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The Compatability of Wind and Solar Technology with Conventional Energy Systems

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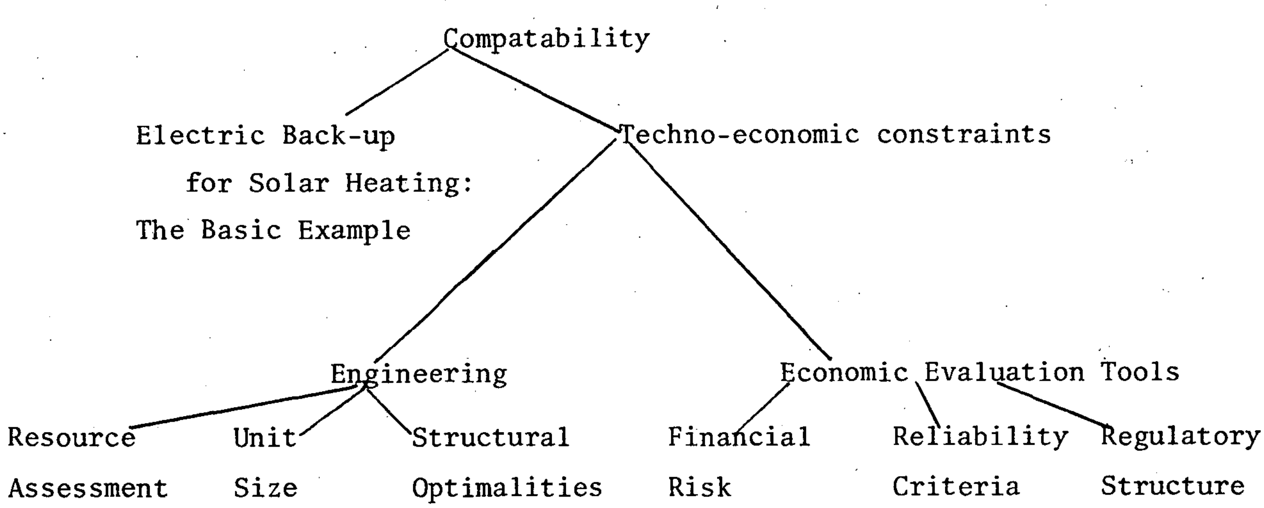
INTRODUCTION

Energy converted directly from the sun and the wind is available intermittently. This is qualitatively different from the conventional sources of energy, mineral fuels. Mineral fuels embody energy stored over geologic time. This energy is available to our use whenever we have the appropriate combination of supply source and conversion device. Energy converted directly from the sun and wind is inherently fluctuating; a random element is fundamental to the nature of the resource. We can count on its "gross availability"; we assume the sun will always be there. But we do not know whether the sun will shine or the wind will blow in any particular period. The supply cannot be directly manipulated to meet the demand. There are some "solar" technologies which do not have this random availability feature (bio-mass, ocean thermal energy.) These will be excluded from the following discussion to focus more narrowly on the consequences of uncertain availability. The questions we will ask involve the interface of the somewhat random availability technology of wind and solar energy with the energy system based on mineral fuels. Are the two compatible?

This question revolves in one way or another around the electric utility industry. There are obvious reasons why this is the case. Most important, of course, is that wind and solar technologies produce electricity or substitutes for electricity. Even in those situations where the substitution or competition effect is relatively weak, electricity can be an attractive supplement or complement to solar energy. The case of electric back-up for solar heating, the first concrete compatability problem to emerge in the literature, is addressed to the impacts of complementary situations. The electric utility must respond to a new structure of demands. In other cases the wind and solar technologies compete directly in the electric utility market with conventional conversion devices. To study the cost implications of either situation requires that we define the appropriate boundaries for engineering economic analysis. The major theme of this review is that new tools are needed for this analysis. The conventional tools of engineering economics require additional development to assess compatability issues.

The discussion which follows is divided into three parts. First we will review the electric back-up to solar heating controversy. This will provide a concrete setting in which to study the interaction of engineering, economic and regulatory constraints. Compatability in general is the result of wind and solar systems design that produces a cost minimum after all indirect effects have been accounted for. The indirect effects are responsible for the subtleties. For convenience we divide the discussion of the relevant constraints into engineering and economic categories. The engineering critera we will review in the second major part of the discussion, include methods of wind and solar energy resource assessment, the appropriate scale of conversion devices, and the structural features of energy systems that minimize total system costs. Finally economic evaluation tools will be analyzed themselves in the third part of the review. In this section we will discuss financial risk adjustments for energy project evaluation, the role of reliability criteria, and the impact of regulatory structure on system costs. The structure of the discussion, is illustrated below.



