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# COST ANALYSIS OF ELECTRICITY SUPPLY SYSTEMS FOR RURAL COMMUNITIES

MARCH 1963

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GENERAL ELECTRIC

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# COST ANALYSIS OF ELECTRICITY SUPPLY SYSTEMS FOR RURAL COMMUNITIES

Ralph H. Hofmeister

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# I. SUMMARY AND CONCLUSIONS

This study is devoted to a cost analysis of rural electrification in underdeveloped regions. Summary conclusions based on some "typical" parameters would be of limited value in view of the widely varying economic and physical environments in which rural electrification is being considered. Most present differences of opinion regarding rural electrification--e.g., local generation versus line extension--derive from different cost and environmental assumptions, many of which are not made explicit. The aim here is to develop an analytic framework of sufficient detail to be generally applicable: the analysis is "open" in the sense that parameters appropriate in a particular context, or reflecting altered cost information, may be readily introduced.

Rural electrification can be undertaken at several different levels of centralization: a local generator may supply one village only; a larger generator may serve a group of villages; or the rural areas may be supplied from the grid system. Or, particular applications may be served directly without electrification at all: e.g., kerosene-fueled lamps, and small internal combustion engines for mechanical power. The components of these alternative means of rural energy supply are illustrated in Figure I-1. The end result (box #1) may be achieved by one of four options: 1) direct energy sources (#2); 2) local generation and distribution (#3, 4, 5); 3) intermediate scale generation with distribution to a group of villages via primary distribution lines (#3, 4, 6 7); or 4) a grid connection (#3, 4, 6, 8).

The choice among these alternatives depends upon the relative total costs of serving a given demand configuration. For efficient evaluation of the options in different environments, costs are stated explicitly and comparably for each of the major components outlined above. The explicit costs are expressed in terms of operational variables and parameters so that differing prices, demand conditions, design variables, etc., may be readily introduced. In similar cost comparisons, costs are frequently stated in terms of averages per unit of power (kilowatt or horsepower) or per unit of energy (usually KWH). For the magnitudes of demand to be expected in rural underdeveloped areas, average costs are very sensitive to the scale of use. Further, summary averages do not isolate the critical parameters and variables.

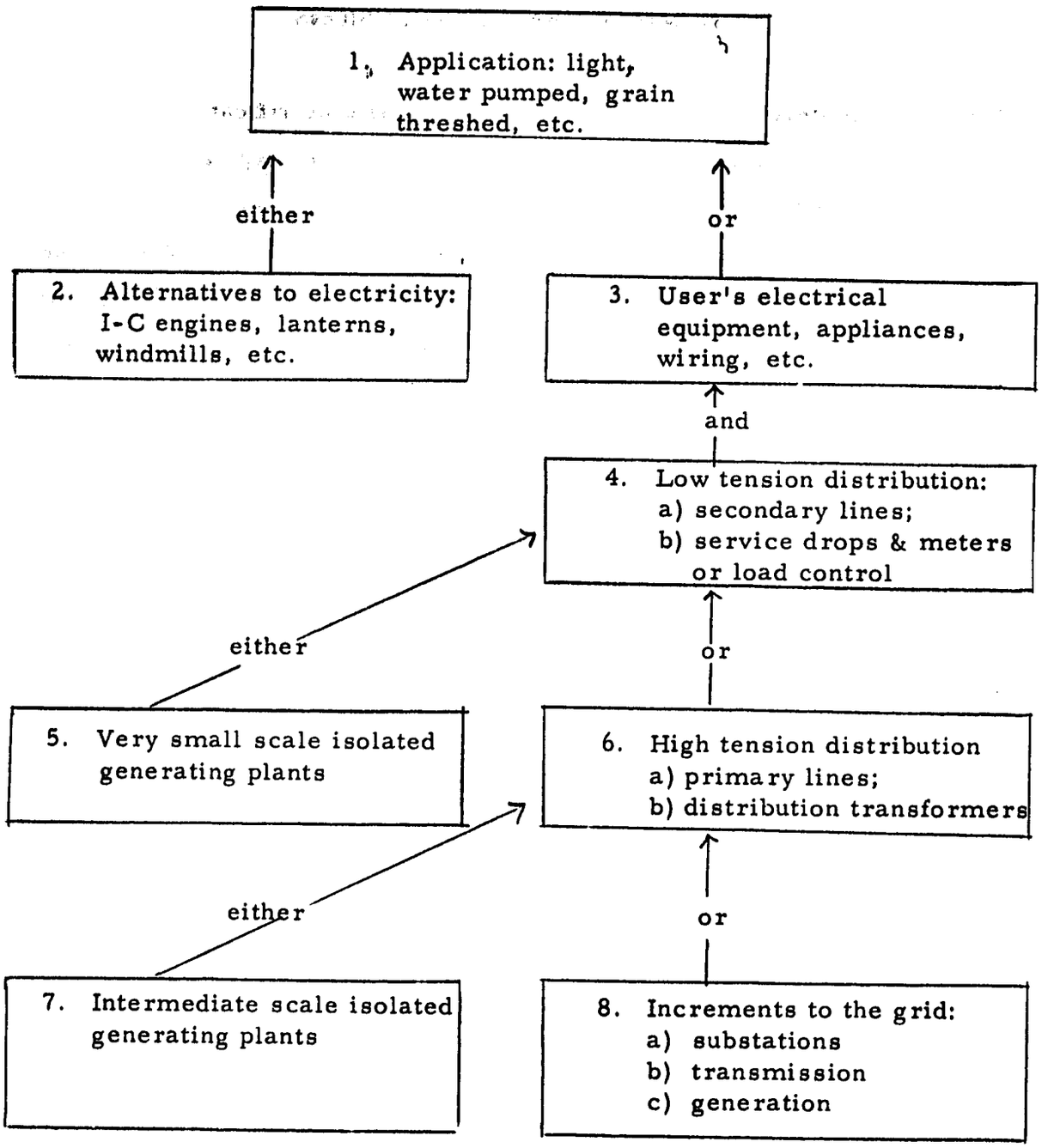


Figure I-1: Components in Alternative Rural Energy Supply Systems

Investigation of detailed equipment costs and underlying technical relationships justify relatively simple cost categories. Within the relevant scale, total costs for each of the system components sketched above may be specified in terms of 1) an indivisible cost; 2) a marginal cost per unit of capacity; and 3) a marginal cost per unit of energy. The indivisible costs are simply the irreducible minimum costs which are incurred for the smallest possible plant. For example, in constructing a distribution line, most of the labor and a large portion of the material costs are invariant with different line capacities: with the smallest feasible capacity these costs must be incurred. Hence the indivisible costs are proportional to the length of the line. The marginal capacity costs represent the additional costs associated with adding another KW of capacity to the system component in question: e.g., the marginal capacity costs per unit length of distribution line are the cost of the increased cross section of conductors and greater losses per KW of load increases. Marginal energy costs are simply the marginal fuel costs per KWH in a fuel-burning plant, and the opportunity cost of hydro energy for supply from a hydro plant.

For each major component of the alternative methods of supply, the detailed items constituting the costs are specified and the underlying assumptions are stated explicitly. Consequently, the implications of alternative assumptions may be readily explored, and new cost data easily introduced. This implies a detailed discussion, and the non-technical reader may prefer to turn directly to the sections wherein summary costs for different alternatives are compared.

Distribution, both primary and secondary, costs are dominant in rural electrification. General cost analyses for lines and distribution systems are not available in the literature; hence, considerable attention is given the development of general long-run cost functions for distribution

lines (III, A) and for distribution systems as a whole (III, B).[1] This analytic framework, with preliminary estimates of the fundamental cost data, is then utilized to evaluate the costs of primary and secondary distribution in a rural environment (III, C, D, E).

Following an analysis of the costs for isolated generating plants--engine generators (IV, A) and hydro and wind (IV, B)--and for grid extensions (V, A), the summary costs for alternative methods of supply are compared. Generation at the village level is compared to generation and primary distribution to a group of villages (V, B, 1), and the latter is in turn evaluated relative to a grid connection (V, B, 2). Small internal combustion engines for direct mechanical drive are compared to electric drive, the electricity being generated in an isolated plant (V, C, 2), or supplied from a grid connection (V, C, 3). Finally, lighting costs with electricity, versus petroleum fuels, are examined (V, D).

The development of a generally applicable analytic model, not data collection, was the primary object of this study. However, approximate demand and cost estimates are essential to determine the appropriateness of the model. Further, preliminary estimates will serve to distinguish between alternatives whose cost differential is wide, and thereby permit research focus on the remaining areas of uncertainty. The values utilized in the succeeding have been carefully interpreted from data now in hand, but should not be applied indiscriminately. No single source has reported costs to the detail employed in this analysis; hence many estimates are composite and draw on several sources which may not be fully comparable.

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[1] The numbers and letters in brackets indicate the chapter and section in which the topic is discussed.

Even with reservations regarding the present data, cost differentials in some cases are sufficiently wide to support fairly general conclusions. The numbers mentioned below are intended to convey the order of magnitude involved; their superficial preciseness cannot be defended, because of both widely varying economic environments, and the preliminary nature of the underlying estimates.

The major conclusions of this study are listed in the following paragraphs. For amplification, and possible minor qualifications, the reader is referred to the chapters and sections identified within the brackets.

1) The scope for small isolated generating plants is very limited. Generally, provision of minimum service to villages within 10 miles of one another would be less expensive from a common diesel generator, than from individual diesel generators; for continuous and fairly dependable supply the economical distance is much greater. These distances aren't sensitive to the maximum demand or the annual energy consumed per village: the dominating costs are the indivisible costs of lines and engine generators. Small generating plants other than diesel-powered are generally higher in cost than diesel, or are restricted to particularly favorable environments. Except where very small quantities of energy are required, wind generation is not feasible. With favorable sites, small hydro plants will provide cheaper energy than local diesel generation, and perhaps cheaper than grid extension. Such sites will be restricted to hilly or mountainous areas, and a grid link may be justified in order to utilize the dump energy otherwise wasted. Even low-cost local fuels, e.g., bio-gas, burned in an engine-generator may provide higher cost energy than a more centralized diesel generator and distribution lines when the uneconomically small scale of plant and limited fuel supply is taken into account. (IV, B, 2, 3; V, B, 1)

2) Isolated intermediate-scale diesel plants serving a group of villages generally compare unfavorably with grid connections for all but the most isolated rural areas. With representative rural load factors, the most favorable conditions for diesel generation--intermittent service and low fuel prices, approximating 2¢/lb.--and very conservative grid cost assumptions, the combined capacity and energy costs for the two may be about equal. But less favorable assumptions increase the relative costs of diesel generation markedly: e.g., with continuous supply, but low fuel costs, diesel generation capacity and energy costs will be about $30/KW per year above moderately high capacity and energy costs. Where rural service cannot be obtained from existing substations, subtransmission line lengths well in excess of 100 miles will yield lower total costs than intermediate-scale diesel plants providing reasonably continuous and dependable supply. (V, B, 2). Where feasible sites for intermediate-scale hydro plants are available, it frequently will be economical to build the necessary transmission lines for integration with the grid system. (IV, B, 3).

3) As a consequence of the above, rural electrification should generally be considered as an area supply from the grid, and should be integrated with the supply to the larger towns in the area. Grid extensions will normally be more economical than local generation, even with the very low demands at initial electrification. With an economic design for the grid extension, marginal capacity costs in rural villages will be about 10 per cent above those in the larger towns in the area, and energy costs will be negligibly higher. The higher costs for electrification of a rural village arise mainly in the indivisible costs of the primary distribution line required for the village. (III, C).

4) Directly coupled engines will provide much cheaper mechanical power than will electric motors supplied from small- or intermediate-scale diesel plants, or any other source having comparable costs. Even if a diesel generator is already installed for an evening lighting load, it may not be feasible to operate it during the day to supply mechanical power via electric motors. (V, C, 2)

5) Given the relative low fuel costs (about 2¢/lb. for distillate fuel) for the alternative direct engine drive, potential agricultural and light industrial loads will constitute little justification for rural electrification in South America, or any area having comparable fuel costs. Only with concentration of a number of small power requirements at one point--as, e.g., in a rural industrial estate--will electric motors supplied from a grid show significant total savings over direct engine drive. Irrigation pumping is especially unfavorable because of the relatively high costs for secondary distribution. (V, C, 3)

6) Even with the relatively high fuel costs in India, diesel engine pumping for irrigation has lower total costs than electric pumping from a grid supply with current patterns of use. With reasonable expectations regarding capacity utilization, contingent on reform of the present uneconomic rate structures, on-peak electric pumping would still show little or no savings relative to diesel engine pumping. However, strictly off-peak pumping will show significant savings ($5-10 per connected HP annually) at net of tax fuel prices (about 4¢/lb.), and marked savings ($15-30 per connected HP annually) at present fuel costs including taxes (about 7¢/lb.). Hence, the implementation of off-peak pumping for irrigation and salinity control is most important. (V, C, 3)

7) The costs for secondary distribution being significantly lower, and utilization patterns more favorable, electric drive for light industrial applications within the village proper appears more favorable than for irrigation pumping. Off-peak operation probably is not feasible, but annual

savings of $100 per power installation are probable at low Indian fuel costs, and double that for fuel costs including taxes. Key factors influencing the relative costs of electric and direct engine drive, and for which data are very scarce, are: the length of secondary distribution line per motor installation, the demand coincidence with the system peak, hours of use per year, and the maintenance costs of small internal combustion engines. (V, C, 3)

8) The chief obstacle to more general domestic service is the customer costs--administration, meter reading and billing, and collecting--with centralized agencies, as these are very high relative to the remaining incremental costs for minimum service to a dwelling within an electrified village. The latter probably are less than present expenditures for lighting with kerosene-fueled lamps. Domestic service may be able to bear a part of the indivisible costs of electrifying the village, but the extent cannot be determined from present inadequate demand data. (III, D, 2, 3, and V, D)

9) In South America, most of the justification for rural electrification must come from household consumption and amenities such as street lighting and recreational uses. Electrification may be economically defensible in the higher income rural areas, but much better demand data than now exists would be required to demonstrate it. Conclusions cannot be based on current usage and rates, as the latter are generally below even the marginal capacity and energy costs.

10) Given the low average income in Indian rural areas, domestic consumption probably could not assume a significant part of the indivisible costs of village supply. In India, the appropriate shadow price of petroleum fuels is important for assessing grid extensions; if the price plus tax approximates the true cost of the fuel due to scarce foreign exchange, one light industrial power application, or 10-15 HP of off-peak

irrigation pumping, will justify a mile of primary line to connect the village. Hence, electrification of even small villages would be indicated. If, on the other hand, the applicable real cost of fuel is near the rural price, less tax, double the above demands are required. But these demands are in the magnitude of probable demands in many villages, and rural electrification in India is fairly promising. This conclusion is not rebutted by the common experience of heavy financial losses for rural electrification programs. Uneconomic rate structures, intended as subsidies to agricultural and small industrial users, encourage uneconomic patterns of utilization and create unnecessarily high costs.

11) There are some possibilities for reducing the costs of rural grid extensions from the higher reported values: copper is not an economic conductor material; primary distribution voltages are generally too low, and require excessive investment in sub-transmission lines and substations; single-phase supply is clearly indicated up to moderate connected motor loads; and lower design standards for rural lines, and simpler distribution transformer installations, may be justified. All of these require learning from the best practices of other countries, with very little technical or engineering development. But new and imaginative technical developments in low-cost load control or metering devices for low domestic demands, and off-peak metering of control devices for small power applications, would be most useful.

12) However, the most promising area for lowering the costs of rural electrification relative to its benefits, lies in purely economic and institutional alterations Economic rate structures, based on marginal cost pricing principles, would eliminate patterns of use which now involve costs higher than the benefits to the user. Utilization with high benefits relative to the marginal costs, such as off-peak irrigation pumping, can be promoted. Transferal of administration and collection

to the village level would markedly lower the costs of service to low-income households, and thereby allow more general use.

## II. THE SETTING OF THE ANALYSIS

This chapter is introductory to the detailed analysis of the succeeding chapters: the demand context is sketched, and the background of the analysis is reviewed.

### A. The Demand Context

Approximate magnitudes of rural demand must be established so that an applicable analytic model may be developed. Further, some knowledge of the probable range for critical demand parameters will enable us to discard the grossly uneconomic supply alternatives and thereby focus attention on the remaining areas of uncertainty.

An important characteristic of most of the rural areas of the underdeveloped countries is the clustering of dwellings into small villages. Supply to isolated farmsteads, as is the rule in the U.S. and Canada, would be prohibitively costly relative to the levels of income and economic activity in underdeveloped rural areas. The rural village approximately corresponds to the feasible secondary distribution area, and is a natural unit for demand analysis.

Potential electricity demands to drive irrigation pumps and a variety of agricultural processing and light industrial appliances would constitute the major portion of rural demand Heating applications of various kinds could consume large amounts of electricity, but the economic feasibility of such uses must be subjected to close scrunity.

Fairly detailed data has been reported for a sample of "typical" villages in Madras State, India, which has maintained a very ambitious electrification program for over a decade [2] Power demands for

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[2] Government of India, "Report . . . on Rural Electrification in Madras," Annexure IX. The data reported in the succeeding have been calculated from the basic tabulations.

agricultural (apparently irrigation pumping is the main use) and industrial use are fairly large: combined, they range upwards from 40 KW connected load. The village sizes are not reported, but they can hardly be less than several thousand persons.[3] Agricultural demands tend to be larger than industrial, representative connected loads are 60 KW and 40 KW, respectively, with agricultural loads reported for all of the villages, but industrial demands for only two-thirds of the total.[4]

The annual energy consumption per connected KW of load is fairly low. For agricultural use, the highest village consumption relative to connected capacity implies an annual use of 1,300 hours; the lowest, less than 200; and a median, about 700. Industrial usage is only slightly higher; the range of annual utilization is 400 to nearly 1,500 hours.[5]

An attempt has been made to derive estimates of power demands in Indian villages from the irrigation requirements--as determined from basic rainfall, soil structure, and cropping data--and from the volume of agricultural commodity processing at the village level.[6] Peak irrigation requirements were estimated at 14-31 KW per square mile, and peak processing demands at 12-20 KW per village. The estimated annual consumption implies annual load factors--taking each class independently--of 50-60% for irrigation, and 10-30% for processing.[7]

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[3] The average village size in Madras is about 1,800 persons, or perhaps 400 households. Only the larger villages have been electrified to date (one-third of the total), so the above estimate is conservative.

[4] Ranges: 8-180 KW and 9-84 KW, respectively. All of these demands are converted from the reported horse-power connected at an assumed motor efficiency of 80%.

[5] These utilization estimates are calculated from the reported electricity consumption and the connected motor HP, assuming an efficiency of 80%. These should not be confused with the load factor of the village, as all the connected loads probably would not be connected simultaneously.

[6] Ahmad, "Analysis of Demand for Electric Power in Rural Communities."

[7] Ibid., Tables II.5 and III.6.

These peak demands are consistent with the Madras data, when the latter are adjusted for probable village size and demand coincidences, but the irrigation utilization of capacity is much higher. This discrepancy emphasizes that present patterns of use must be interpreted with caution. Special subsidized rates are allowed irrigation pumping in Madras, also subsidies are given for pump installations; the combined effect being the installation of pumping capacity which is only partially utilized.[8] Under a more rational rate scheme the pattern of use might be quite different.

However, annual utilization rates higher than the upper limit of the Madras sample are not plausible. For example, assume a motor in a light industrial application which runs an average of six hours in each eight-hour shift for 250 days each year; the resulting annual utilization is only 1500 hours. Multi-shift operation would be required for appreciably higher utilization Irrigation utilization will vary widely depending on the climate and number of crops. But again, if irrigation is supplementary to rainfall (as most pump irrigation is), and taking account of the advantages of high rates of delivery, annual utilization periods greater than 1,200 - 1,500 hours do not seem probable. These rates are far above averages reported for rural Japan.[9]

The diversity between power demands[10] is important as it determines the generating capacity which is required to supply a given connected load.

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[8] For the rates and subsidies, see Gov't of India, "Report on . . . Rural Electrification in Madras," pp 13-14 and Annexure VII. The resulting use patterns are such that diesel engine pumping would yield lower total costs (but not to the cultivator). See below, sec. V, C, 3.

[9] Sasamori, "Statistical Report on the Use of Electricity in Agriculture in Japan," Table 14, p. 12.

[10] Commonly indicated by "coincidence factor," which is the ratio, (coincident peak demand)/(sum of non-coincident peak demands). The reciprocal, the "diversity factor," is also used.

But only one source reporting diversity factors from underdeveloped rural areas could be found: "representative" factors of .47 for small industry and .64 for agriculture (tubewells) are given.[11] Generalizations from these data would be hazardous.

No data for electricity consumption for irrigation or agricultural processing in South America could be obtained. This is not surprising as our later cost comparisons suggest that electric drive has very slight, if any, advantages over direct engine drive with the low fuel prices prevailing in South America.[12]

Domestic consumption is very low in electrified villages in India. Per connected household in the above sample of Madras villages, it ranges from 7 - 33 KWH per month, with the average (unweighted) being 14 KWH. But the number of domestic consumers is small: 30 -50 is representative, omitting the villages which appear to be recently connected. Making minimal assumptions regarding population per village,[13] this implies scarcely one-tenth of the dwellings in the village. Thus it appears that only the most prosperous 10 per cent of the population can afford any electricity at all under present rates, and within this fraction, the annual consumption is on the order of 30 KWH per capita. According to data reported from another group of villages, essentially the same pattern of utilization is repeated in Mysore State.[14]

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[11] West Pakistan Water and Power Development Authority, "Power Market Survey and Forecast of System Loads: An Interim Report on the Hyderabad and Khairpur Divisions," p. 11. The basis for the estimates is not given: "it is believed that the following factors are representative."

[12] See below, V, C, 3.

[13] See note 3 immediately above.

[14] From a tabulation supplied by D. R. Gadgil, Gokhale Institute of Politics and Economics.

Domestic consumption obviously will vary with the level of income. In a demand study in West Pakistan, villages were grouped into four classes by the level of prosperity, and within each class demand per capita was estimated to increase with population, e.g., at a population of 2,000, domestic and small commercial consumptions of .6, 1.8, 3.6, and 9.1 KWH per capita are indicated, and at 4,000 population, 1.0, 2.7, 5.0, and 11.2 KWH per capita are shown.[15] This differential consumption by village prosperity may arise from both increasing consumption per household with higher income, and a larger fraction of the dwellings connected in the more prosperous villages. The distinction is important for the relative cost of service.

Electricity rates for domestic use in India and Pakistan are in the magnitude of the probable capacity and energy costs of service. In South America, the rates are generally far below the marginal costs of supply. Consequently, the present domestic consumption is probably higher than it would be with economic rates, and should be interpreted cautiously in any cost-benefit analysis.

The demand data which could be obtained for this study are not adequate to support a meaningful feasibility study, and it appears that useful data are not being collected for lack of understanding of the pertinent demand variables. Actual energy consumed by classes of demand is the easiest information to obtain as metering and billing is most commonly done on this basis; however, in rural electrification, costs are generally less sensitive to energy consumption than to capacity requirements and distribution distances. The spatial dimension must be included as a key demand variable; household demand in a given context

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15. West Pakistan Water and Power Development Authority, op. cit., pp. 8, 9, and Exhibit I. Unfortunately, the criteria for classifying the villages are not reported.

should be accompanied by the distribution distances involved; the feasibility of irrigation pumping is highly sensitive to the lengths of secondary line required; small villages will have lower demands, but they may be more closely spaced; etc. Demand elasticity with respect to price of electricity, levels of income, and indices of agricultural and rural industrial production, must be explored for reliable projections of demand in non-electrified areas, and predictions of future demands. The connected load and annual energy consumption is not a sufficient specification of consumption patterns. Additional information is needed on the timing of the demands, i.e., the coincidence within a given class of demand, the coincidences with other demand classes, and especially with the system peak of an integrated grid. Further, how might these patterns of use be affected by different rate structures? Is off-peak consumption possible, and at what cost to the user?

B. Cost Specifications

Costs of generators and other equipment are commonly described in terms of average cost per unit of capacity. But average costs are not very helpful for cost comparisons when they vary significantly with the scale of plant. Given the potential demand in rural areas, the irreducible minimum, or indivisible, costs constitute an important part of the total, and average costs rise sharply for small demands.

A much more efficient approach to comparative costing is to compare the marginal costs of the available alternatives.[16] Marginal costs are generally much less variant with scale changes, and hence a comparison can be made which is applicable to a wider range of demand conditions.

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[16] "Incremental costs," as used by engineers in the U.S., is nearly equivalent to marginal costs. In the short-run context, the two are identical; however, engineers rarely work with the long-run concept.

For the scales involved in rural electrification, the total costs for components can be described by a linear function of scale: total costs = A + B (size). The indivisible cost is simply the A term, and the marginal, the B.

For investment decision, "long-run" costs, including both the fixed capital costs and the recurring variable costs, are relevant. The initial investment costs and the continuous flow of operating costs must be made comparable. The best theoretic basis, and the only accurate and relatively simple basis if the flow of recurring costs varies with time, is the present discounted value. Each of the expected future costs is discounted at the appropriate compound rate of interest back to the time of the initial investment. However, costs are frequently desired on an annual basis, or per unit of output, and the investment is reduced to an annual cost. The most direct method for obtaining the annual costs of an investment is to take the annuity payments which have a present discounted value equal to the initial investment, if they are continued for the life of the investment. This method is essentially neutral regarding the implied depreciation profile of the investment; the total investment costs, interest and depreciation, are simply assessed to each year uniformly.

Consistently throughout the succeeding analysis, costs are compared on an annual basis, as the advantages of so doing in this context seemed to outweigh the disadvantages. As annuity tables for the discount rates considered appropriate in underdeveloped countries are not generally available, Table A-1 has been appended to enable the reader to quickly adjust the annual capital charges for differing discount rate and useful life assumptions. Cost comparisons on a present discounted value basis may be easily made from the basic cost descriptions; for this purpose, present values for a stream of annually recurring costs are also listed in Table A-1.[17]

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[17] Section II of Table A-1 simply lists the reciprocals of the corresponding entries of section I.

For comparing capital and recurring costs, a discount rate of 10 per cent is uniformly used in the succeeding, except for rural consumers, whose discount rate is taken at 12-20 per cent. This rate is not suggested as a single best estimate, and the "openness" of the model permits easy adjustment. There are strong economic arguments for utilizing a much higher rate of interest than the nominal rates which government agencies involved in electricity supply tend to use for their evaluations.[18] Capital is scarce in underdeveloped countries, and investment opportunities must be passed up. The probable yield on the least productive of these foregone investments determines the opportunity cost of capital in that country, or the real social costs incurred for investing elsewhere. Investment programmers speak of this higher real rate of interest as the "shadow price" of capital to distinguish it from the nominal price. Estimates of the appropriate shadow price of capital in underdeveloped countries are in the range of 8-12 per cent compounded annually.

On the matter of real prices versus nominal prices, difficulties also arise in the appropriate prices for imported goods, whether taxes should be included or excluded; and in the real costs of underemployed labor In estimating the costs of alternatives involving imported equipment in the following, no attempt is made to adjust the nominal exchange rate upwards--there is first the difficulty in estimating the appropriate shadow exchange rate, and then in distinguishing the relative portion of imports within the alternatives Thus, the costs of alternatives which require relatively larger amounts of imports tend to be understated Excise or sales taxes and import duties in themselves do not constitute real costs, but only transfer payments, and ought to be excluded. However, some taxes or duties are indirect means to alter

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[18] In many cases the agencies receive their capital funds from the treasury at very nominal rates.

a nominal price towards the shadow price. An example is petroleum fuel in India; imported with an over-valued currency, its final price to the user includes an excise tax expressly designed to reduce consumption, and in turn, conserve foreign currency. The shadow price of underemployed local labor is taken to be near zero. Hence the cost of clearing land for distribution line construction is considered negligible, and any additional local labor contribution to construction is assumed to require only the costs of training and supervision.

Electricity rate analysts have traditionally distinguished the customer, capacity, and energy costs for providing service, leaving the remaining costs as a residual. The analytic approach in the succeeding is analogous, but marginal concepts are used rather than the common averages. For each major component of the alternative methods of supply, the indivisible, the marginal capacity, and the marginal energy (which may be negligible for some components), elements of cost are traced back to a few operational parameters and variables.[19] Thus to determine the costs of service--e.g., to a rural village, or to a householder--via one supply option, the indivisible costs of each of the up-stream components are summed; likewise, the marginal capacity costs of the components (with possible adjustment for demand diversity), and finally the marginal energy components are summed. The costs of a second supply option may be determined in the same manner, and the two compared. The costs for one option, net of those of the other, may be easily stated within each category, thereby yielding a summary cost comparison which is applicable to a wide range of demand variables.[20]

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[19] The distinction between parameters and variables is not rigid in our analysis; usually we will consider cost data as given parameters and explore the effects of changing the variables which describe the physical environment. But if one takes a particular setting, he may wish to hold the latter constant and vary prices and cost data.

[20] For a simple example, see the comparison of village engine generators with larger generators serving a number of villages in sec. V, B, 1, below.

All of the substation indivisible costs, and much of the indivisible costs of the primary distribution line, are joint costs; i.e., the facilities serve more than one village, and would be required to serve any one of the several. This lends an "all-or-nothing" character to the investment decision for grid extension; once an extension serves some villages in an area, the additional costs for connecting the remaining will be low relative to the initial extensions. Thus, isolated local generation (there being no, or negligible, joint costs with other villages) cannot be compared with the costs of a long line extension to a single village in isolation, but rather to the incremental costs of linking a village, given in extensions already in the area. If the latter are less, the net savings for all the villages in the area which could be feasibly connected, should be compared with the joint indivisible costs of connecting them. Essentially the same problem exists within the village regarding the joint costs for the individual users.

The dynamic investment problems posed by indivisibilities in investments and growing demands turn out to be of minor consequence in choosing among alternative methods of energy supply in rural areas. As the main example, the indivisible costs of the small engine generator are shown to be so high relative to the indivisible cost of distribution lines, that interim "load-building" generator installations are not justified. This is one of the major advantages of the present method of analysis, as the usual comparison of average costs does not show this unambiguously.

In many contexts, cost elements may be simply summed to obtain a summary cost specification. But in other cases the optimum combination of inputs must be determined in order to obtain the long-run cost function. The first sections of the next chapter take up this problem for distribution lines.

## III. DISTRIBUTION COSTS

Electricity is distributed at two voltage levels: the higher voltage, or primary, lines carry energy from a central point--a substation connected with the grid supply, or a large isolated generator--to a number of villages. The low voltage secondary lines operate at the utilization voltage and are fed from the primary system via step-down transformers, or possibly from small local generating sets. In this analysis the primary distribution system is defined so as to include the distribution transformers, but not the substation feeding the secondary lines, and the secondary system includes the users' service drops and metering or load control devices.

The aim is to establish summary costs for distribution which are based on operational fundamental data Thus, the summary costs can be quickly derived for varying component prices and costs.

The initial derivation is complicated by the fact that some inputs, e.g., size of wire and electricity losses, are partial substitutes, and the total cost can be determined only after the least-cost combination of inputs has been established Further, there are questions of technical design, e.g., the size of a distribution area, which must be answered before a summary cost can be calculated In the terminology of economists, this implies a necessity to explore the production function(s) behind the desired cost function(s), and requires that the optimization problem be explicitly studied. An engineer would perhaps explain that he must estimate the costs of the several technical alternatives, and then report the lowest as the relevant cost The succeeding analysis differs from the usual engineering cost study in that a higher degree of generality, and hopefully, a wider area of applicability, is sought.

The categories of indivisible and marginal capacity and energy costs arise naturally from the technical characteristics of distribution lines and equipment, and from the physical constraints in distributing electricity to demand points dispersed in space. Because marginal energy costs are so small relative to marginal capacity costs, and because of analytic difficulties in satisfactorily separating them, the energy costs are included within the capacity costs. A common analytic model serves for both primary and secondary distribution, and yields cost specifications based on the distribution area as a whole, and also per point of delivery. Thus, we obtain the indivisible and marginal costs of primary distribution for a whole primary distribution area, and for an individual village. Similarly, the indivisible and capacity costs of secondary distribution are defined for the distribution area (normally the village) and for individual users

The analytic model is developed in the first two sections. The first derives for distribution lines, long-run cost functions of several variables The second outlines a simple analytic model for the distribution system as a whole. In the concluding two sections, economic variables defined in the earlier sections are estimated from the preliminary data now in hand, in order to simultaneously illustrate an application of the model, and to establish preliminary estimates of the various cost categories

## A. Costs for Distribution Lines

The major cost of electricity distribution lines is in the initial investment required. The capital charges against this investment, and the operating and maintenance expenditures, constitute the fixed costs of the lines. The variable costs are the capacity and energy costs of the resistance losses in the lines. To obtain the least-cost line, the cost of losses must be weighed against the investment costs of extending the capacity of the line.

1. Fixed costs of distribution lines

An overhead line[21] consists of poles and pole-top hardware supporting several conductors. The installed cost of the poles and pole-top structures varies somewhat with the number of conductors, but is relatively insensitive to the sizes of the conductors over the normally used range. The cost of conductors is very nearly proportional to their weight and cross-sectional area, and hence their current-carrying capacity.[22] Thus, the construction cost (in$/mile) of lines may be closely approximated by a linear function:[23]

(3.1) $$\text{Investment in lines} = A_1 + w A_w + B_w (G - G_m).$$

$A_1$ = Indivisible cost of line, $/mile

$w$ = Number of phase conductors or wires

$A_w$ = Indivisible cost of minimum size conductor and supporting hardware, $/mile of conductor

$B_w$ = Variable cost of conductor, $/mho-mile

$G$ = Conductance of conductor, mho-mile, or the reciprocal of the resistance expressed in ohms per mile

$G_m$ = Conductance of minimum size conductor consistent with mechanical strength requirements

The voltage level of the primary lines would influence the indivisible items, $A_w$, chiefly due to different insulator costs. Because of the savings

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[21] Underground lines to date have consistently higher costs than overhead lines and are hardly appropriate for rural construction.

[22] See Figures III-3 and III-4 below for examples of reported estimates for primary and secondary line constr ction costs. Economic analyses of distribution costs usually assume a simple linear function for investment costs. See, e.g., Petri, et al, "The Influence of Electricity Consumption on the Electric Transmission and Distribution Costs," World Power Conference, Montreal, 1948, Vol. V, p. 2137. Also, Campbell, et al, "Economical Analysis of Residential Secondary Distribution Systems," AIEE Transactions, Part III, Vol. 76, pp. 574-85; Vol. 79, pp. 423-43.

