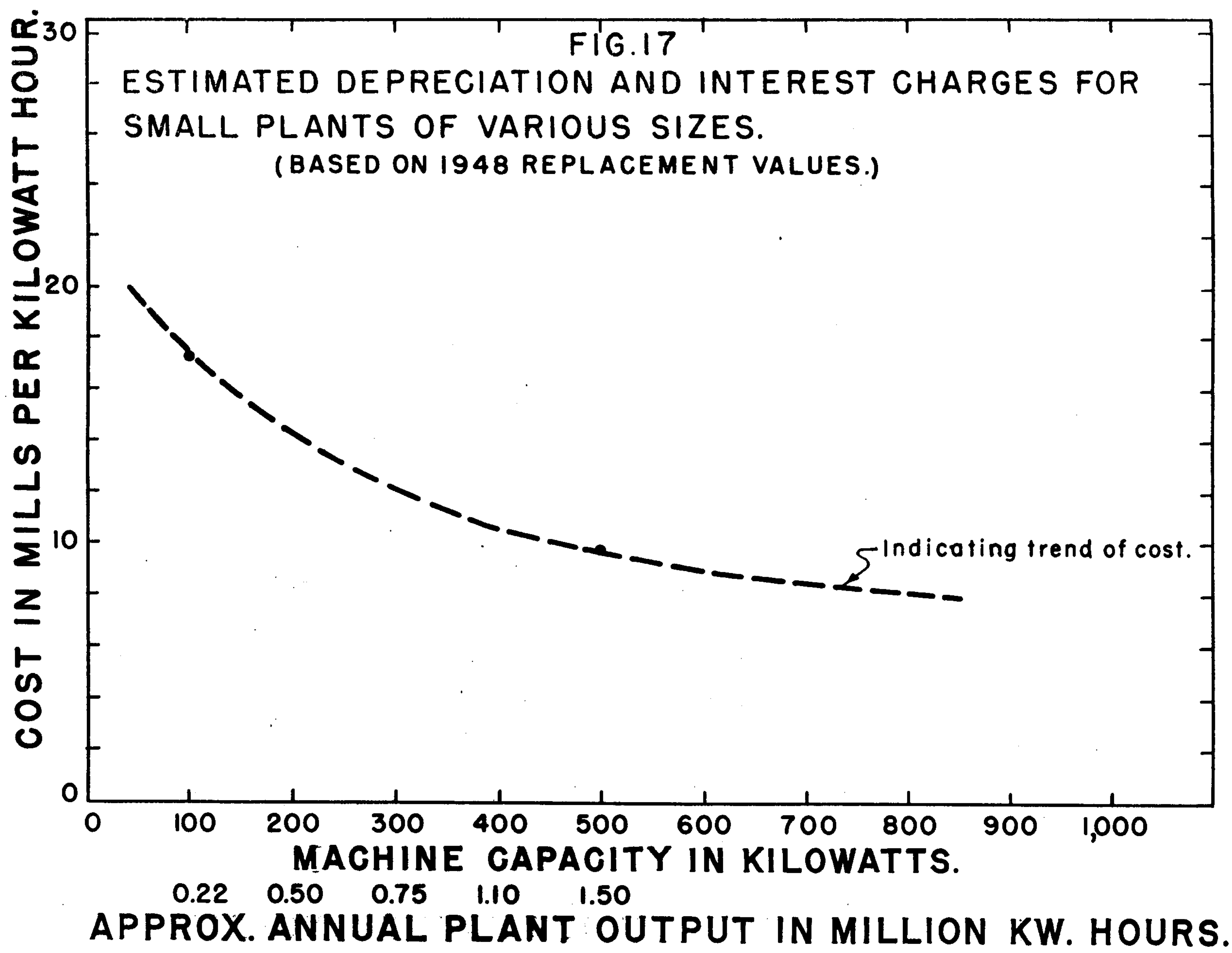


FIG. 17
ESTIMATED DEPRECIATION AND INTEREST CHARGES FOR SMALL PLANTS OF VARIOUS SIZES.
(BASED ON 1948 REPLACEMENT VALUES.)
COST IN MILLS PER KILOWATT HOUR.
30
20
10
0
Indicating trend of cost.
0
100
200
300
400
500
600
700
800
900
1,000
MACHINE CAPACITY IN KILOWATTS.
0.22
0.50
0.75
1.10
1.50
APPROX. ANNUAL PLANT OUTPUT IN MILLION KW. HOURS.

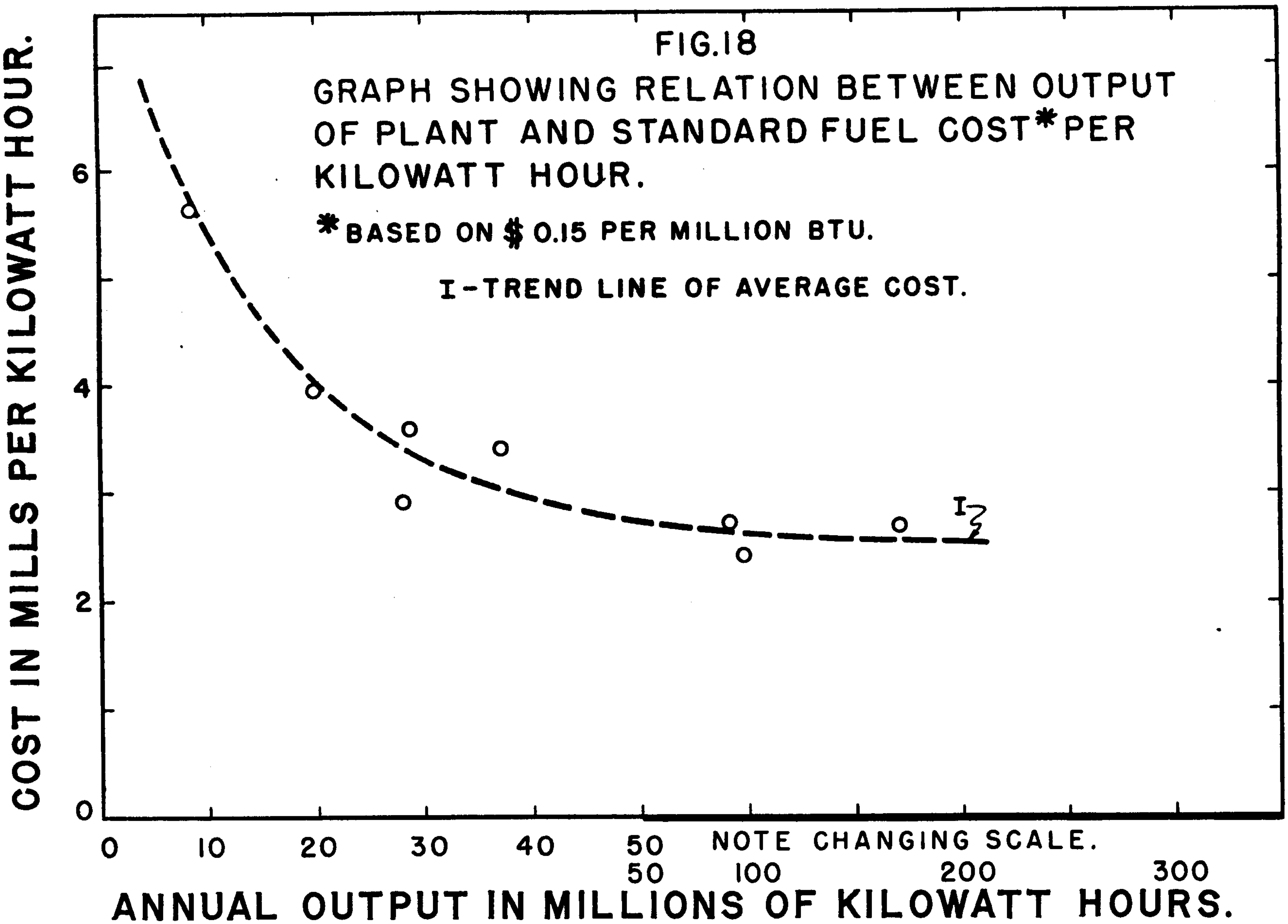


FIG.18
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND STANDARD FUEL COST* PER KILOWATT HOUR.
*BASED ON $ 0.15 PER MILLION BTU.
I-TREND LINE OF AVERAGE COST.
I
COST IN MILLS PER KILOWATT HOUR.
0
2
4
6
0
10
20
30
40
50
50
100
200
300
NOTE CHANGING SCALE.
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