A final word is necessary about the "maturity" of the subject we will be discussing. Compatability is not a well-defined research area with established and conclusive results. Rather it is a somewhat loosely coupled network of problems that revolve around the common elements to be articulated below. Therefore this review must be understood as an introduction to a research agenda, a preliminary definition of a field of inquiry. There is as yet no theory of compatability only a taxonomy of competing constraints.

Back-up Requirements for Solar Heating

Solar heating is typically thought of as providing less than 100% of the thermal requirement for buildings. This means that there must be some auxiliary heating system to provide for the fraction of load that solar does not supply. Electric resistance heating has a low capital cost. This is a desirable feature for an "auxiliary" or back-up system which will be used infrequently. Therefore many solar designs incorporate electric resistance as the supplemental supply. It began to be noticed, however, that if there were many such solar buildings, electric back-up could impose a problem on the utility. This was the first compatability problem to receive much attention in the solar energy literature. The problem has two aspects; a peaking effect and a load factor/revenue effect. We will take these up in turn.

Solar back-up demand results from long periods of sustained cloudiness. This condition is likely to effect relatively large geographic areas. "Large" here means comparable to the size of a utility service area. Therefore the demand for solar back-up energy would be co-incident to a great degree for many buildings. This in turn would impose a large demand on the utility system for power. Such a demand could create a "peak" condition, during which there was little reserve generating capacity and correspondingly greater risk of outage. In the extreme case, solar back-up demands could cause a black-out that would affect all the utility's customers.

Even if the risk of black-outs never materialized, it has been argued (1-5) that the existence of a large solar back-up demand would create a revenue problem for the utility. The back-up service is a "low load factor" proposition. This means that the magnitude of the peak demand is great in comparison with the average use (load factor = average demand/peak demand.) The "peak" energy is expensive to produce, i.e. is above average cost per kWh. The back-up customer pays at an average rate, however. Therefore the utility fails to recover costs unless there is a discriminatory solar rate or cross-subsidization from other non-solar customers. One state regulatory commission has already adopted the discriminatory rate approach for solar back-up and others are considering such action. (3)

The crux of this argument lies in the distinction between expensive "peak" energy and relatively cheaper "off peak" energy. The solar back-up user requires the expensive electricity but only pays some average price. Recognizing the importance of this distinction, Asbury and Mueller (4) have even argued that if we limited back-up demand to off-peak energy, then solar systems themselves become uneconomic compared to storage. The Office of Technology Assessment has examined this problem and found some support for the argument that load-managed (i.e.off-peak) storage has lower levelized annual costs than solar heating with electric back-up (5). The main reason for this result is that storage capital costs are typically less than solar capital costs. The Asbury and Mueller argument therefore seems plausible.

There are problems with this argument, however. A fundamental difficulty with the notion of a solar back-up incompatability is the assumption that thermal loads and individual building peak demands are fixed quantities and not design variables. In fact, as more and more conservation investments are made in building (insulation, double and triple glazing, thermal shutters) the peak demand for back-up goes down along with average energy use. This relationship is shown in Figure 1. On the horizontal axis the average energy use is plotted