[23] The neutral is conveniently included within the indivisible cost of the line, except in 1ϕ, ϕ-N, lines where it is properly a conductor. See note 29 below, in this section.

resulting from standardization, only a few optional voltages are available, and an attempt at general relationships isn't justified. Thus $A_w$ should be adjusted for the assumed voltage. Secondary voltages over the feasible range would not affect the costs of secondary lines.

Measuring the size of a conductor in terms of its conductance requires a brief explanation. Conductance is the current-carrying capacity of the wire, or the reciprocal of resistance. If the resistance of a conductor is given in ohms per mile (the usual catalog or handbook listing), the conductance in mho-miles is simply the reciprocal. The advantages of using conductance directly are: 1) conductors of different materials and varying combinations of materials are made directly comparable; and 2) analytic convenience is realized by avoiding conversions from cross-section to resistance or conductance in a generalized cost model.[24]

Original investment costs and annually recurring costs must be converted to a common basis, either present discounted value or annual charges. For present purposes, the latter is more convenient and the annual capital charges on the original investment may be represented as a decimal fraction, $\underline{acc}_1$, of the original investment.[25]

Operating and maintenance charges on a yearly basis are frequently estimated as fractions of the line investment. This is satisfactory if a uniform design and quality of line is being considered, and labor and material costs in operating and maintenance may realistically be considered to be proportional to the labor and materials costs in the

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[24] Measuring cross-sections isn't as straightforward as might be imagined; cross-sections are measured in square inches, square millimeters, circular mils and several guage number systems. Further, there is ambiguity in that the steel cross-section is not uniformly excluded in designating the cross-section of ACSR.

[25] See above, Section II, B, for a discussion of this method of combining interest and depreciation charges into a single annual charge, and for realistic values for this charge.

original construction. If, however, different qualities of construction are being considered, a lower quality of construction, and therefore lower first cost, will generally require greater expenditures on operation and maintenance. In this case, operating and maintenance estimates as uniform percentages of first cost are clearly inappropriate. Thus, the operating and maintenance factor, $om_1$, used below must be adjusted for the particular quality of construction assumed. Also, it appears that the operating and maintenance costs are insensitive to the sizes of the conductors installed; i.e., the operating and maintenance factor should be applied only to the indivisible items, $A_1$ and $A_w$.

From the above, the annual fixed costs of the line may be represented by the formula:

(3.2) $$\text{Annual fixed costs} = (acc_1 + om_1)(A_1 + w\,A_w) + acc_1\, w\, B_w(G-G_m).$$

2. Variable costs--losses in lines

The variable components of distribution line costs are the capacity and energy costs of the resistance losses in the line. The instantaneous rate of loss is given by the basic physical relationship, losses in watts = $I^2 R$, wherein I is the current in amperes, and R, the resistance in ohms for the length of wire in question. For a given power flow (usually designated in kilowatts, KW) through an alternating line, the current in each wire depends on the voltage (conveniently expressed in kilovolts, KV), the number of phases, and the phase angle between the voltage and current in the wires (commonly indicated by "power factor," PF).[26] In a single-phase line, the current in each wire, $I = \frac{KW}{(KV)\ (PF)}$, and in a three-phase

[26] The apparent power, kilovolt-amperes, KVA, equals the product of voltage and current, irrespective of phase angle: actual power, KW, equals the product (KV) (I) (cos θ), θ being the phase angle between current and voltage. PF, a non-dimensional ratio, KW/KVA, equals cos θ.

line, $I = \frac{KW}{\sqrt{3}\,(KV)\ (PF)}$, wherein the voltage is measured between conductors. Noting that two-phase wires are required for 1ϕ, and three for 3ϕ, and that the conductance of each wire is defined as G = 1/R, losses, in kilowatts, in single- and three-phase lines are given by the following equations:

$$\text{(3.3a)} \qquad \text{Loss, } 1\phi = \frac{1}{500}\left(\frac{KW}{(KV\ (PF)}\right)^2 \frac{1}{G}\ ;$$

$$\text{(3.3b)} \qquad \text{Loss, } 3\phi = \frac{1}{1000}\left(\frac{KW}{(KV)\ (PF)}\right)^2 \frac{1}{G}\ .$$

The line length dimension will be that in which the conductance is expressed: if conductance is measured per mile of wire, losses will be in KW/mile of line.

Generally, the maximum load on the distribution line, and hence the maximum power loss, approximately coincides with the peak demand on the system. Thus the system capacity must be increased by the maximum power dissipation in the line. The marginal costs of this capacity must include all distribution, transmission, and generating capacity required.[27]

Energy losses must be accumulated over time, the most convenient period usually being a year. For the special case of a uniform load, the annual energy losses (KWH) equal the product of the power loss (KW) and the annual hours of connection. However, the demand generally varies continuously throughout the year from the peak level to very low or zero levels. Power losses on a line of given capacity vary with the square of the power carried, and precise computation of the energy losses would require complete knowledge of the demand curve over the full year. One operational method is to estimate the equivalent number of hours (here

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[27] In some instances, the load and associated line loss will not coincide with the system peak demand. E.g., de-watering or drainage pumps, and probably irrigation pumps, connected to an urban grid could well be disconnected during the system peak-demand hours. Hence, the capacity costs for the losses, as for the load in question, are zero.

abbreviated ehr), i.e., the hours for which the maximum demand ($KW_m$) would need to be connected to yield the energy loss created by the continuously varying load. The equivalent hours vary with the usage and is sometimes estimated directly for lines of a particular class. Another approach defines a "loss factor" (IsF), as the nondimensional ratio, (average power loss), (Maximum power loss).[28] The equivalent hours equals the product (hours in the time period) (IsF). Empirical formulas relating the loss factor and the load factor ($LdF = \frac{\text{average demand}}{\text{peak demand}}$) are based on past operating experience. The usual form is $LsF = a\,(LdF)^2 + (1-a)\,(LdF)$, the value of the coefficient a varying slightly with the shape of the demand curve, but approximating 0.7 or 0.8. Thus in contexts where the coefficient a is empirically established, the annual losses can be easily estimated from the load factor, which in turn can be fairly readily measured or estimated However, as data supporting estimates for loss factors in underdeveloped rural areas are not available, approximate values will be assumed directly for the equivalent number of hours, in the succeeding.

The cost per kilowatt-hour of energy losses, after capacity costs are otherwise accounted for, is simply the marginal cost for energy. As most of the operating and maintenance costs in a system are fixed or quasi-fixed, the marginal energy cost is mainly the marginal fuel cost. Denoting the marginal capacity cost per KW per year as CC, and the marginal energy cost per KWH as EC, the annual cost of losses is simply related to the maximum rate of loss as follows:

(3.4) $$\text{Annual cost of losses} = \text{Loss}_{max}\,(CC + ehr\ EC).$$

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28 Which is equivalent to the ratio:

$$\frac{\text{actual energy losses}}{\text{(peak power loss) (hours in the time period)}}$$

The maximum rate of loss is related to the peak demand by equations 3.3a & b for 1$\phi$ and 3$\phi$, respectively. Combining equations 3.3a & b and 3.4, the formulas for the annual variable costs for 1$\phi$ and 3$\phi$ are:

$$\text{(3.5a)} \qquad \text{Annual variable cost, } 1\phi = \frac{1}{500}\left(\frac{KW_m}{(KV)\,(PF)}\right)^2 \frac{CC + ehr\ EC}{G}$$

$$\text{(3.5b)} \qquad \text{Annual variable cost, } 3\phi = \frac{1}{1000}\left(\frac{KW_m}{(KV)\,(PF)}\right)^2 \frac{CC + ehr\ EC}{G}$$

These costs may be added to the fixed costs of the preceding section to obtain the total costs of lines. For example, for a three-phase, three-wire, primary line, the short-run total costs would be given by simply setting w = 3 in equation 3.2 and adding equation 3.5b. Short-run costs imply that the size of the line is given, and that adjustment for the demand and cost conditions prevailing is either not possible, or not feasible. In contrast, the economists' long-run costs assume that the least-cost optimizing design can be anticipated and erected. Long-run cost functions will be developed in the next section.

## 3. Optimum line capacity and long-run costs

For the present we will consider the wire size of the line to be the only relevant capacity variable. Voltage of the line affects line capacity directly, and is variable within certain limits. But, for reasons of data availability, the necessity of a few standard voltages, and analytic simplicity, the choice of voltage will be treated by direct comparison of several alternatives rather than as a floating decision variable.

The most direct derivation of the optimum line capacity is to set the partial derivative of the short-run total costs (the sum of the fixed and variable costs), with respect to the wire size variable, G, equal to zero, and solve the resulting equation for the optimum wire size, $\overline{G}$. For single- and three-phase we obtain:

$$(3.6a) \qquad \bar{G}_{1\phi} = .0316 \frac{KW_m}{(KV)\ (PF)} \left( \frac{CC + ehr\ EC}{acc_1\ B_w} \right)^{1/2}$$

$$(3.6b) \qquad \bar{G}_{3\phi} = .0183 \frac{KW_m}{(KV)\ (PF)} \left( \frac{CC + ehr\ EC}{acc_1\ B_w} \right)^{1/2}$$

These equations are simply one method of stating the traditional "Kelvin's Law," long used by utility engineers to determine the size of conductor to install.[29]

By substituting equations 3.6a & b into the earlier equations for fixed and variable costs (3.2, 3.5a & b), the line size variable is eliminated from the latter. Summing the fixed and variable costs, and simplifying the result, we obtain long-run total cost functions. For example, for a three-phase, three-wire, line the

$$(3.7) \quad \text{Annual total costs, long run} = (acc_1 + om_1)(A_1 + 3A_w) - acc_1\, w\, B_w G_m + .110 \frac{KW_m}{(KV)\ (PF)} (acc_1 B_w)^{1/2} (CC\ ehr\ EC)^{1/2}$$

The first and second terms are "indivisible costs" in that they are invariant with the demand on the line; the third varies directly with the peak demand and yields the marginal capacity cost. The negative term is small compared to the first term, the other indivisible cost term. In the following indivisible cost specification it is omitted for two reasons. First, its inclusion implies an erroneous reduction in actual indivisible costs since the constraint, $G \geqslant G_m$, was omitted from the previous optimization for simplicity's sake. Second, its exclusion permits an

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[29] The engineer will note that the neutral wire has been neglected in the above optimization. The assumption is that the neutral in a well-designed system carries a small and probably negligible amount of current. Its size is frequently dictated by minimum mechanical strength requirements, and hence can most conveniently be included within the indivisible cost component of the line. In some cases, necessary load unbalances between

upward adjustment from the ideal costs for perfect load and line capacity matching, to account for the cost implications of growing loads with fixed line capacity. On the latter, the reader is referred to section 4 immediately following.

Indivisible line costs ($IC_1$, \$/mile) are thus given by

$$IC_1 = (acc_1 + om_1)\,(A_1 + W\,A_w) \tag{3.8}$$

The long-run marginal costs are simply the additional costs associated with increasing the load on a line. The units for $MCC_1$ arising from the preceding formulas are \$/KW-mile.

$$MCC_{1\ 1\phi} = \frac{.127}{(KV)\ (PF)}\ (acc_1\ B_w)^{1/2}\ (CC + ehr\ EC)^{1/2} \tag{3.9a}$$

$$MCC_{1\ 3\phi} = \frac{.110}{(KV)\ (PF)}\ (acc_1\ B_w)^{1/2}\ (CC + ehr\ EC)^{1/2} \tag{3.9b}$$

"Marginal costs" will imply long-run marginal costs unless short-run costs are specifically stated.

As the above marginal cost is expressed per kilowatt-mile, it appears as a marginal capacity cost, although the equation includes both capacity cost (CC) and energy cost (EC) variables. In this case our distinction between capacity and energy costs is blurred somewhat and very minor elements of energy costs are hidden within the capacity cost definition. In the general long-run cost function the capacity and energy cost of losses cannot be simply differentiated, whereas they can be readily separated in the short-run cost function. This arises from the economics of the optimizing process; essentially, the capacity and energy costs of losses are joint costs, and there is no non-arbitrary manner of entering them separately. The full costs are included in the

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the phase wires will yield appreciable losses in the neutral, and significantly higher losses in the phase conductors than for the ideal balanced load. The ratio, (sum of currents in all wires with unbalance)/(sum of currents in all wires with balanced load), will approximate the factor by which the succeeding marginal costs of the line should be multiplied for predictable load unbalances.

above equations for indivisible and marginal costs, and marginal energy costs in distribution lines will be considered negligible. With the expected extent of utilization of rural distribution lines, the capacity cost of lines is inflated approximately 5 per cent by the inclusion of the energy cost, but this amounts to a negligibly small change in the total capacity cost at the consumer's connection.

4. The implications of growing demand and possible technical constraints

The above long-run costs implicitly assume that the demand is constant, and that the line capacity can be exactly adjusted to the demand. Neither assumption is justified, and the implications of continuously growing loads and discrete wire sizes must be examined. Fortunately, the inherent substitution between wire conductance and resistance losses causes costs to increase only slightly from the hypothetical least-cost, for reasonable departures from the optimum design. Excess capacity in the line implies higher annual fixed charges than would result from an optimum line, but the higher fixed charges are partially offset by lower losses. Conversely, a line loaded beyond its optimum has higher losses, but lower fixed charges, than the ideal.

The magnitude of cost increases for non-optimal lines is illustrated in Figure III-1, which is based on the median cost estimates of Section III, D, 1, below.[30] The short-run total, marginal, and average curves represent the costs of a secondary line designed for a load of 20 KW. The dotted long-run curves are drawn for the assumption that the wire size may be exactly adjusted to a constant load, except that conductors smaller than #4 AAC cannot be used The solid long-run curves correspond to the median estimates for indivisible and marginal capacity costs of

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[30] At PF = .90, on a 3ϕ, 230/400 volt line. For the illustration, the wire size is exactly optimized for the cost parameters assumed, although it doesn't coincide with a standard U.S. guage.

Table III-7, below. These latter curves are somewhat higher than the other (dotted) long-run curves, because the strict marginal cost for very small loads on the line, where the wire size is determined for mechanical strength, is less than the assumed constant marginal cost.[31] At one-third of the design load, the 20-KW line has total costs about 10 per cent above the hypothetical ideal; loaded at double the design, or 40 KW, about 15 per cent higher. Clearly, lines need not be exactly scaled to the load. A few standardized sizes of conductors are feasible, and loads increasing to perhaps four- or five-fold the initial value may be economically served without altering the line--provided sufficient excess capacity has been initially installed.

The excess capacity to be installed initially can be worked out analytically,[32] although in actual practice, "rules-of-thumb" seem to be observed. But detailed investigation of this problem isn't warranted in our present context. More important is the comparison of costs for a fixed conductor size but varying load, with the summary cost description utilized in this analysis. By assuming a constant marginal cost per KW in addition to an indivisible cost, which already allows for a small amount of line capacity because of the mechanical constraints on conductor size, our line costs will be uniformly slightly above the

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[31] The difference arises from the omission of the small negative term in the indivisible costs. See the immediately preceding section. Including the term, except where $\bar{G} < G_m$, yields the dotted curves; including it without exception would produce a perfectly linear total cost curve coincident with the linear portion of the dotted curve, and with an erroneously low vertical axis intercept; omitting it entirely results in the simpler and preferred estimates.

[32] The only such analysis which the author has seen neglects to discount the cost of future losses, and assumes a terminal load after an indefinite period of time. (R. E. A., Economical Design of Primary Lines . . . , Bul. 60-9, Appendix II. The author has worked out the analytic result for variable growth rates and planning horizons; a more general solution in which the appropriate planning period is determined in the model appears possible.

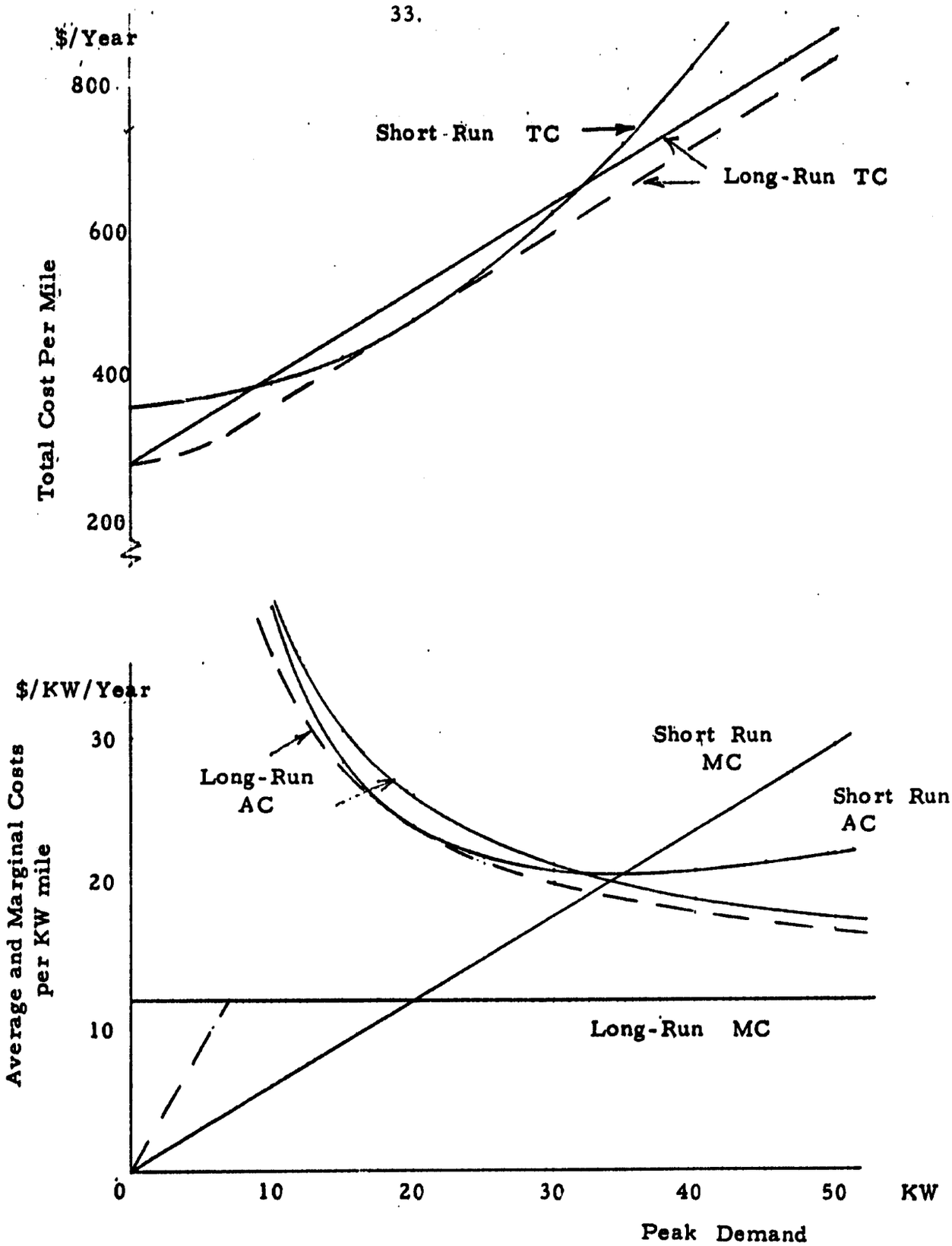


Figure III-1

Illustrative Short- and Long-Run Total, Marginal, and Average Cost Curves for a Secondary Distribution Line

hypothetical least-cost which implies perfect matching of load and line capacity. Thus, in Figure III-1, the actual annual total and average costs for the 20-KW line would be below the estimated long-run costs for loads between about 60 per cent under, and 60 per cent over, the design load. Over most of this range the short-run costs are well under the long-run estimates, and we may conclude that the latter make adequate allowances for the expected load variations from the design load of the line.[33]

Possible technical constraints which might invalidate the above optimization and resultant costs must be noted. Account has already been taken of the minimum conductor size dictated by tensile strength requirements. Permissible conductor temperature is not a constraint on the economical design of overhead lines; with realistic cost parameters, the design loading of a conductor will be one-fifth, or less of the conductor's current carrying capacity.[34] Thus, even under emergency loading conditions, the thermal capacity of the line will not be exceeded.

The allowable voltage drop in a long line, however, may require a larger conductor section than the economic optimum. The voltage drop, usually measured as a per cent of the nominal voltage, may be approximated by the per cent loss, as the two are approximately equal for small conductors. The per cent loss can be derived from equations (3. 3a & b) and (3. 6 a &b) above. Substituting the optimum conductor size, $\bar{G}$, from the latter into the former, and multiplying the result by 100/KW, these equations for per cent loss per mile of line are obtained:

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[33] Probably our summary estimates err slightly towards overstatement: however, they do not take explicit account of possible load unbalances between the phase conductors with the attendant slight increase in costs. In any case, the error is negligibly small.

[34] Based on handbook data for approximate current capacity, and economic conductor size calculated according to equations (3. 6 a,b) above, at representative cost parameters from succeeding sections.

$$\text{(3.10a)} \qquad \%\ \text{loss},\ 1\phi = \frac{6.33}{(KV)\ (PF)} \left(\frac{acc_1\ B_w}{CC + ehr\ EC}\right)^{1/2}$$

$$\text{(3.10b)} \qquad \%\ \text{loss},\ 3\phi = \frac{5.48}{(KV)\ (PF)} \left(\frac{acc_1\ B_w}{CC + ehr\ EC}\right)^{1/2}$$

Each of the variables is defined as before.

At unity power factor, the per cent voltage drop would exactly equal the per cent loss. At probable power factors on rural distribution lines, the former is slightly less than the latter for very small lines, and the reverse for the largest conductor sizes which would be used in rural electrification. Table A-4 in the Appendix lists the ratios, (% voltage drop) (% power loss), for the relevant size range of conductors. For medium demand densities, the economic sized primary distribution systems will probably be sufficiently small that voltage drops on optimum capacity lines will be within the allowable limits. In secondary distribution, excessive voltage drops may require that either the distribution area be reduced from the optimum, or the line size be increased.[35] But the model for the distribution system as a whole should be developed before this is pursued further.

## B. Costs of Distribution Systems

Having established simple summary cost descriptions for distribution lines, we may consider the distribution system as a whole. The essential analytic problems are identical in both primary and secondary distribution, and a common conceptual model will simplify the summary cost descriptions of both. Distribution of electricity from a central supply point to a number of spatially dispersed consumption points can

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[35] In this country, momentary voltage drops due to motor starting loads is of major concern to distribution engineers. In a rural underdeveloped context, there will be fewer motors, and each will start less frequently, than on residential systems in this country. Further, not so high a price can be paid to prevent intermittent lamp flicker, and it seems that momentary voltage drops may be neglected in the present context.

be viewed as two separable problems: 1) the linking of all the points via the distribution lines, and 2) the transportation burden, in units of electricity weighted by the distance carried. The first involves indivisible costs for lines and terminal equipment, and is dependent on the spacing between consuming points, but not on the individual or aggregate demand. The second problem implies capacity costs per unit of load-distance (and small capacity costs at the terminals), and varies with the density of demand.

This distinction is justified because the indivisible line costs are large relative to the marginal costs of carrying the electricity and are especially disproportionate in low demand density rural areas. Additional line length, with the attendant indivisible line costs, in order to provide more direct paths from the central supply to the peripheral demand points, is more costly than the minor savings resulting from a slightly shorter mean distribution distance. Hence, economic design of the distribution system requires that the total line length be near the minimum required to connect the supply and demand points.[36] Evidence of the very limited substitutibility between line length and reduced marginal transport costs is given in section 3.

Based on this distinction between the costs for lines to link the distribution points, and the transport costs over these lines, equations for the indivisible and capacity costs for distribution are given in the first section. Possible distribution line arrangements are illustrated in the second section, and the considerations determining the

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[36] More exactly, the total indivisible line costs are approximately minimized, as the most direct line between two points is not always the least expensive. Also, the distance electricity is carried cannot be totally disregarded; e.g., "back-feeding," or carrying electricity first away from, and then back towards the central supply point, is usually avoided.

relevant line length are discussed. The next section develops an "equivalent length" concept which aids in estimating the capacity costs of delivering the power to the distribution points. And, finally, the optimum sized distribution area, dependent on the demand density, the marginal capacity cost of distribution lines, and the indivisible costs of the central supply point, is derived.

1. Indivisible and marginal capacity costs for a distribution system

This section will define indivisible and marginal costs for primary and secondary distribution systems. Explanation of new parameters here defined will be given in the three succeeding sections.

Given negligible substitution between length of line and the mean distance over which electricity is carried, the indivisible costs of distribution may be obtained directly from the indivisible costs of lines and terminal equipment. First, the indivisible costs for the area as a whole may be defined. For primary distribution, the relevant area is normally that served by one sub-station, and for secondary distribution, a single village.[37] All costs are on an annual basis for comparability.

(3.11a) $$ICd_{pa} = L_{pa}\ IC_{1p} + n_v\ IC_{tf}$$

(3.11b) $$ICd_{sv} = L_{sv}\ IC_{1s} + n_u\ IC_u$$

$ICd_{pa}$ = Indivisible costs for primary distribution for an area ($)

$L_{pa}$ = Primary line for an area (miles)

$IC_{1p}$ ($IC_{1s}$) = Indivisible cost for primary (secondary) line ($/mile)

$n_v$ = Number of villages in the area

$IC_{tf}$ = Indivisible costs per distribution transformer ($)

$ICd_{sv}$ = Indivisible costs for secondary distribution for a village ($)

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[37] Within the feasible size of secondary distribution areas, more than one village would be unusual. While larger villages may require two or more distribution transformers, which probably will be interconnected on the secondary side, no problem is created for the analytic model. The village is

$L_{sv}$ = Secondary line, for a village (miles)

$n_u$ = Number of electricity users in the village

$IC_u$ = Indivisible costs for users' connection

The definitions for primary and secondary distribution are symmetrical, as they are in the succeeding equations, with minor exceptions. Within the village, users may be classified into two groups: domestic and small commerical where lighting is the almost exclusive load, and power for agricultural and light industrial use. Where the distinction is useful, it will be made by the addition of subscript d and p, respectively.

In some contexts, the indivisible costs incurred per point of delivery--the village for primary distribution, and the final user for secondary--will be required. These are:

(3.12a) $$ICd_{pv} = L_{pv} IC_{1p} + IC_{tf}$$

(3.12b) $$ICd_{su} = L_{su} IC_{1s} + IC_u$$

$ICd_{pv}$ = Indivisible costs for primary distribution per village ($)

$L_{pv}$ = Primary line per village (miles)

$ICd_{su}$ = Indivisible costs for secondary distribution per user ($)

$L_{su}$ = Secondary line per user (miles, or fractions thereof)

Separate equations might be written for the indivisible costs of domestic and power users.

In the usual case, the sum of indivisible costs for primary distribution per village for all villages in an area will not equal the total indivisible costs for the same area, and likewise for users' indivisible costs in

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simply treated as having two or more secondary distribution areas, and the indivisible terminal costs are multiplied accordingly.

secondary distribution. For meaningful use in later analysis, the primary line per village, and secondary line per user, must be defined as the incremental length, i.e., the additional line required to serve that point, and that point only. An equivalent definition is the avoidable length, or the line length which would not be needed if service were not made to that point, but were made to all more feasible nearby points. Normally, some common lines, or portions of lines, will serve two or more points, and the resulting joint costs cannot be defensibly allocated between the points served. Only rarely will the incremental line length approach the average, and allocation by averaging in order to exhaust the total can only furnish misleading guides for investment decisions.

The marginal capacity costs for distribution depend on the mean distance the power is carried from the central supply to the individual distribution points, and not on the actual line length in the area, or the incremental length per distribution point. Reserving further elaboration of the concept for subsection 3 immediately below, we will simply define the weighted mean distance electricity is carried in the area as the equivalent length for distribution (EL). Thus,

(3.13a) $$MCCd_p = EL_p \; MCC_{1p} + MCC_{tf}$$

(3.13b) $$MCCd_s = EL_s \; MCC_{1s}$$

$MCCd_p$ ($MCCd_s$) = Marginal capacity cost for primary (secondary) distribution ($/KW)

$EL_p$ ($EL_s$) = Equivalent length, primary (secondary) distribution (miles)

$MCC_{1p}$($MCC_{1s}$) = Marginal capacity cost of primary (secondary) line ($/KW-mile)

$MCC_{tf}$ = Marginal capacity cost of distribution transformer ($/KW)

No capacity cost component is assumed in the users' connection and metering costs. This is appropriate only over a reasonable range of usage, and if

different indivisible costs are estimated for domestic and power users.

Joint cost arise in the capacity cost of lines, as in all capacity costs, due to the partial non-coincidence of peak demands. Given the probable demand diversity between the small number of points in rural areas served from a common line, joint capacity costs on lines may be usually neglected.

While the derivation of total costs from the above is fairly obvious, the equations are given here for future reference.

(3.14a) $$TCd_{pa} = ICd_{pa} + MCCd_p \sum_{i=1}^{n_v} D_{vi}$$

(3.14b) $$TCd_{sv} = ICd_{sv} + MCCd_s \sum_{i=1}^{n_u} D_{ui}$$

(3.15a) $$TCd_{pv} = ICd_{pv} + MCCd_p \; D_v$$

(3.15b) $$TCd_{su} = ICd_{su} + MCCd_s \; D_u$$

| | | |
|---|---|---|
| $TCd_{pa}$ | = | Total costs for primary distribution for an area |
| $TCd_{sv}$ | = | Total costs for secondary distribution for a village |
| $TCd_{pv}$ | = | Total costs for primary distribution per village |
| $TCd_{su}$ | = | Total costs for secondary distribution per user |
| $D_v$ | = | Maximum demand for a village |
| $D_u$ | = | Maximum demand per user |

These total costs must of course be understood as incremental or avoidable costs in the same sense as the antecedent indivisible costs were defined.

## 2. Line arrangements and lengths

Simple schematic models for a distribution system are illustrated in Figure III-2. "Mains" or "feeders" leave a central supply point and feed "laterals" which are distributed along each side of the mains. The laterals may lead directly to the delivery point, (especially primary distribution, where these are sometimes called "spurs"), or may pass nearby a number of delivery points. In secondary distribution, the connections between the laterals and the consumers are commonly called "service drops." In built-up areas with streets in a grid-like pattern, secondary lines may approach fairly closely a rectangular grid as in Figure III-2A. Secondary lines would be much less regular, and more on the pattern of Figure III-2C

Given the low density of demand in a rural area, both primary and secondary distribution lines will follow a relatively simple radical pattern. Two possible exceptions are, 1) possible interconnections between primary lines away from the common supply point to provide greater security of supply; 2) in a large village, two or more transformers, each at a separate location, may be connected through the secondary lines. Neither will significantly affect the succeeding analysis.

At feasible utilization voltage levels the economic maximum length of secondary lines is on the order of one mile.[38] This implies that each village should be considered to be as a separate secondary distribution area. Generally, this secondary system would be supplied at one point,

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[38] For approximately 230 volts phase-to-ground. The U.S. standard of 120 volts implies about half that length. Hence, in the electrification of individual farmsteads in the rural areas of the U.S., there is very little secondary line construction. The primary line is extended to each farmstead, and a transformer is installed for each consumer.

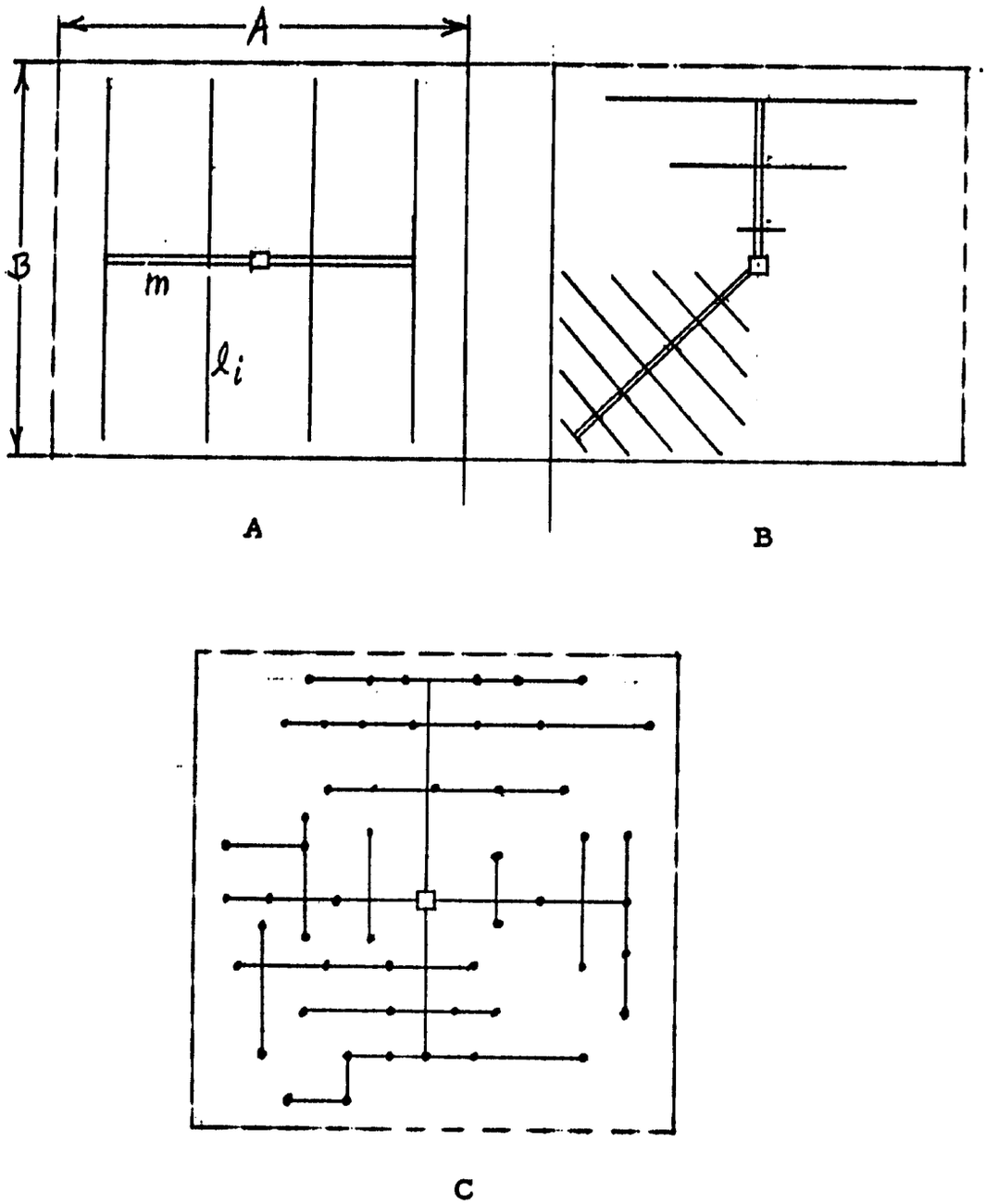


Figure III-2

Schematic Models for Distribution Areas

although the larger villages might require several transformer locations. Hence it is reasonable to assume that the primary line would be extended to the center of each village, but that no secondary lines would connect villages.