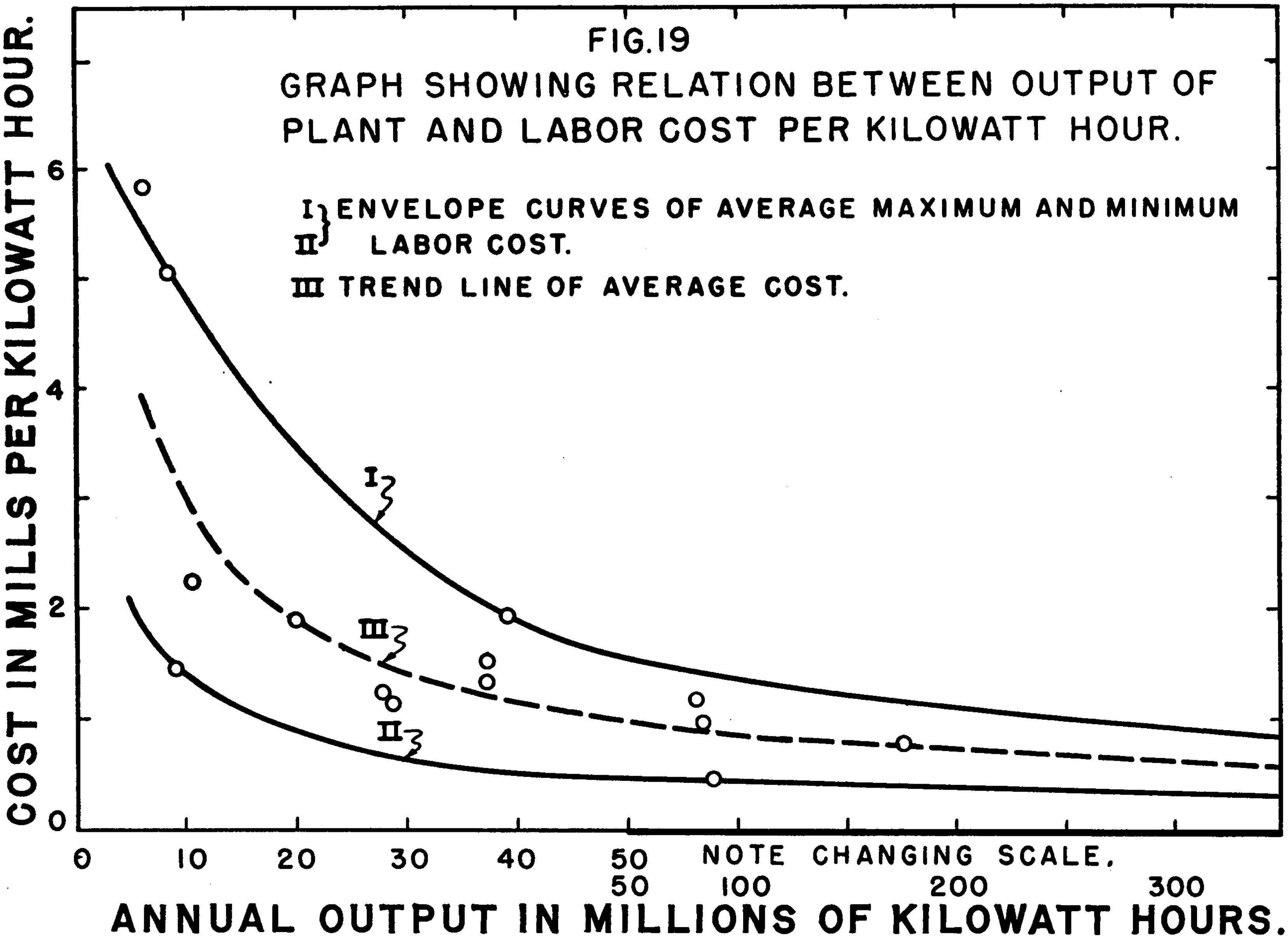


FIG. 19
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND LABOR COST PER KILOWATT HOUR.
I } ENVELOPE CURVES OF AVERAGE MAXIMUM AND MINIMUM
II } LABOR COST.
III TREND LINE OF AVERAGE COST.
I
II
III
COST IN MILLS PER KILOWATT HOUR.
0
2
4
6
0
10
20
30
40
50
50
100
200
300
NOTE CHANGING SCALE.
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

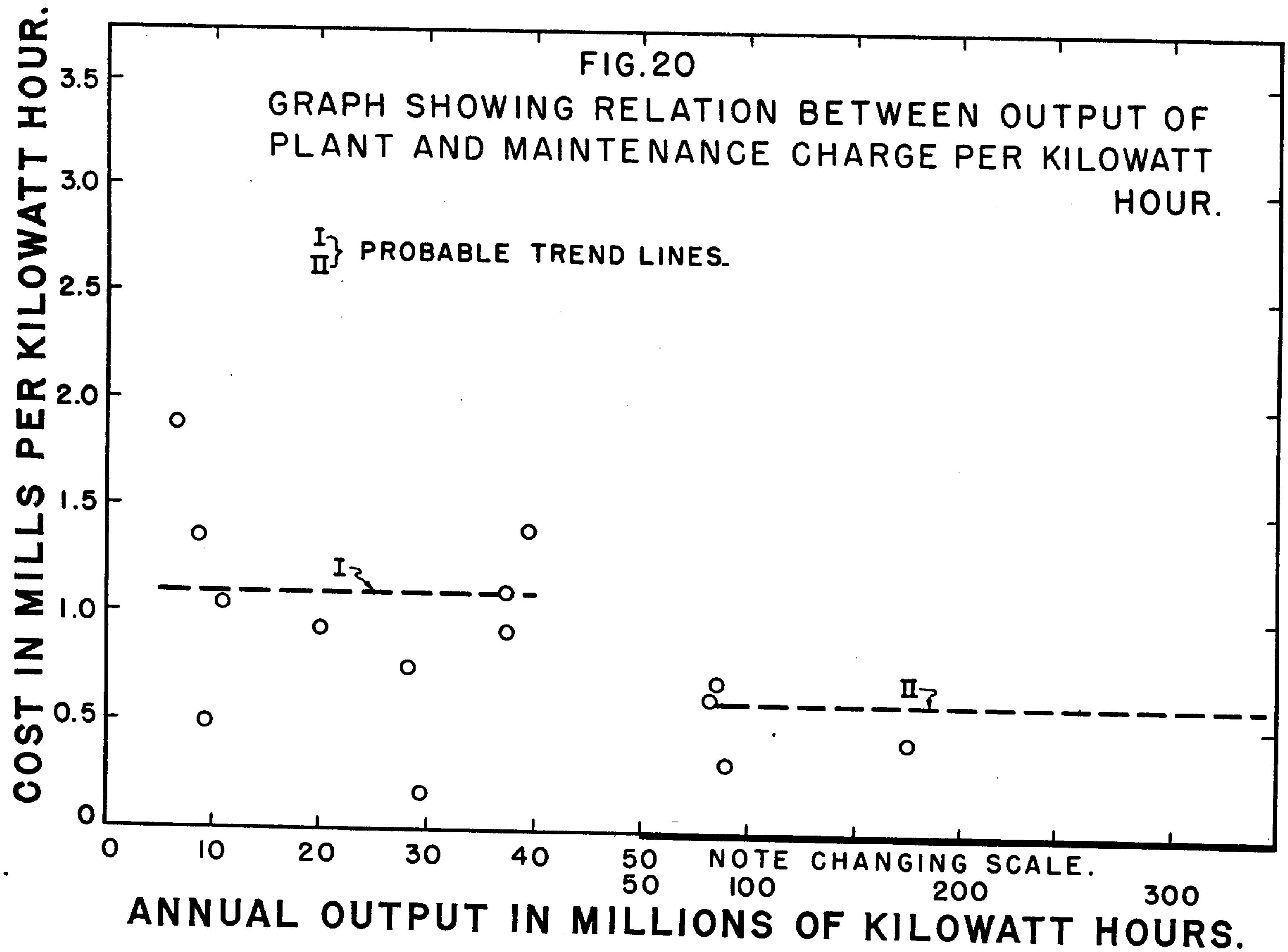


FIG. 20
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND MAINTENANCE CHARGE PER KILOWATT HOUR.
I
II
PROBABLE TREND LINES.
COST IN MILLS PER KILOWATT HOUR.
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0
I
II
0
10
20
30
40
50
50
100
200
300
NOTE CHANGING SCALE.
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