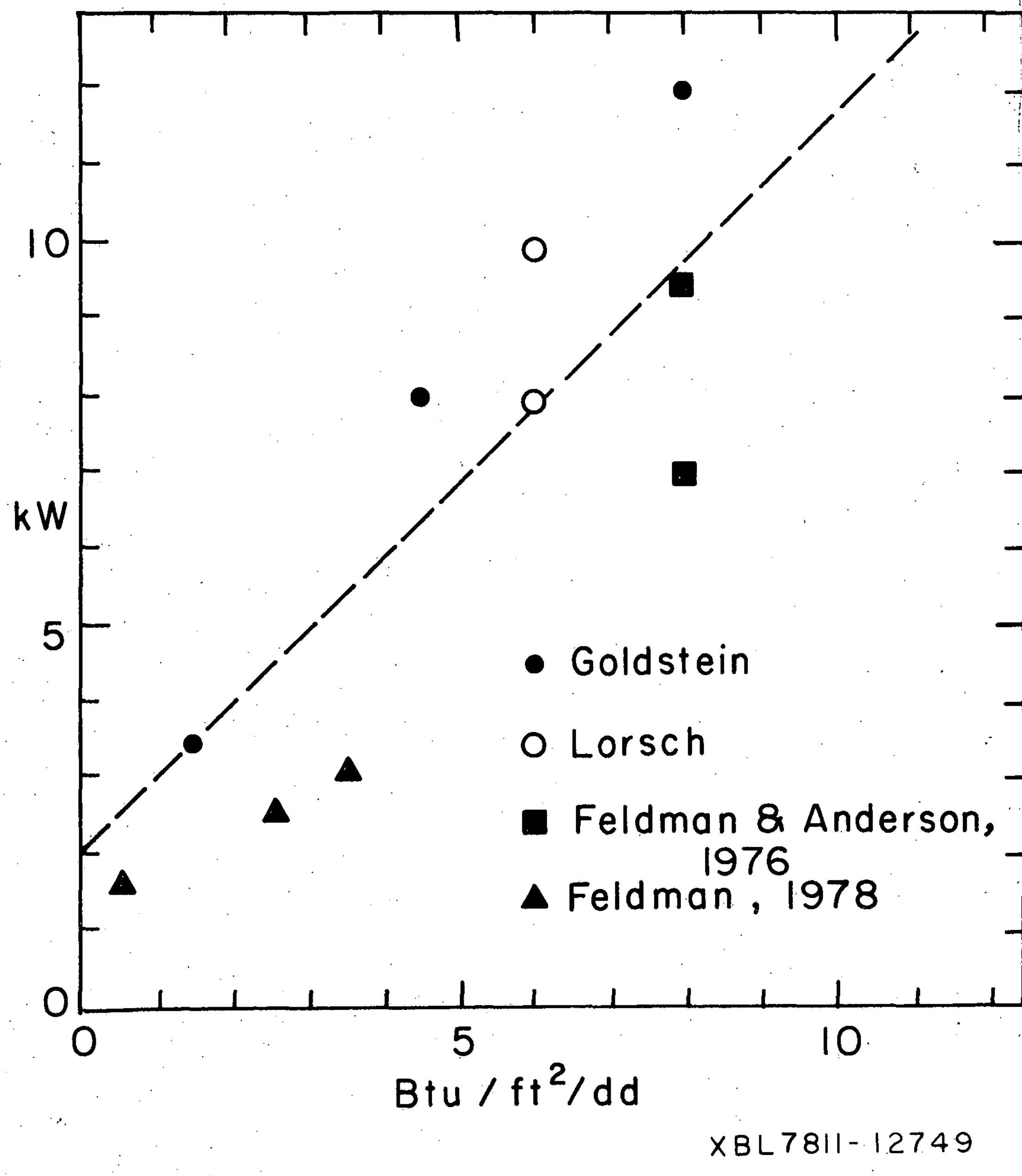


Fig. 1 Peak Demand vs Average Energy Use for Single Family Houses

in units of Btu per square foot of dwelling per degree day. This approximately normalizes the energy demand for size and climate. The vertical axis shows peak demand. The studies which first identified the load factor/revenue problem looked at buildings that were in the upper right-hand region. This corresponds roughly to the current building code. The buildings represented in the lower left hand region incorporate many conservation measures. Some of these are explicitly passive solar houses.

The advantages of the low energy use buildings are several. First, the magnitude of the peaking problem for back-up is reduced by a factor of two or three compared to conventional buildings. By comparison, storage heating devices have a peak demand that is 1½ to 2 times greater than ordinary resistance heat (6). This difference becomes important when many such devices are in place. Low energy use buildings, however, reduce the magnitude of the load factor/revenue problem. Reduced peak demand means the gap between expensive peak energy and average cost rate structures is reduced. The problem does not go away, of course, but its magnitude is less than say the impact of electric cooking with its high co-incident peak demand and few hours of usage. What remains, however, is less of an inherent solar incompatability with electric utilities, than an incompatability of optimal building design and current building codes. The low energy use building is relatively rare today, however justified by its favorable marginal costs (7). Diffusion of innovation in the housing industry is slow (8). Moreover the regulators of the housing industry and the utility are institutionally distinct. They have no common meeting ground and they face differing incentives and constituencies.