While accurate estimates of the line lengths required to electrify a village or a larger area must be based on direct observation, it is helpful to know the order of magnitude which may be expected. The total primary line required to reach all villages in an area ($L_{pa}$), can be approximately estimated from the average distances between villages, or from the average village area. The average length of line per village will correspond to the average distance between the villages in question; generally, one would expect the line length to be slightly more than the straight-line distance between villages, but no more than the actual road distance.[39] The average, and hence the total, line length can also be related to the geographical areas of villages. Assume that the areas of the villages in an indefinitely large area, A, are relatively uniform in size. If all $n_v$ villages in the area are to be electrified, the average line length per village will be approximately equal to the square root of the village area. That is, average line length = $(A/n_v)^{1/2}$, and the total line length, $L_{pa} = (n_v A)^{1/2}$ [40]

For investment decisions, the relevant primary line length per village ($L_{pv}$) is the incremental length required to connect the village. Joint lines, or portions of lines, which would serve another village irregardless of service to the village in question, are excluded. No general estimates of the incremental length can be made, as it is

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[39] On the one hand, it is convenient and slightly less expensive, for both construction and maintenance, to parallel roads. On the other, lines are less constrained by terrain and streams than roads, and may frequently take a more direct path than would be feasible for road construction.

[40] For a relatively large $n_v$, strictly uniform village areas, each arranged in the form of a square, and no physical barriers, the above holds quite closely. Size variance about the mean usually lowers slightly

contingent on decisions whether to serve other villages. If only large, widely spaced villages are connected the incremental length per village will be high. Smaller villages, near the lines which have been constructed to serve the larger villages, will require short additional line lengths. An approximate upper limit to the incremental length can be set; assuming lines in the area already serve larger villages or towns, the incremental line length ($L_{pv}$) for villages of a given geographical size class should rarely exceed the average distance between villages of that size.

Turning to secondary lines, the distinction between incremental and average line lengths per customer is equally important. Typically, a line is run along a street or service alley, and serves customers along each side. The average length of lateral is thus about one-half the frontage of the customer's lot to the street. The average length of main per customer will probably fall within 25-50 per cent of the average lateral length, depending on the depth of the lots and the arrangement of mains and laterals. But the appropriate incremental line length for connecting a customer when the line passes his lot is strictly zero. This is quite important when the feasibility of connecting very low usage domestic customers is considered. On the other hand, serving an irrigation pump in the fields outside the village proper may require a considerable length of line which can serve no other customer. Normally, the major portion of the secondary line will serve a number of domestic and power users jointly and would be required to serve either group separately. Hence, for decisions whether to serve a given user or group of users, these joint costs are considered to be an essentially indivisible cost at the village level.

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the average length per village, but a highly skewed distribution might raise it. Approximately circular or hexagonal shaped areas also tend to lower the average slightly. Difficult terrain or bodies of water would raise the average.

## 3 The equivalent line length in distribution

The marginal costs of carrying electricity on a line vary with load and distance. At each demand point, the relevant variable is the product of the load at that point and the distance back to the supply source. Calculating the load-distance variable separately for each demand point, points near the central supply will have lower costs of supply per unit of load. But a particular pattern of relative costs is consistent with only one location of the supply point. If the supply point to the distribution system in question were relocated, nearby points would become more distant, and vice versa. As a consequence, the marginal costs of distribution on an individual demand point basis become ambiguous and apparently arbitrary. However, a weighted mean distribution distance, or an equivalent line length "EL," circumvents this difficulty and simplifies the general model of distribution costs. It is equally appropriate for primary and secondary distribution.[41]

Assume uniformly dispersed load-points, each having an identical demand, over an approximately rectangular area, as in Figure III-2. An equivalent distance variable which corresponds to the sum of the individual load-distances divided by the aggregate load is desired. The problem is analogous to that of finding the center of gravity of a body of uniform thickness. The distribution lines are separated into appropriate sections; the equivalent distances, or lengths, are determined for each section; and the several equivalent length variables are then summed for a single equivalent length variable for the whole distribution area.

An inductive argument will serve; consider the main feeder m in Figure III-2A. Assume its extension from the supply point, the center

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[41] And also for the sub-transmission portion of an integrated system, as the sub-transmission lines perform a distribution function. But transmission lines are of secondary interest in this study.

of the rectangular area, to the edge of the area, or a distance of about A/2. The load on the main decreases from its maximum at the central supply to zero at the end by equal amounts at each tapping of the laterals. Hence, the aggregate load-distance of the main is approximated by the maximum load on the main concentrated at the mid-point of the main. Noting that each main carries one half of the total load for the distribution area, and that both mains are symmetrical, the equivalent length on the mains is approximately A/4.

The same argument holds for the laterals: on any lateral $\underline{l}_i$, the equivalent load point is half its length, or B/4. Summing the loads on all of the laterals, the equivalent distance on the laterals is B/4. Thus, for a rectangular area, AxB, with a total demand evenly dispersed over its area, the equivalent length for distribution, EL = (A/4 + B/4). A special case is the square distribution area; when A = B, EL = A/2.

These results are not sensitive to the particular arrangement of the mains and laterals. For example, the arrangement on the top of Figure III-2B--four mains, each serving a triangular shaped area--yields exactly the same result. Four mains along the diagonals as on the lower left of Figure III-2B produce an equivalent distance of .472 A for a square area, and relatively less discrepancy from the above for rectangular areas. Even a hexagonal area--the ideal shape for a distribution area--with a main for each of the six triangular segments, produces an equivalent length within 1 per cent of the simple A/2 for a square having the same geographic area. Where a regular grid is not built, as illustrated in Figure III-2C, the above results are also essentially correct so long as the mains and laterals meet one another at approximately right angles. In general, it appears that feasible arrangements of lines will not appreciably

alter the equivalent length from that of the simplest ideal case.[42]

More complex line arrangements, and greater total length of line, yield very small reductions in the equivalent length for a distribution area of a given size. The high indivisible costs for additional line length outweigh the consequent reduction in the capacity costs of distribution. Hence, our earlier assumptions of essentially zero substitution between line length and marginal transport costs is justified.

The assumptions underlying the above derivation should be noted. First the load has been assumed to be uniformly distributed over the whole distribution area. But frequently the load is more dense in one part of the distribution area, and it is desirable to locate the central supply point within this more dense portion in order to lower the aggregate load-distance. Where the simple model above yields results significantly different from the actual, it might be modified in either of two ways. If load density can be described as a simple function of distance from the center, a general formula for the equivalent load-distance can easily be derived. Or the equivalent lengths and loads can be estimated separately for the areas having significantly different densities, and the results summed.

The second important assumption is that "back-hauling" or "back-feeding" is negligible; i.e., an insignificant amount of electricity is carried back towards the central supply point. Generally there will be slight back-feeding, e.g., in about one-half of the service drops from the secondary lines. But significant amounts of back-feeding will be justified only in special circumstances, and the equivalent length can then be adjusted upwards accordingly.

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[42] This equivalent length should not be confused with equivalent length definitions for losses which assume a uniform wire size on the line. Our definition assumes that the wire size is approximately matched to the load.

Further assumptions which should cause little difficulty in application include the neglect of physical obstructions. In the rectangular lay-out of lines there is considerable latitude for bypassing obstructions without appreciably raising the equivalent length. Also, the discrete changes in loading and necessary discrete changes in wire sizes have been neglected. But this is merely the problem of matching the line to the load, and allowances are made in the cost description of the line as described previously.

One final point: for a very low demand density, allowable voltage drops may constrain either the size of the distribution area, or the conductor sizes in the lines. Hence, we should note the line length to the farthest point of the distribution area. Referring again to Figure III-2, in the simple grids of A and the left of B, the corners of the areas are $A/2 + B/2$ from the central supply point. With the arrangement on the right of B, the longest line is slightly shorter, but the less regular pattern of C again places the farthest points about $A/2 + B/2$ from the central point. This we will assume to approximate the general case, noting that it reduces to A for a square area.

4. Distribution area optimizing

The capacity costs of distribution are contingent on both the mean distance electricity is carried and the carrying cost per unit of load-distance. The mean distance, or equivalent length, has been related to the size of the distribution area. In turn, the size of the distribution area must be explored. In some cases demand is concentrated at particular points, with little or no demand in the intervening spaces. Each demand concentration then forms a natural distribution area. But the more general case, and especially for area-wide rural electrification, is that of an approximately uniformly dispersed demand over space. The size of the distribution areas within this space then becomes a problem of economic optimization.

The equivalent length concept of the previous section may be further generalized. The uniformly dispersed demands within an indefinitely large area, A, may be described as a demand density per unit area, D. For units consistent with the earlier specification of marginal line costs, the units of D should be $KW/mile^2$. For a square distribution area, whose sides measure S (in miles), the equivalent length, EL = S/2; the total load for the area is $DS^2$; and the transportation burden within the area is thus $(DS^3)/2$. Within the indefinitely large area, A, there are $A/S^2$ such distribution areas, and the total transportation burden is (ADS)/2, in KW-miles.

The costs of carrying this electricity is the product ( (ADS)/2) $(MCC_1)$. For the optimum $\bar{S}$, these costs must be weighted against the indivisible costs of the feeder ($IC_f$--the substation or transformer and the supply lines) for each of the $A/S^2$ distribution areas. In short, the partial derivative of the relevant costs, with respect to S, may be set equal to zero, and the equation solved for the optimum $\bar{S}$:

$$\frac{\partial C}{\partial S} = \frac{AD}{2} \quad MCC_1 - \frac{2A}{S^3} \quad IC_f = 0;$$

$$(3.16) \qquad \bar{S} = \left(\frac{4\ IC_f}{D\ MCC_1}\right)^{1/3}$$

Where the only indivisible costs for a distribution area are the terminal costs, i.e., where a feeder line already exists and may be tapped anywhere on its length, the above yields the exact optimum -- providing of course that the underlying assumptions hold. However, the total length of supply lines required will generally vary with the number and size of the distribution areas. If a defensible general relationship can be established, it may be entered into the analytic solution directly. Otherwise, the indivisible costs of the supply line for the anticipated area size may be included within the term $IC_f$; if the resulting size is

significantly different from the anticipated, an adjusted supply line cost may be entered and the calculation done again.

The above derivation for the optimum area will be used for comparing the costs of alternative primary line voltages, and for estimating the magnitude of indivisible costs for substations and subtransmission lines for electrifying areas at considerable distances from pre-existing lines.

## C. Cost Estimates for Primary Distribution

This section will set forth preliminary cost estimates for primary distribution based on presently available data. The data are admittedly unsatisfactory, as only a few sources reporting estimated costs in underdeveloped countries are available, and in none is the basis of estimation made explicit. However, the range of costs can be established, and the preliminary estimates will illustrate how the analytic model can be applied. Further, the approximate magnitude of costs is sufficient to support tentative conclusions when costs are quite disproportionate. And in some cases relative costs are relevant, and these can frequently be estimated to greater accuracy than absolute cost levels--providing the critical components or variables have been isolated.

But the whole purpose in elaborating the analytic model in the preceding sections was to facilitate the introduction of varying cost parameters, fitting particular environments. And this the reader is urged to do.

The costs for primary lines and transformers are discussed in separate sections. Component cost estimates are given, and their sensitivity to environmental assumptions is discussed. Illustrative summary costs are given in the concluding section, and conclusions regarding economic voltages and phase arrangements are stated.

### 1. Primary line cost estimates

No attempt will be made to examine all the possible operating voltages and phase arrangements. Present discussion abroad regarding the optimum

voltage centers around alternatives in the 10-12 KV and the 20-25 classes. Estimates will be made for 11 and 22 KV, single and three-phase.

Preliminary estimates of the line construction cost parameters defined above (Section A, 1) are given in Table III-1. The low estimates are an attempt to establish a plausible lower boundary for line construction costs, the median estimates approximate or slightly exceed the actual costs reported from several countries; and the high estimates are intended for unfavorable situations, but are not proposed as maximum cost estimates. In appropriate designs, e.g., use of copper conductors and mountainous terrain may push costs much higher.

Three-phase 22 KV line construction costs, calculated from the estimates in Table III-1 according to equation 3.1, are plotted in Figure III-3. Reported rural line costs from the U.S. and several other countries are shown for comparison. Our median estimates appear to be fairly representative.

Pole costs usually comprise the major part of the indivisible costs of the line, and hence a substantial portion of the total cost of a low-capacity line. Thus, both the spacing between the poles and the unit cost per pole will have a significant impact on the line cost. From the available information, construction in underdeveloped rural areas uses surprisingly short spans compared to the practice in Canada and Sweden where wind and ice loading and temperature variations are generally more severe than in the underdeveloped countries. It appears that a critical review of the design standards could yield considerable economy in some instances.

An average span of 400 feet, as assumed here, is conservative for ACSR in level country, and can be obtained with 30 foot poles (total length) where no ice loads are expected, and with 35 foot poles under heavy ice loads. Ceteris paribus, longer spans require longer and more costly poles, which in part offsets the savings due to fewer poles.

TABLE III-1

CONSTRUCTION COST ESTIMATES FOR PRIMARY DISTRIBUTION LINES[a]

| | Low[b] | Median[b] | High[b] |
|---|---|---|---|
| Indivisible Structure Costs of Line:[c] $A_{1p}$ | | | |
| Poles | $65 | $400 | $790 |
| Miscellaneous (Guys, grounding, etc.) | 80 | 100 | 120 |
| Labor and overhead (including supervision and inspection) | 80 | 160 | 300 |
| TOTAL | 225 | 660 | 1210 |
| Indivisible Conductor Cost: $A_{wp}$ | | | |
| Conductor | 119 | 143 | 168 |
| Pole-top hardware | | | |
| 11 KV | 24 | 28 | 32 |
| 22 KV | 50 | 61 | 72 |
| Labor and overhead | 4 | 32 | 60 |
| TOTAL | | | |
| 11 KV | 147 | 203 | 260 |
| 22 KV | 173 | 236 | 300 |
| Variable Cost of Conductor: $B_{wp}$ | | | |
| Conductor | 250 | 300 | 350 |
| Labor increment | - | 5 | 9 |
| Pole and hardware increment | 8 | 25 | 46 |
| TOTAL | 258 | 330 | 405 |

Notes:

a. The unit length is uniformly one mile: for a kilometer basis, multiply by 0.621. The average span between poles is assumed to be 400 feet; the minimum conductor size to be #4 ACSR. No land and clearing costs are included.

b. For assumptions behind the Low, Median, and High categories, see the text.

c. Excluding neutral: if required, add $A_{wp}$ at 11 KV.

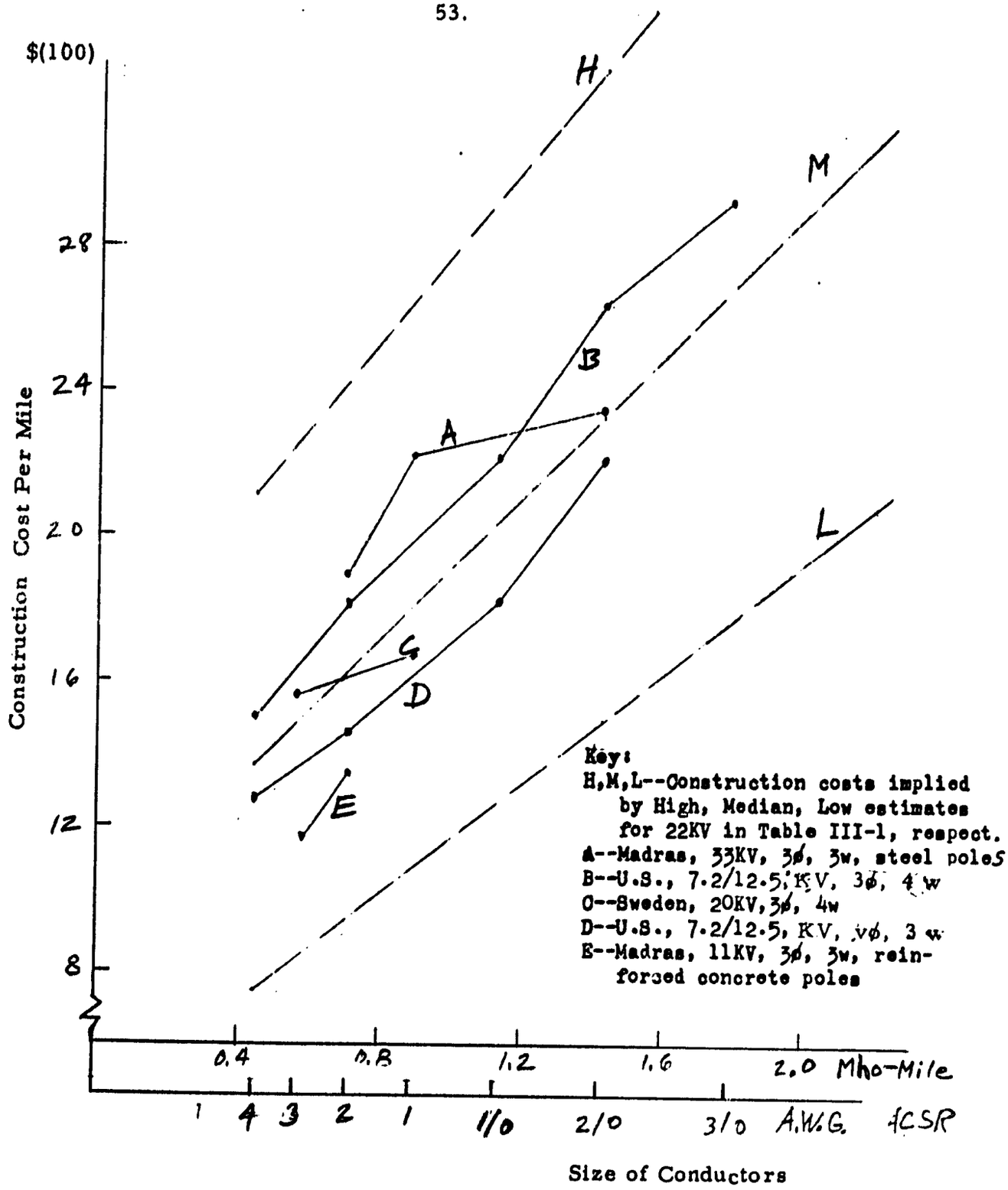


**Figure III-3**

**Comparative Construction Cost Estimates for Primary Distribution Lines**

Sources: REA, "Construction Costs ~~for~~ of Rural Distribution and Transmission Lines and Substations," Table 1; Gov't of India, "Report...on Rural Electrification in Madras," Annexure III; Kaijser, WPC, Belgrade, 1957, p. 229.

Pole costs commonly are higher in underdeveloped countries than in the U.S. Impregnated (usually creosote) wooden poles, the most economical in the U.S., are not available in sufficient quantities in many underdeveloped areas, and importation involves high transport costs, plus foreign exchange difficulties. Consequently, steel and reinforced concrete poles are being used, especially in India and Pakistan. A study of on-site costs for alternative poles in the latter country has been made; for poles of uniform height (30 feet above ground), steel poles would cost $80-90 each; pre-stressed concrete poles from a central plant and imported treated poles from Scandinavia would each cost about $60.[43] Reinforced poles, not pre-stressed, are reported to cost Rs. 75-110 ($15.80-23.10), depending on length, at decentralized casting stations in Madras. Decentralized casting reduces the subsequent transport costs to the site. In Kerala, 32-35 foot poles cut from teakwood plantations, and impregnated with chemicals, are estimated to cost Rs. 100 ($21.00). Wooden poles, 35 feet long for rural primary distribution are estimated to cost $37.40 in Puerto Rico.[44]

In view of these costs, there has been considerable interest in using locally available poles, even though the life might be fairly short. In some communities, especially in South America, local poles are available at essentially zero cost, these could be used with no treatment or with a superficial chemical application. If local labor is used, the replacement cost is very low. Another possibility is to set the wooden pole on a concrete or steel stub extending above ground, thus obtaining most of the advantages of concrete or steel poles at substantial cost savings.[45]

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[43] Miner and Miner, Presentation Report, Exhibit B, "Distribution Structure Cost Comparison Study," p. 3ff. However, without any explanation, summary cost estimates for line construction include poles at half or less of the above. Cf. pp. 40, 41, of the main report.

[44] "Report of the Study Team on Rural Electrification in Madras," p. 8, and Annexure IV, p. 29; Gainneos, "Rural Electrification in Kerala," ECAFE, Bangkok, 1961, pp. 6-8, and 14; and from cost estimates prepared

In view of the wide range of possible pole costs, three alternatives are included in Table III-1; Low--local poles are available at very low real costs, $5 each; Medium--permanent poles are available at $30 at the site, about the most favorable cost to be expected; High--a less favorable cost of $60, which should rarely be exceeded.

Labor costs will depend heavily on the participation of local labor, which usually involves very low or zero real cost because of underemployment, in some seasons of the year at least. No allowance is made for land clearing in these estimates, as this can generally be done by local labor. Local labor and animals can be used for transport, but the feasibility of further use of local labor is not clear.[46] The low estimate of Table III-1 assumes that local labor can do most of the actual erection under the supervision of a centralized staff, especially in rough terrain, not having to bring large work crews and/or heavy equipment into the area would mean substantial savings.

The labor costs in the "Median" column are probably near the lower limit for a centralized work force; low wages and efficient organization would be required. The total centralized labor costs, including supervision, are comparable to those estimated for Pakistan. They are somewhat higher than those listed for Kerala, but it is not clear whether overhead and indirect items are in the latter.[47] The costs listed in the "High" column should not be exceeded in most underdeveloped countries. However, they are about two-thirds of the estimated labor costs for rural electrification in Puerto Rico.

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by the Puerto Rico Water Resources Authority in 1962.

[45] See Mikes, "Reseaux Rationnels de Distribution d'Energie Electrique pour les Besoins Agricoles Tchecoslovaquie," WPC, Belgrade, 1959, Vol. VI, pp. 862, 6, 7; and Idnani and Seethapathy, "Rural Electrification in India," ECAFE, Bangkok, 1961, Appendix.

[46] More problems are posed for major use of local labor in primary line construction, as higher standards are required, and the construction is usually on a larger scale. See below, Section D 1, for some of the arguments for local labor participation.

[47] Miner and Miner, op. cit., p. 41; and Gainneos, op. cit., p. 14.

Material costs other than poles are not expected to vary widely in cost as the items are of fairly uniform design, and transport costs relative to value are not high. Imported goods might be somewhat higher in real costs than U.S. prices would suggest due to the shortage of foreign exchange. The "Miscellaneous" category under indivisible line costs is intended to include the materials required for anchoring and grounding poles, and for a pro rata share of special angle and terminal structures and simple sectionalizing devices. The "Pole-top-hardware" category includes all items required per conductors, including the insulator assembly, brackets or a share of the cross-arm loot, and armor rods and tie-wires. The major difference in cost between 11 KV and 22 KV arises in the required insulators.[48]

The conductor costs are based on U.S. delivered prices in the Fall of 1962 for ACSR. Low, Median, and High estimates are 125 per cent, 150 per cent, and 175 per cent, respectively, of the lowest U.S. costs. The available foreign cost data is consistent with the Low and Median estimates.[49] The cost of copper conductors is about double that of the equivalent capacity ACSR in the U.S., and as this ratio is consistent with the relative world market prices for ingots of the two metals, relative costs anywhere in the world should be comparable. Although there are slightly higher costs in installing aluminum rather than copper conductors,[50] copper, without steel reinforcement, cannot be used for as long spans as ACSR, and it is unlikely that copper conductors can be justified for primary lines anywhere in the world.

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[48] The opinion that there need be no significant differences in line structure, other than the insulators, for the two voltages is based on a careful comparison of the R.E.A. design specifications for 7.2/12.5 KV and 14.4/24.9 KV given in Form 804 and Form 803, respectively.

[49] E.g., Gainneos, op. cit., p. 14; the cost is just 125 per cent of the U.S. cost net of discounts.

[50] Primarily because greater care must be taken in making joints, and because armor rods at each insulator are always required for aluminum--the cost would be several dollars per conductor per mile--and copper, for relatively short spans, may not require similar rods.

For the annual fixed cost of the line, estimates of the annual capital charges and the operation and maintenance costs must be made. With permanent poles, a primary line has a physical life of perhaps thirty years. Even if the economic amount of excess capacity has been installed initially, major rebuilding may be required much sooner, and the economic life is very difficult to estimate. However, examination of Table A-2 in the Appendix will show that the annual capital charges are not sensitive to the exact life of a long-lived investment when the discount rate is fairly high. In the succeeding, a discount rate of 10 per cent and a twenty-year life are assumed, yielding an annual capital charge, $acc_{1p}$, of approximately 12 per cent. Using Table A-2, the implications of other assumptions are easily explored. If non-permanent local poles are used, their life will probably be less than the economic life of the line, and an appropriately higher rate should be charged against the pole component of the investment.

The annual operating and maintenance costs cannot be estimated without qualification, as no unambiguous data from underdeveloped countries have been found. According to the Madras State Electricity Board, operating and maintenance amounts to 7.2 per cent of the investment in rural extensions, but secondary lines are included, and probably user billing and collection [51] The R. E. A. suggests a range of 1.5-3.5 per cent of original investment for rural lines in the U. S. [52] Recalling that the basis for estimating operation and maintenance is here only the indivisible costs of the line and conductor, an annual factor, $om_{1p}$, of 4 per cent seems reasonable. It would, of course, be higher with the use of local poles.

The first section of Table III-2 reproduces annual indivisible cost estimates calculated from the above estimates according to equation 3.8

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[51] "Report . . . on Rural Electrification in Madras," p. 15.

[52] REA, Economical Design of Primary Lines for Rural Distribution Systems, p. 4.

above. The effects of other assumptions may be explored by substitution of the appropriate values into the basic equation.

The second section of Table III-2 lists marginal capacity costs calculated according to equations 3.9a and b. Representative values for the marginal capacity and energy costs at the distribution substation output are $40/KW and 3.4 mills/KWH, respectively.[53] A power factor of 90 per cent, and equivalent hours for energy losses equal to 1,000 are assumed for primary lines. The marginal capacity costs are not very sensitive to different construction cost estimates, and experimentation with different capacity and enrgy costs will also indicate low sensitivity. However, the voltage of the line has a marked effect on the capacity costs; doubling the voltage halves exactly the marginal capacity cost. The small differential between 1ϕ and 3ϕ results from the assumption of 2 phase wires on the 1ϕ line, so that the voltage between conductors is the same for both 1ϕ and 3ϕ. Of course the wire sizes would be larger on the 1ϕ line than on the 3ϕ, for a comparable load. Over-all cost comparisons for 1ϕ and 3ϕ must include the relative costs of transformers, to which we will now turn.

## 2. Transformer costs

In each village one or more step-down transformers will be required to convert the primary voltage to the standard utilization level. The relative costs of transformers must be considered in weighing the advantages of alternative primary voltages, and a major objection to higher primary voltages has been the increased cost of the distribution transformer. Consequently, we will analyze transformer costs in some detail so that the relative costs for different primary voltages and phase arrangements can be established.

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[53] See below, Section V, A, 7.

TABLE III-2

ILLUSTRATIVE ANNUAL COSTS FOR PRIMARY DISTRIBUTION LINES[a]

| | Low[b] | Median[b] | High[b] |
|---|---|---|---|
| Indivisible Costs: $IC_{lp}$ ($/mile)[c] | | | |
| Single-phase[d] | | | |
| 11 KV | 83 | 170 | 277 |
| 22 KV | 92 | 181 | 290 |
| Three-phase[e] | | | |
| 11 KV | 107 | 203 | 318 |
| 22 KV | 120 | 219 | 338 |
| Marginal Costs: $MCC_{lp}$ ($/KW-mile)[f] | | | |
| Single-phase[d] | | | |
| 11 KV | .47 | .53 | .59 |
| 22 KV | .24 | .27 | .29 |
| Three-phase[e] | | | |
| 11 KV | .41 | .46 | .51 |
| 22 KV | .20 | .23 | .25 |

Notes:

a. Assuming a 20-year life for construction, except 10-year for poles in "Low" category; 10% rate of interest; and $om_{lp}$ = 4%.

b. Using the corresponding construction cost estimate in the preceding Table, III-1.

c. Calculated according to equation 3.8.

d. Two phase conductors, no neutral.

e. Three wire.

f. Calculated according to equations 3.9a and b, assuming CC = $40, EC = 3.4 mills, ehr = 1000, and PF = .90.

The total transformer costs include the initial purchase and installation cost, operation and maintenance, and the cost of power and energy losses.[54] Over the relatively narrow size range of transformers which would be used in rural electrification (perhaps 10 to 200 KVA),[55] the installed cost of transformers may be closely approximated by linear cost functions.

(3.17) Installed transformer cost = $A_t + B_t$ (KVA)

The annual capital cost of the investment may be obtained by multiplying the above by a factor, $acc_t$, representing both depreciation and interest charges. Annual operating and maintenance costs may be estimated as a decimal fraction, $om_t$, of the original cost.

The power and energy losses must be divided into two categories: the "core" or "iron" losses which are fixed for a given capacity of transformer irrespective of the load on the transformer, and the "coil" or "copper" losses which vary as the square of the load on the transformer. Maximum copper losses are evaluated at the full load rating of the transformers. Each of these losses may be estimated over the relevant size range as linear functions of the KVA rating of the transformer. In kilowatts, they are:

(3.18a) Iron losses = $a_f + b_f$ (KVA);

(3.18b) Maximum copper losses = $a_c + b_c$ (KVA)

The costs of losses include both marginal capacity and energy costs. Iron losses continue at a constant rate throughout the year, and

(3.19a) Annual cost of iron losses = $(a_f + b_f$ (KVA)), (CC + 8, 760 EC)

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[54] Exciting current costs are very low relative to the power and energy losses, and are neglected in the succeeding.

[55] Transformers are rated in kilovolt-amperes, which is equivalent to KW/ (Power Factor).

Copper losses are resistance losses and vary with the square of the load, as do line losses, and the concept of loss equivalent hours may be used here also.

Hence,

(3.19b) Annual cost of copper losses = $(a_c + b_c\,(KVA))\,(CC + ehr\ EC)$

From the above equations, the annual costs of a transformer installation may be derived. Again, the indivisible costs per installation, $IC_{tf}$, and the marginal capacity cost per kilowatt of demand, $MCC_{tf}$, will be the most useful. These costs are defined as follows:

$$(3.20) \qquad IC_{tf} = (acc_t + om_t)\,A_t + (a_f + a_c)\,CC + (8{,}760\ a_f\ tehr\ a_c)\,EC$$

$$(3.21) \qquad MCC_{tf} = \frac{1}{PF}\left[(acc_t + om_t)\,B_t + (b_f + b_c)\,CC + (8{,}760\ b_f + ehr\ b_c)\,EC\right]$$

A small strictly energy component--the term, $ehr\ b_c\ EC$--has been included within the capacity cost definition. It is not directly proportional to the energy thruput of the transformer, and it is negligibly small relative to the marginal energy cost at the transformer. Thus, a separate energy cost specification for the transformer is needless, and the term is included with the capacity cost so that equations 3.20 and 3.21 will include all components of the transformer costs.

Given the relatively high cost of installing a transformer, considerable excess capacity will usually be installed in anticipation of a growing demand. On the other hand, transformers are generally designed with an actual capacity exceeding the nominal rated capacity by a fairly large margin.[56]

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[56] The feasible capacity of a transformer of a given design and size is determined by thermal considerations as the insulation deteriorates increasingly more rapidly as its temperature increases. Thus the maximum load which can be carried depends on the ambient temperature and the duration of the load. Short-term over-load capacities on the order of 150 per cent of the rated capacity are common on U.S. transformers.

Consequently, averaging over the installed life of a transformer, the annual peak load may be approximately equal to the design rating of the transformer. In the succeeding, it will be assumed that negligible error results from setting the nominal rating of the transformer in KVA equal to the annual peak demand in KW, corrected for Power Factor.

Not enough data on transformer costs abroad could be obtained to support representative estimates. Consequently, the following estimates are based on current U.S. costs. Technical design parameters determining the loss components of costs should not be significantly different. Manufacturing costs abroad may or may not be higher: Indian commercial quotations approximate U.S. prices at the official exchange rate, and selling prices are substantially lower in Europe and Japan. It appears that transformer installations in foreign rural areas are frequently much more elaborate than U.S. practice, and are difficult to justify for low demand areas. Design standards evolved for dense demand urban areas seem to be used without critical review of their applicability in different situations.[57]

The installed cost parameters reproduced in Table III-3 have been estimated from manufacturers' current listed prices, on a delivered basis, and on R. E. A. estimates of installation costs.[58] The listed voltages are not consistently standard U.S. designs, but estimates were based on the nearest standard rating. The transformers are uniformly "self-protected," including fuses and lightning arrestors on each primary phase conductor and circuit breaker protection on the secondary side as an integral part of the unit. Under and over nominal voltage taps

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[57] Where utilization voltages are high, as in Europe, the distribution transformer economically serves a larger area and heavier load, and tends to have more elaborate switching and protective gear. The low U.S. standard utilization voltage has forced the development of relatively low-cost transformer installations in order to serve low density loads, especially in rural areas.