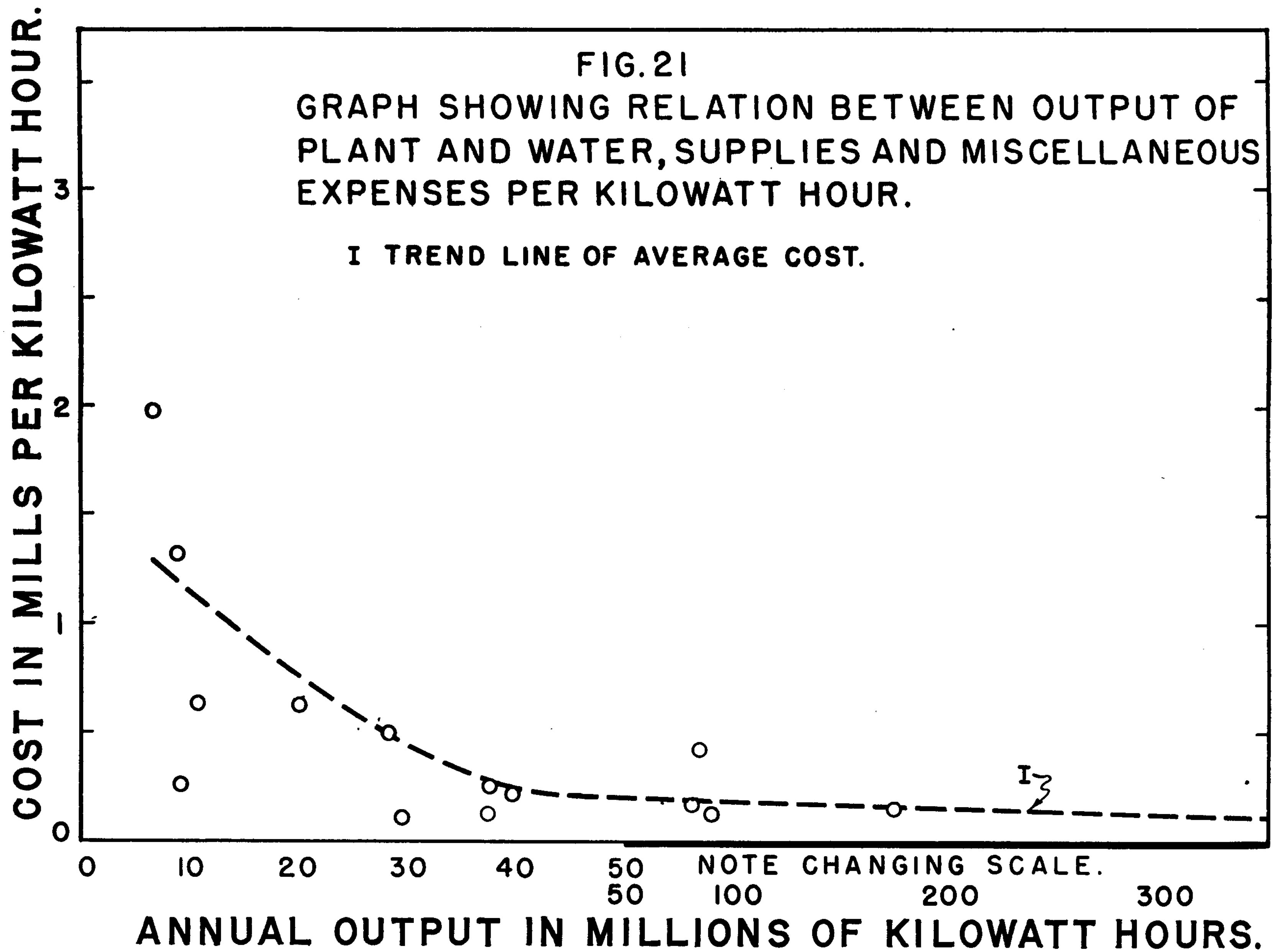


FIG. 21
GRAPH SHOWING RELATION BETWEEN OUTPUT OF PLANT AND WATER, SUPPLIES AND MISCELLANEOUS EXPENSES PER KILOWATT HOUR.