Even if solar buildings were to be inefficiently designed, there is an important consequence of the fact noted above that peak storage demand is roughly twice peak back-up demand for conventional inefficient buildings. There is a saturation effect. Asbury and Mueller assume that off-peak energy is available without constraints. It is not. After a certain amount of off-peak "valley-filling", the off-peak period disappears. Typical winter load curves show that this happened in Hamburg, West Germany for example over a five-year period (11). Davitian, Bright and Marcuse point out that this valley-filling will limit the market penetration of storage heating compared to solar back-up that has been scheduled off-peak (12). It takes fewer storage heater to fill up an off-peak valley, than solar buildings. For efficient solar buildings the difference in saturation limit grows. If solar is viewed only as a limited option to be adopted by few consumers, this effect is unimportant. Widespread use of solar heating will make the saturation limit correspondingly important.

Back-up demand for solar heating is the archetype of compatability problems. We will see the same themes re-iterated with variations in the discussion to follow. Solar and wind energy is inherently stochastic in nature. Its use will require interface with other forms of energy use. This interaction will have technical consequences such as utility load factor changes. There will also be economic consequences such as utility revenue deficiencies. These must be allocated to the various financial actors involved. Technical design issues and amenity levels are potential decision variables when the interaction of solar and conventional energy systems is examined. The "best" design of a solar or wind energy conversion device depends upon whether it is imagined as a marginal element in the future energy portfolio or major one. This is really the difference between the view of Davitian, Bright and Marcuse, who look to widespread adoption of solar heating, as opposed to Asbury and Mueller, who do not. If solar is viewed as a potentially major contributor, then penetration limits are relevant variables to compare with "competing" technologies. If solar is viewed as peripheral, then short-run economics are the dominant consideration. Compatability issues may be seen as only tactical or as largely strategic. The difference reflects one's perspective about the size of the potential market for solar systems.

ENGINEERING CONSTRAINTS

Resource Assessment for the Solar Electric Technologies

It is obvious that energy in the solar flux (solar radiation, wind and tides) exhibits certain random variations. We do not have a detailed knowledge of the basic patterns and deviations. This makes planning and design more difficult. An abundance of data exists in fragmented form, but even much of that is not useful for detailed study oriented to energy conversion. There is no standard definition of "cloudy" weather. (13) Airport records of wind speed are measured at too low a height to be reliable indicators of wind turbine performance. (14) Much of our data has to be "synthesized" using models and limited measurement. (15) This problem of data quality will obviously diminish as more actual measurements are taken. Of equal or greater importance, however, is knowing what to do with the data that has been collected.

Let us consider an example of the conceptual problems of assessing the value of the energy in the solar flux. Several studies of the value of photovoltaic devices in electric utility systems are based upon data for Phoenix, Arizona. (16, 17) A typical result of such studies is the limited "capacity credit" for these devices because of a mismatch between utility loads and the solar resource. A representation of this problem is shown in Figure 2. Here we see a lag between the peak solar output and the peak utility demand. The availability of solar falls faster than the demand for electricity late in the day. Thus we need to back up the photovoltaic device with storage or gas turbines to meet the demand with the reliability that is typical in utility systems. "Capacity credit" is a measure of the difference between installed solar capacity and the back-up requirements. In some sense it is a measure of compatability.

GEOGRAPHICAL DISPERSAL Conclusions based on an analysis such as Figure 2 should not be treated as definitive. One missing dimension of this approach is the effect of geographic dispersal. The solar