[58] Prices from manufacturers' price lists current, in the Fall, 1962, and R. E. A. estimates from Staff Instruction 80-3, "Construction Costs of

TABLE III-4

REPRESENTATIVE ANNUAL INDIVISIBLE AND CAPACITY COSTS FOR DISTRIBUTION TRANSFORMERS[a]

| | Indivisible Costs: $IC_{tf}$ ($) | Marginal Capacity Costs: $MCC_{tf}$ ($/KW) |
|---|---|---|
| Single phase | | |
| 11 KV, ϕ-N | 34.50 | 2.60 |
| 11 KV, ϕ-ϕ | 40.40 | 2.60 |
| 22 KV, ϕ-N | 44.40 | 2.80 |
| 22 KV, ϕ-ϕ | 56.10 | 2.80 |
| Three phase | | |
| 11 KV | 90.70 | 2.80 |
| 22 KV | 107.00 | 2.80 |

Notes:

a. Calculated from equations 3.19 and 3.20 under the following assumptions:

1. Cost and loss parameters of Table V;
2. 10% discount rate, 15 year life, implying $acc_t$ = .13;
3. Annual operating and maintenance, $om_t$ = .04;
4. Marginal capacity costs at the transformer, CC = $45/KW; marginal energy cost, EC = 3.4 mills/KWH;
5. Equivalent hours for copper losses, ehr = 1000 hr./year;
6. Power factor at the transformer, PF = .90.

for each village will be the indivisible costs ($ICd_{pv}$) as defined above in equation 3.12 a:

$$ICd_{pv} = L_{pv} \; IC_{1p} + IC_{tf}$$

The relevant line length ($L_{pv}$) is the incremental length for connecting the village in question, and the reader is reminded of the above discussion of joint lines (section B, 2). As an illustration, assume a village size of 3 square miles, which is fairly representative of Indian rural areas. If the towns in the area are already electrified, the incremental primary line per village should not exceed $\sqrt{3}$, or about 1.7 miles.[60] A few villages fortunately situated near existing lines might require shorter lines.

Our basic estimates for $IC_{1p}$ assume $3\phi$ lines; the conditions under which $1\phi$ service yields lower total costs will be discussed later. Using the median estimates of Table III-2 for $IC_{1p}$, transformer cost estimates from Table III-4, illustrative indivisible costs for primary distribution per village, $ICd_{pv}$, are \$436 and \$479 for 11 and 22 KV, respectively.

The capacity costs for primary distribution are given by equation 3.13a:

$$MCCd_p = EL_p \; MCC_{1p} + MCC_{tf}$$

As the equivalent length ($EL_p$) varies with the size of the distribution area, and the economic area size is dependent on the demand density and the costs of substations and subtransmission lines, several alternative assumptions will be made. Three levels of demand density (D) over the whole distribution area may be assumed: 1) demand for lighting, with very little power use, 3 $KW/mi^2$; 2) power for processing and minor irrigation pumping, plus lighting, 10 $KW/mi^2$; and 3) pump irrigation over most of the area, plus processing and lighting, 30 $KW/mi^2$. These are maximum demands at the village and take account of some non-coincidence between the various demands.[61]

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[60] For the justification of this estimate see above, sec. B, 2.

[61] See above, Sec. II, A, and the cited references for the range of demand parameters.

Still assuming 3 mile$^2$ per village, these demand density assumptions imply maximum village demands ($D_v$) of 9, 30, and 90 KW, respectively.

Alternative assumptions regarding the indivisible costs of a primary voltage source feeding the distribution area ($IC_f$) are: 1) only the indivisible costs of the substation are incurred, $4,800/year; 2) to the substation costs are added the indivisible costs of 20 miles of subtransmission line at $600/mile/year, or a total of $16,800/year; and 3) 30 miles of line must be built, plus the substation, or $22,800/year.[62]

According to these assumptions, and marginal line capacity costs from Table III-2 (median estimates for 11 and 22 KV), the optimum size of the distribution area may be determined from equation 3.16:

$$\bar{S} = \left(\frac{4\ IC_f}{D\ MCC_l}\right)^{1/3}$$

Calculated values for the side ($\bar{S}$) of an optimum sized area are listed in Table III-5. These values should not be interpreted too precisely, as they rest on several simplifying assumptions.[63] In addition to illustrating the effects of different environmental assumptions, these estimates may be interpreted as the approximate dimensions of the distribution areas which might be economically served from an existing substation, given the stated costs of providing another substation with its supplying subtransmission line.

Recalling that the equivalent length for distribution, EL = S/2 for a square shaped distribution area,[64] the marginal capacity costs for

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[62] See below, sec. V, A, 2 and 3, for substation and subtransmission line cost estimates.

[63] Which are discussed above, sec. B, 4.

[64] After the derivation in sec. B, 3, above.

TABLE III-5

OPTIMUM DISTRIBUTION AREAS AND RESULTING ANNUAL CAPACITY COSTS FOR PRIMARY DISTRIBUTION

| | Demand Density (KW/mile$^2$) | | | | | |
|---|---|---|---|---|---|---|
| | 3 | | 10 | | 30 | |
| | $\bar{S}$[a] (miles) | $MCCd_p$[c] ($/KW) | $\bar{S}$[a] (miles) | $MCCd_p$[c] ($/KW) | $\bar{S}$[a] (miles) | $MCCd_p$[c] ($/KW) |
| I. Substation only: $IC_f$ = $4,800 | | | | | | |
| 11 KV: $MCC_{1p}$ = .46 | 24 | 8.30 | 16 | 6.50 | 11 | 5.40 |
| 22 KV: $MCC_{1p}$ = .23 | 30 | 6.30 | 20 | 5.10 | 14 | 4.40 |
| II. Substation plus 20 miles Subtransmission line: $IC_f$ = $16,800 | | | | | | |
| 11 KV: $MCC_{1p}$ = .46 | (37)[b] | (11.20)[b] | 25 | 8.60 | 17 | 6.70 |
| 22 KV: $MCC_{1p}$ = .23 | 46 | 8.10 | 32 | 6.50 | 21 | 5.30 |
| III. Substation plus 30 miles Subtranmission line: $IC_f$ = $22,800 | | | | | | |
| 11 KV: $MCC_{1p}$ = .46 | (39)[b] | (11.90)[b] | 26 | 8.90 | 18 | 7.00 |
| 22 KV: $MCC_{1p}$ = .23 | 50 | 8.50 | 33 | 6.60 | 23 | 5.40 |

Notes:

a. The optimum length of one side of an approximately square distribution area, as calculated from equation 3.16 for the listed values of D, $IC_f$, and $MCC_{1p}$. See sec. III, B, 4.

b. Voltage drops would probably be excessive for the theoretic optimum conductor size and distribution area. See the end of sec. III, A, 4, including equation 3.10b. With load compensating voltage regulation, and under and over nominal voltage taps on the distribution transformers, maximum voltage drops, to the end of the primary line, of 10-15% can be tolerated. See also sec. III, E.

c. Calculated from equation 3.13a, with the $MCC_{1p}$ values (median estimates, 3$\phi$ lines from Table III-2) used for calculating $\bar{S}$, and transformer costs from Table III-4.

primary distribution ($MCCd_p$) may be calculated from equation 3.13a. Using the same $MCC_{1p}$ values as were used for calculating $\bar{S}$, and marginal transformer costs from Table III-4, $MCCd_p$ estimates on an annual basis are entered opposite the corresponding $\bar{S}$ in Table III-5. As might be expected from the relative values for $MCC_{1p}$, 11 KV consistently yields higher capacity costs ($MCCd_p$) than 22 KV. Capacity costs steadily decline as demand density increases, and smaller distribution areas become economical. With increasing indivisible substation costs, the least-cost distribution area increases, and therefore the capacity costs increase also. The bracketed entries for 11 KV imply that voltage drops would be excessive for the theoretic least-cost area size and conductor capacity. However, this might not be a constraint, because portions of lines in such low demand density areas would be very lightly loaded, and the excess conductor capacity would yield less voltage drop than is implied for the optimum conductor size.

The total costs for primary distribution per village are simply the indivisible primary distribution costs, plus the product of the capacity costs and the village demand, as given by equation 3.15 above The relative total costs for 11 and 22 KV may be quickly calculated for the conditions assumed in Table III-5; the total costs are nearly the same for a demand density of 10 KW/mile$^2$ and the lowest substation costs. Higher demand densities and/or higher substation costs imply savings for 22 KV. Only for very low demand densities would 11 KV appear to have lower total costs, but for these demand densities 1$\phi$ service, with lower indivisible costs than for the 3$\phi$ assumed above, would be economical.

But the choice of primary distribution voltage should not rest exclusively on the primary distribution costs. Substation and subtransmission line costs will also be affected by the primary voltage. Further discussion of this topic is reserved for section E below, after the secondary distribution costs are reviewed.

## D. Cost Estimates for Secondary Distribution

The first two sections following establish preliminary estimates of the costs for secondary lines, and domestic and power users' service costs. Factors influencing these costs will be discussed, and possibilities of reducing costs from present levels noted. The final section relates these estimates to the costs of supplying different classes of users.

### 1. Secondary line costs

Again the major determinant of total line costs is the initial investment required. The low, median, and high estimates reproduced in Table III-6 are to be interpreted in the same fashion as the similar estimates for primary lines. The median estimate is intended to approximate the most frequently encountered costs; the low and high estimates are attempts to set reasonable lower and upper boundaries.

A pole spacing of 200 feet is assumed in the estimates of Table III-6. This spacing may be varied somewhat, according to the distance between service drops.[65] Especially with expected ice loads, small sizes of aluminum strand may not have sufficient tensile strength for spans which would otherwise be allowable. Where convenience for service drops is not a constraint--e.g., in extending a line to serve an irrigation pump--it will probably be economical to use ACSR and extend the pole spacing.

Locally available poles with minor chemical treatment are assumed to cost $5 each; permanent poles will cost about $20 each on-site under favorable conditions, and should rarely exceed $40. These costs are slightly lower than those suggested above for primary lines, because secondary lines usually have shorter spans and lower clearances, and

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[65] Each service drop should originate at a pole, and feasible maximum lengths of service drops without poles in mid-span are about 100 feet. More than 6 or 8 drops per pole lead to severe congestion on the pole.

TABLE III-6

CONSTRUCTION COST ESTIMATES FOR SECONDARY DISTRIBUTION LINES[a]

| | Low[b] | Median[b] | High[b] |
|---|---|---|---|
| Indivisible Structure Costs of Line:[c] $A_{1s}$ | | | |
| Poles | $135 | $530 | $1050 |
| Miscellaneous (Guys, grounding, etc.) | 125 | 160 | 190 |
| Labor & overhead (including supervision and inspection) | 100 | 240 | 400 |
| TOTAL | 360 | 930 | 1640 |
| Indivisible Conductor Costs: $A_{ws}$ | | | |
| Conductor | 102 | 122 | 142 |
| Pole-top hardware | 40 | 50 | 60 |
| Labor & overhead | 5 | 35 | 58 |
| TOTAL | 147 | 207 | 260 |
| Variable Cost of Conductor: $B_{ws}$ | | | |
| Conductor | 182 | 218 | 255 |
| Labor increment | - | 7 | 13 |
| Pole & hardware increment | 13 | 35 | 62 |
| TOTAL | 195 | 250 | 330 |

Notes:

a. The unit length is uniformly one mile. For a kilometer basis, multiply by 0.621. The average span between poles is assumed to be 200 feet; the minimum conductor size to be #4 AAC. No right-of-way costs are included.

b. For assumptions behind the Low, Median, and High categories, see the text.

c. Excluding neutral; when required, add $A_{ws}$.

can hence utilize shorter poles. For the different pole materials and the range of reported costs, the reader is referred to Section III, C, 1, above and the references there cited.

The participation of local labor appears more feasible in secondary, than in primary line construction, and merits some consideration. Real labor costs could be drastically reduced if most of the construction labor could be supplied in the village. Chronic underemployment in underdeveloped villages implies essentially zero real wage costs. The effective use of local labor is probably dependent to a large extent on the institutional arrangements for electricity supply; if all operations at the local level are administered by a central agency, the high costs of administration and coordination will work against major use of local labor. Alternatively, if a local organization, probably a cooperative, is in charge of local distribution, local labor can undertake most construction and maintenance with central resources available for technical matters and some supervision, inspection, and training support.

Arguments against a centralized approach to local construction include the following: 1) Centralized work forces must have substantially higher wages and living allowance. 2) Relatively high costs are involved in transportation and communication to rural sites. 3) Initial expenditures on materials will generally be higher because of the greater difficulty in utilizing any available local materials, especially poles; and the relatively higher costs of later extensions will require larger initial installations. 4) Rarely are all service connections made initially, and the time and cost involved in making later connections is much higher. 5) Local men competent to complete consumers' wiring are required to keep these costs to reasonable levels; these skills are comparable to those required for secondary line construction.

The following arguments apply against local construction: 1) Local labor will have to be trained. However, any substantial construction

program will require training labor anyway, and it can be argued that less fully employed rural labor ought to be trained. 2) Some supervision and inspection will still be required, and enforcement of minimum technical standards may be difficult. This would be the key problem in a decentralized scheme. 3) In many instances local poles may be unavailable or unsuitable even when installed by very low cost labor.

For comparison, secondary line construction cost estimates from several countries are shown in Figure III-4, together with the implied total costs (after equation 3.1) from the component estimates of Table III-6. Costs reported in foreign currency have been converted at the official exchange rate. It appears that our low and median estimates are consistent with reported foreign costs; and that costs will rarely reach our high estimate.

Based on the alternative construction cost estimates of the preceding table, annual indivisible and marginal costs for secondary lines are given in Table III-7. The additional assumptions are noted in the table; the indivisible costs were calculated according to equation 3.8 above, and the marginal costs following 3.9ab. In calculating the marginal costs, a utilization voltage of 230 volts, phase to neutral, was assumed. This is the standard for India and Pakistan, and mid-way between the Continental European 220V and the English 240V. At the U.S. standard, 120V, marginal costs are increased by 230/120, or nearly doubled. The choice of utilization voltage is not a trivial matter, and new extensions in Latin America ought to be standardized to relatively high levels.[66] The indivisible costs are minimized by using as few conductors as possible--i.e., 2, in a 1$\phi$, two-wire supply. But the marginal costs are halved in a 1 $\phi$, three-wire line (the effective voltage is doubled assuming a balanced load) and total costs are lower with the latter construction for loads exceeding 2 or 3 KW.

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[66] See below, sec. 3 for the effect on distribution distances and capacity costs. The claim is sometimes made in this country that higher utilization voltages are not desirable because greater safety hazards are presented. This objection is rarely, if ever, raised in countries which have adopted higher voltage standards. Of course some attention must be given the design and quality control of utilization appliances.

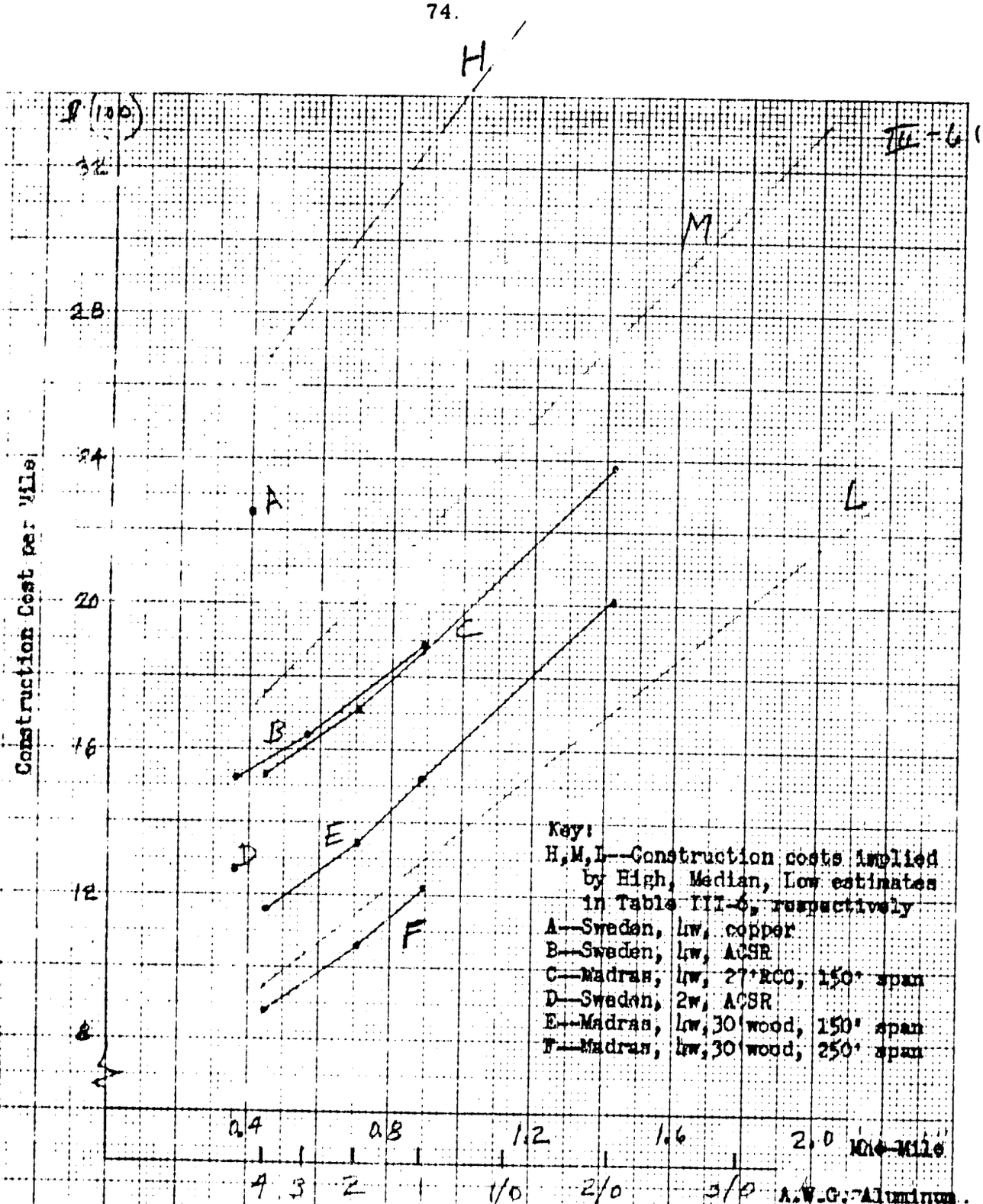


Figure III-4

Comparative Construction Cost Estimates for Secondary Distribution Lines

Sources: Gov't of India, "Report ... on Rural Electrification in Madras," Annexure III; Kaijser, WPC, Belgrade, 1957, p.229.

TABLE III-7

ILLUSTRATIVE ANNUAL COSTS FOR SECONDARY DISTRIBUTION LINES[a]

| | Low[b] | Median[b] | High[b] |
|---|---|---|---|
| Indivisible Costs: $IC_{1s}$ ($/mile)[c] | | | |
| Single-phase | | | |
| 2-wire (230 V) | 105 | 215 | 345 |
| 3-wire (230/460 V) | 128 | 248 | 387 |
| Three-phase | | | |
| 4-wire (230/400 V) | 152 | 281 | 428 |
| Marginal Costs: $MC_{1s}$ ($/KW-mile)[d] | | | |
| Single-phase | | | |
| 2-wire (230 V) | 21.20 | 23.80 | 27.70 |
| 3-wire (230/460 V) | 10.60 | 11.90 | 13.80 |
| Three-phase | | | |
| 4-wire (230/400 V) | 10.60 | 11.90 | 13.80 |

Notes:

a. Assuming a 20-year life for construction, except 10-year for poles in "Low" category; 10% rate of interest; and $om_{1s}$ = 4%.

b. Using the corresponding construction cost estimate in the preceding table, III-6.

c. Calculated according to equation 3.8.

d. Calculated according to equations 3.9a and b, assuming CC = $48, EC = 4 mills, ehr = 700, and PF = .90.

The marginal costs are identical between 1 $\phi$, 3-wire (230/460V), and 3 $\phi$, 4-wire lines, with the same phase-to-neutral voltage. There is a fairly common misconception that 1 $\phi$ distribution is necessarily less efficient than 3 $\phi$.[67] Single-phase, three-wire lines are not only equally efficient in the use of conductor equipment as 3 $\phi$; they involve lower indivisible costs as one less conductor is used.

2. Users' costs

Two components in users' costs may be distinguished; the annual capital charges and the operation and maintenance costs of the service connection, including the metering or control devices; and the administrative, accounting, and billing costs per user. Both components are essentially invariant with the rate of usage, and can be considered as indivisible costs per user--hence the notation, $IC_{ud}$ for domestic users, and $IC_{up}$ for power users. Marginal capacity costs are either zero or negligibly small. For domestic service, the minimum wire sizes required for tensile strength in the service drop have excess capacity relative to the low levels of demand, and losses are negligible. Meters or other load control devices are unchanged for wide ranges of demand. Service leads for power connections are short, and their cost, which may vary slightly with the demand, is small relative to that of the meters. Accounting and billing costs per user do not increase with larger usage; if such costs vary at all, they may increase for low levels of use due to the difficulties of collection from low income users.

While the following cost estimates appear small, they are large relative to the expected low demand levels. For example, in estimates

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[67] E.g., see Menezes and Filho, "Disadvantages of Single phase Lines on Pioneer Rural Lines," U.N. Conference on the Application of Science and Technology for the Benefit of the Less Developed Areas, Geneva, 1963. The present generalization applies to distribution only, and does not include relative costs of utilization equipment.

for Pakistani villages, the installation costs of meters and services amounted to 165% of the secondary line construction costs.[68] Also, the costs of billing and collection from a centralized agency may constitute half or more of the total applicable costs--capacity, energy, and user's indivisible costs--for low domestic demands.[69] Meter reading and billing costs in the rural areas would hardly be lower than in urban areas in the U.S., where such costs approximate $5-$7 per customer per year. Some kind of decentralized administration--perhaps a local cooperative in each village or group of nearby villages--is probably a prerequisite for a reasonably self-supporting service to the major part of the population of a rural village.

The cost of the service connection, and hence the annual capital charges on it, will vary widely, depending on local versus centralized installation, and on the kind of meter or control devices. A detailed estimate for domestic service installations in rural Pakistan totals to $34.48 for materials, including a meter at $16.50, and $11.29 for labor. However, this installation seems to be inappropriate for the relative material and labor costs and demand levels of an underdeveloped village.[70] Without sacrificing any safety standards, it appears that the material costs can be reduced to the order of $6 for an 80-ft. drop, excluding metering.[71] Labor costs are dependent on the participation of local labor. Especially for connections subsequent to the initial electrification, centralized construction will involve very much higher

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[68] Miner and Miner, op. cit., pp. 41-2.

[69] See Gainneos, op. cit., pp. 13, 14, and Annex F, for the number of staff maintained in rural areas and the collection practices in Kerala State, India. One regional accounting office has already been equipped with imported automatic computing machines to process users' invoices.

[70] Miner and Miner, op. cit., p. 42.

[71] Assuming 1 bare and 1 polyethylene insulated #6 solid aluminum wires at current U.S. list prices plus 25%; simple insulators, entrance cable, ground wire, etc., at $3.50.

costs over local administration and labor.[72] The real labor costs for local construction may be no more than one-tenth of the total labor, transportation, supervision, and overhead costs involved for a central agency.

Standard meters are prohibitively costly relative to the energy consumed in a low-income rural household. U.S. prices for a 1ϕ meter are about $15 each, and $20 is reported for meters of Indian manufacture. Meter costs might be reduced; European meters are available at about $9 each, and Japanese at $5.[73] A more economical possibility is to leave off the meter altogether. At very low consumption levels the exclusive use is for evening lighting, and a flat rate for wattage installed is perfectly feasible. The consumer can be connected to the street lighting circuit which is energized for only the evening hours, and his demand limited to the agreed wattage by a simple magnetic or thermal relay.[74] This device should be integrated with the fuse and disconnect box which is required for circuit protection. Thus, the load control device might cost little, or no more than the service switch and fuse required in any case. Its cost might approximate $2.50, based on current catalog prices.

To conclude, a lower cost of about $10.00 per domestic connection seems attainable with local administration and labor; for a centralized agency costs might approach $20.00 for the minimum service. The upper limit is probably about $50 for a metered service. Allowing about 20% per year for capital charges and maintenance, the annual costs are thus $2, $4, and $10, for the respective assumptions Assuming

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[72] See the discussion in the preceding section regarding local versus central labor.

[73] From memorandum prepared by the Meter Department, General Electric Co.

[74] Ibid.

negligible collection costs for a local cooperative, the lowest value for $IC_{ud}$ is \$2/year. Assuming, optimistically, that collection costs for a central agency approximate \$5/year, minimum and maximum values for $IC_{ud}$ might be \$9 and \$15/year respectively, for service from a central agency.

For light industrial and agricultural services, the indivisible costs ($IC_{up}$) are not so high relative to the annual energy consumed. From the same source cited above, 3ϕ service in Pakistani villages was estimated to cost \$103.62, including a meter at \$47.50.[75] The above comments on least-cost design in view of low labor costs apply here also, and a material cost of \$15, excluding the meter, appears attainable. To this, labor charges of a few dollars for local labor, or about \$25 for a central agency, should be added.

Flat rate service is probably not feasible for the larger power consumption. For 1ϕ the \$15 U.S. meter has ample capacity for most rural power loads. U.S. prices for 3ϕ meters are about three times the 1ϕ meter price. Part of this differential represents a larger capacity meter.

When there is only one motor at the service connection operating at a constant load, e.g., an irrigation pump motor, the hours of operation could be counted on a very simple and low-cost running time accumulator. The billing units could then be HP-hours, or conventional KWH by converting the motor size rating to KW demand.

A load supplied exclusively off-peak involves very much lower costs due to the implied zero generating and transmission capacity costs. But to implement off-peak operation requires some means of either preventing peak hour use, or of charging differential rates between on-and-off peak

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[75] Miner and Miner, op. cit., p. 42.

hours. Meters which accumulate on-peak and off-peak hours separately are available in the U.S. at a price somewhat more than double that of the standard meter. Meters incorporating a timed switch for disconnecting the load at peak hours are slightly cheaper. The availability and prices of comparable devices abroad isn't known, but are expected to be favorable relative to U.S. prices.

For the single motor service mentioned above an off-peak control may be advantageously combined with the motor controller so that the heavy circuit switches are not duplicated. Combining a simple time clock and a running time accumulator (much of the clockwork could be common to both) with the motor-controller would yield an inexpensive metering and control device. Such a design would be simpler than a 1ϕ meter; its cost might be $5-$10, irrespective of the motor capacity or phases of supply.

Thus the annual indivisible costs per power user will vary widely depending on the kind of metering equipment. Assuming again an annual charge of 20% for capital charges and maintenance, and $5/year for accounting and billing from a central agency, possible estimates for $IC_{up}$ are:

| | Local Administration $ 4 | Central Administration $15 |
|---|---|---|
| Simple time accumulator, 1ϕ or 3ϕ | | |
| 1ϕ Metering | 7 | 18 |
| 3ϕ Metering | 13 | 24 |
| 1ϕ Off-peak metering | 10 | 21 |
| 3ϕ Off-peak metering | 24 | 35 |

Given capacity costs at the user in the order of magnitude of $50/KW/year, some method of off-peak control or metering will be economical for all but the smallest power demands.

3. Summary secondary distribution costs for different classes of users

As in primary distribution, indivisible costs represent the major portion of the total secondary distribution costs. Per village, the indivisible secondary distribution costs are described by equation 3.11b:

$$ICd_{sv} = L_{svt} \quad IC_{ls} + n_u \quad IC_u.$$

The total secondary line length in the village ($L_{svt}$) is quite variable. Secondary line lengths for "typical" villages in Madras are reported from less than one mile to nearly 10 miles, but 2 to 5 miles appears to be more common.[76] The line length required will depend on the location of users, as well as their number. The indivisible costs for service connections may vary widely, as we saw in the preceding section, and the number of connections will depend on the demand and on rate policies. But $1,000 or more per year for secondary indivisible cost does not seem unreasonable for a village.

The costs per user are more relevant to investment decisions. The user's indivisible costs are simply his connection costs and the costs of the incremental line length required to serve him, i.e., after equation 3.12b:

$$ICd_{su} = L_{su} \quad IC_{ls} + IC_u.$$

The chief difficulty is in estimating the line length, $L_{su}$; for some users it is effectively zero as lines pass them to serve larger demands. The problem of joint line use is inescapable, and averaging the total among all the users yields misleading results. In some cases, a relatively homogenous group of users may be considered as a unit, and the incremental length for the whole group allocated equally within the group. Power connections within the village proper can be made with relatively short line

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[76] "Report . . . on Rural Electrification in Madras," Annexure IX.

lengths, but the incremental length for a single isolated irrigation pump may approach one mile.

Given the great variability in users' indivisible costs, single general estimates should not be given. But the range of possible values must be established for comparing electrification costs with alternatives. For a domestic user, the indivisible costs per year ($ICd_{sud}$) may be as low as $2, assuming that he may be connected to an existing line.[77] For a group of dwellings in a closely built-up village, the lines required to serve them independently of any other service might come to about 40 ft. per dwelling, implying an additional $2,[78] or $ICd_{sud}$ = $4. Central administration would increase these minimum costs drastically; from the estimates in the preceding section, by $7 for the minimum service, and perhaps $13 if metered service is provided.

Power for processing and light industry within the village proper could be served from relatively short lines; for some the incremental length will be zero, and as a group one-tenth of a mile seems realistic, and indivisible line costs might come to $25-$30 per year. More than double this length would hardly be required in the built-up village. The indivisible terminal costs vary widely depending on the kind of metering equipment, the estimated range above being $4-35. Hence, the plausible range for $ICd_{sup}$ is from $5 to perhaps $100. Incremental line lengths for irrigation depend on the number and location of the wells. The maximum line length would rarely exceed one mile because of the feasible limits to the secondary distribution area, and the minimum would be scarcely less than .3 mile.[79] Including the terminal costs, an approximate range for irrigation pumping of $ICd_{sup}$ is $80-$300.[80]

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[77] And assuming local administration, after the discussion in the preceding section.

[78] Following the discussion of line lengths in sec. B, 2, above, and with median line costs from Table III-7.

[79] Assuming that each well commands .1 $mi^2$, and the distance between wells is hence about .3 mile.

The capacity cost for secondary distribution is given by equation 3.13b above: $MCCd_s = EL_s \; MCC_{1s}$.

The marginal capacity cost on secondary lines ($MCC_{1s}$) may be taken from Table III-7; the estimate for 3ϕ, or 1ϕ, 3-wire, is relevant as 2-wire, 1ϕ, laterals would be short and lightly loaded. The equivalent length ($EL_s$) depends of course on the size of the distribution area. In small and medium-sized villages the village proper would be smaller than feasible distribution areas, and $EL_s$ might be estimated from the size of the built-up area. Assuming an approximately uniform demand density througnout the village proper, the $EL_s$ would approximate half the distance across the built-up area.[81] For example, if the built-up area covered one-tenth square mile, $EL_s$ would equal .16 mile. With the median estimate of Table III-7. $MCCd_s$ would hence be about $2/KW. This value will be used in later comparisons for domestic and power consumption within the village proper.

For supply to the fields surrounding the village, as for irrigation pumping, the distribution distance is increased, and hence the capacity costs are higher. The feasible size for a secondary distribution area, as determined by allowable voltage drops on the secondary line, and by cost minimization, may be smaller than the agricultural land belonging to the village. For the demand densities associated with major irrigation pumping (about 25 KW/mile$^2$), and the median cost estimates above, and neglecting voltage drops, the optimum sized secondary distribution area is about 1.5 miles on a side, after equation 3.16. But the voltage drop on a least-cost designed line of 3ϕ, 230/400V, or 1ϕ, 230/460V, is

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[80] At median line costs from Table III-7; alternative line costs will make a significant difference as the line costs make up the major part of the total.

[81] After the derivation in sec. B, 3, above.

about 12% per mile.[82] As the maximum allowable voltage drop on a secondary line is about 5%, lines longer than about 1/2 mile would require larger wires than the optimum. The resulting cost penalties steadily increase as the line construction departs farther from the optimum,[83] and the feasible distribution area will hardly exceed 1.5 miles on a side. This approximates the total area of small Indian villages, but larger villages will require two or more distribution transformers for irrigation pumping.

Taking the equivalent length ($EL_s$) to be one-half the distance across the distribution area, or about .75 mile, the capacity cost of secondary distribution ($MCCd_s$) for irrigation will approach $9/KW. This is substantially higher than the estimated capacity cost for distribution within the built-up portion of the village, and indicates a part of the higher costs of serving dispersed demands--the remainder of the differential costs being the indivisible costs noted above.

## E. Least-Cost Phase Arrangements and Voltages for Rural Distribution

While the technical design of the distribution system is the engineer's province, our analysis sheds some light on several long-standing arguments over line design.

Single-phase supply has frequently been suggested as a feasible means of lowering the costs of minimum service to low demand density rural areas, and it has proven entirely satisfactory in the United States. While admitting that possibly some savings are possible in primary lines, the case against 1$\phi$ has been argued in terms of higher secondary distribution line costs and higher motor costs. The implications for the secondary

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[82] Following equation 3.10ab above, with the same cost assumptions as in Tables III-6-7, and taking the % loss to equal the % voltage drop. See Table A-4.

[83] For an example, see Figure III-1 above.

distribution lines have already been noted:[84] long-run marginal costs are the same for a 1ϕ, 3-wire line as for a 3ϕ line, if the phase-to-neutral voltage is the same in each case. There are savings, however, in the elimination of one conductor from the line--by our median estimates, amounting to more than $30/mile per year. Higher motor costs for 1ϕ are clear, but perhaps not as markedly so as some have concluded in countries where only 3ϕ motors are regularly manufactured. From prices in the U.S. marginal purchase costs per HP for 1ϕ are about $15 higher than 3ϕ, and other costs are comparable.[85] Allowing for capital charges and maintenance, our estimate for the cost penalty for 1ϕ is $3.30/HP annually.

There is no question that the main primary distribution lines should be 3ϕ. Possible savings in primary distribution would then arise in the lower cost transformer, and in the elimination of 1 or 2 conductors in the relatively short spur line serving the low demand village, or villages. Where a substantial part of an area is served with 3ϕ, the 1ϕ spur consisting of a 1-phase wire and a neutral from a 3ϕ, 4-wire main feeder--the standard design for rural electrification in the U.S. --is not promising, and we will neglect it. Taking a 1ϕ tap from 2 of the main phases will eliminate one conductor (for which our median cost estimate is $33 or $38 per year, depending on the voltage), and allow savings of about $50 per year for the transformer.[86]

Single-phase supply is indicated whenever the savings in lines and transformers are greater than the penalties for motors, as there is no

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[84] In section III, C, 1, above.

[85] See below, sec. V, C, 1. Indivisible costs are lower for 1ϕ; fractional horsepower motors are generally 1ϕ. In the larger 1ϕ motors a capacitor is justified to improve the running power factor to a level equalling or exceeding that of the usual 3ϕ squirrel cage motor. The cost of this running capacitor is included in our cost differential.