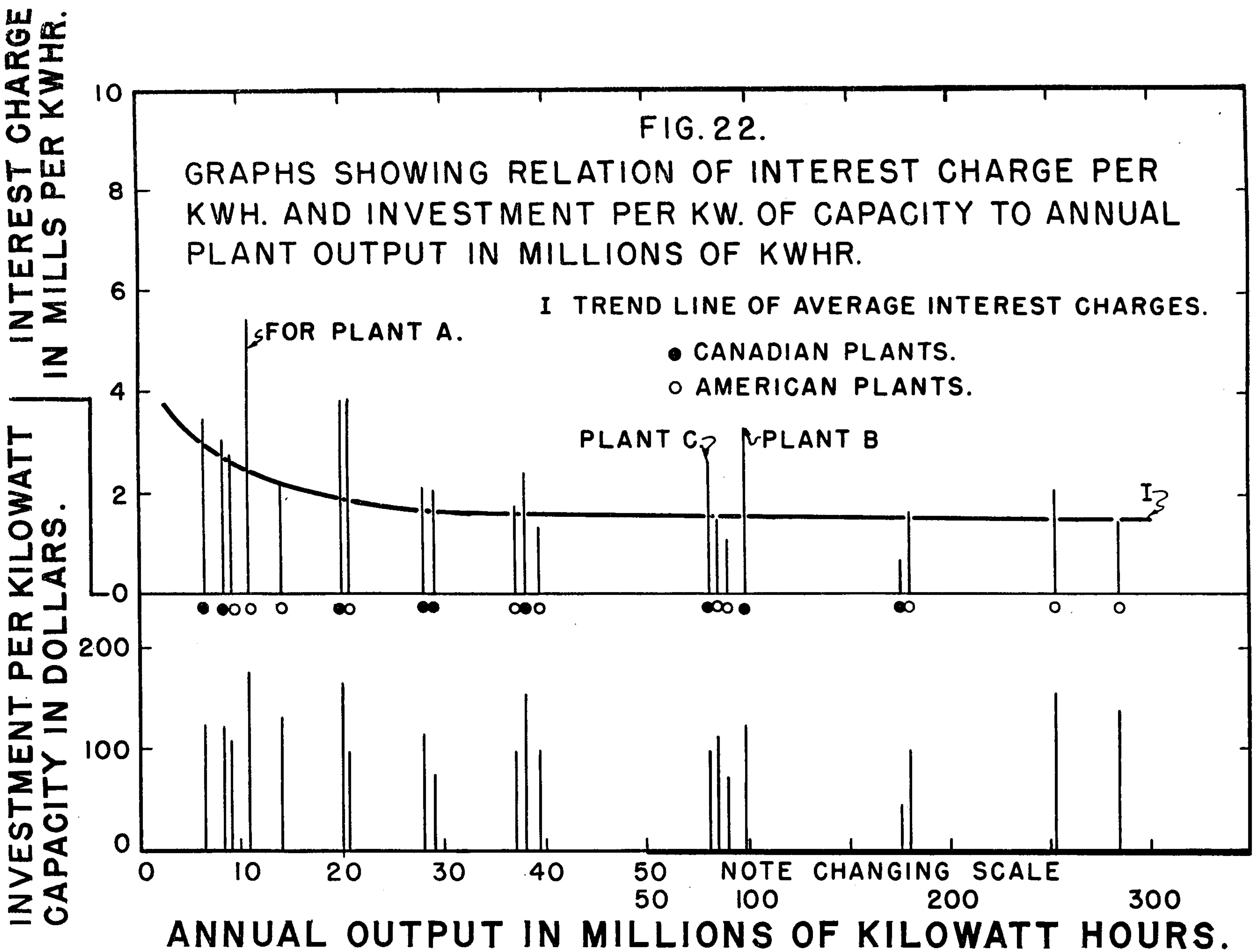


FIG. 22.
GRAPHS SHOWING RELATION OF INTEREST CHARGE PER KWH. AND INVESTMENT PER KW. OF CAPACITY TO ANNUAL PLANT OUTPUT IN MILLIONS OF KWHR.
I TREND LINE OF AVERAGE INTEREST CHARGES.
CANADIAN PLANTS.
AMERICAN PLANTS.
FOR PLANT A.
PLANT C
PLANT B
I
INTEREST CHARGE IN MILLS PER KWHR.
INVESTMENT PER KILOWATT CAPACITY IN DOLLARS.
10
8
6
4
2
0
200
100
0
0
10
20
30
40
50
50
100
200
300
NOTE CHANGING SCALE
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

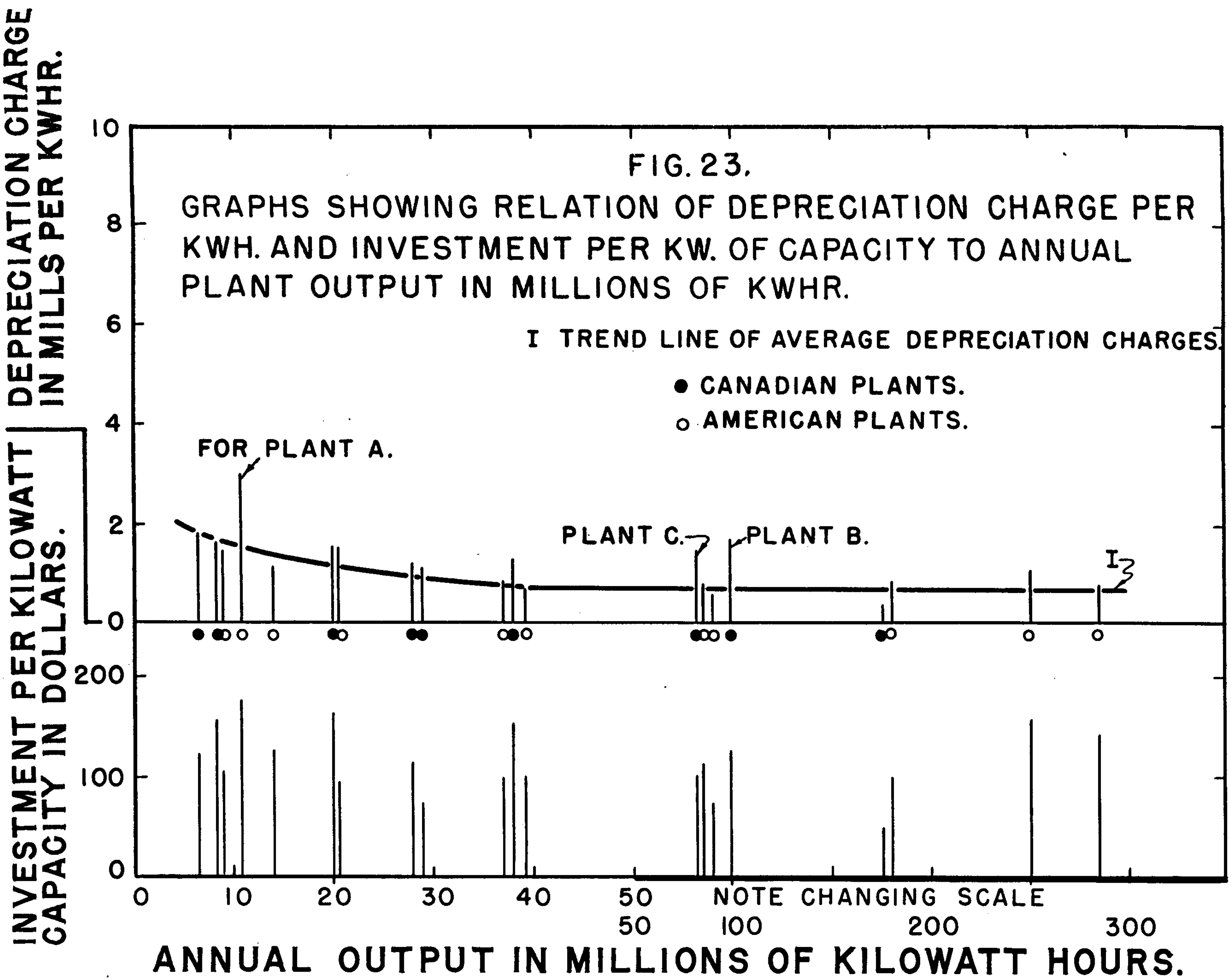


FIG. 23.

GRAPHS SHOWING RELATION OF DEPRECIATION CHARGE PER KWH. AND INVESTMENT PER KW. OF CAPACITY TO ANNUAL PLANT OUTPUT IN MILLIONS OF KWHR.