[86] Primary line costs from Table III-2, and transformer costs from Table III-4.

cost differential for other utilization appliances. On this basis, 1ϕ supply is more economical whenever the installed motor HP in the village is less than 15, plus 10 for each mile of secondary and primary line in the village.[87]

Although ground return for 1ϕ has never been attempted in the U.S., successful trials are reported from India and Pakistan.[88] Where the subsoil resistivity allows, probably precluding arid regions, this system requires only a single metal conductor and allows transformer savings of about $60 per year from the 3ϕ cost. The break-even connected HP in the village is thus about 18, plus 20 for each mile of primary line, plus 10 for each mile of secondary line.

These numbers should not be interpreted rigorously, but they do indicate that significant reductions in the indivisible costs of serving a village can be obtained by using 1ϕ extensions. Initial 1ϕ service, with eventual change to 3ϕ, also provides an economical way of increasing the line capacity as it is required.

Considerations bearing on the appropriate primary distribution voltage were mentioned above. For moderate demand densities (10 KW/mile$^2$), the lower line capacity costs with 22 KV rather than 11 KV offset the slightly higher indivisible costs of the higher voltage line. Higher demand densities allowed significant savings. The optimum size of the primary distribution is also increased with higher voltages, and the corresponding

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[87] A few minor considerations are neglected, as they do not appreciably alter the conclusion; there are very slightly higher capacity costs on the short 1ϕ primary spur; and some of the lightly loaded secondary line in the village might be 2-wire in either case.

[88] Sviden, "Note on an Economic Type of Distribution System for Rural Areas," ECAFE. Bangkok, 1961; and Idnani and Seethapathy, "Rural Electrification in India," ECAFE, Bangkok, 1961, pp. 12-13.

indivisible substation and subtransmission line costs per village are reduced.[89] Our summary cost specifications for lines overstate the cost penalties for lightly loaded high voltage primary lines; the minimum conductor size, whose cost is included within the indivisible cost of the line, provides more capacity with less loss at higher voltages. By assuming a constant marginal capacity cost at all loads, we neglect this relative advantage of the higher voltage.

A significant advantage of higher primary voltages arises from the resulting larger capacity distribution substations. In addition to the above noted indivisible cost savings on substations and subtransmission lines, the larger load on the subtransmission line makes higher subtransmission voltages economically feasible and results in significant savings in subtransmission costs.[90]

The most marked advantages of higher primary voltages arise in the initial stages of electrification; demand densities are quite low, due to low demands per village and possibly only the larger villages being connected. Medium or low primary voltages, with allowable voltage drops constraining the maximum length of the line, require the installation of costly substations and subtransmission lines to serve very small loads. High primary voltages permit the efficient carrying of electricity over relatively long distances, and large areas of low demand

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[89] For example, the following table shows the annual savings on substation-subtransmission costs per village for 22 KV rather than 11 KV. The assumptions are: 3 mile$^2$/village, the same cost data as in Table III-5, and uniform allocation of costs over the whole area.

| Annual Substation-subtransmission costs: | Demand density (KW/mile$^2$) 3 | 10 | 30 |
|---|---|---|---|
| $4,800 | $9 | $21 | $43 |
| 16,800 | 14 | 29 | 64 |
| 22,800 | 16 | 37 | 75 |

[90] For the trend in marginal capacity costs for transmission lines, relative to the load, see below, sec. V, A, 3, and Table V-1.

density can be economically served from a few substations.[91] As demand grows, the system capacity would be increased by the interposition of additional substations.

It is impossible to generalize the quantitative savings for using 22 KV primary voltages rather than 11 KV, due to the possible variations in relative component costs, and to the wide differences in demand density and proximity to electrified urban areas. But the magnitude of possible savings is sufficient to warrant careful investigation. e.g., postponing the installation of one substation with its sub-transmission link for only one year may allow savings comparable to the total investment requirements for linking up 10 small villages. After the supply distribution system is fully developed, it is plausible that the total costs for 22 KV may be 20% under the costs for 11 KV.

Perhaps more significant is the difficulty one has in assembling a set of plausible cost and demand assumptions such that 11 KV yields lower over-all costs, when the distribution system is built from the beginning. This proviso is important, because the costs of changing an established system voltage are high. But the implied commitment to the initial voltage makes the design of new extensions in underdeveloped areas especially important, and present practice questionable. Pakistan's rural electrification is apparently proceeding with 11 KV as the exclusive standard, most of Indian rural electrification is 11 KV; and in South America the primary voltages vary, but the field teams of this project reported no voltage higher than 13.2 KV.[92] Careful investigation of relative costs may show that primary voltages higher than the 22 KV class are desirable. Above all, rural construction should not proceed in blind deference to standards evolved for urban service some decades ago.

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[91] In sparsely settled areas of northern Sweden, 20 KV primary lines as long as 1000 Km., the most remote transformer being 190 Km. from the substation, have been successfully operated. Kaijser, "Experience Gained in the Rural Electrification of a Sparsely Populated Region in Northern Sweden," WPC, Belgrade, 1957, p. 225.

[92] See Miner and Miner, op. cit., "Basic Design Requirements for Transmission and Distribution," paragraph 2.7 and Table VII; Idnani and Seethapathy, op. cit., p. 8; and G. E., "Preliminary Report of Field Survey Teams," pp. 139, 161, 166, 172c.

## IV. SMALL-SCALE GENERATING PLANTS

Electric generators operating independently of the grid supply may be grouped into two general categories--1) engine-driven generators which are relatively independent of the physical environment, i.e., their location and hours of operation are determined by demand conditions; and 2) generators driven by energy sources which are not generally available, either in location, or at the times required. Examples of the latter are hydro and wind. For the first group cost analysis is straightforward, and generalizations, with some qualifications, can be made. For the second, economic feasibility depends to a large degree upon the characteristics of each site. Further, variability in the timing of supply influences strongly the value of the supply.

In the following we will first develop an analytic approach for evaluating the economic feasibility of engine generators of various types. Then we will turn to the complications presented by the environment-dependent class of electricity sources.

### A. Isolated Engine Generators

Engine generators convert fuel to electricity, and fuel can generally be transported and stockpiled as required to meet the demand for electricity.[93] Thus, environmental constraints may be neglected, except insofar as they affect the prices of factor inputs. For any particular class of equipment, substitution between inputs is considered to be very limited, and hence cost functions may be written with unique technological coefficients.[94]

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93 With some qualification for local fuels: e.g., the bulk of most agricultural waste raises transport and storage costs sharply. Likewise for bio-gas. But storage for daily, even weekly, demand cycles at the village level is feasible.

94 But these coefficients vary slightly with possible design variations of the equipment; once the equipment is built, virtually no substitution is possible.

Given the assumption of negligible substitution between the three classes of inputs--equipment, fuel, and operation and maintenance--their costs may be itemized independently. The indivisible, the marginal capacity, and the marginal energy cost components of each input may be distinguished, and summary equations written for the indivisible, capacity, and energy cost of generation.

Diesel engine driven sets are the most generally applicable small-scale generating facility. Thus, diesel sets are the basis for discussion in the following, and estimates for diesel generation are developed. However, the analytic framework is quite general and may be readily applied to any fuel-electricity conversion scheme by introducing the appropriate parameter values.

1. Investment and Annual Capital Charges

The major part of the initial capital cost of an isolated plant is the purchase cost of the generating set or sets. A survey of 1962 list prices, f.o.b. U. S. manufacturers, indicates a linear relationship between price and the size of the set. For diesel sets, 1800rpm, 3ø, from 10-250 KW capacity, including minimum control equipment, the median purchase price was $2600 + $81 (KW).[95] But actual equipment costs delivered to the site may diverge considerably from this median. First, these are list prices and probably would not be firm under competitive bidding; second, foreign sources, including suppliers indigenous to the country of the installation, might vary in either direction,[96] third, transportation costs to the site, including ocean shipment for imported units must be added; fourth, excise duties might be required although the justification for their

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[95] G. E., "Small-Scale Power Supplies. . . ", pp. 18-20. The cost curve for optional equipment should read, C = $600 + $5 (KW), so that the correct marginal increase per KW is $81, not $127.5 as reported on p. 18.

[96] E.g., the estimates for Indian sources contained in "Report of the Power Sub-Committee . . . ", Ministry of Commerce and Industry, Government of India are substantially lower than the above. But Indian commercial quotations obtained Summer, 1962, are consistent (at the official rate of exchange) with U. S. list prices.

inclusion would depend on the situation, and finally, the nominal foreign exchange rate might not reflect the true shortage of foreign exchange for the importing country.

For transport to rural Indian sites from Indian city of manufacture, 13 per cent of f.o.b. price has been estimated.[97] U.S. list prices probably have sufficient "slack" to absorb export crating and freight to port of embarkation, and perhaps part of ocean freight. To the equipment cost, delivered at the site, must be added installation expenses, the cost of any protective enclosure, and such auxiliary installations as fuel storage tanks. Erection expenses depend on location and the type of equipment: small- and medium-size sets may be factory assembled as packages requiring a minimum of on-site assembly and adjustment. Foundation and structural costs depend in part on the design of the equipment, but mainly on the material cost on-site; local unskilled labor may be taken at zero cost. Clearly these costs will vary considerably from area to area. For a small "power house" in rural India the estimated cost was equivalent to $1,970.[98] But this masonry and reinforced concrete structure seems more elaborate than would generally be required.

The total investment in an isolated generating plant may be summarized as follows:

(4.1) Investment in generating plant $= A_p + n_g A_g + B_g KW_p$

| | Diesel | | Gasoline | |
|---|---|---|---|---|
| | Preferred | Range | Preferred | Range |
| Number of sets in plant $= n_g$ | | | | |
| Indivisible plant costs $= A_p$($) | 600 | 300-1200 | 600 | 300-1200 |
| Indivisible installed costs per generator $= A_g$($) | 3000 | 2400-3600 | 1800 | 1300-2300 |
| Marginal installed costs per KW $= B_g$($/KW) | 100 | 80-120 | 95 | 70-115 |
| Kilowatt capacity of plant $= KW_p$ | | | | |

[97] Ibid.

[98] Ibid.

The above parameters are approximations over the range 10-250 KW for relatively high-speed units, 1800 and 1500 rpm (for 60 and 50 cps, respectively) in the smaller sizes, and 1200 and 1000 rpm in the larger. Heavier slow-speed sets with appreciably higher equipment, transport, and installation costs, may exceed this range. The estimates for gasoline-fueled sets would apply also to bio-gas fueled sets as little modification is required.[99] Engines operated on producer gas from solid fuels would yield a reduced output, and equipment costs would increase accordingly.

As an alternative to bio-gas and producer gas, the solid fuels or agricultural waste might be burned under a boiler to raise steam for a small steam engine driven set. But the costs for the equipment now currently available are much higher than the above approximations for internal combustion engine sets.[100] And, in view of the complexity of the boiler, engine, condenser, and feed-pum combination relative to the I-C engine, there is no reason to expect costs to approach that of I-C engines. Of course, when process steam is required as well as power--as in sugar extraction--the steam cycle may compare favorably in over-all costs.

The annual cost of the fixed investment in the generating plant may be estimated as a decimal fraction, $\underline{acc_g}$, of the original investment.[101]

(4.2) Annual capital charges on plant $= acc_g A_p + acc_g n_g A_g + acc_g B_g KW_p$.

For small high-speed plants, a life of ten years is reasonable. At annual discount rates of 10 per cent, the implied $\underline{acc_g}$ is about 0.16. The units are now

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[99] For exclusive operation on bio-gas ( which is mainly methane) efficiency would be improved slightly by higher compression ratios. But it may be advantageous to operate the set on either gasoline or bio-gas, which is feasible.

[100] G.E., Small-Scale Power Supplies. . ., pp. 39-41

[101] For a justification of combining both interest and depreciation charges into a single annual charge, see Section II, B, above

$/year, and these terms are directly comparable to annual fuel and operating cost data. The first two terms constitute the indivisible component, and the third, the capacity.

2. Fuel Costs

Fuel consumption per KWH depends on the efficiency of the engine in converting fuel to mechanical energy, and on the efficiency of the conversion of mechanical to electrical energy in the generator. As a first approximation, both efficiency parameters are frequently assumed to be constant; i.e., the fuel consumption per KWH is assumed to be independent of the capacity of the plant or its rate of output.

Unfortunately, the simplification of a constant rate of fuel consumption per KWH conceals a major disadvantage of small isolated plants. The local demand is highly variable, and for most of the time, is only a small fraction of the peak demand. Given the high costs of decreasing the size of units and increasing their number, during most hours of operation generating units will operate at a fraction of their rated capacity.

Fuel consumption per KWH increases steadily at lower rates of output, and the part-load fuel consumption is relatively higher for small engine-generating sets than for larger. A considerable portion of the total energy losses in an engine-generator unit (especially in the engine) are incurred whenever the set is operated and are independent of the rate of output. Figure IV-1 illustrates this with several typical curves. The axes are non-dimensional and indicate the per cent of full load output versus per cent of full load fuel consumption. Generalization regarding details of the curves isn't possible but generally larger engines show better part-load performance. The marginal fuel consumption per KWH for a given set is relatively constant over the relevant range of output. We will assume that it is constant but recognize that zero load consumption will be somewhat understated.[102]

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[102] Further refinement of the fuel consumption curve would be of no value unless the frequency distribution of demand were also known to a fair degree of accuracy. The latter would be very difficult to estimate.

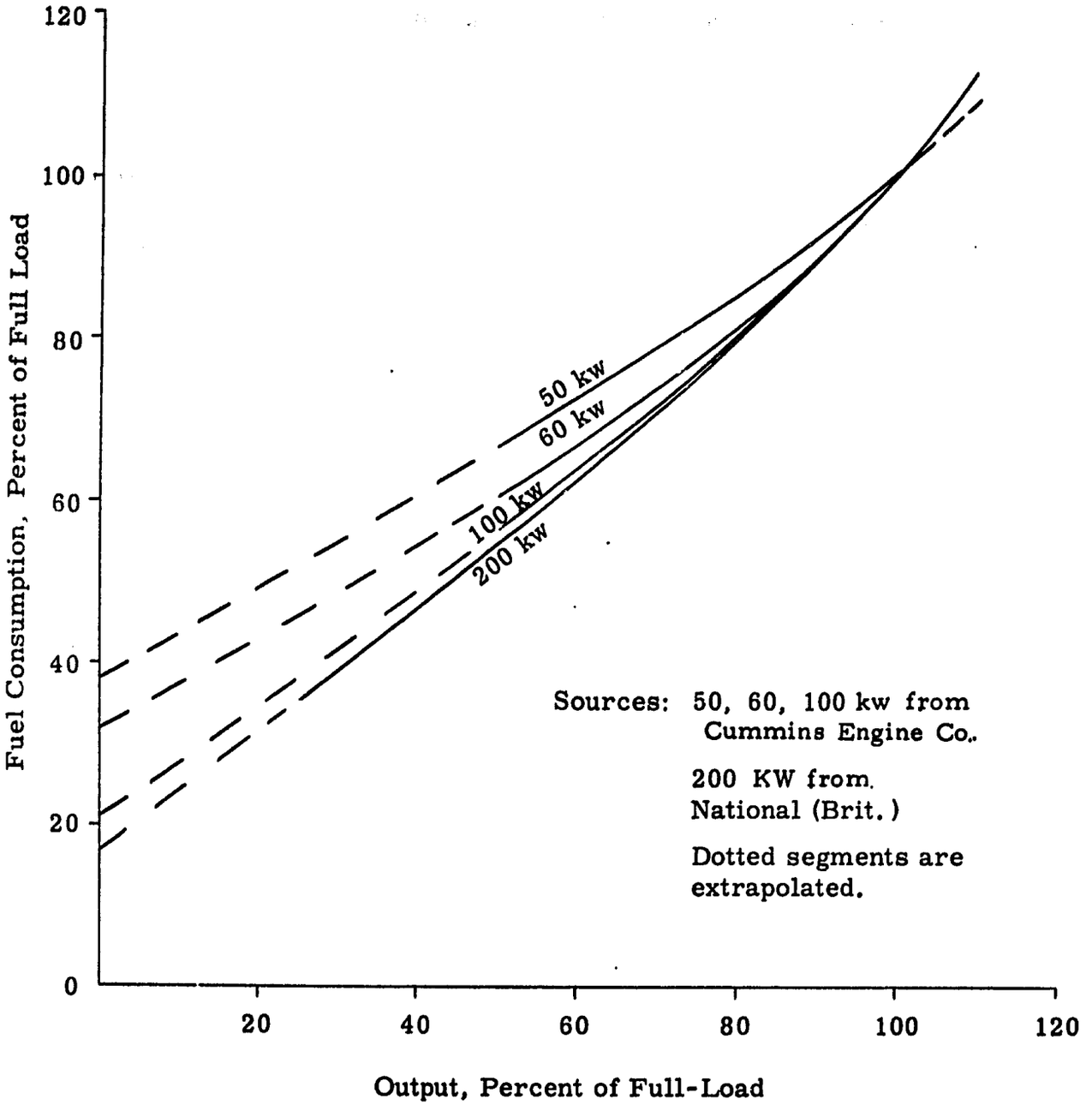


Figure IV-1

Illustrative Part-Load Fuel Consumption in Diesel Generating Sets.

Defining the zero-load fuel consumption as a quasi-fixed cost (i.e., incurred with operation regardless of output) and adding a constant marginal component, a straightforward specification for a single set is obtained:

(4.3) Total annual fuel consumption = $Ff_g KW_g hr_o + Fm_g KWH$.

Idle fuel consumption = $Ff_g$(lb./hr./$KW_g$)

Marginal fuel consumption = $Fm_g$(lb./KWH)

Capacity of set = KW

Hours of operation of the set = $hr_o$

Again, we are simplifying: neither the idle nor marginal fuel consumption rates are independent of the scale of the plant, its design, etc. But analytic complexity yields diminishing returns, and it seems more appropriate to adjust the parameter values to the specific applied situation than to attempt a more generalized definition. Examination of guaranteed fuel consumption rates for engine sets reveals considerable variation among sets of the same size. Hence, application of this analysis in a particular setting should rest on accurate reporting of the equipment options available. Figure IV-2 indicates the approximate values to be expected for different sizes of diesel sets: the marginal consumption varies very little, and most of the variation in average consumption per KWH arises from the changes in the idle consumption. The high heat value of fuel oil assumed here is 19,350 Btu per pound, and appropriate adjustment should be made for other heat values.[103]

Gasoline engine driven sets are less efficient than diesel, especially at low loads. Full load consumption of gasoline (pounds) would approach 150 per cent of diesel oil (pounds); zero-load consumption would be about double; and the marginal consumption per KWH approximately 125 per cent. For non-standard

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[103] Or the fuel consumption can be left in heat units, Btu, or large calories, and fuel prices can be stated per heat unit: this is standard for coal-fired thermal plants, as coal varies widely in heat value.

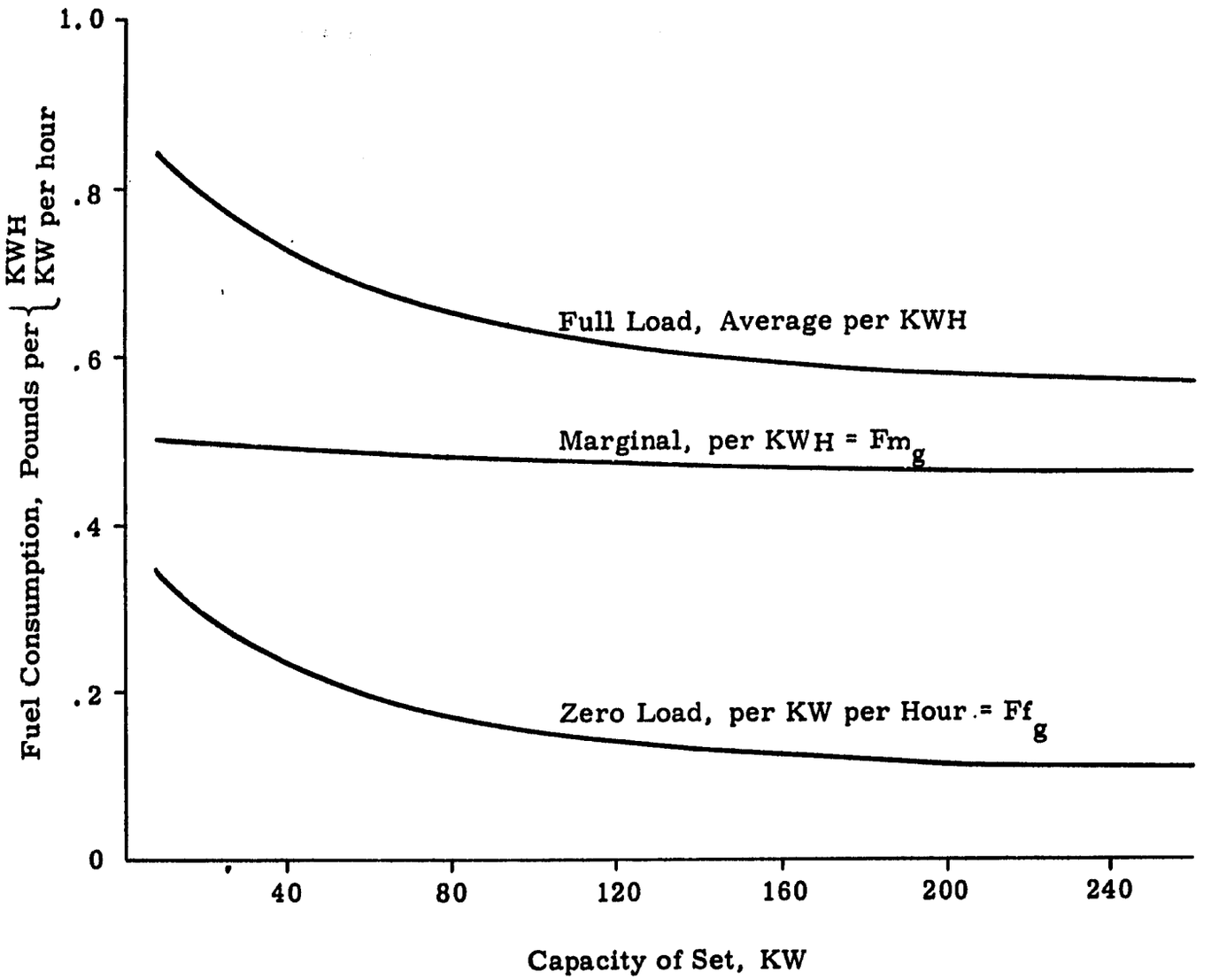


Figure IV-2

Approximate Fuel Consumption Parameters for Diesel Generating Sets.

fuels in a spark ignition engine, e.g., bio-gas, the efficiency should be comparable to that obtained in burning gasoline. Once the heat value of the fuel is determined the conversion can be easily made.[104]

For small vapor engine sets, an over-all energy conversion efficiency of 3-8 per cent, depending on the equipment design, has been postulated:[105] part-load operation would show a decline in efficiency at least comparable to that illustrated above (Figure IV-1) for diesel sets. Given the heat characteristics of the particular fuel, appropriate coefficients may be calculated for insertion in the fuel specification equation.

Finally, fuel consumption data must be converted to costs. If fuel prices, $P_f$ are stated in dollars per pound, annual fuel costs are price times the consumption:

(4.4) Annual fuel costs $P_f Ff_g KW_g hr_o + P_f Fm_g KWH$

The first term is a capacity cost varying with the installed capacity and the hours of its operation. The second term varies only with the energy output.

Petroleum fuel prices vary widely, being generally low in South America and quite high in India. Reported prices in rural areas of South America, Summer, 1962, for high speed diesel oil, ranged from 1.35¢/lb. (Columbia, North Coast) to 2.9¢/lb. (Chile, Cautin Area), with about 2¢ a common price. In the same areas regular gasoline was priced from 1.8 to 3.6¢/lb., 2.7¢ being representative. High speed oil in rural Indian locations varied from 6.5 to 8.0¢/lb; 7¢ was fairly typical. "Low speed oil," a heavy distillate, cost about 4¢/lb.[106]

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[104] About 37 $ft^3$ of bio-gas will substitute for a pound of gasoline. This is on the basis of a LHV comparison with the methane content assumed to be 56 per cent. Higher compression ratios for bio-gas would permit somewhat better efficiency: bio-gas could also be burned in a dual-fuel diesel engine, but higher capital costs probably make this uneconomic in a small engine. See Parikh, "Cost Benefit Analysis of Bio-Gas Plants in India;" G. E. "Small-Scale Power Supplies. . ." p. 108.

[105] G. E., "Small Scale Power Supplies. . .," pp. 37-46

[106] G. E., "Preliminary Report of Field Survey Teams . . .," pp. 64, 65.

The above Indian fuel prices include taxes which make up about one-half of the total price. The argument can be made that the taxes do not represent social costs and ought not be included in a comparison of local generation with alternatives. However, the larger part of these taxes has been instituted to reduce consumption, and hence foreign currency expenditures to pay for the imported oil. This, in effect, admits a shortage of foreign currency and a shadow foreign exchange rate substantially higher than the nominal rate. Hence, the after-tax price of fuel may more nearly represent the true cost than the price before tax.

Regarding the low-speed oil, which is commonly used in India in small low-speed (up to about 500 rpm) diesel engines: this oil is not suitable for the high-speed (1500-1800 rpm) engines which yield the most favorable equipment costs in small sets. However, above approximately 100 KW, medium-speed engines might utilize the much cheaper fuel with relatively small or no equipment cost penalties. Bunker, or residual, fuel oil is frequently burned in heavy marine and power-station diesels. The approximate lower size limit for technical feasibility is 1500 KW per unit, or well beyond the range for local distribution in rural areas.[107]

Prices for non-commercial fuels cannot be estimated generally. One important point should be recognized: the requirements for even a modest generator are so large relative to present demands and supplies, that present prices do not indicate future costs. Very high transport costs prevent the concentration of fuels from a large surrounding area, and hence the supply curve will be inelastic.

3. Operation and Maintenance

This category is highly variable and difficult to estimate. It includes wages of operators, supplies (including lubricating oil) and minor repairs and major overhauls. The first might be estimated separately; the latter are frequently estimated either as an annual expense equal to some decimal fraction of original equipment cost, or as a charge per KWH of output. Either of these methods

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[107] Cf. G.E., "Small-Scale Power Supplies. . .", pp. 15-16

understates the relative costs for small-scale sets. Most operating and maintenance expenses increase with the scale of plant less rapidly than does the equipment cost: i.e., the "indivisible" costs are relatively higher. Also, energy output is less relevant than the running hours of the set; and smaller plants generally operate at a smaller fraction of their capacity simply because of greater variation in small loads.

The following is proposed as a more useful approach to operating and maintenance costs. The annual costs for a single engine-generator unit may be described by:

(4.5) Annual operating and maintenance $= Of_g + Ov_g hr_o + Ovs_g KW_g hr_o$

The first term, $Of_g$, is the strictly fixed component of operating and maintenance costs; the second, $Ov_g hr_o$, indicates the costs which are indivisible with respect to the size of the unit but variable with its hours of operation; and the third, $Ovs_g KW_g hr_o$, is the portion which varies with both the capacity and the period of operation. The first two terms are indivisible costs, the third a capacity cost, and there are no energy cost components. For a plant comprising several units, the plant operating and maintenance costs are obtained by summing the costs for the individual units.

These parameter estimates for high-speed multi-cylinder diesel sets are consistent with data now in hand:

| | $O_f$ | $O_v$ | $O_{vs}$ |
|---|---|---|---|
| Operators | \$100 | \$.05 | \$.001 |
| Lubricating oil, supplies, and minor repairs | 50 | .05 | .002 |
| Overhauls | 150 | .18 | .003 |
| Total | 300 | .28 | .006 |

The underlying assumptions are:

1) Operators' wages are 10¢/ hour: this is probably too low if staffing is from a centralized agency, and may be too high for local semi-skilled labor in India, but approximates observations in rural South America for local operators.

2) Full-time supervision is not required in very small plants. Multiple-unit plants will have more nearly continuous supervision than single-unit plants.

3) The operator has about the skill of the frequently-encountered driver and casual auto mechanic, and can perform most routine maintenance work. His responsibility is probably more critical than his skill, Major overhauls require a skilled mechanic from outside the villages.

4) Repair and overhaul periods depend mainly on hours of actual operation, with energy output within the period of operation not significantly affecting the rate of wear; also, some deterioration takes place independently of hours of operation--this is caused by accelerated wear at each cold start-up, and by rust and corrosion while a set stands idle.

5) Overhaul costs are comparable to U. S. costs, lower wages being off-set by lower skills, higher relative cost of equipment and greater distance to service facilities. These costs have relatively high indivisible components so average costs per KW rise sharply with small sets.

6) Injection system and valve overhaul is required every 2,500 hours of operation: its cost is approximately $300 + $3.00 KW.

7) A general overhaul, rings, pistons, liners, bearings, etc., is done every 5,000 hours: its additional cost beyond the above minor overhaul, which is done simultaneously, is $300 + $10.00 KW.

The above estimates are reasonably optimistic: except in isolated locations where higher transport costs exist, these costs could be approximated. Substantially lower costs would be exceptional.[108] On the other hand, careless and negligent operators could raise repair costs several-fold. Poorly-trained and incompetent mechanics, while perhaps requiring low wages, would exact a high

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[108] Small, slow-speed, single-cylinder engine sets might show lower overhaul costs, but at the expense of higher equipment costs.

toll in unnecessarily frequent repairs and wasted materials. Lack of equipment standardization would require large inventories of repair parts and/or delays and additional expense in procurement.

Heavy-duty gasoline engines should yield comparable estimates: the savings in not having the expensive injection system of the diesel are approximately offset by the general experience of more frequent repairs. Non-standard fuels such as bio-gas might raise maintenance costs somewhat.

The above perhaps over-states somewhat the relative maintenance costs of larger engine sets: no adjustment has been made for the longer service periods between overhauls which might generally be expected. Also, one could expect higher standards of routine supervision and maintenance. However, these considerations are difficult to quantify and are probably an order of magnitude smaller than the above estimates.

Maintenance considerations are one of the most crucial disadvantages of small-scale generation. Thus these estimates should not be applied indiscriminately in varied circumstances: more appropriate estimates may be readily introduced.

4. Indivisible, Marginal capacity, and marginal energy costs

Having identified the parameters for each of the three inputs, equations 4.2, 4.4 and 4.5 can be summed into a single total cost function. To distinguish the indivisible, the marginal capacity and the marginal energy costs within the total is more useful in the present analysis.[109]

The indivisible costs, $IC_g$, in dollars per year, are obtained from equations 4.2 and 4.4:

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[109] The marginal capacity cost is simply the partial derivative of the total cost with respect to the capacity variable, KW, and the marginal energy cost is the partial derivative with respect to the energy output, KWH.

(4.6) $IC_g = acc_g A_p + (acc_g A_g + Of_g)n_g + Ov_g n_g hr_o$.

The marginal capacity costs, $MCC_g$, ($/KW/year) include parameters from all three equations, 4.2, 4.4 and 4.5:

(4.7) $MCC_g = acc_g B_g + (Ff_g P_f + Ovs_g)\, hr_o$.

Finally, only the fuel input (equation 4.5) enters into the marginal energy cost ($/KWH):

(4.8) $MEC_g = Fm_g P_f$.

The indivisible costs increase with the number of generating sets within the plant and with the average number of hours of operation per set. While a single set per plant yields the minimum indivisible costs, a fairly dependable supply--as would be required, e.g., to supply a produce refrigeration plant--would require at least two sets per plant. Three alternative patterns of plant operation seem feasible: 1) supply for the evening hours only, lighting being the almost exclusive load, and annual plant operation approximating 2,000 hours; 2) supply for day-time agricultural and light industrial use in addition, with annual hours approaching 4,000; and 3) continuous supply for 8,760 hours per year. With two or more sets in the plant, the average hours of operation per set would be substantially less than the hours of plant supply, the exact amount depending on the shape of the load curve.

Table IV-1 lists the indivisible and capacity costs calculated according to the formulas and preferred parameter estimates given above. In two-set plants, the sets are assumed to be equal in size, and each to operate on average 60 per cent of the time for which the plant is supplying power. The apparently precise figures should not mislead the reader: they are no better than the underlying assumptions and estimates.

The marginal capacity cost is dominated by the operation and maintenance costs and the fixed component of fuel costs, especially for longer hours of plant operation. Note in Table IV-1 the effect of the fuel price: at 7¢/lb., capacity costs

TABLE IV-1

ILLUSTRATIVE ANNUAL COSTS FOR ISOLATED DIESEL PLANTS

Indivisible Costs: $IC_g$ [a]

| Hours of Operation per Year | 1 Set | 2 Sets |
|---|---|---|
| 2000 | $1440 | $2330 |
| 4000 | 2000 | 3000 |
| 8760 | 3330 | 4600 |

Marginal Capacity Costs: $MCC_g$ [b]

| Size of Plant and Hours of Operation | 1 Set | | | 2 Sets | | |
|---|---|---|---|---|---|---|
| | $P_f$ = 2¢/lb. | $P_f$ = 4¢/lb. | $P_f$ = 7¢/lb. | $P_f$ = 2¢/lb. | $P_f$ = 4¢/lb. | $P_f$ = 7¢/lb. |
| 25 KW | | | | | | |
| 2000 | $ 39 | $ 50 | $ 66 | $ 30 | $ 36 | $ 46 |
| 4000 | 62 | 83 | 116 | 43 | 56 | 76 |
| 8760 | 116 | 133 | 234 | 76 | 104 | 147 |
| 50 KW | | | | | | |
| 2000 | 36 | 45 | 57 | 28 | 33 | 41 |
| 4000 | 57 | 74 | 99 | 40 | 51 | 66 |
| 8760 | 105 | 142 | 197 | 70 | 91 | 125 |

Notes:

a. Calculated from equation 4.6, with preferred installed cost estimates, 10-year life, and interest rate of 10 per cent. With two sets, each is assumed to run 60 per cent of plant hours of operation.

b. Calculated from equation 4.7, with the same assumptions as above.

approach double the costs at 2¢/lb. Two sets show consistently lower capacity costs than one set. This differential is more marked with higher fuel prices, and results from the capability to more nearly match the running capacity to the varying load. This saving tends to offset a part of all of the above noted indivisible cost of the second set; under present assumptions and Indian fuel prices (including taxes), total costs are lower for two sets than for a single set in the 25KW plant running continuously, and in the 50 KW plant running 4000 hours or more. Larger sets show, ceteris paribus, slightly lower marginal capacity costs--largely due to a lower idle fuel consumption per unit capacity.

The marginal energy cost is easily estimated as it includes only the marginal, or incremental, fuel consumption per KWH, and the price of fuel. For small diesel generators, the marginal energy cost will range from about 1¢/KWH in South America to near 4¢/KWH in India.

One final note: contrary to frequent assertions, it is not clearly economical to operate a generating set, which has been installed to serve an evening lighting load, during the day to supply electric motors for mechanical power. The additional costs for operating the generator, excluding the marginal energy cost, are obtained by noting the terms including the operating hour variable, $hr_o$, in the indivisible (4.6) and capacity (4.7) cost formulas. For one set, indivisible costs increase at $Ov_g$/hour, and capacity costs at $(Ff_g P_f + Ovs_g)$KW/hour. With the above estimates, the former is 28¢/hour, and the latter, for a 25 KW set, 1.1¢/KW/hour with fuel at 2¢/lb., and 2.5¢/KW/hour with 7¢/lb. fuel. Assuming further an optimistic plant factor of 1/2 during the hours of additional operation, the resulting additional costs per KWH amount to 4.5¢ and 7.2¢ at the respective fuel prices. These amounts hardly represent bargain rates for energy, especially when the marginal energy costs of 1¢/KWH and 3.5¢/KWH at the respective fuel prices are added. In fact direct mechanical drive from small diesel engines is frequently cheaper than to operate an existing generator longer hours

to supply the load electrically.[110]

B. Small-Scale Wind and Water Driven Generating Plants

Other than fuel-fired generators, interest in small-scale electric generation has been focused on small hydro developments and wind power. Whereas fuel can be transported and stored at a reasonable cost, these "free" sources of energy are not generally available at the location and time required by demand conditions. Economical water power can be developed only at favorable sites, and water storage to regulate the timing of supply is very costly in a small-scale installation. Winds, even in the best of sites, are quite variable, and even high mean velocities hardly yield economical energy production.

While solar energy is ubiquitous, its cyclical supply and low energy level imply exceedingly high investment in equipment to provide mechanical or electrical energy output. All present and foreseen conversion schemes are so high in cost relative to other alternatives, that solar energy need not be considered as a potential source of energy in the rural village.

The first section notes the appropriate modifications in the preceding cost specifications for generators, and suggests approximate cost parameters for wind and small hydro generators. Then the problem of supply variability, and its implications for capacity and energy costs, is discussed. Finally, the implications of "dump" energy for the feasibility of grid interconnections are reviewed.

1. Cost Specifications for small hydro and wind generation

The energy source being freely available in nature, there are no direct energy costs: the sole costs for wind and hydro generation are those of the installation required to harness the energy. Most of the costs are the initial investment; by the nature of the equipment, the operation and maintenance requirements are much less than for the small engine generator. The installed equipment costs are more variable than for engine generators for several reasons: the equipment is not as widely

[110] For estimates of small diesel engine costs, see below, Sec. V, C, 1.

manufactured; the site strongly influences the design of the installation and its resulting costs; and transport costs to the site may be very high. However, general cost parameters are analytically helpful, the most relevant being the installed cost for the smallest capacity plant -- an essentially indivisible cost, $A_g$ -- and the marginal cost per KW of capacity, $B_g$. Over a fairly narrow range of capacity, $B_g$ may be taken as constant, although the marginal cost of hydro installations declines slowly, but steadily, as capacity increases.

Operation and maintenance costs are relatively small, and as the plant will operate continuously, there is no need to differentiate these costs by hours of operation. Operation and maintenance costs may be separated into the annual costs for the minimum plant, $Oi_g$, and the marginal costs per KW, $Om_g$ -- again on an annual basis. Alternatively, given the small magnitude of operation and maintenance costs, they might be satisfactorily estimated as a per cent of the installed cost of the plant.

The annual capital charges on the plant investment may be represented by a decimal fraction, $acc_g$, including both interest charges and depreciation. Hence, the indivisible costs of the plant, on an annual basis, are simply:

(4.9) $$IC_g = acc_g A_g + Oi_g .$$

Similarly, the marginal capacity costs are:

(4.10) $$MCC_g = acc_g B_g + Om_g .$$

The indivisible investment costs, $A_g$, of a small hydro plant will vary widely, depending on the amount of civil construction required for the site, and the contribution made by local labor. Even the equipment costs cannot be estimated closely, due to design differences, head at the site, degree of factory pre-assembly, etc. The minimum equipment costs -- for a factory assembled turbine-generator package, plus penstocks, gates, etc. -- would hardly be less than $5,000 installed. If a standard packaged unit is not available to fit the site requirements, the assembly of separate components, including the necessary design work, implies equipment costs of $8-10,000 for a minimum plant.[111] For units connected to the grid,

[111] See G.E., "Small-Scale Power Supplies...," pp. 32-36, for estimates combining U.S. manufactured components. Small self-contained units are manufactured in Europe.

asynchronous induction generators, which are simpler and require less control equipment, may be used with substantial savings in initial equipment costs.[112]

Any dam providing storage capacity will be prohibitively costly for a small-scale hydro plant. The usual construction would be a weir or low diversion dam, with a canal or open conduit to the intake gates. Even taking the cost of local labor at zero, the on -site costs of cement and other necessary materials, in addition to the costs for competent engineering design and supervision, would hardly be less than $2,000. In many cases, costs will be much higher, as the site characteristics and location are critical determinants of cost.

The marginal investment per KW, $B_g$, will vary with the site, being lower with a higher head and faster revolving turbine. For a generator capacity of about 100 KW, the equipment component is in the magnitude of $100/KW. With larger sizes, it should decline slowly. At any given site, the construction requirements for increased generating capacity should be small: for later use, a minimum of $25/KW is suggested.

The above estimates are optimistic compared to the reported average construction costs of $400-500/KW for small plants (60-300 KW) in Japan.[113] Of course the more favorable sites would have been developed earlier in Japan. But, more probable costs of construction are well above the minimum. Conservative, but far from maximum, estimates, might place $A_g$ = $15,000, and $B_g$ = $200.

Annual maintenance costs are low for hydro equipment: the repair and routine supplies component of $Oi_g$ might amount to about $200 per year.[114] The supervision staff required depends on the degree of automation: with the low wages prevailing in underdeveloped countries, fully automatic control would probably not be justified

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[112] Oda, "The Present State of Small Hydraulic Power Stations in Japan," WPC, Belgrade, 1957, Vol. VI, p. 543.

[113] Ibid., Fig. 3.

[114] Ibid., p. 547.

(and has not been assumed in the construction cost estimates). As a minimum, one resident operator with annual wages of $300, may be suggested. If continuous attendance is required, operators' wages will approach $1,000 per year. Hence, the implied range of $Oi_g$ is perhaps $500-1,200 per year. The marginal operating and maintenance costs, $Om_g$, would be low--$5/KW annually is reasonable.

With a realistic interest rate of 10 per cent per year, and a 20-year plant life, $acc_g = .12$. Thus, from the above estimates, the lowest plausible indivisible costs for a small hydro plant, $IC_g$, is $1,340 per year. A more defensible value is $3,000. For the marginal capacity costs, $MCC_g$, a low of $20/KW, and a more conservative estimate of $29/KW, are indicated.

Any estimates of wind generation costs must be largely hypothetical, as only pilot plants have been built to date, excepting the very small D.C. generators. The smallest of the D.C. generators, under one KW, can be installed for about $1,000, including a low tower.[115] This establishes a lower limit for $A_g$, but the minimum cost for an A.C. generator would be substantially higher, due to the more difficult control problems. Not enough comparable estimates have been reported to indicate the cost variations with the size of the plant, but there is no evidence for a significant decrease in the marginal costs with increased size, and marginal costs clearly increase if capacity is extended beyond a few hundred KW.[116] The most optimistic construction cost estimate which the author has seen is the equivalent of $160/KW of rated capacity for a 200-KW machine.[117] This we may take as a minimum estimate for $B_g$, as the indivisible costs, averaged on a KW basis, would be small for this size. More common cost estimates approximate

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[115] See Golding, "The Potentialities for Rural Electrification in Asia and the Far East," p. 19.

[116] Larger diameter rotors must rotate more slowly, necessitating increased costs for the mechanical transmission from rotor to generator and/or the generator. One estimate places the lowest average cost at 200-500 KW rated capacity. See Buhl, "Operating Experience of Wind Power Plants," WPC, Belgrade, 1957, Vol. VI, p. 573, 4.

[117] Ibid., p. 575.

an average of $400/KW,[118] which may be suggested as a more conservative estimate for $B_g$.

Wind generators must be controlled automatically, and supervision costs should be low. However, the risk of storm damage is fairly great, and maintenance costs might prove to be high. An annual allowance, for operation and maintenance, of 6 per cent of the original investment seems reasonable for both the indivisible and marginal capacity costs.[119]

With a 20-year life, and 10 per cent interest rate, $acc_g$ = .12, and annual capital charges plus maintenance amount to 18 per cent of the original investment. Thus, our minimum estimate for $IC_g$ is $180/year for a small wind-driven D.C. generator, and perhaps twice that amount for an A.C. machine. Minimum and conservative estimates for $MCC_g$ are $29 and $72/KW, respectively.

2. Variability of supply and energy storage costs

A "firm" or reliable capacity is commonly estimated for a variable energy source. Strictly, this capacity is not firm in the sense of being always available, but rather is a lower capacity which is reached or exceeded with an acceptable high probability. For example, a "run-of-the-stream" hydro plant might have its firm capacity estimated at a .95 probability level, i.e., it would be expected to fall short of its firm capacity 5 days in each 100. The firm capacity ($KW_f$) of a run-of-the-stream plant is below the average feasible capacity of the stream ($KW_a$).[120]

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118 E.g., Golding, op. cit., p. 18. Other than equipment design differences, and different manufacturing cost assumptions, a significant factor in the capacity cost is the rated wind speed for which the generator is designed; at high rated speeds the cost per KW of capacity is lower, but the plant would produce less energy per KW of capacity at low wind speeds. The optimum design would depend on the wind velocity profile at the site.

119 Compare Buhl, op. cit., pp. 574, 5, 7.

120 The average feasible capacity of a stream will be less than the average water flow rate converted to KW. The upper peak of the water flow curve would last such a short period in each year that the capital charges on the equipment to harness it would be excessive relative to the value of the energy captured. An

The firm capacity can be increased with storage, but for the small hydro developments with which we are presently concerned, significant amounts of storage would rarely be feasible, and the output would be dependent on the natural flow rate of the stream. Hence, the ratio $KW_f/KW_a$ varies with the stream characteristics, but is always less than 1. This implies that some potential energy must escape in an isolated run-of-the-stream plant. If the minimum power demands and the minimum flow rates are positively correlated, or if the power demands can be shifted to coincide with higher flow rates, the relevant minimum capacity of the plant may be somewhat higher than the usual definition of the firm capacity.

Following the simplifying and useful fiction that "firm" capacity is indeed always available on demand, a KW of firm capacity in a small hydro plant is a perfect substitute for a KW of capacity in a small engine generator or in a grid connection. In addition, negligible energy costs are incurred in the hydro plant. The marginal capacity costs for small hydro plants will almost certainly be lower than those of small diesel plants, and probably lower than capacity costs for a grid connection, if the electricity is generated in thermal stations. However, for a grid with hydro generation, the economies of scale in larger hydro plants may more than compensate for the capacity costs of transmission. To evaluate the feasibility of a small hydro plant, its savings on capacity costs, plus the energy premium--which = (8.760) (Load Factor) (MEC for the alternative source), on a KW basis, must be weighed against the relative indivisible costs. Where the indivisible costs of the site development are low, small hydro plants will show much lower total costs than local diesel plants, and will compare favorably with grid connections and thermal generation.[121]

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economic maximum capacity is that at which the marginal costs of the last KW of capacity are equal to the value of the energy which can be obtained by it. The average feasible capacity is the first moment of the density function whose upper tail is terminated at the maximum economic capacity. Adding storage reduces the discrepancy between the average feasible capacity and the average water flow rate: i.e., storage increases both the firm generating capacity and the feasible energy output.

[121] For grid costs, see below, sec. V, A.

Sites may be economically developed, whose indivisible costs, net of indivisible connecting line costs, are less than or equal to the total capacity and energy savings relative to the lowest cost alternative.

Whether generating capacity beyond the firm capacity of the stream ought to be installed in an isolated run-of-the-stream hydro plant is problematic. Interruptable capacity is necessarily lower valued than firm capacity, the discount depending on the extent of correlation between higher demands and water flows. In a plant integrated with the grid, the feasible peak generating capacity will normally be greater than the firm capacity, and the additional energy which can be thereby obtained is one of the justifications for a grid connection. This topic will be taken up in the next section.

For wind generation, even in the most favorable sites, the firm capacity is zero.[122] The implications are two-fold. First, the costs of the plant depend on its rated capacity ($KW_r$), but the latter will be utilized only intermittently. For comparison with other methods of generation the average capacity ($KW_a$) is relevant. The effective cost per KW is increased to $MCC_g \frac{KW_r}{KW_a}$. The value of the ratio, $KW_r/KW_a$, will depend on the site, but at least 3 may be expected, with 5 a more probable value.[123]

Second, wind energy can be utilized in one of two ways, or some combination of the two: as more or less random energy which can be used whenever it is generated,[124] or by means of some energy storage device. For a wind generator in parallel with other generators, the random energy can replace fuel, or conserve water for later use in hydro plants with storage. As an isolated plant without energy storage, its output could be used only by loads which could be shifted from one time period

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[122] See the monthly power generation curves for two installations on the Danish coast, one of the more favorable areas for wind power, in Buhl, op. cit. Figure 2, p. 572.

[123] See ibid., Table 1, for actual values at 2 Danish sites, and Figure 3 for potential values at other sites.

[124] At some sites, the variation in wind is fairly predictable.

to another. Adapting the energy use to its highly variable availability naturally entails additional cost. There is no need now to estimate the penalty for varying wind energy relative to a dependable source: for some uses, e.g., communications equipment, wind energy without storage would have almost zero value; in other uses, e.g., water pumping, the final work output might be storable or deferable, at a reasonable cost.

Since no firm capacity is available, the cost per KWH is a more meaningful basis for comparison than the cost per KW. Even with quite flexible loads, it is entirely unrealistic to expect to utilize all of the randomly available energy. The appropriate discount can only be hypothesized: one-half the annual energy might be usable, i.e., $KWH_u/KWH_a = 1/2$. The resulting costs per $KWH_u = \frac{MCC_g}{8,760} \frac{KW_r}{KW_a} \frac{KWH_a}{KWH_u}$. With our most optimistic estimates for wind generator costs, and for average output, the cost is about 20 mills/$KWH_u$; more probable estimates yield 80 mills. These costs are comparable to those of small diesel generators, but well above the combined capacity and energy costs of a grid connection; further, electric motors supplied at 20 mills/KWH, plus distribution costs, would provide more costly mechanical work than directly coupled diesel engines burning high priced fuel.[125] And each of these alternatives provides energy on demand, not only when the wind blows. Hence, independent wind generation without storage holds very little promise.

For decades, storage batteries have been used for energy storage with small D.C. wind generators to supply small amounts of electricity. The implied costs depend on several variables: P, the number of hours in the storage cycle; and $K_s$, the annual cost of one KWH of storage. Assuming that sufficient storage capacity is provided to supply the average load for one storage cycle with no generation, the storage equipment cost, per KWH of output = $\frac{PK_s}{8,760}$.[126] For heavy-duty lead-acid

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[125] For summary diesel generation costs, see Sec. IV, A, 4 and Table IV-1; for grid costs, Sec. V, A, and Table V-4; for small engines, Sec. V, C, 1.

[126] The annual cost, $K_s$, is distributed over the output of 8,760/P cycles in the course of a year. The above assumes that the rate of power delivery can be disregarded in the storage cost specification. This is reasonable for most storage battery applications, as most of stored energy can be withdrawn within a few hours, or a small fraction of the probable cycling period for wind energy storage.

storage batteries, a reasonable value for $K_s$ is \$10.[127] A 24-hour storage cycle thus implies costs of 27 mills/KWH; a 48-hour cycle, of 55 mills/KWH, etc. If storage is provided for only a part of the average cycle consumption, the costs/KWH delivered are reduced proportionately.

The energy losses in the two-way conversion between electrical and chemical energy are not included in the above, as they are more conveniently included with the direct energy cost of wind generation. Denoting the efficiency of energy storage by $N_s$, and the fraction of the total which is stored before use by $F_s$, the costs of wind generation and energy losses in storage, per KWH of output =

$$\frac{MCC_g \frac{KW_r}{KW_a}}{8,760} \left( \frac{F_s}{N_s} + 1 - F_s \right).$$

For a lead-acid battery, $N_s = 2/3$, approximately, and we may assume $F_s$ to be 1/2, for an example. Optimistic assumptions for wind generator costs and average output imply costs of about 12 mills/KWH, and more conservative estimates, about 50 mills/KWH. If the average output of the generator could not be utilized, even with storage, this cost would be increased correspondingly. Adding the costs of the storage batteries, wind energy might cost about 40 to 100 mills/KWH. At a realistic load factor of 30 per cent, this would convert to \$105 and \$260/KW, respectively, and the lower the load factor, the more favorable the cost per KW appears. In spite of the relatively high cost of storing energy in batteries, the cost per unit of usable electricity from wind generation is probably not much higher with storage, than without, especially for short storage cycles. And, most important, the supply is relatively independent of wind variations, and allows a short-term peak capacity in excess of the generating capacity.

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[127] Assuming an initial cost of \$50/KWH capacity, a life of 10 years, 10 per cent interest rate, and annual maintenance costs of 4 per cent of original cost.

The probable costs with storage being higher than our preceding estimates, the above conclusions regarding wind generation costs relative to available alternatives are relevant for the storage case also. However, where small amounts of electricity are required -- e.g., for an isolated communications relay station -- and the sole alternatives are wind generation or small engine generation, wind generation with storage batteries will probably yield lower costs. The indivisible costs will be higher for an engine generator, and the marginal capacity and energy costs will also be higher, unless very low cost fuel is available. Small continuous demands, or low load factor demands, are especially favorable for wind generation and storage batteries.

3. Integration of a variable energy source with the grid

The chief advantage of linking a small hydro plant to the grid is the ability to utilize energy on the grid which would be otherwise unused. A hydro plant with a firm capacity, $KW_f$, may provide annual "dump" energy = 8,760 (1 - LF) $KW_f$, wherein LF is the load factor of the local load. For example, if the marginal fuel cost on the grid is 4 mills/KWH, and LF = .3, the dump energy is worth nearly $25 annually per KW of firm capacity. The only costs for utilizing this energy are those of the necessary linking line to the grid, and median estimates of the latter suggest that one mile of line could be built per 10 KW of firm capacity.[128]

An additional possible justification for a grid connection arises when the local demand does not match the firm capacity of the stream. Any firm capacity beyond the local peak requirements may contribute energy to the grid on a continuous basis, and also firm generating capacity. The probable marginal costs of additional generating capacity in even a small hydro development will show savings on the order of $35 per $KW_f$ against median capacity and energy costs for thermal generation;[129]

[128] A small or intermediate-scale plant, up to perhaps 1,000 KW, could be satisfactorily linked with a 22-KV primary distribution line, of which the costs are estimated in Table III-2 above.

[129] For cost estimates at the thermal station, see below, Sec. V, A, 5, and Table V-3, and for estimates including transmission costs, see Table V-4.

i.e., 6 or 7 KW of excess firm capacity might justify a mile of line. If, however, the alternative generating capacity is in large-scale hydro developments, the possible savings will probably be less.

Given the indivisibilities in generating equipment, it will be economical to anticipate future demand growth in the initial installation. Even if the available firm stream capacity will eventually be fully utilized by the local load, during an interim period significant amounts of energy and firm generating capacity could be used on the grid, at no additional costs. The replacement value of this energy and generating capacity will offset a portion of the cost of the connecting line.

Finally, some generating capacity beyond the firm capacity of the stream will usually be feasible if the resulting non-firm energy can be used on a grid to replace fuel, or allow water to be held behind dams for later use. The amount of additional capacity, and the resulting average feasible capacity of the development, will be determined by the shape of the water flow profile.[130] Generalizations regarding the magnitude of the feasible increase over the firm capacity are difficult, if not impossible, in view of the unique flow characteristics at each site. However, the implications for integration of small hydro plants with the grid should not be overlooked.

Thus, in all but the most isolated areas, the feasibility of linking a small hydro plant with the grid should be seriously investigated. In Japan, which has a well-developed grid system, substantial numbers of small plants are still being constructed and connected into the grid, because the total costs are comparable to, or lower than, those of larger scale alternatives.[131] In the more mountainous regions of South America, conditions should be equally favorable.

Substantial experimental work continues in England and Denmark to determine the feasibility of wind generators linked to a grid. Taking the optimistic construction

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130 See note 102 immediately above.

131 Oda, op. cit., p. 543, 4.

cost estimates of one of these groups of investigators (the low estimate utilized in the preceding section), the actual output per unit of capacity for several pilot plants, and their maintenance and capital charges assumptions (interest at 5 per cent), the implied energy cost is 11 mills/KWH.[132] Adjusting the interest rate upwards to reflect the opportunity cost of capital in underdeveloped countries -- to perhaps 10 per cent -- but leaving the other assumptions unchanged, the implied costs are more than 14 mills/KWH. More conservative construction cost estimates will of course raise the energy cost. Wind energy provides no firm capacity, and this energy has only the replacement value of the marginal energy cost on the grid. Comparing the probable marginal energy costs with thermal generation,[133] wind generation for delivery into the grid could be feasible only with the combination: a most favorable site, low construction and interest costs, very high fuel prices, and small-scale inefficient steam generators.[134] Relatively higher discount rates alone are sufficient to rule out significant wind generation in underdeveloped areas, with or without a grid connection.

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[132] Buhl, op. cit., pp. 575-7, and Table 1.

[133] See below, V, A, 5, and Table V-3.

[134] Even in fuel-poor and wind-rich Denmark, true marginal energy costs on the grid, rather than average, would probably preclude wind generation, even under the most favorable assumptions for the latter.

## V. RELATIVE COSTS FOR DIFFERENT METHODS OF SUPPLY

This chapter utilizes the summary cost specifications developed in the preceding chapters for comparing different methods of electricity supply to the village, and electricity versus direct alternatives. For comparison with isolated generation and direct alternatives, summary costs for grid extension are estimated in the first section. Next, small-scale generation in the village is compared with intermediate-scale generation and primary distribution to a number of villages. Then the costs for isolated intermediate generation are compared with those of grid extension. Finally, the costs of electrification are examined relative to the costs of small directly coupled engines, and of lighting by kerosene fueled lamps.

### A. Costs for Grid Extension

As the costs of an integrated grid are outside the main emphasis of this study, we cannot undertake a detailed analysis comparable to that above for distribution and small-scale generation. However, as will be evident from succeeding cost comparisons, grid extension will be in most cases the cheapest means of supply in rural areas, and estimates of the costs of supply must be based on grid supply costs.

Because of data availability, the estimates in this section are largely based on current U.S. experience. No claim can be made that U.S. costs are representative of costs in underdeveloped countries, but there is no clear presumption that the latter will be consistently above or below U.S. costs: from the available data, foreign costs are consistent with the following estimates.[135] Further, the exact level of costs is less important than the differential between average and marginal costs, and the trend of marginal costs with larger sizes of installations.

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[135] If U.S. equipment is installed, foreign costs will generally exceed U.S. costs -- an increase of 25 per cent is plausible. However, European equipment installed in an underdeveloped country will usually cost less than comparable U.S. manufactured equipment installed at home. All underdeveloped countries are largely, if not exclusively, dependent on imports for heavy electrical equipment.

1. The System Cost Components

Costs are based at the output of the distribution substation: Thus, the costs of an intermediate-scale isolated plant can be directly compared. Again the three categories are the indivisible costs, $IC_{sd}$; the marginal capacity costs, $CC_{sd}$; and the marginal energy costs, $EC_{sd}$. Each category includes all of the relevant costs back to, and including the central generating plant.

As an existing grid is assumed, no indivisible costs for generating plants and transmission substations and lines are incurred for extending the supply to rural areas. Indivisible costs for the distribution substation ($IC_{sd}$) and the subtransmission line feeding it ($IC_{tm}L_{tm}$, the product of indivisible costs per mile and the length in miles) are incurred only if the substation is required exclusively for the additional rural load.[136]

Marginal capacity costs at the substation output ($CC_{sd}$) include all of the capacity costs from the generating station. This is simply the sum,

(5.1) $$CC_{sd} = MCC_{sd} + MCC_{tm}L_{tm} + MCC_{st} + MCC_g,$$

wherein,

$MCC_{sd}$ = marginal capacity cost of the distribution substation itself,
$MCC_{tm}$ = marginal capacity cost of the transmission line per mile,
$L_{tm}$ = length of the transmission line,
$MCC_{st}$ = marginal capacity cost of the transmission step-up substation,
$MCC_g$ = marginal capacity cost of the generating plant.

Frequently the electricity will be transmitted at several voltage levels between the generating plant and the distribution substation. Thus, where appropriate, additional terms for transmission line segments and intermediate substations should be added

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136 We are neglecting the possible element of joint costs in a substation designed to serve a town and a surrounding rural area. It seems probable that neither the location nor the design for serving both loads would be substantially altered from that required to serve the town only.

to the above equation.[137]

The marginal energy cost at the substation likewise includes all marginal energy costs from the generating plant outwards. The major component is of course the marginal energy cost of generation ($MEC_g$), but energy losses in transmission lines ($MEC_{tm}$) is significant except in very short lines. In the estimates for substation costs below the relatively very small marginal energy loss in substation transformers is included within the capacity cost.[138] Thus no terms are included for the energy cost of the substations. The resulting marginal energy cost at the substation is:

$$EC_{sd} = MEC_{tm}L_{tm} + MEC_g. \tag{5.2}$$

The succeeding sections will give estimates for the above parameters. From these estimates, approximate values can be calculated for the capacity and energy costs within different scale systems.

2. Distribution Substation Costs

The costs for substations of a given capacity may vary a great deal depending on the design of the station. More elaborate switching and protective gear tends to increase the indivisible costs of the substation more rapidly than the marginal costs. Substations installed for rural service exclusively would have a relatively small capacity, and would be of a simple design. Larger stations serving a town or city would be more complex, but the marginal costs for additional capacity will be comparable to that of the simpler station.

Thus, for our purposes, the costs of the simple, standardized design distribution substation used by R. E. A. cooperatives in this country are most

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137 There may be significant diversity between the peak demand of the individual distribution substation and the system peak, in which case a coincidence factor, or factors, should be introduced to deflate the affected capacity cost variables.

138 The core component of energy loss is properly included within the capacity cost of the transformer, and the coil component is negligibly small (about 0.2 per cent) compared to the $MEC_g$. The costs for supplying exciting current, being quite small, are neglected.

useful.[139] From R.E.A. estimates of installed costs, excluding land, the investment costs may be approximated by a linear function over the range of 500-5,000 KVA. For input voltages near 66 KV, the

installed cost = \$30,000 + \$8.00 (KVA), approximately.

Lower input voltages imply slightly lower indivisible costs.

The life of the substation is 30-35 years, and the implied annual charges on investment are slightly less than 11 per cent with an interest rate of 10 per cent. Annual operating and maintenance costs are on the order of 5 per cent of the installed cost. Over the restricted capacity range, the power losses are about 1 per cent of the output, with the core losses about 1/3 of the total. The annual capacity and energy cost of the losses are thus about 50¢/KVA, at representative capacity and energy costs at the substation.[140]

Thus, from the above, the indivisible cost of the substation, $IC_{sd}$ = \$4,800/year. The marginal cost per KVA is about \$1.80/year, and converting to a KW basis at a power factor of .90, $MCC_{sd}$ = \$2.00/KW/year. There is a slight bias toward overstatement of $MCC_{sd}$ at the upper end of the designated capacity range -- neither the construction cost nor the loss component is strictly linear -- and beyond 5 MVA, the overstatement may be significant.

3. Transmission Line Costs

Where a subtransmission line must be built to supply the rural area, the indivisible costs of the transmission line ($IC_{tm}$) must be estimated. As with primary distribution

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139 R.E.A., Construction Costs of Rural Distribution and Transmission Lines and Substations, Staff Instruction 80-3, 1954. As this is the most recent edition available, adjustments have been made for current prices. The estimates include incoming air break switch, 4-1ϕ transformers (for added security: a single 3ϕ transformer would be more economical), voltage regulators, 3 outgoing circuits with oil circuit reclosers, and fence and miscellaneous.

140 $CC_{sd}$ = \$38; $EC_{sd}$ = 3.4 mills; and ehr = 2,000 for coil losses. Strictly, these values should be adjusted for the actual values at each site, but the refinement is not justified for the approximate estimates being made here.

lines, the construction cost of the minimum line will vary with the terrain, the expected wind and ice loading, the availability of poles at a reasonable cost, labor costs, etc. The order of magnitude to be expected for a 66 KV line is $4,000/mile.[141] Lower voltage lines will be less costly: e.g., a 33 KV line is reported to cost Rs. 9,000 (1,890) in Madras, India.[142] But primary distribution in the 22 KV class, as recommended in this report, implies higher capacity transmission lines and a minimum standard voltage in the 66 KV range. Allowing 4 per cent of original cost for annual operating and maintenance expenditures, and 11 per cent annual capital charges, $IC_{tm}$ may equal approximately $600/mile/year.

The marginal capacity and energy costs of transmission lines are of more general interest. The common practice of estimating line costs on an average basis is grossly misleading because marginal costs are far below average costs up to very high line capacities. Present evidence suggests that marginal transmission line costs are about one-third of average costs over the normal range of transmission line voltages and capacities.[143]

For later reference, Table V-1 lists marginal inputs and costs calculated from general construction cost estimates prepared by the Federal Power Commission,[144] and from representative capacity and energy costs for losses. The costs for wooden pole and frame construction are probably lower than would be found in many underdeveloped countries. However, considering relative labor costs, the steel construction estimates may be higher than in most underdeveloped countries.

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141 Compare transmission line construction cost estimates in R.E.A., op. cit., Table XI, XII.

142 Government of India, "Report...on Rural Electrification in Madras," Annexure III.

143 Based on analysis of the data underlying Table V-1 below. This differential between average and marginal costs is not surprising in view of the fact that the production function for electricity transmission may be approximated by a Cobb-Douglas function in which the exponents sum to 2 -- i.e., doubling inputs increases output fourfold. This, plus the essentially indivisible components in construction costs, implies very marked economies of scale.

144 F.P.C., Bureau of Power, "Technical Memorandum No. 1: Instructions for Estimating Electric Power Costs and Values," Revised March, 1960, Table 19.

TABLE V-1

APPROXIMATE COSTS PER MILE OF TRANSMISSION LINE

| Line Construction | | Approximate | PER KW OF CAPACITY | | | | Per 1,000 KWH DELIVERED |
|---|---|---|---|---|---|---|---|
| Nominal Voltage KV | Conductor Size ACSR | Economic Loading[a] MW | Construction Cost[b] ($/KW) | Annual O & M[c] (Mills/KW) | Capacity Cost of Losses[d] (Mills/KW) | Annual Capacity:[e] $MCC_{tm}$ (Mills/KW) | Energy Cost of Losses:[f] $MEC_{tm}$ (Mills/1,000 KWH) |
| Wood Towers: | | | | | | | |
| 66 | 30 A.W.G | 5 | .502 | 9.4 | 12.5 | 77 | 1.10 |
| 110 | 336 (1,000 circular mils) | 16 | .187 | 3.4 | 7.4 | 31 | .66 |
| 132 | 477 " | 28 | .126 | 2.3 | 6.2 | 22 | .55 |
| 154 | 636 " | 43 | .094 | 1.8 | 5.3 | 17 | .47 |
| 220 | 795 " | 79 | .059 | 1.2 | 3.7 | 12 | .33 |
| Steel Towers | | | | | | | |
| 66 | 40 A.W.G. | 8 | .703 | 4.6 | 15.4 | 97 | 1.40 |
| 110 | 336 (1,000 circular mils) | 22 | .327 | 2.1 | 9.2 | 47 | .81 |
| 132 | 477 " | 38 | .220 | 1.4 | 7.7 | 33 | .70 |
| 154 | 636 " | 59 | .163 | 1.1 | 6.6 | 26 | .60 |
| 220 | 795 " | 107 | .104 | .7 | 4.6 | 17 | .42 |

Notes:

a. Estimated load for which the indicated structure would be optimum, from estimated variations in costs for different voltages and conductor sections, and capacity and energy costs noted below.

b. Construction cost estimates from FPC, "Technical Memorandum No. 1," Table 19.

c. From Ibid., Table 23.

d. Assuming CC = $30/KW, annually.

e. From preceding three columns, the annual charges on investment being 11 per cent (35-year life, 10 per cent interest, and minor insurance and interim replacement allowances).

f. Assuming EC = 3.5 mills/KWH, and ehr = 3,000.

4. Transmission Substations

A step-up substation is always required at the generating plant. Frequently, an additional substation is required to convert a high voltage for bulk transmission to the intermediate voltage used in subtransmission. Our interest is in the marginal capacity cost ($MCC_{st}$) of the substation. Again average costs decrease markedly with size increases, and marginal costs are less than two-thirds of average costs up to very large capacity and high voltage substations. Table V-2 lists on an annual basis, the components of the marginal capacity cost, and the summary cost per KW, for a range from 5-200 MVA. These estimates are derived from construction cost and annual operating and maintenance cost estimates prepared by the Federal Power Commission, and from typical transformer core and coil losses.[145] In the smaller sizes the marginal capacity cost estimates are higher than the above estimate for distribution substations. One cause is the more elaborate design assumed for the transmission substations, which involves more high voltage switches and circuit breakers. Equally, or more important, the voltage is assumed to increase with the capacity so as to correspond to the efficient transmission voltages for different line capacities. Ceteris paribus, higher voltage implies higher costs, and hence unit costs do not decline as rapidly when both capacity and voltage are increased, as when capacity is increased with voltage held constant.

5. Thermal Generation.

Generation costs constitute a major portion of the marginal capacity costs for grid supply, and practically all of the energy costs. About three-quarters of the marginal capacity cost of thermal generation is the capital charges on the plant investment. Hence the assumed interest rate will have a marked effect on the generation capacity cost. The remaining components of the capacity cost are a fixed fuel component and the operating and maintenance expenditures. The fixed fuel costs are frequently neglected in preparing capacity cost estimates, and total fuel costs are

[145] F.P.C., op. cit., Tables 8 and 22, pp. 77 and 96; Westinghouse, Electrical Transmission and Distribution Reference Book, pp. 102, 103.