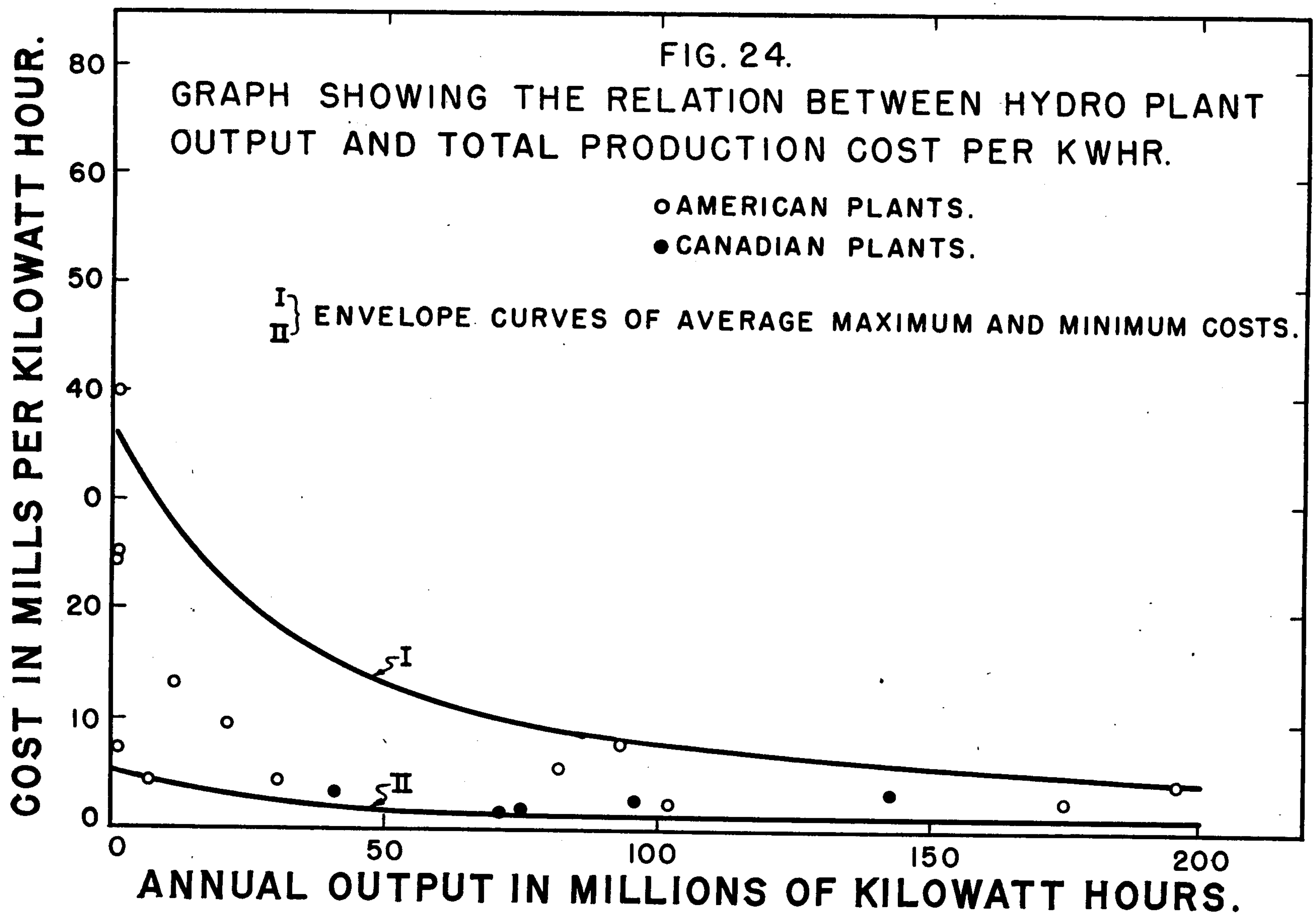


FIG. 24.
GRAPH SHOWING THE RELATION BETWEEN HYDRO PLANT OUTPUT AND TOTAL PRODUCTION COST PER KWHR.
○ AMERICAN PLANTS.
● CANADIAN PLANTS.
I, II ENVELOPE CURVES OF AVERAGE MAXIMUM AND MINIMUM COSTS.
COST IN MILLS PER KILOWATT HOUR.
80
60
50
40
0
20
10
0
0
50
100
150
200
I
II
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

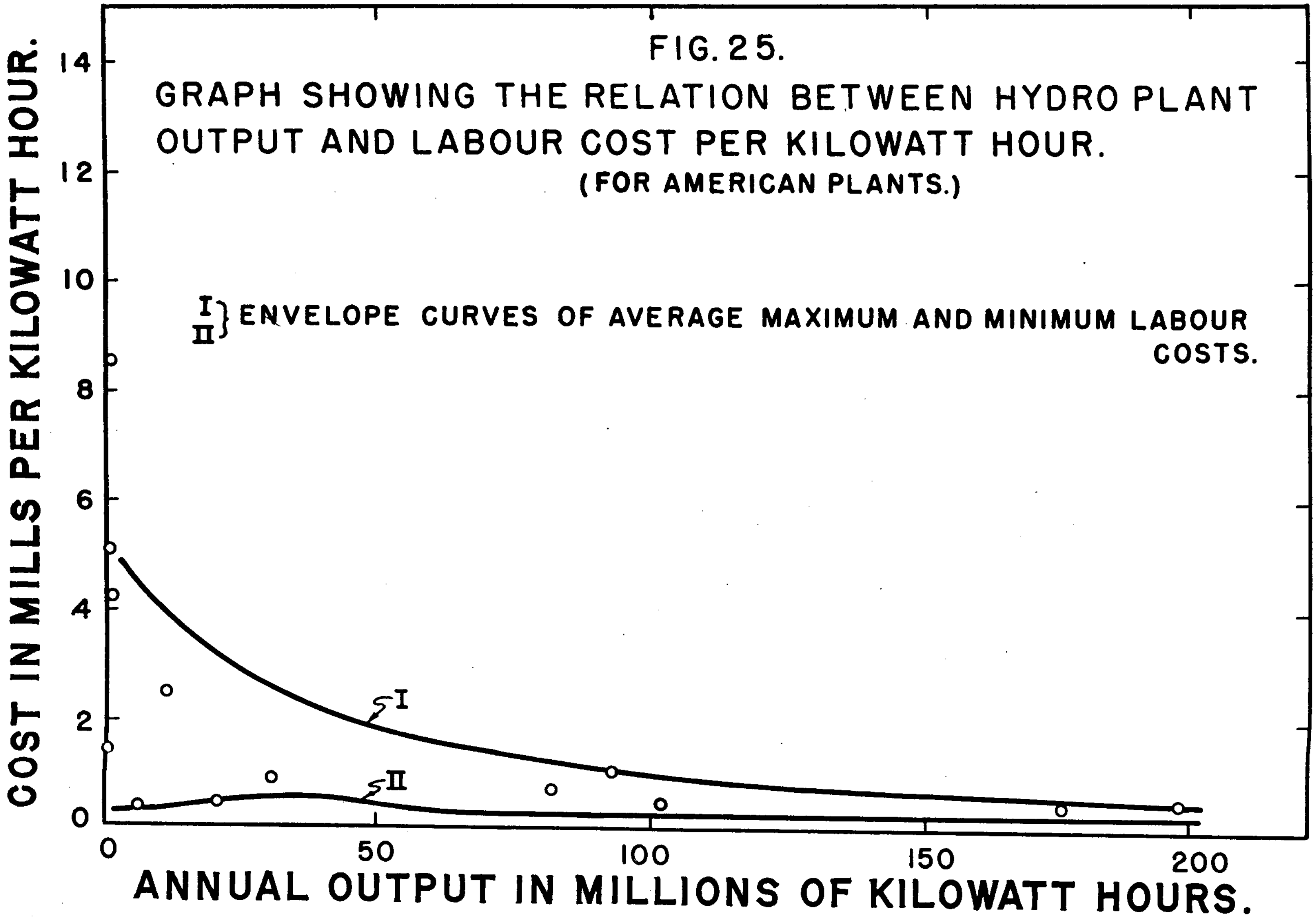


FIG. 25.
GRAPH SHOWING THE RELATION BETWEEN HYDRO PLANT OUTPUT AND LABOUR COST PER KILOWATT HOUR.
(FOR AMERICAN PLANTS.)
I } ENVELOPE CURVES OF AVERAGE MAXIMUM AND MINIMUM LABOUR COSTS.
II
COST IN MILLS PER KILOWATT HOUR.
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.
I
II
0
2
4
6
8
10
12
14
50
100
150
200

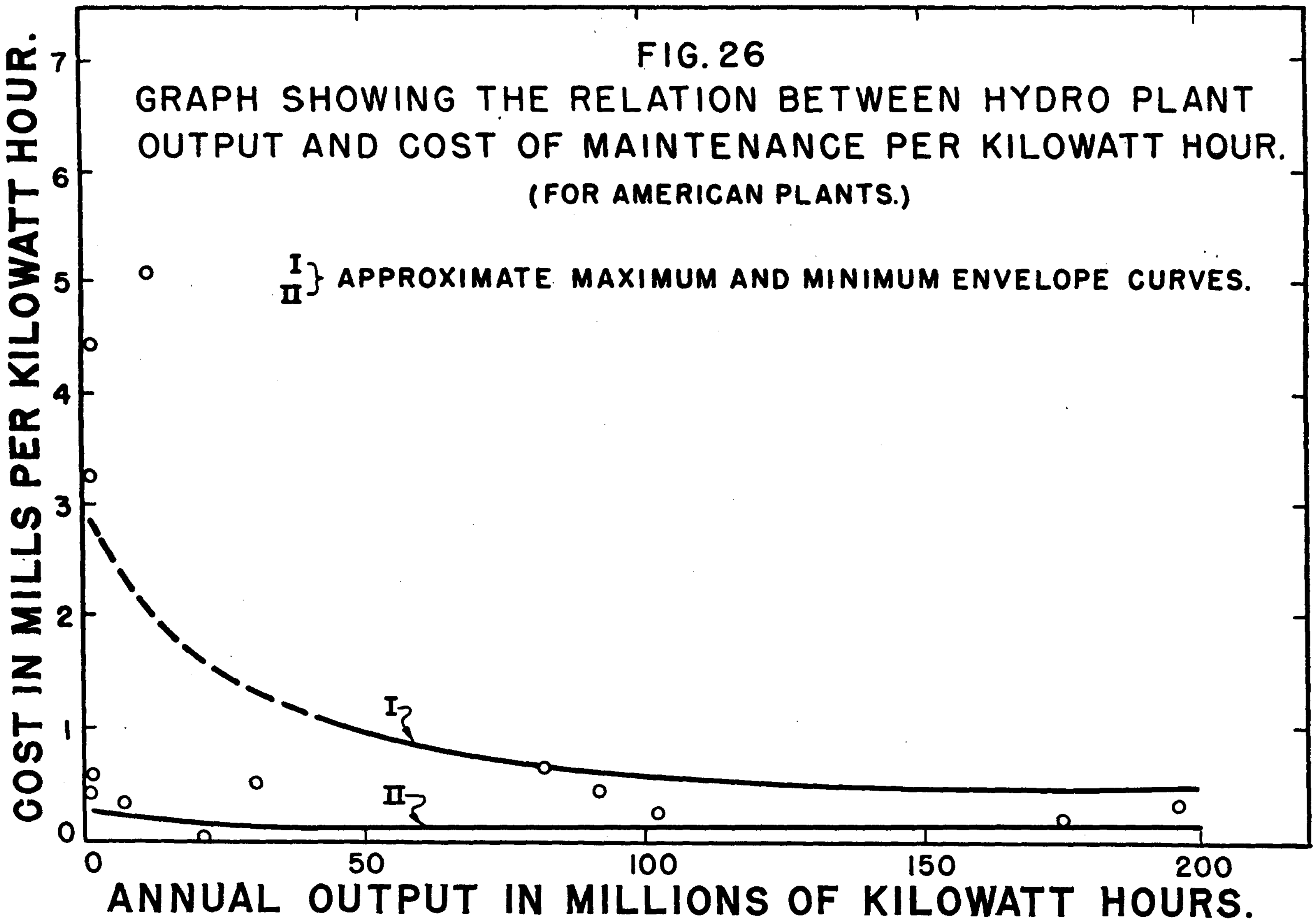


FIG. 26
GRAPH SHOWING THE RELATION BETWEEN HYDRO PLANT OUTPUT AND COST OF MAINTENANCE PER KILOWATT HOUR.
(FOR AMERICAN PLANTS.)
I
II
APPROXIMATE MAXIMUM AND MINIMUM ENVELOPE CURVES.
COST IN MILLS PER KILOWATT HOUR.
0
1
2
3
4
5
6
7
0
50
100
150
200
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

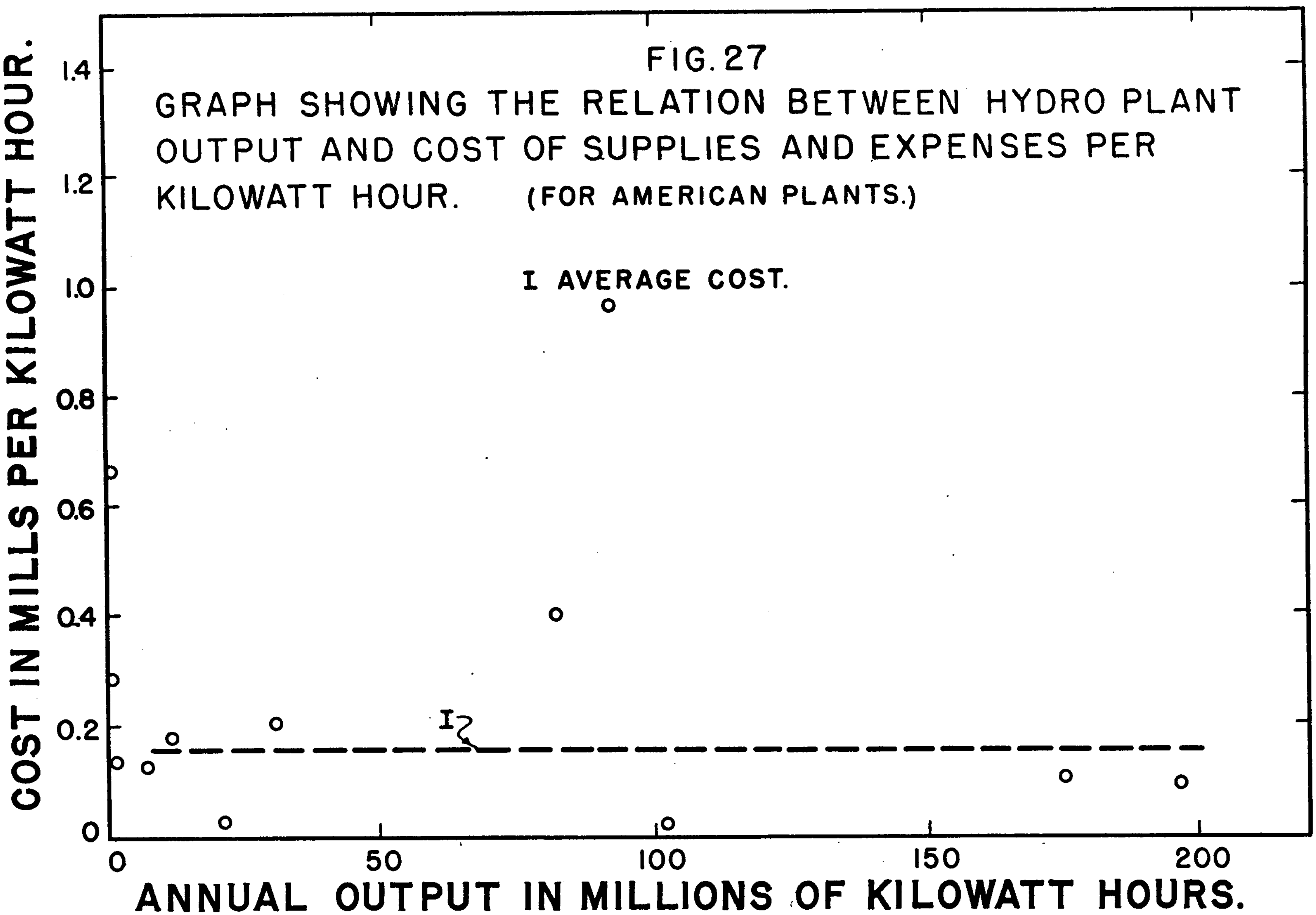


FIG. 27
GRAPH SHOWING THE RELATION BETWEEN HYDRO PLANT OUTPUT AND COST OF SUPPLIES AND EXPENSES PER KILOWATT HOUR. (FOR AMERICAN PLANTS.)
I AVERAGE COST.
I
COST IN MILLS PER KILOWATT HOUR.
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0
0
50
100
150
200
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.