TABLE V-2

ILLUSTRATIVE MARGINAL CAPACITY COSTS FOR TRANSMISSION SUBSTATIONS

| Capacity MVA | Construction Cost[a] ($/KVA) | Annual Operation and Maintenance[b] ($/KVA) | Annual Capacity and Energy Cost of Losses[c] ($/KVA) | Annual Capacity Costs: $MCC_{st}$[d] ($/KW) |
|---|---|---|---|---|
| 5 | 24.20 | 1.10 | .32 | 4.50 |
| 10 | 16.60 | 0.78 | .29 | 3.20 |
| 20 | 11.90 | 0.55 | .25 | 2.10 |
| 50 | 9.40 | 0.38 | .20 | 1.80 |
| 75 | 8.10 | 0.32 | .18 | 1.50 |
| 100 | 7.30 | 0.29 | .17 | 1.20 |
| 200 | 5.30 | 0.23 | .16 | 1.10 |

Notes:

a. Derived from F.P.C., Bureau of Power, "Technical Memorandum No. 1," Table 8.

b. Derived from Ibid., Table 22, including allowance for administrative and general.

c. For typical core and coil losses from Westinghouse, Electrical Transmission and Distribution Reference Book, pp. 102, 103, and CC = $30/KW, EC = 3.4 mills/KWH, and ehr = 3,000.

d. At annual charges of 11 per cent on investment (35-year life, 10 per cent interest, and minor insurance and interim replacement charges), plus operation and maintenance and cost of losses, all converted to a KW base at a power factor of .90.

averaged over the KWH output. This practice is misleading as it overstates the energy cost (which is no longer a marginal energy cost), and understates the capacity cost -- by about 10 per cent in each instance.

Table V-3 lists illustrative marginal capacity and energy costs, with their components, for coal-fired plants over a considerable size range. The basic data is U.S. experience,[146] but there is no reason for a consistent bias relative to foreign costs. The underlying assumptions are detailed in the notes, and the reader can readily make adjustments for alternative assumptions. The fuel price in particular will vary widely: prices 50 per cent of the assumed 30¢/million Btu., or near the other end of the range, 50 per cent higher are likely.[147] The consistent decline in marginal costs with larger scale plants should be noted. For a given scale of plant marginal costs are consistently about four-fifths of average costs. The costs listed in Table V-3 are representative of plants designed for long period operation. Short-term peaking capacity could be obtained somewhat more cheaply, but the marginal energy costs would be higher.

6. Hydro Generation

Simple cost estimates for hydro generation cannot be given. The largest portion of the costs is usually the dam and associated construction, and is highly variable with the characteristics of the particular site. The equipment component of costs also varies significantly with the site: ceteris paribus, high heads will allow lower equipment costs. Further, separations of costs into capacity and energy categories is not unambiguous.

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146 From F.P.C. op. cit., Tables 1, 3, 5, and pp. 28, 29. See note 1 above.

147 With wide departures in fuel prices from the assumed, there would undoubtedly be some fuel-equipment substitution. I.e., very low fuel costs will make a less efficient plant, requiring less investment, but burning more fuel, more economical than a plant designed for average cost fuel. But the possible substitution isn't great, and may be neglected for present purposes.

TABLE V-3

APPROXIMATE VALUES FOR MARGINAL INPUTS AND ANNUAL COSTS BY SCALE OF COAL-FIRED PLANT[a]

| | PER KW OF CAPACITY | | | | PER KWH OF OUTPUT | | |
|---|---|---|---|---|---|---|---|
| Plant Size[b] MW | Investment[c] ($) | Fixed Fuel[d] ($10^6$ Btu) | Annual O and M[e] ($) | Annual Capacity[f] $MCC_g$ ($) | Fuel[g] ($10^3$ Btu) | O and M (Mills) | Energy[h] $MEC_g$ (Mills) |
| 15 | 232 | 9.25 | 5.79 | 34.10 | 11.9 | 0.55 | 4.1 |
| 38 | 199 | 8.06 | 3.90 | 28.20 | 10.3 | 0.37 | 3.5 |
| 66 | 178 | 7.43 | 3.23 | 25.10 | 9.6 | 0.31 | 3.2 |
| 99 | 166 | 7.29 | 2.79 | 23.30 | 9.4 | 0.28 | 3.1 |
| 132 | 158 | 6.85 | 2.52 | 22.00 | 8.8 | 0.25 | 2.9 |
| 225 | 145 | 5.96 | 2.09 | 19.80 | 7.6 | 0.20 | 2.5 |
| 300 | 137 | 5.82 | 1.85 | 18.70 | 7.5 | 0.18 | 2.4 |

Notes:

a. Derived from basic data in F.P.C., Bureau of Power, Technical Memorandum No. 1, Rev. March 1960.

b. Assuming three equally sized units in each plant.

c. For coal-fired, conventional construction: deduct 5 per cent for outdoor boilers, 15 per cent for non-coal fuel.

d. At HHV of fuel, and assuming units are spinning 80 per cent of the time. Reduce by 6 per cent for oil fuel, and 13 per cent for gas.

e. Including allowance for Administrative and General.

f. From preceding three columns: assuming 35-year life, 10 per cent interest rate, and minor allowances for insurance and interim replacements, the sum of which amounts to 11 per cent annual charges on investment; and assuming fuel price of 30¢/$10^6$ Btu.

g. At HHV: add 5 per cent for oil fuel, and 10 per cent for gas.

h. From preceding two columns, assuming fuel to cost 30¢/$10^6$ Btu.

Most frequently, both thermal and hydro generation are integrated into the same system. If the economic hydro sites have been exploited, the relevant marginal energy costs on the system are those for thermal generation. Without storage capacity, the marginal capacity costs would also be determined by thermal costs. However, given sufficient storage behind the dams, peak demands could be met by installing additional hydro generators and increasing the hydro output during peak periods, but reducing it during off-peak periods. Thus, under certain conditions, the marginal capacity cost to supply peak demands may approach the marginal cost of hydro generating equipment only.[148] The capacity costs for supplying continuous loads, "base-loads," would be higher and might approach the marginal capacity cost for thermal generation.[149]

Where unexploited hydro sites remain which permit lower costs than thermal generation, the marginal generation costs on the system will be determined by the costs for the new sites to be developed. With storage on the system, in old or new developments, the peaking capacity costs approach the marginal equipment costs. The distinction between capacity and energy costs for base load operation on an exclusively hydro system are ambiguous, as a major part of the costs are essentially joint costs. The upper limit for the combined costs would be the capacity and energy costs for base-load operation in a thermal plant (otherwise the thermal plant would be more economical), and the actual costs would be highly variable from site to site.

With the vast indivisibilities in hydro site development, for significant interim periods of time, the relevant capacity cost, peaking or base-load, is the marginal equipment

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148 "Hydro equipment" is intended to include the penstock, turbine, generator, and all associated equipment.

149 To refine the concept of marginal capacity cost on an integrated system becomes complex. Basically, one should distinguish capacity to deliver power by the time period over which it can, or will, deliver power. In thermal generation, this problem can be avoided by an assumption that all generation equipment is homogenous. The assumption is not strictly correct, as peaking capacity, with lower investment costs, but higher fuel costs than base-load designed plants can be installed. But the assumption can be tolerated as a first approximation. For an integrated system with hydro storage (either natural or pumped), the differential costs between peaking and base-load capacity are so great, that a single capacity cost specification is not useful.

cost. Also, the marginal energy cost would be almost zero with water pouring over the dam. But the costs, economically defined, would increase as demand increased.

In view of the above, there is no need to attempt general hydro generation cost estimates. The equipment cost category is however helpful, as it frequently determines the relevant peaking capacity cost. The marginal equipment cost for hydro will be lower than any possible thermal capacity costs, the annual costs being on the order of one-third or one-quarter those of a steam turbine generator of the same size. Hydro generating equipment shows significant economies of scale up to an upper economic limit for generator sizes, which depends on the head of the plant. Generators beyond 125 MW are rare in high and medium head plants, and the maximum feasible size is much smaller in low head plants. Thus higher head plants will show lower unit costs as larger generator sizes are permitted.

7. Illustrative Capacity and Energy Costs at the Substation

The relevant marginal capacity and energy costs at the substation are those of the lowest cost source of supply on the system, all transmission costs included. Costs may be lower from a more distant and larger generating plant than from a near-by plant, in spite of longer transmission distances and probably one or more intermediate transmission substations.

To illustrate possible costs for connection to a grid where most of the supply comes from coal-fired steam plants, Table V-4 has been prepared. Three alternatives are included: a low capacity system in which the lowest cost generating unit is only 5MW capacity, thus yielding near the highest probable costs; a median cost estimate with units of 33 MW each, but involving longer transmission distances than the preceding; and a low estimate for supply from 100 MW units, which would be found only on systems supplying major urban centers. The fuel cost is uniformly taken to be 30 ¢/$10^6$ Btu., but the estimates may be easily altered by referring to Table V-3. The transmission distance assumptions are itemized, and may be readily changed. These summary estimates will be compared with the costs of isolated diesel generators, and for estimating the costs of grid extension relative to direct methods of energy supply. On systems

TABLE V-4
ILLUSTRATIVE CAPACITY AND ENERGY COSTS AT A GRID SUB-STATION

I. Marginal Capacity cost: ($/KW)[a]

| | Low[b] | Median[c] | High[d] |
|---|---|---|---|
| $MCC_{sd}$ | 2.00 | 2.00 | 2.00 |
| $MCC_{tm}(a)\ L_{tm}(a)$ | 1.50[e] | 4.00[e] | 10.00[f] |
| $MCC_{st}(a)$ | 1.70 | 2.40 | 2.40 |
| $MCC_{tm}(b)\ L_{tm}(b)$ | 3.50[g] | 5.00[g] | [h] |
| $MCC_{st}(b)$ | 1.00 | 1.50 | [h] |
| $MCC_g$ | 18.70 | 25.10 | 34.10 |
| $OC_{sd}$ | 28.40 | 40.00 | 48.50 |

II. Marginal Energy cost: (mills/KWH)[i]

| | Low | Median | High |
|---|---|---|---|
| $MEC_{tm}(a)\ L_{tm}(a)$ | .04[e] | .07[e] | .15[f] |
| $MEC_{tm}(b)\ L_{tm}(b)$ | .05[g] | .075[g] | [h] |
| $MEC_g$ | 2.4 | 3.2 | 5.0 |
| $EC_{sd}$ | 2.5 | 3.4 | 5.2 |

Notes:

a. After equation 5.1, with cost estimates from the preceding three tables.

b. Assuming marginal generating units are 100 MW each, and substation and transmission capacities are scaled accordingly.

c. With 33 MW marginal generating units and corresponding scale of transmission facilities.

d. With 5 MW marginal generating units and corresponding scale of transmission facilities.

e. 50 miles subtransmission line length.

f. 100 miles subtransmission line.

g. 100 miles bulk transmission.

h. No bulk transmission.

i. After equation 5.2.

with major hydro generation, the estimates may be adjusted according to the discussion of the immediately preceding section. Generally, longer transmission distances than those assumed in Table V-3 should be anticipated for hydro supply.

B. Isolated Generation versus Grid Supply

The relative costs of alternative methods of electricity supply to the village will now be examined. The costs of small-scale generation in the village will be compared to the costs of a larger generating plant with primary distribution to a number of villages in the area. The latter, in turn, will be compared with grid supply costs. We will proceed by comparing the indivisible, capacity, and energy cost categories for each pair of alternatives. Thus, the comparison may be readily applied to a wide range of demand assumptions.

1. Village Generation versus Intermediate Scale Isolated Supply

The reference for comparing village generation with larger scale generation is the point of supply to the secondary distribution lines in the village. For generation at this point, the relevant indivisible, capacity, and energy costs, are simply the corresponding categories ($IC_g$, $MCC_g$, and $MEC_g$) for the small generating plant itself. For the more centralized supply, the indivisible and capacity costs must include those of the primary distribution lines ($IC_{lp}$ and $MCC_{lp}$) and transformers ($IC_{tf}$ and $MCC_{tf}$), as well as the larger generating plant. The energy costs are the marginal energy costs at the generator in both cases, as the very small energy costs of primary distribution have been included in the capacity cost of the line.

For convenience denote village generation as option a, and the larger scale plant as b. Within each cost category, the savings with b are given by:

(5.3) $$\text{IC savings} = IC_{ga} - (IC_{tf} + IC_{lp}\, L_{pv});$$

(5.4) $$\text{CC savings} = MCC_{ga} - (2\, MCC_{tf} + MCC_{lp}\, L_{pv} + CF_{vv}\, MCC_{gb});$$

(5.5) $$\text{EC savings} = MEC_{ga} - MEC_{gb}.$$

The relative total costs may be readily obtained from the above, plus estimates of the village peak demand and annual consumption.

Diesel engine driven generators are the most generally applicable method of producing electricity in both small and intermediate-scale plants, and the generating cost variables may be taken from the summary Table IV-1, and estimated from the equations and basic estimates of section A in the preceding chapter. As an example, assume the following: a village peak demand of 50 KW, which can be satisfactorily served by a plant operating 4,000 hours per year, and a load factor of 40 per cent on a 4,000 hour base; an alternative plant, serving a number of villages, of 600 KW capacity in 3 generating sets, also running 4,000 hours per year; a coincidence factor between village peak demands ($CF_{vv}$) of .95, and 3ø, 22 KV, primary distribution lines between villages.

The distribution line costs may be taken from the median estimates of Table III-2,[150] and the transformer costs from Table III-4. If the fuel price is 4¢/lb., examination of the estimates in Table IV-1 will show that two sets can supply the 50 KW demand, at 4,000 hours running time, slightly more cheaply than a single set. Calculating the costs of the intermediate-scale plant according to the above assumptions and the same 4¢/lb. fuel price, the annual savings for the larger plant (option b) are:
IC, ($2,900 - $219 $L_{pv}$), CC, ($6.40 - $ .23 $L_{pv}$)/KW EC, 1.2 mills/KWH.
The total savings for a 50 KW demand, and a load factor of 40 per cent on the 4,000 operating hour base, are thus about $3,320 - $230 $L_{pv}$. That is, for primary line lengths between villages less than about 14 miles, the larger plant with distribution is more economical, and for more normal line lengths of 5 miles per village, the annual savings would exceed $2,000.

The savings on the indivisible costs of the small plant make up most of the total savings in the above example. The relative costs are not sensitive to the fuel price, so long as fuel for both plants is the same price: e.g., with fuel at 7¢/lb., the equal-cost line length is about 16 miles. On the other hand, if fuel costs 7¢/lb., in the small

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[150] Strictly, $MCC_{lp}$ is thus slightly understated, as the cost of losses is slightly greater in this example than that assumed for the estimates in the table. But the difference is negligible here.

plant, and 4¢/lb. in the larger, the costs are equated with line lengths of about 23 miles. Other assumptions might be explored -- e.g., continuous supply raises the relative costs for local generation markedly -- but strong arguments against local generation can be made from assumptions which are most favorable for small-scale plants.

Neglecting the capacity and energy savings,[151] lines about 10 miles long can be justified on the basis of savings in the indivisible costs of one generating set only, the set providing supply for 4,000 hours annually. Even for minimum lighting service (supply during the evening hours only), the indivisible costs of one set approximate the costs of 8-10 miles of line plus transformer.[152] Thus, from our preliminary estimates, local diesel generation cannot be defended even with low initial demands, unless villages are very isolated.

The above estimates neglect the probable greater dependability of supply from the larger plant. Also, they are based on the implicit assumption that the capacity of the small local plant could be adjusted to the actual village peak demand. The normal case of a growing demand necessitates excess capacity due to the high indivisible costs of the engine-generator sets. If the resulting higher costs per unit of demand are included, local generation appears even less favorable.

There has been considerable interest in the use of locally available fuels for electricity generation in the village. Bio-gas fuel from dung and agricultural waste in particular has attracted attention. Hence a comparison between a bio-gas fueled generator in the village and a larger diesel generator supplying several villages is enlightening. For the bio-gas plant, the cost estimates for gasoline fueled generators in section IV, A, may be used, with the conversion from gasoline to bio-gas fuel there noted. The cost of bio-gas fuel cannot be predicted with accuracy, but we will assume

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[151] The capacity and energy costs will be consistently lower for the larger plant with distribution, with a possible exception when low-cost noncommercial fuels are used in the small plant, and very high cost fuels are used in the larger plant. See the succeeding discussion of bio-gas fueled plants.

[152] Assuming a 1¢ extension as this is the most economical way to supply the very low demand.

that bio-gas equivalent in heat content to one pound of gasoline will cost two cents.[153] Assuming one 25-KW set running 4,000 hours per year, for the bio-gas fueled plant, $IC_g$ = \$1,800, $MCC_g$ = \$80/KW, and $MEC_g$ = 1.2¢/KWH, all on an annual basis. Assuming the same intermediate scale diesel plant as above, with its fuel costing 7¢/lb., the local generator has CC penalties of \$30/year, and EC savings of 23 mills/KWH. The fuel savings would offset the additional capacity costs at a realistic load factor of slightly more than 30 per cent on a 4,000 hour base. Hence, under the most favorable conditions for the local bio-gas fueled generator, costs other than the indivisible costs might be about equal. But the indivisible costs of the local plant are equivalent to those of about 8 or 10 miles of line plus a transformer. With fuel costs of 4¢/lb. in the diesel plant, fuel savings would not compensate for the capacity cost penalty at any load factor, and the equal-cost length of line would be increased accordingly. Shorter operating hours, as for lighting only, reduce the costs of both alternatives, leaving the relative costs essentially unchanged. Thus, neglecting the problem of adequate local fuel supplies in the village, bio-gas fueled generation appears to be more costly than larger scale diesel generation for normal distances between villages.

The above numbers are no more trustworthy than the underlying assumptions and estimates. In particular, the reader may wish to review the estimates for indivisible costs of small generators. But the cost differentials are so great that one must conclude that small-scale engine driven generation in the village will be generally more costly than supply from a larger plant serving a number of villages. The higher costs are chiefly the indivisible costs of the small-scale plant, and there is no advantage in installing local generators to serve low demands in the initial

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153 If there is an ample supply of dung and waste in the village relative to the demand for bio-gas, the cost of the latter will be the capital charges on the conversion equipment and operation and maintenance. Our estimates are based on the costs reported by Parikh in the appendix to G.E., Small-Scale Power Supplies..., with assumed interest rates of about 10 per cent per annum. In a community with limited supplies of bio-gas relative to demand, the appropriate price for bio-gas might approach that of the commercial fuels for which it is a substitute.

stage of electrification. With very few exceptions, economical rural electrification will require primary distribution. Whether the supply to the primary distribution system should be from an isolated generator or a grid connection is the subject of the next section.

2. Intermediate Scale Isolated Generation versus Grid Connections

Intermediate scale (about 500-10,000 KW) generating plants will most likely be diesel plants. While the construction cost of gas turbine plants is favorable, their relatively high fuel consumption, especially at part loads, make them poor candidates for base-load operation in an isolated plant.[154] Steam plants in these size ranges compare unfavorably to diesel because of their higher capital cost and much lower efficiency. As was shown in the preceding chapter, grid connections to intermediate scale hydro plants will frequently be economical.

Hence, for purposes of illustration, we will assume the same intermediate scale diesel plant as in the preceding section--three 200-KW sets operating in parallel. The plant may be alternatively assumed to supply energy for 4,000 hours per year, or continuously, with the average operation per set to be 60 per cent of the period for which supply is provided. Alternative fuel prices of 7¢, 4¢, and 2¢/lb. may be assumed.

The savings for grid connection within each cost category are:

(5.6) $$\text{IC savings} = IC_g - (IC_{sd} + IC_{tm} L_{tm});$$

(5.7) $$\text{CC savings} = (MCC_g + MCC_{sd}) - CF_{rg} CC_{sd};$$

(5.8) $$\text{EC savings} = MEC_g - EC_{sd}.$$

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[154] With two possible exceptions: the free piston gasifer driving a power turbine is in concept an efficient and flexible unit, but it has not yet been widely used. Also, in fairly large units (about 20 MW), the gas turbine is being compounded with a steam turbine to obtain efficiencies equal, or superior to, that of a comparable scale of conventional steam turbine. Large diesel engines may burn any fuel which gas turbines have burned successfully to date.

The indivisible, marginal capacity and energy costs for the diesel plant may be calculated from equations 4.6, 4.7, and 4.8, and the estimates of section A in the preceding chapter. With our alternative operating and fuel cost assumptions, they are, on an annual basis:

| | for $hr_0$ = 4,000 | for $hr_0$ = 8,760 |
|---|---|---|
| $IC_g$: | \$4,460 | \$6,850 |
| $MCC_g$: | | |
| at $P_f$ = 7¢ | \$49/KW | \$88/KW |
| = 4¢ | 41 | 71 |
| = 2¢ | 37 | 63 |

| | |
|---|---|
| $MEC_g$: | |
| at $P_f$ = 7¢ | 33 mills/KWH |
| = 4¢ | 19 |
| = 2¢ | 9 |

By referring to the estimates for grid supply summarized in Table V-4 above, it is obvious that grid supply from an existing substation will be cheaper than isolated generation when continuous supply is desired, regardless of fuel prices, load factors, or scale of generation. Still assuming connection to an existing substation, all cost categories show savings for grid connection relative to 4,000 hour/year supply from the isolated generator, except for possible slightly higher capacity costs from a grid with small scale generating capacity. For the amount of the total savings, one must assume values for the coincidence factor between rural areas and the grid ($CF_{rg}$), and for the load factor on the rural portion of the system. Reasonable assumptions are 95 per cent and 30 per cent, respectively. With continuous supply, and taking the most favorable circumstances for isolated diesel generation -- diesel fuel at 2¢/lb. and small scale, high cost central generation and transmission -- the energy savings for the grid connection amount to \$11/KW, and the capacity savings to \$19/KW per year. That is, the total savings per year,

under these assumptions, of connecting to an existing substation is $6,800 for the indivisible costs, plus $30/KW for combined capacity and energy savings. If a new substation and subtransmission line must be constructed for the service, the annual indivisible costs being estimated above at $4,800 and $600/mile, respectively, costs will be equalized at a transmission line length of 3 miles plus 5 miles per 100 KW of substation capacity. Recalling that the economic distribution area from a single substation implies substation capacities in excess of 5,000 KW, even with average demand densities as low as 3 KW/mile$^2$,[155] rural areas sufficiently far from a possible grid connection to justify continuous isolated generation would be very rare.

The same exercise can be undertaken with assumptions less favorable to isolated generation. For example, assume the same low fuel costs and operating conditions for the isolated plant, but connection to a medium capacity scale grid corresponding to the median estimates summarized in Table V-4: the combined energy and capacity cost savings for the grid connection are $43/KW/year and imply corresponding equal-cost transmission line lengths. The same assumptions, save low grid costs, result in energy and capacity cost savings of $56/KW/year. Higher fuel costs for the isolated diesel plant will raise the relative costs markedly.

The only situation in which isolated generation costs will approach those for grid connection is one in which high grid costs and low isolated plant costs, due to low fuel costs, are combined with intermittent supply. Assuming a load factor of 40 per cent on a 4,000 hour base, the energy savings for the grid connection would be offset by the higher capacity costs. The indivisible costs of the isolated plant would about match those of a substation, but any transmission line requirements would place a penalty on the grid connection corresponding to the indivisible costs of the line. This makes no allowance for the obvious fact that continuous service is more valuable than intermittent:

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[155] The optimum size of the distribution area is taken from column one of Table III-5, for 22 KV primary distribution and substantial subtransmission requirements.

some loads, such as refrigerated storage, must have continuous service, and others, such as pumping, can be economically served in off-peak hours. And for assumptions other than the most favorable for isolated generation, combined capacity and energy costs are less for grid connection: low isolated plant costs and median grid costs yield savings in excess of $10/KW for the latter; median isolated plant costs and high grid costs result in savings of $19/KW for grid connection.

As the above costs for isolated plants are so much higher than grid costs, there is no need to investigate closely several additional disadvantages of isolated generation. The first is the lower degree of dependability of the isolated plant. Units must be down for scheduled repairs from time to time, and unexpected breakdowns occur. Hence some compromise between service interruptions and excess generating capacity must be reached. For both the service interruptions and the excess capacity, costs are relatively higher for the isolated plant but they are not included in the simplified comparison above. Also because of scale economies, demand growth is anticipated by installing excess capacity each time a new generating unit is installed. On an integrated grid, with a large number of generating units, the relative cost of the excess capacity is less than in a small isolated plant.

While the above cost estimates will require modification in differing locations, the cost differentials are sufficient for us to conclude that isolated diesel generating plants will generally be more costly than grid connections. Quite long transmission lines, well in excess of 100 miles, will be more economical than diesel plants providing continuous service to reasonably sized primary distribution areas. Isolated diesel plants may be economical only for very low demand areas widely separated from electrified areas, and from areas to be served within a reasonable time. With low demand densities in the initial stages of electrification, the economical solution is large distribution areas, served with a relatively high primary distribution voltage from grid-supplied substations, interim diesel plants at scattered locations result in sufficiently higher capacity and energy costs to more than offset possible savings in subtransmission and primary distribution. Hence, with very few exceptions, rural electrification should proceed by grid extension.

## C. Electrification versus Direct Engine Drive

The potential demand for electricity to provide mechanical power in light industrial and agricultural applications, especially for pump irrigation, is quite large. This mechanical power can also be provided, and is being provided in non-electrified areas, by small internal combustion engines directly coupled to the driven equipment and appliances. Hence the relative costs of serving these power requirements via engines or by electric motors are most important for assessing the feasibility of rural electrification.

The first section develops the relevant cost parameters of the engine and motor installation. These costs are then used, with the estimates for distribution and generation above, for an over-all comparison of costs. A range of alternative assumptions is explored, and the critical variables in determining relative cost are isolated.

### 1. Costs for engines and motors

For comparability, all engine costs and all electric motor costs, excluding the cost of electricity supply, must be expressed on the same basis. We assume that an appliance may be driven by either an electric motor or a small internal combustion engine (the usual higher installation costs for the latter being included in the engine cost specifications), and that the alternative drives may be compared directly horsepower for horsepower. The familiar cost categories are again used: the indivisible costs per installation ($IC_e$ and $IC_m$, the subscripts signifying "engine" and electric "motor," respectively), the marginal capacity costs per horsepower ($MCC_e$ and $MCC_m$); and the marginal energy component -- $MEC_e$ in dollars/HP-hr for engines, and the conversion efficiency of motors, $N_m$ in KW/HP.

The initial cost of the engine installation constitutes a major part of the total. Over the relevant scale range of about 3-20 HP, the installed cost follows closely a linear function,

(5.9) Investment in engine installation $= A_e + B_e$ HP,

wherein approximate parameters for diesel and gasoline engines are:[156]

| | Diesel | | Gasoline | |
|---|---|---|---|---|
| | Preferred | Range | Preferred | Range |
| $A_e$(\$): | 400 | 300-600 | 200 | 150-250 |
| $B_e$(\$/HP): | 50 | 40-65 | 25 | 20-30 |

For annual capital charges, a life of 10 years, with interest rates at least as high as 12 per cent per annum in the rural village, may be assumed. This implies an $acc_p$ of 18 per cent per year, which will be used in the succeeding comparisons, although the reader may wish to revise this upwards for higher interest rates.

As for small generating sets, the annual operation and maintenance costs are very difficult to estimate. A fixed component ($Of_e$) per installation irrespective of the size of the engine, or its operating hours appears appropriate to account for deterioration while the engine is idle and for accelerated wear with each start-up. Additional costs are incurred for each hour of operation, and these would seem to be largely independent of the size of the engine within the relevant range. Hence, a variable component ($Ov_e$) is suggested to include lubricating oil and supplies, supervision, and a part of the periodic repair and overhaul costs. Operating and maintenance costs would not vary significantly with the energy output. Thus,

(5.10) Annual operation and maintenance costs = $Of_e + Ov_e \; hr_0$.

No data on actual operating and maintenance costs of small engines could be obtained from underdeveloped areas. Thus, preliminary estimates of $Of_e$ = \$50/year, and $Ov_e$ = \$ .15/hour, are based on approximate costs in the U.S. for repairs and supplies. But labor costs for routine operation and maintenance are very much lower

156 Data on engine costs were obtained from commercial quotations, Summer, 1962, data on installed costs from the field survey teams of this project, and from a detailed listing of costs by size of engine for a sample of 98 installations, supplied by D.R. Gadgil, of the Gokhale Institute of Politics and Economics.

than in the U.S., and intermittent supervision is assumed. Major overhaul costs may be fully comparable to those experienced here.

Operating and maintenance costs are essentially indivisible costs by the above assumptions. Adding the indivisible component of the capital charges against the initial investment in the installation, the indivisible costs become:

(5.11) $$IC_e = acc_p A_e + Of_e + Ov_e hr_o.$$

The marginal capacity costs include only the annual charges on the marginal investment per horsepower:

(5.12) $$MCC_e = acc_p B_e.$$

Normally, the size of the engine may be matched to the single driven load,[157] and fuel consumption may be estimated on an average basis without significant error. Average fuel consumption per HP-hr ($F_e$) varies somewhat with the design of the engine, and tends to decrease slightly with increased size. But for present purposes, a single parameter estimate, which may be easily adjusted, is adequate. Thus the marginal energy cost is simply

(5.13) $$MEC_e = F_e P_f.$$

For small diesel engines, $F_e = .5$ lb./HP-hr is a good single estimate; gasoline engines will show a higher fuel consumption, about $F_e = .75$ lb./HP-hr.

The installed cost of electric motors is only a fraction of the investment required for a comparable capacity internal combustion engine. For integral horsepower ratings to about 20 HP, the initial cost may be represented linearly:

(5.14) Investment in electric motor installation = $A_m + B_m$ HP.

Single-phase and 3ø motors have significantly different marginal investment costs. Including all accessory equipment, approximate parameters for induction motors

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[157] There may be exceptions to this: a single engine may be alternately belted to several appliances which have somewhat differing power requirements.

are:[158]

| | Three-phase | | Single-phase | |
|---|---|---|---|---|
| | Preferred | Range | Preferred | Range |
| $A_m$(\$): | 120 | 100-150 | 100 | 80-130 |
| $B_m$(\$/HP): | 25 | 20-30 | 40 | 35-50 |

For costs on an annual basis, annual capital charges ($acc_p$) of 18 per cent may be assumed as above. Operation and maintenance costs are small, and can be satisfactorily estimated as a fraction ($om_m$) of the original cost of the motor installation: 4 per cent per year seems realistic. Hence, the indivisible costs are:

(5.15) $$IC_m = (acc_p + om_m)\, A_m.$$

Marginal capacity costs are equally simple:

(5.16) $$MCC_m = (acc_p + om_m)\, B_m.$$

The energy costs for motors may be estimated on a horsepower-hour of output basis, in order to obtain comparability with the energy costs of directly coupled engines. An efficiency factor, $N_m$, in KW/HP, is multiplied by the relevant marginal energy cost per KWH to obtain the cost per HP-hr. The motor efficiency increases as the size increases, but only slightly from 2 or 3 HP upwards, for which a single estimate of $N_m = .9$ introduces negligible errors.[159]

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[158] 3ø motors are standard 230/400 V squirrel-cage; 1ø are either capacitor-start, capacitor-run, or repulsion-start, capacitor-run, operating on 230/460 V. 1ø through at least 15 HP are presently available in this country, although they are not widely manufactured abroad. These estimates are for synchronous speeds of 1,800 and 1,500 rpm on 60 and 50 cps, respectively, although the lower speed motor would be slightly more expensive for the same rating. The sources are current U.S. manufacturers' price lists and retail quotations, and commercial quotations from Indian suppliers, which are comparable to U.S. quotations. To the motor and equipment costs are added representative estimates for delivery and installation, not including the cost of the service drop.

[159] 1ø motors are also slightly less efficient than 3ø; for comparable sizes, perhaps 3 per cent.

2. Electric drive from small generators versus direct drive

Although all evidence suggests markedly higher costs for electricity from small generators than from grid connections, isolated diesel-electric generation has been proposed in some circles to supply light industrial and agricultural demand for mechanical power in rural areas. Hence we will review the relative costs of electric drive from small generators, and direct diesel engine drive.

The total costs for both alternatives may be separated into the indivisible, marginal capacity, and marginal energy components. All will be consistently given on an annual basis. Setting aside for the present the indivisible costs of the generators, the possible savings in indivisible costs, per power installation, for electric drive are given by:

(5. 7) $\quad IC \text{ savings for electric} = IC_e - (IC_m + ICd_{sup})$.

Only the direct indivisible costs incurred for the power installation are included: generator and line costs common to several users are excluded. These savings may very well be negative, i.e., the indivisible costs may be higher for the electric drive. The indivisible costs of engines and motors, $IC_e$ and $IC_m$ are defined, and preliminary estimates given, in the immediately preceding sections and the indivisible secondary distribution cost per power user, $ICd_{sup}$, in section III, D, 3, above. Using our earlier preferred estimates, the probable maximum savings in indivisible costs for an electric installation served by a short distribution line might be \$50/year plus 15 ¢ per hour of operation, due to the operating and maintenance costs of a small diesel engine.[160] A reasonable utilization of 1,000 hours per year would thus mean annual savings of perhaps \$200. But the higher line indivisible costs for an electric powered irrigation pump[161] imply approximate equality of the indivisible costs: with high utilization and fairly short lines, savings of \$100/year with electric drive are possible, but an equivalent penalty results from moderately long lines and moderate usage.

The capacity cost "savings" for electric drive are consistently negative.

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[160] $IC_e$ = \$122 + \$.15 $hr_o$, $IC_m$ = \$26; $ICd_{sup}$ is variable with line length and metering assumptions -- see Section III, D, 3.

[161] $ICd_{sup}$ would be hardly less than \$80/year, and may approach \$300.

(5.18) CC savings for electric = $MCC_e - (MCC_m + N_m(MCCd_s + CF_{pp}\ MCC_g)$.

Estimates for the marginal capacity costs for engines and motors, and the efficiency factor for motors, $MCC_e$, $MCC_m$, and $N_m$, may be taken from the preceding section; and the capacity cost for secondary distribution, $MCCd_s$, is estimated in Section III, D, 3, above.[162] Neglecting the capacity cost of the generator, and taking preferred estimates, capacity savings for electric drive might be $1.70 for distribution within the village proper, but a penalty of $5 might be incurred for irrigation.[163] The generating capacity cost, $MCC_g$, varies considerably depending on the hours of electricity supply. But the most favorable conditions imply annual costs of $30-40/KW.[164] The coincidence between power demands, $CF_{pp}$, cannot be estimated precisely, but values of .7 to .9 are plausible. Thus, the annual capacity cost penalty for electric drive will range upwards from about $20/HP. Note that this will generally be sufficient to offset any possible indivisible cost savings for electric drive.