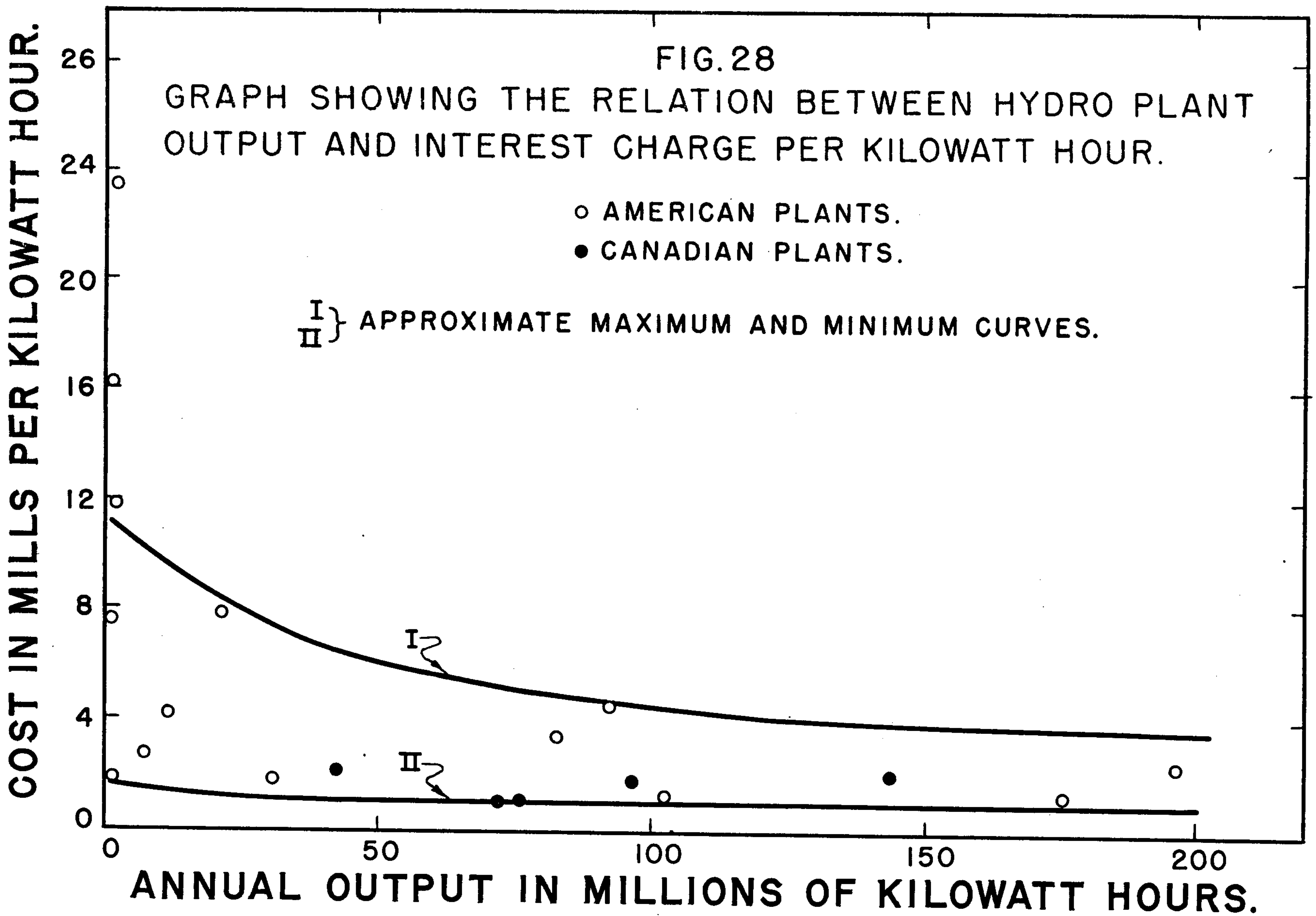


FIG. 28

GRAPH SHOWING THE RELATION BETWEEN HYDRO PLANT OUTPUT AND INTEREST CHARGE PER KILOWATT HOUR.

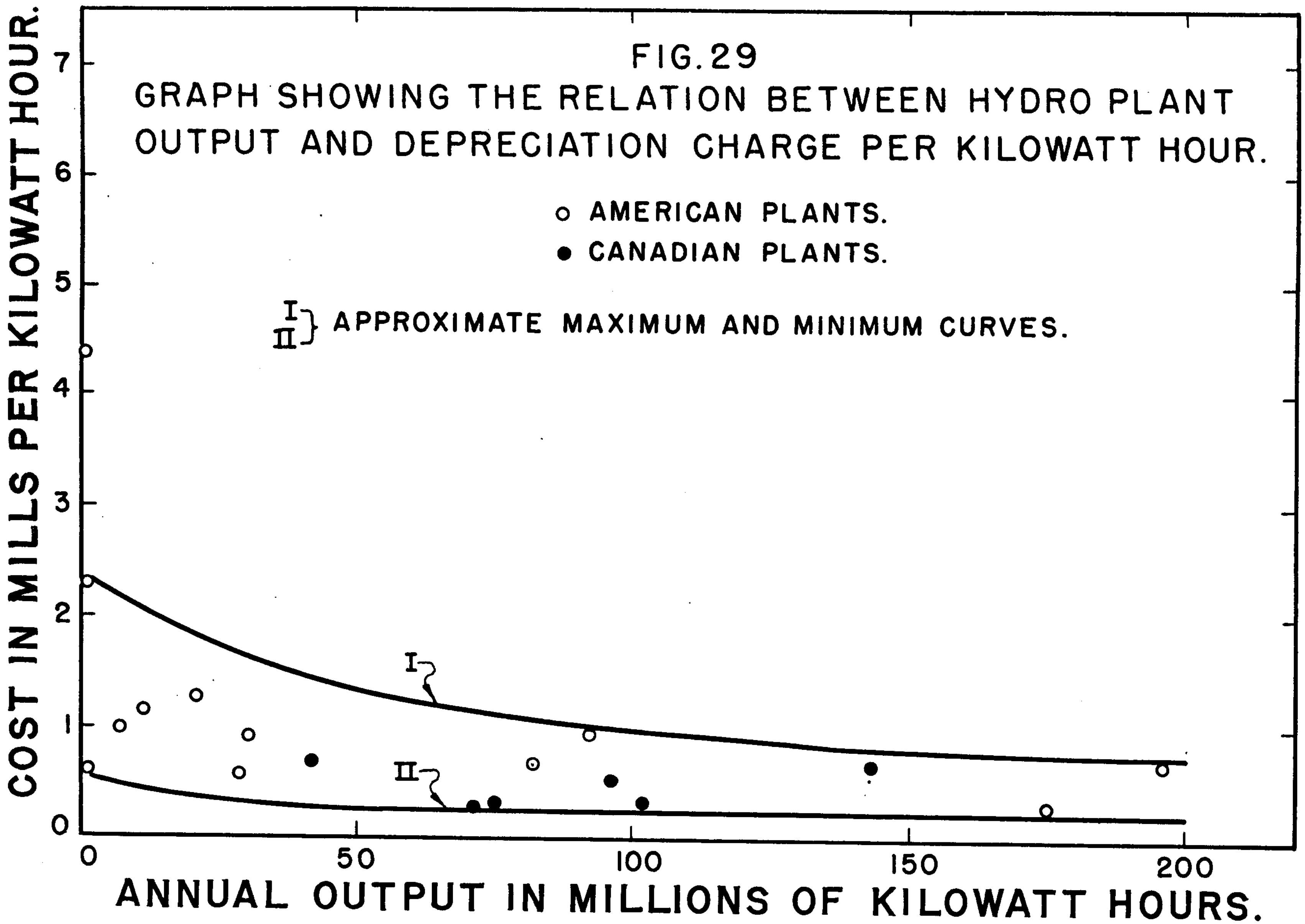


FIG. 29
GRAPH SHOWING THE RELATION BETWEEN HYDRO PLANT OUTPUT AND DEPRECIATION CHARGE PER KILOWATT HOUR.
o AMERICAN PLANTS.
● CANADIAN PLANTS.
I } II } APPROXIMATE MAXIMUM AND MINIMUM CURVES.
COST IN MILLS PER KILOWATT HOUR.
ANNUAL OUTPUT IN MILLIONS OF KILOWATT HOURS.
0
1
2
3
4
5
6
7
50
100
150
200
I
II

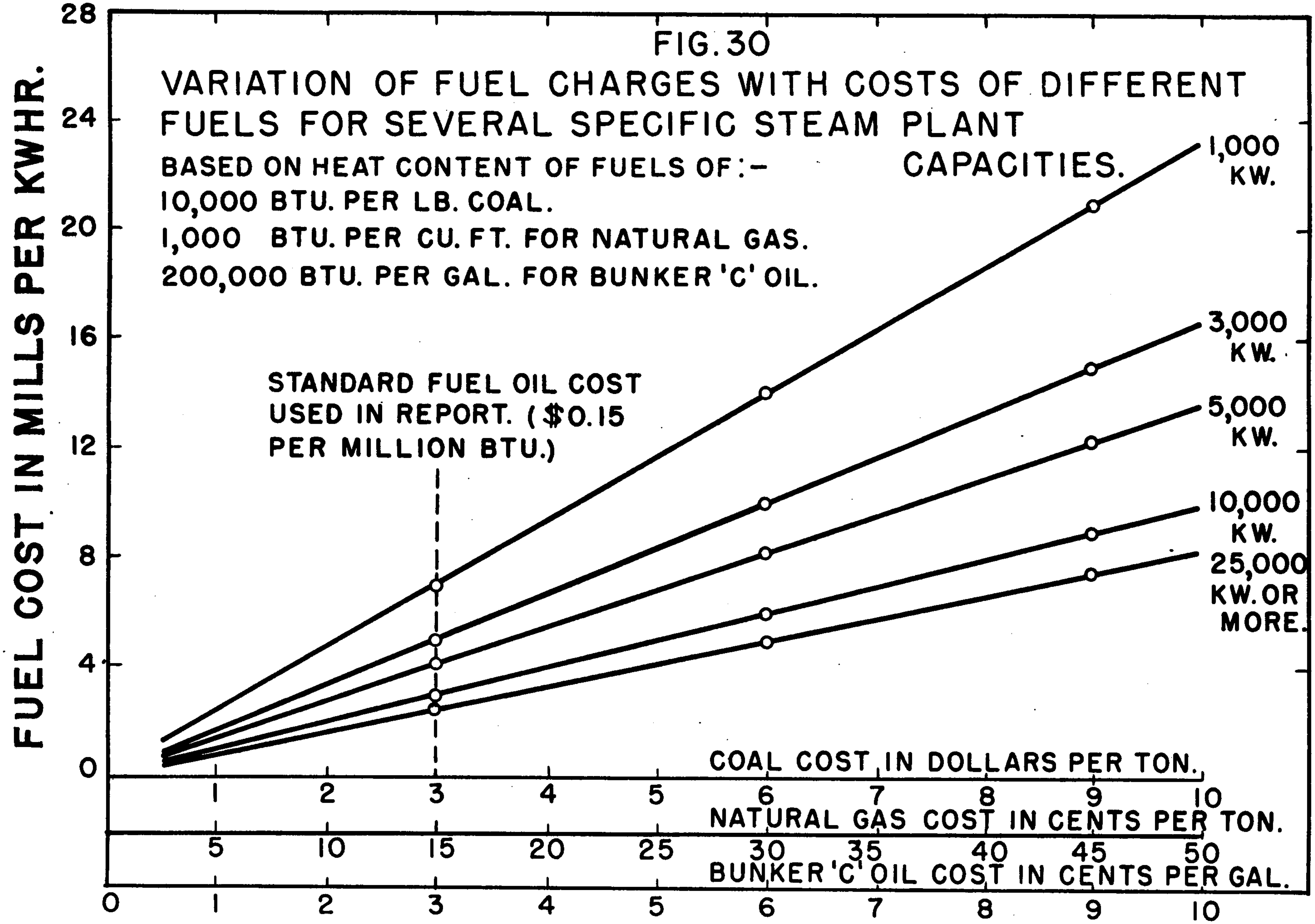


FIG. 30
VARIATION OF FUEL CHARGES WITH COSTS OF DIFFERENT FUELS FOR SEVERAL SPECIFIC STEAM PLANT CAPACITIES.
BASED ON HEAT CONTENT OF FUELS OF:-
10,000 BTU. PER LB. COAL.
1,000 BTU. PER CU. FT. FOR NATURAL GAS.
200,000 BTU. PER GAL. FOR BUNKER 'C' OIL.
STANDARD FUEL OIL COST USED IN REPORT. ($0.15 PER MILLION BTU.)
1,000 KW.
3,000 KW.
5,000 KW.
10,000 KW.
25,000 KW. OR MORE.
FUEL COST IN MILLS PER KWHR.
0
4
8
12
16
20
24
28
COAL COST IN DOLLARS PER TON.
1 2 3 4 5 6 7 8 9 10
NATURAL GAS COST IN CENTS PER TON.
5 10 15 20 25 30 35 40 45 50
BUNKER 'C' OIL COST IN CENTS PER GAL.
0 1 2 3 4 5 6 7 8 9 10

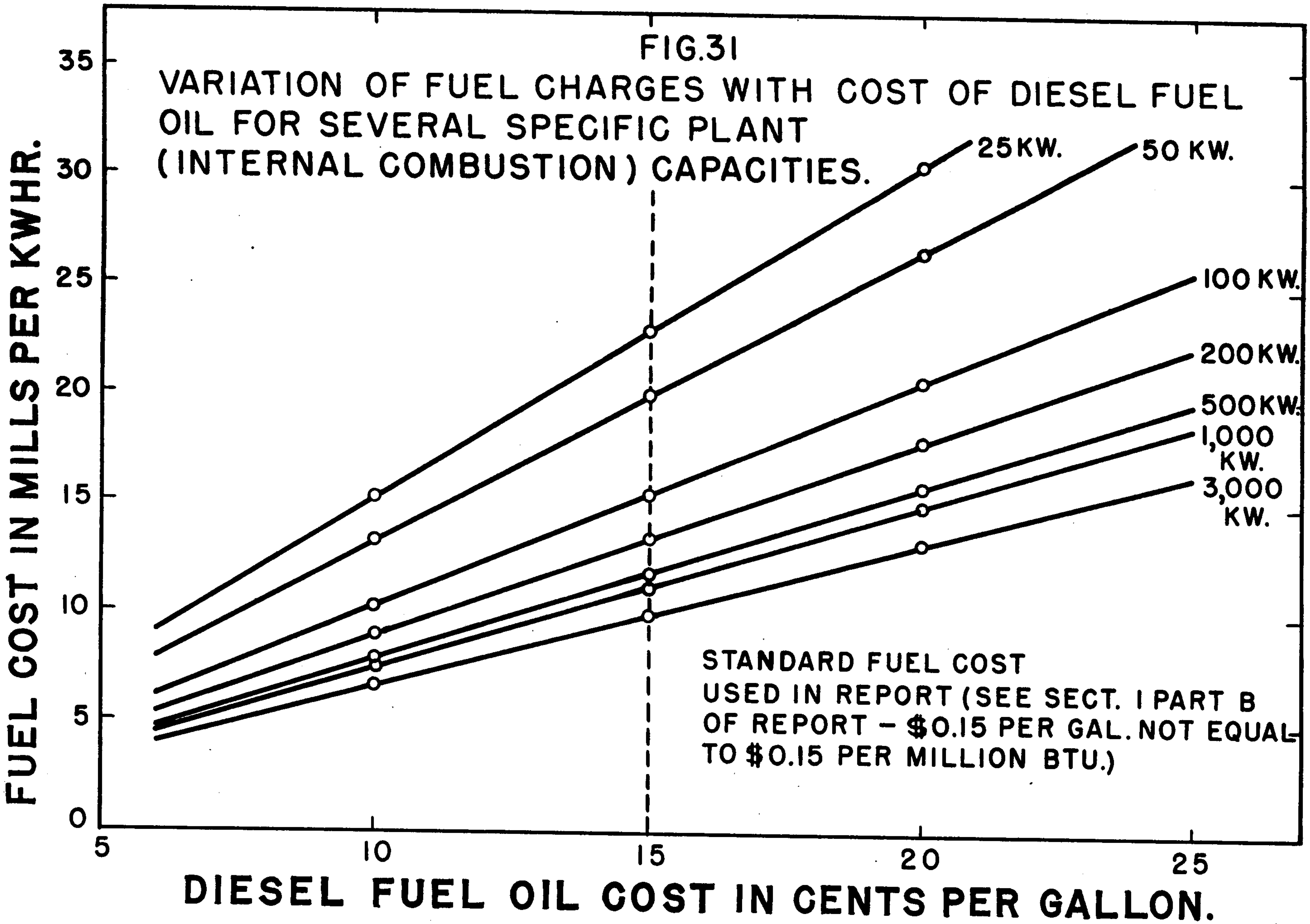


FIG.31
VARIATION OF FUEL CHARGES WITH COST OF DIESEL FUEL OIL FOR SEVERAL SPECIFIC PLANT (INTERNAL COMBUSTION) CAPACITIES.
25 KW.
50 KW.
100 KW.
200 KW.
500 KW.
1,000 KW.
3,000 KW.
STANDARD FUEL COST USED IN REPORT (SEE SECT. I PART B OF REPORT – $0.15 PER GAL. NOT EQUAL TO $0.15 PER MILLION BTU.)
FUEL COST IN MILLS PER KWHR.
DIESEL FUEL OIL COST IN CENTS PER GALLON.
0
5
10
15
20
25
30
35