The quasi-fixed component of fuel consumption in the generator is included in our specification of the capacity costs of the generator. Hence the energy savings are given on the basis of strict marginal energy costs:

(5.19) EC savings = $MEC_e - N_m\ MEC_g$.

If the same fuel is used in the small engine as in the engine driving the generator, marginal energy costs will probably be slightly lower with the generator, the quasi-fixed component of fuel consumption being included in the capacity cost specification.[165]

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[162] Strictly, $MCCd_s$ would be slightly higher here than in the above estimates, due to higher energy, and possibly capacity, costs for losses. But the difference is negligible.

[163] $MCC_e$ = $9; $MCC_m$ = $5.50, for 3ø; $MCCd_s$ = $2, for short distances, and possibly $9 for irrigation -- see Section III, D, 3.

[164] See Table IV-1, and the discussion of Section IV, A.

[165] The marginal fuel consumption rates, $F_e$ (lb./HP-hr), and $Fm_g$(lb./KWH), are about equal, and the relative fuel consumption will depend on the motor efficiency, $N_m$. Taking $N_m$ = .9, the marginal energy savings might be 10 per cent for the electric drive, neglecting losses in the secondary distribution line. The relative total fuel consumption is given by $(N_m(Fm_g + Ff_g/PlF))/F_e$, wherein PlF is the plant factor, or the average fraction of the generator capacity utilized. Total fuel consumption for electric supply is at least 30 per cent above the directly coupled engine. See the generator fuel consumption parameters in IV, A, 2.

But the possible savings are small relative to the capacity cost penalties.

Thus, the best case that can be made for electric drive from a small generator versus direct engine drive is that the savings on indivisible costs for the motor installation might offset most of the capacity cost penalties. This would, however, be rare, as a combination of short distribution lines, small power demands at each location, high rates of utilization of each power installation, and a low demand coincidence would be required.[166] Normally, and especially for irrigation, the capacity cost penalties for electric drive would be much greater than any savings on the indivisible costs of the installation. When taking into account the indivisible costs of the engine generator or generators, and common distribution lines, not included in the above, total costs will be much higher for the electric drive. The penalties are of the magnitude of several thousand dollars per year per village,[167] and one must conclude that the installation of local diesel generators to supply mechanical power is grossly uneconomic.

Whether an existing generator, which has been installed to serve an evening lighting load, should be run during the daytime to supply electric motors, is not such a clear-cut case. The relative marginal energy costs would again show a slight advantage for the generator. But the fixed capital charges on the generator are properly zero for off-peak operation. Omitting entirely any generator costs from the capacity cost comparison, the capacity cost for electric supply will fall short of the capacity costs for the engine for short distribution distances, but may be as much as $5/HP/year higher for the distribution distances involved in irrigation.[168]

Within the indivisible category, the costs which vary with the hours of engine operation may be conveniently separated. The remaining indivisible cost components will

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[166]The last two of these conditions are inconsistent, as higher rates of utilization imply higher demand coincidence.

[167]Compare the indivisible cost estimates for diesel generators in Table IV-1 above.

[168]The savings are given by $MCC_e - (MCC_m + N_m\ MCCd_s)$. (Compare equation 5.18 above). Taking preferred parameter estimates, the result is $1.70 for distribution in the village proper, and negative $4.60 for irrigation.

show slight savings for electric drive with short distribution distances, but penalties as high as $200 for the distances involved in irrigation pumping.[169]

There remain the hourly operation and maintenance costs of the small engine ($Ov_e$), which we have estimated to be 15 ¢/hr. Against this must be set the additional costs per hour of operating a generating set, the operation and maintenance and quasi-fixed fuel costs, which we have estimated at 28¢/hour, plus 1¢ to 2¢ per KW of capacity per running hour.[170] If power installations average 5 HP, and about half of the generator's capacity is utilized on average in the off-peak period, both of which seem realistic, the running costs of the generator, excluding the marginal energy component, will consistently exceed the corresponding combined running costs for small engines driving the loads directly.

In conclusion, operating an existing diesel generator in the village to serve irrigation loads, will generally be more costly than to install and operate small diesel engines at each pump. Power demands within the village proper may be economically served -- providing the existing distribution lines are adequate, the generator operates at a relatively high percentage of capacity during the additional running time, and several power applications can be served simultaneously. If these conditions are not met, direct engine drive will be more economical. An exception to these conclusions is the case where grid connection may be expected in the near future: higher interim costs for the electric drive may be justified to avoid investment in engines which would be soon replaced by electric motors.

There is no need to compare in detail the costs of direct engine drive with electric drive, the electricity being generated in a diesel plant serving several villages, as the relative costs are not markedly changed from the above. Installing additional diesel generating capacity to serve the power demand will not be justified under any plausible

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[169] From 5.11 and 5.17, we have the possible savings for electric drive, on the strictly fixed components, $acc_p A_e + Of_e - (IC_m + ICd_{sup})$: or, by preferred estimates, $96 - $ICd_{sup}$, on an annual basis.

[170] I.e., $(Ov_g + (Ff_g P_f + Ovs_g)$/hour: see above, Section IV, A, 4.

circumstances. However, adding power demands, which can be served off-peak demand from existing capacity, will tend to be more economical. The larger generator will have lower additional running costs per KW, and should serve more power applications at a higher fraction of capacity, than a generator serving only one village.

3. Electric drive from a grid connection versus direct drive

As we earlier found the costs of electricity from a grid extension to be generally below the costs of isolated generation, we should expect the most relevant alternative to directly coupled engines to be electric motors supplied from a grid connection. As a wide range of alternative assumptions might be explored, we will proceed by detailing the parameters and variables which affect the relative costs. Preliminary estimates may then be introduced to support conclusions regarding alternative situations.

The possible savings in the indivisible component of costs for an electrically driven installation are given by equation 5.17 of the preceding section. The same estimates there proposed are applicable here, and we note that reasonable annual rates of utilization, and short secondary distribution line lengths, might yield savings of $200 per year. But longer lines, as for irrigation installations, would not show marked savings, and penalties would result from low rates of utilization. Note that the indivisible costs which are common to several users -- the transformer and primary line for the village, and probably some of the secondary line -- are not included.

To the previous comparison of capacity costs, the marginal primary distribution cost ($MCCd_p$) and the marginal capacity cost at the distribution substation output ($CC_{sd}$) must be added. Thus,

CC savings for grid connection =

(5.20) $$MCC_e - (MCC_m + N_m (MCCd_s + CF_{pp}\, MCCd_p + CF_{pg}\, CC_{sd})).$$

The primary distribution capacity cost, $MCCd_p$, is estimated in Section III, C, 3, above.. The capacity cost at the substation output, $CC_{sd}$, must include the generation, transmission, and substation marginal capacity costs on the grid; representative estimates are given in Table V-4 above. The coincidence between the power demand and the peak

grid load, $CF_{pg}$, is one of the most critical variables in determining the relative costs, but we have no firm data from underdeveloped areas to support estimates.[171] For strictly off-peak operation, it is of course zero. With no off-peak control, it will depend on the kind and timing of the rural power demand, and its load factor, as demands with higher load factors are clearly more likely to coincide with the system peak demand. Rather than attempt a single estimate, we will show the effect on relative costs of alternative estimates.

Taking median and preferred estimates, and assuming $PF_{pp} = .8$, and $PF_{pg} = .7$, equation 5.20 suggests that marginal capacity costs, on an annual basis, will be about $28/HP higher for electric supply than for a small diesel engine, for the short secondary distribution distances implied for service within the village proper.[172] The amount of the penalty for electric drive depends chiefly on the values of $CF_{pg}$ and $CC_{sd}$; if $PF_{pg} = 0$, it is only $2.60/HP, and the remaining terms are not highly variable. Still assuming a median $CC_{sd}$ of $40/KW, the relative cost for grid supply will increase by $3.60/HP for an increase in the $PF_{pg}$ from .7 to .8, and the converse for a decrease. Holding $PF_{pg}$ constant at .7, the relative costs of grid supply will be $6.30/HP more (less) for a $10/KW increase (decrease) in $CC_{sd}$, i.e., over the approximate range in grid capacity costs which may be anticipated on thermal systems. Low cost hydro peaking capacity would hardly yield a $CC_{sd}$ below $20/KW.

Altering only the value of $MCCd_s$, to adjust for longer secondary distribution distances,[173] from the above assumptions, the capacity costs for irrigation pumping off the grid peak demand would be about $9/HP higher than the capacity costs for diesel engine pumping. However, assuming $CF_{pg} = .7$ (and this is probably low for

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[171] See the discussion on demand data, Section II, A.

[172] From V, C, 1, above, $MCC_e = \$9$; $MCC_m = \$5.50$; $N_m = .9$. $MCCd_s = \$2$ (Section III, D, 3); $MCCd_p = \$6$ (Table III-5); and $CC_{sd} = \$40$ (Table V-4).

[173] To $MCCd_s = \$9$ (Section III, D, 3).

uncontrolled usage at uniform on-and off-peak rates during the irrigation season), and $CC_{sd}$ = \$40/KW, the capacity penalty for electric pumping is about \$34/HP. For changes in $PF_{pg}$ and $CC_{sd}$, the relative costs will be affected as noted in the preceding paragraph.

The relative marginal energy costs will be consistently favorable for grid supply.

(5.21) EC savings for grid connection = $MEC_e - N_m EC_{sd} = F_e P_f - N_m EC_{sd}$.

For a small diesel engine, $F_e$ = .5 lb./HP-hr: with a fuel price of 4 ¢/lb., and median energy costs on the grid, savings are about 17 mills/HP-hr. The highest plausible estimates for grid energy would reduce the savings by about 4 mills, and the lowest would increase them by about 2 mills/HP-hr.[174] The diesel fuel price will have much more impact on the possible savings: 2¢/lb. fuel will lower savings by 10 mills from the above, and 7¢/lb. implies additional savings of 15 mills/HP-hr.

With capacity costs consistently higher for electric drive, and energy costs consistently lower, the annual hours of use at which costs are equal may be obtained by dividing the CC penalty by the EC savings. For the median estimates of grid capacity and energy costs within the village proper, on peak use at a plausible coincidence factor, and 4¢/lb. diesel fuel, the CC and EC would offset one another at 1,650 ( = 28/.017) hours of annual operation. This is a considerably higher use rate than that reported in electrified villages in India:[175] it may be attainable for light industrial use, but seems high for agricultural processing, due to the seasonal nature of the latter. For the corresponding assumptions, the equal cost annual use for irrigation is 2,000 hours, which again is higher than reported usage, but might be reached with two or three crop irrigation. The effects of alternative diesel fuel prices, but other assumptions unchanged, may be noted: for $P_f$ = 7¢, the equal cost annual use is 880 and 1,060 hours for applications within the village proper, and for irrigation, respectively; for $P_f$ = 2¢, the corresponding hours of use are 4,000 and 4,860. The lower use

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[174] Median $EC_{sd}$ = 3.4 mills/KWH; high, approaching 8 mills; low, scarcely over 1 mill.

[175] For evidence of present use rates, see above, Section II, A.

rates should be reached, but the higher are unrealistic.[176]

The implications of the above costs should be noted for various underdeveloped areas. With low diesel fuel prices in South America (about 2 ¢ /lb.) on-peak grid supply for irrigation is generally higher in cost than direct pumping with diesel engines, even though electricity is already available in the village. For short distribution distances within the village proper, and assuming electricity is available, costs are about equal for electric drive and direct engine drive. Low-cost hydro generating capacity, small power demands at each installation, and high average rates of utilization make electric drive somewhat more favorable. Exclusively off-peak electric pumping will be about equal in cost to diesel pumping for use rates approximating 1,200-1,500 hours per year, but higher in most instances for low utilization. For the highest reasonable use rates, off-peak electric pumping will show only minor savings against diesel pumping. Consequently, the supply of electricity for power applications can be at most only a minor justification for rural electrification in South America.

In India, a low estimate of 4¢ /lb. for diesel fuel is appropriate for the "low-speed" oil, or for standard distillates less the tax. Not including any indivisible costs for supply to the village, and with median cost estimates for thermal generation and grid supply, on-peak electric irrigation pumping is more expensive than diesel pumping up to use rates of about 2,000 hours per year. Low cost hydro generating capacity would lower the equal cost utilization to about 1,200 hours annually. However, off-peak electric pumping will break even with diesel pumping at about 500 hours per year, and use rates as low as 800 hours per year, representing current experience, would show savings of perhaps $5/HP per year for electric pumping. A use rate of 1,200 hours per year is perhaps the highest to be anticipated for small pumping sets, even with a more rational rate structure: this would imply a maximum saving of about $10/HP per year for off-peak electric pumping. Taking the indivisible costs to be equal for diesel

[176] Save for salinity control pumping, and possibly large tube-well irrigation.

and electric irrigation installations,[177] we may conclude that diesel costs, with 4¢/lb. fuel, will be lower than electric, unless off-peak service is used. In the latter case, savings of $5-$10 per HP per year are possible with electric pumping.

For general light industrial and agricultural processing demands in the village proper, and median grid costs with thermal generation, the capacity and energy costs for electric drive will equal diesel costs for about 1,600 hours annual use. Present use rates approximating 900 hours per year imply a penalty of about $13/HP of connected capacity. If peaking capacity can be obtained from low cost hydro sources, the combined capacity and energy costs for diesel and electric power are about equal, at present use rates. But the electric installation would show significant savings on indivisible costs -- $100 to $200 is probable -- and with an average of 5 HP per installation, electric drive will show savings of perhaps $100 per installation, at present use rates and including thermal generating capacity costs.

These possible savings should be compared with the indivisible costs of supplying electricity to the village. We estimated the indivisible distribution costs to the village ($ICd_{pv}$) to approach $500 per year for 3φ supply to a moderately small village.[178] Hence, it appears that as few as 5 power installations within the village would justify electrification, under relatively conservative assumptions. With reduced capacity costs, or with a lower demand coincidence with the system peak, fewer installations would be required to make up the indivisible costs of supplying the village.[179] And off-peak irrigation pumping may contribute about $5-10/HP toward the joint indivisible costs of supply. Hence, it appears that quite defensible power demand assumptions will indicate lower over-all costs for electrification, even with fuel cost assumptions which are relatively low for Indian conditions.

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[177] Electric drive might show minor savings in indivisible costs -- up to perhaps $100 -- with moderate line lengths and medium to long periods of operation, but penalties, again minor, for long lines.

[178] See Section III, C, 3, above.

[179] With small power demands, 1φ supply will be more economical than 3φ, and the indivisible costs of village supply are lowered. See Section III, E.

The above is not inconsistent with heavy losses being incurred on present rural electrification undertakings. Present rate structures permit and perhaps encourage a pattern of use which could be more economically served from directly coupled engines. E.g., in Madras, India, electric pumping loads are served with no on- and off-peak differentiation, for which a typical utilization is 750 hours per year.[180] Under our present assumptions, and 4¢/lb. diesel fuel, the penalties for electric supply are $21/HP per year for medium scale thermal generating capacity, and about $10/HP for low cost hydro generating assumptions. Even with 7¢/lb. fuel, thermal generation implies about $10/HP higher costs each year for electric supply.

Higher diesel fuel costs lower the relative cost of electrification. As we noted above, under median grid cost assumptions the annual use for equating capacity and energy costs of electric and diesel engine drive is 880 and 1,060 hours, for nearby power applications within the village proper, and for irrigation, respectively. This is consistent with present light industrial and processing usage, but is high for present irrigation use and not far below reasonable expectations under rational pricing. Hence, unless irrigation pumping is done off-peak, even with high diesel fuel costs, directly coupled engines may yield lower costs than electric drive. Off-peak electric pumping may, however, show savings in excess of $15/HP per year over diesel, even at present use rates, and feasible use rates of 1,200 hours per year would show annual savings of approaching $30/HP for electric pumping. For other power uses, where off-peak operation is not feasible, the capacity and energy costs would be about equal, and all of the savings of the electrically driven installation, relative to the indivisible costs of an engine drive, may be applied against the indivisible costs of supplying the village. Hence, a very moderate power demand would justify village electrification.

Given the detail in our analytic model, the reader may readily investigate the effects of alternative cost and utilization assumptions. An important cost category is the indivisible costs per installation, both because these costs are relatively large for small power demands, and because our estimates are least certain here. Within

[180] "Report...on Rural Electrification in Madras," p. 12, and basic data in Annexure IX. However, the peak demand has become so great that a lower demand coincidence is being enforced by alternatively disconnecting supply lines. See pp. 16, 17.

the indivisible costs, the most difficult components to estimate are the operation and maintenance costs of small engines, and the secondary distribution line requirements for electric installations. Both may be expected to vary widely from particular case to case.

No attempt has been made in the above to include the dynamic investment problem posed by an increasing demand. Even if the present power demands do not justify electrification, anticipation of increasing demands in the near future may constitute a decisive argument for electrification. In the present context, the key consideration is the capital losses involved in shifting from diesel engine power to electric drive. If no losses were involved, i.e., the salvage value of the engines exactly equaled their remaining value in the installation, without electrification, no demand anticipation would be justified. However, significant losses would usually be involved, the upper limit being the total investment in an installation. An attempt at a precise estimate is not warranted, but it appears probable that village electrification should be advanced one year from the break-even point of time, for each potential engine installation before that time.

While admitting the only apparent preciseness of the above estimates, certain preliminary conclusions may be reached. First, with the low diesel fuel prices prevailing in South America, the need to supply rural mechanical power requirements in rural areas provides, at most, only a minor argument for rural electrification. Second, unless electric pumping can be done off the system demand peak, irrigation demands will not justify electrification, even with very high diesel fuel prices. However, off-peak electric pumping will represent some savings over engine pumping at median fuel prices, and major savings at high fuel prices. Hence the provision of differential on- and off-peak rates, or some manner of off-peak control, is extremely important. Third, electric power applications requiring short distribution distances should show moderate savings over diesel drive at median fuel prices, and major savings at high fuel prices. However, the extent of utilization is important, and poor rate structures will encourage use patterns which could be more economically

provided by direct engine drive. Finally, the possible savings for electric drive at high fuel prices may equal the indivisible costs of electricity supply to the village at relatively low power demands -- providing moderate annual utilization rates and off-peak irrigation pumping are obtained by rational rate policies. With median fuel prices, the amount of power demand which would, of itself, justify electrification cannot be estimated closely, but it is within the approximate magnitude of possible demands in most Indian villages.

D. Electrification versus Petroleum Fuels for Lighting

At very low levels of income, the domestic demand for electricity would be lighting exclusively. At somewhat higher levels of income some amenities such as fans and radios would also be included. But general use of electricity for cooking and heating would be prohibitively costly relative to the incomes in the most prosperous rural areas of the underdeveloped countries. Consequently, for evaluating the feasibility of domestic electric service, the key cost comparison is between electric lighting and lamps or lanterns fueled by kerosene.[181] The magnitude of the costs for present methods of lighting should not be underestimated: e.g., in India, about one-third of all petroleum products consumed is kerosene,[182] which is mainly used for household lighting, and the consumption is especially important because scarce foreign exchange must be spent for the imported oil.

For kerosene lighting, the costs are the fuel and the lamp or lantern, both of which the householder purchases directly. The lamp may be treated as a capital item as it should last several years, with some annual maintenance costs. For comparability with kerosene lighting, electric lighting costs will be estimated at the household level, and on a single lighting fixture basis. Table V-5 lists several groups of lighting

[181] And also by gasoline, especially in South America, as gasoline is a more satisfactory fuel for the high pressure mantle type of lantern. Formerly, vegetable oils or animal fats were widely used, either in candles or crude lamps, but these generally have higher value alternative uses, and have been replaced by petroleum fuels.

[182] See National Council for Applied Economic Research, Utilization of Primary Energy in India, Table 19.

## TABLE V-5

## APPROXIMATE LIGHTING EQUIPMENT COSTS AND ENERGY CONSUMPTION[a]

| | | Annual Equipment Cost[b] | Energy Consumption for 1,000 hours use |
|---|---|---|---|
| I. | 15 watt incandescent | $1.50[c] | 15 KWH |
| | Flat-wick kerosene lantern | 1.20[d] | 110 lb. kerosene |
| II. | 60 watt incandescent | 1.50[c] | 60 KWH |
| | 20 watt fluorescent | 2.10[e] | 24 KWH[g] |
| | Single mantle (high pressure) gasoline lantern | 5.40[f] | 70 lb. gasoline |
| III. | 100 watt incandescent | 1.50[c] | 100 KWH |
| | 30 watt fluorescent | 2.50[e] | 36 KWH[g] |
| | Double mantle (high pressure) gasoline lantern | 6.60[f] | 130 lb. gasoline |

Notes:

a. Within each group, the levels of illumination are approximately equivalent. Output and energy consumption estimates are based on data in Handbook of Chemistry and Physics, 31st Ed., p. 2096, and Standard Handbook for Electrical Engineers, 8th Ed., Tables 16-5 and 16-8.

b. Taking current U.S. retail prices for lanterns and economy lighting fixtures, including installation of electric lighting with supply circuit, but excluding main switch; useful life and annual replacement costs as noted below, and effective interest rates of 20 per cent per annum.

c. Useful life of 10 years, 40¢ annually for bulb replacement.

d. 3-year life; 50¢ yearly for maintenance.

e. 10-year life, including bulb.

f. 5-year life. $2.00 annually for mantle, generator, and globe replacement.

g. Including 20 per cent losses in ballast.

appliances: within each group the alternatives provide approximately equal levels of illumination. Approximate annual equipment costs are listed, with supporting details in the notes. For electric lighting the equipment costs include the wiring for one light; the circuit protection device is assumed to be combined with the load control, and to be included within the cost of electricity service ($ICd_{sud}$). Thus the estimate would cover minimum lighting provision in very low income homes, but would approximate the cost per room in higher income homes. The last column lists the energy input for 1,000 hours of use, in KWH or pounds of fuel.

The annual wiring, fixture, and bulb costs for incandescent lighting are about equal to those of the simplest kerosene lamp.[183] Hence, for minimum lighting supply, the cost of the kerosene burned may be compared to the incremental cost of electricity supply. For supply from a grid extension, the latter is given by:

(5.22) Incremental cost of domestic service =

$$ICd_{sud} + D_{ud}\ (MCCd_s + MCCd_p + CF_{dg}\ CC_{sd}) + D_{ud}\ hr_d\ EC_{sd}.$$

The marginal capacity costs for primary and secondary distribution ($MCCd_p$ and $MCCd_s$) do not vary widely, and $8/KW per year is a good median estimate, for the two combined.[184] The coincidence factor between rural domestic demands and the system peak would vary with the pattern of use in the household: with an evening system peak, minimum service of one light per household implies a $CF_{pg}$ very nearly one, especially if service is provided on a capacity charge basis, with no energy measurement. Marginal capacity costs at the substation ($CC_{sd}$) may be taken at $40/KW per year, and the energy costs ($EC_{sd}$) at 3.4 mills/KWH.[185] Assuming an annual use as high as 2,000 hours per

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183 While the initial costs are higher with electric lighting, the life, excepting the bulb, is much longer.

184 See above Section III, C, 3, and D, 3, for the basis of this estimate, and possible variations.

185 See Table V-4. Thermal generation implies a range for $CC_{sd}$ of about $30-50, and low cost hydro capacity, a low of perhaps $20/KW. On a thermal system, $EC_{sd}$ will normally be in the range 2-5 mills/KWH.

year, and complete peak load demand coincidence, the capacity and energy costs per KW of demand are thus about $55 per year, of which the major portion is the capacity cost. To compare the costs for a representative Indian rural household, now spending about $4.00 per year for kerosene (implying one lamp burning about 1 1/2 hours each evening): an equivalent level of illumination could be obtained with one 15 watt incandescent bulb ($D_{ud}$ = .015), for which the capacity and energy costs are 83¢ per year (for lighting throughout the whole evening). With electrification, a higher level of illumination is probable; a 25 watt bulb on the same basis implies annual capacity and energy costs of $1.40, and a 40 watt, $2.20.

Even high cost local diesel generation permits brighter and longer illumination at a lower marginal cost than for burning kerosene. For evening lighting operation only, the marginal capacity cost ($MCC_g$ + $MCCd_s$) is about $70/KW with fuel at 7¢/lb.[186] At this fuel price the marginal energy cost ($MEC_g$) is about 3.5¢/KWH. Hence the capacity and energy costs for a 25 watt light burning 2,000 hours per year is about $3.50. This does not include any of the indivisible costs of the generator, as the above grid connection does not include the indivisible costs of connecting the village.

Thus, for supply to low income households, the indivisible component of costs assumes critical importance. Where the service connection can be made to an existing line, $ICd_{sup}$ may be as low as $2/year with local administration. Adding a probable maximum share of the indivisible cost of the secondary distribution line, $ICd_{sup}$ may come to $4/year, or to a level where annual costs per household are slightly higher for minimum electric lighting than for present expenditures on kerosene. However, the necessarily higher costs, for meter reading or load control enforcement and bill collection, with a centralized administration imply minimum costs at least twice as high.[187]

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[186] See Table IV-1 for the generator capacity cost estimates.

[187] See Section III, D, 2 and 3, above for a detailed discussion of the components of these indivisible service costs, current estimates and the cost reduction possibilities.

In South America, both the market and the real social cost of kerosene and gasoline is much lower than in India. Hence the relative savings per unit of illumination are less than in India. However, due to lower fuel prices and somewhat higher incomes, the average level of use is higher in South America. No detailed data on kerosene and gasoline consumption for lighting in non-electrified areas could be obtained, but one evidence of the ability to pay for lighting is the reported fairly common use of gasoline fueled, high pressure mantle lanterns. Noting the relatively high annual equipment costs of these lanterns in Table V-5, the direct savings on lighting equipment could cover a major part, or all, of the user's indivisible service costs.

Incandescent electric lighting converts fuel energy to light much more efficiently than do lamps, but fluorescent lighting is still more efficient. With only moderate illumination levels, fluorescent lamps yield lower over-all costs due to the resulting savings on generating and distribution capacity costs. The key consideration is the demand coincidence of the lamp with the system peak demand: e.g., to use a 20 watt fluorescent tube rather than the equivalent 60 watt incandescent bulb, or a 30 watt fluorescent instead of a 100 watt incandescent, is economical for demand coincidences greater than one-third -- at the relative lighting fixture costs in Table V-5, and median capacity cost estimates. The relative energy savings for normal household use are much less important: to replace the 60 watt incandescent implies about 12 ¢ savings per 1,000 hours of use, at median energy cost estimates. Thus, investment in more efficient lamps appears frequently to be more economical than investment in additional generating capacity. Street lighting with incandescent bulbs should be subjected to critical scrutiny. And a rational rate structure would encourage the householder to make the additional investment in more efficient lighting fixtures where over-all economy would result.

The incremental cost per household for minimum electric lighting can be less than the present expenditures on lower quality lighting, only for service to dwellings in a closely built-up village. Supply to isolated farmsteads would incur high indivisible costs per user, and would be uneconomic for domestic use only, in virtually all underdeveloped areas. However, in most underdeveloped rural areas, the isolated

dwelling is rare.[188]

The most critical requirement for economic service to most, or all, of the households in an electrified village, is to lower the indivisible costs of initiating and administering the service. Administration of domestic connections, billing, and collection at the village level is the most promising means to reduce these costs. High indivisible costs of central administration relative to low rates of consumption are the only apparent explanation why such a small fraction (about one-tenth) of the households in rural India are connected in electrified villages.[189] If our inference is correct, the constraints of the present administrative and institutional arrangements are especially unfortunate: not only might many more families enjoy electric lighting, the net real costs of providing this amenity are very low, and perhaps negative. Secondary lines already run through the village to serve prosperous householders and light industrial demands, hence the required secondary line construction required would be minimal. The kerosene now being burned entails high real costs, because of the foreign exchange shortage. Further, given local administration over secondary distribution and user billing, and economic rate structures, service probably could be given to most dwellings without suffering any financial loss, and possibly with net revenue over and above the incremental cost of service.

The amount of benefits from electric lighting in excess of the direct savings on alternative methods of lighting is very difficult to estimate. Some knowledge of the demand elasticity for lighting service, with respect to both its price and the income of the purchaser, is required. Electricity demand studies of this sophistication are rarely made in the developed countries, let alone in the rural areas of underdeveloped countries. However, it is clear that the convenience, cleanliness, etc., of electric lighting makes it a higher valued consumption item than its lumen-hour equivalent of kerosene. If the

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[188] Rural electrification in the U.S. has involved supply to isolated farmsteads almost exclusively, as towns and villages in rural areas which could be profitably served by commercial companies had already been connected. Hence, extensions from U.S. experience may not be relevant to the service of rural villages abroad.

[189] See above, Section II, A.

incremental costs for electric lighting are equivalent to those of the substitutes, the premium for electric lighting, which the domestic consumer would be willing to pay, could therefore be applied toward the indivisible costs of supplying electricity to the village and its residents. The magnitude of this premium is especially important for electrification decisions in areas where potential agricultural and power applications do not justify the indivisible costs of connecting the villages. In South America, due to low costs for alternative sources of power, agricultural and small industrial power applications are, at best, only minor justifications for village electrification, and the benefits of domestic service, plus public amenities, must constitute the main argument for connection. Personal incomes are higher in South America than in India, and it is not implausible that many rural extensions could be defended on the basis of domestic service exclusively. In India, electrification of many villages may be justified for power applications only, and the benefits of domestic consumption are useful only for allocations of the indivisible costs between the various classes of service -- it being understood that the incremental costs for domestic electric service, relative to alternative lighting costs, indicate domestic connections. But there will remain marginal villages, in which the decision for electrification will depend on an assessment of the full benefits of domestic service.

In conclusion, the greater efficiency of electric lighting power lamps burning petroleum fuel permits superior electric lighting at a lower cost than that of the fuels now being consumed, providing the indivisible user costs are low, and electricity is already provided in the village. The first condition can apparently be met by local administration, billing and collection, and connection of most, if not all, dwellings in an electrified village is indicated. Where only a small fraction of the dwellings in electrified villages are connected, due to the very high costs of centralized administration relative to the low consumption levels, institutional alterations are suggested. The amount of the benefits of domestic connections, beyond the direct savings on alternative methods of lighting, cannot be estimated for lack of adequate data, but these benefits should offset a part, and perhaps a substantial part in relatively prosperous areas, of the indivisible costs of supplying the village.

# APPENDIX

## TABLE A-1

## ANNUAL CAPITAL CHARGES ON INVESTMENTS AND PRESENT DISCOUNTED VALUES OF ANNUALLY RECURRING COSTS

I. The annual capital charge, beginning one year after the investment and continuing for n years, which has a present discounted value of one (1), the discount rate being r, compounded annually:

$$acc = \frac{r}{1 - (1 + r)^{-n}}$$

| n\r | .06 | .08 | .10 | .12 | .14 | .16 |
|---|---|---|---|---|---|---|
| 5 | .2374 | .2505 | .2638 | .2774 | .2913 | .3054 |
| 10 | .1359 | .1490 | .1627 | .1770 | .1917 | .2069 |
| 15 | .1030 | .1168 | .1315 | .1468 | .1628 | .1794 |
| 20 | .0872 | .1019 | .1175 | .1339 | .1510 | .1687 |
| 25 | .0782 | .0937 | .1102 | .1275 | .1455 | .1640 |
| 30 | .0726 | .0888 | .1061 | .1241 | .1428 | .1619 |
| 35 | .0690 | .0858 | .1037 | .1223 | .1414 | .1609 |
| 40 | .0665 | .0839 | .1023 | .1213 | .1407 | .1604 |

II. The present discounted value of one (1) recurring at the end of each year for n years, beginning one year hence, the discount rate being r, compounded annually:

$$pdv = \frac{1 - (1 + r)^{-n}}{r}$$

| n\r | .06 | .08 | .10 | .12 | .14 | .16 |
|---|---|---|---|---|---|---|
| 5 | 4.212 | 3.993 | 3.791 | 3.605 | 3.433 | 3.274 |
| 10 | 7.360 | 6.710 | 6.145 | 5.650 | 5.216 | 4.833 |
| 15 | 9.712 | 8.559 | 7.606 | 6.811 | 6.142 | 5.575 |
| 20 | 11.470 | 9.818 | 8.514 | 7.469 | 6.623 | 5.929 |
| 25 | 12.783 | 10.675 | 9.077 | 7.843 | 6.873 | 6.097 |
| 30 | 13.765 | 11.258 | 9.427 | 8.055 | 7.003 | 6.177 |
| 35 | 14.498 | 11.655 | 9.644 | 8.176 | 7.070 | 6.215 |
| 40 | 15.046 | 11.925 | 9.779 | 8.244 | 7.105 | 6.233 |

TABLE A-2

APPROXIMATE RATIOS OF PER CENT VOLTAGE DROP/PER CENT POWER LOSS FOR ALUMINUM AND ACSR CONDUCTORS IN AC CIRCUITS[a]

| Conductor Size | | Power Factor = .90 | | Power Factor = .80 | |
|---|---|---|---|---|---|
| A. W. G. Gauge | Mho-mile | 1 ft. Spacing | 3 ft. Spacing | 1 ft. Spacing | 3 ft. Spacing |
| 4 | .45 | .92 | .94 | .77 | .80 |
| 2 | .71 | .98 | 1.02 | .84 | .89 |
| 1/0 | 1.13 | 1.06 | 1.12 | .95 | 1.02 |
| 2/0 | 1.42 | 1.12 | 1.19 | 1.02 | 1.11 |
| 3/0 | 1.79 | 1.19 | 1.28 | 1.10 | 1.22 |
| 4/0 | 2.25 | 1.27 | 1.39 | 1.21 | 1.35 |

Notes:

a. Calculated from the approximate formula,

$$\frac{\text{Per cent voltage drop}}{\text{Per cent } I^2 R} = \frac{\cos\Theta \ \cos(\phi - \Theta)}{\cos\phi}$$

, wherein $\Theta$ = voltage-current phase angle, and $\phi$ = impedance angle, i.e., $\tan\phi$ = reactance/resistance. (See Standard Handbook for Electrical Engineers, 8th Ed., Sec. 14-42.)

b. One ft. spacing is approximate for secondary lines; 13 ft., for primary lines.

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