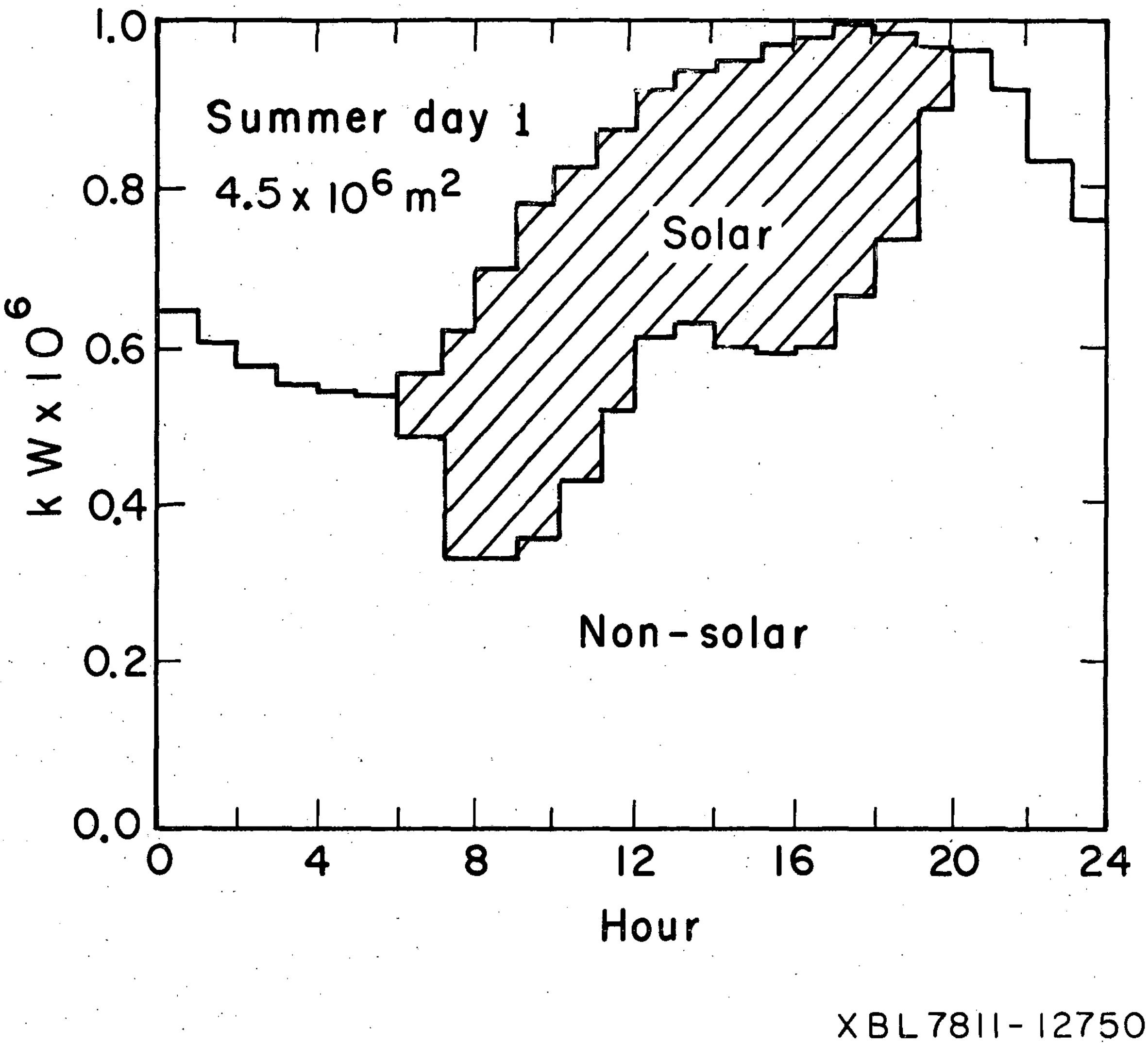


Fig. 2 Solar Contribution to Utility Load - Diurnal Cycle

resource is not uniform spatially, but varies from place to place. Many major utility service areas are not confined to single cities. Even where the utility is confined to a single urban area, extensive electrical interconnections usually exist between utilities and even major geographic regions. Thus it is not unreasonable to investigate the correlation of wind and solar availability between pairs of sites that are separated by some distance.

The relationship between aggregate energy availability and geographical dispersal has been investigated more extensively for wind energy conversion than for direct solar conversion. Only one study makes an explicit analysis of this effect for solar plants (18). This research found a benefit in reliability from broadening the region over which the resource is assessed. Required back-up capacity in the best case was one half that required at the poorest site. Other comparisons made in this study yield a smaller benefit. The case of wind energy is more dramatic. In Figure 3 we reproduce results of a study of the dispersal benefit for sites in West Germany (19). The best single site in this set had zero power output for about 1500 hours per year. As the number of sites studied increased, the aggregate lull fell to several hundred hours for three sites, and to less than 20 hours for twelve sites when mean wind speed was 6 m/s. For conditions in the United States there have been several regional studies of the wind resource conducted by C. G. Justus and associates (20, 21) which assess the benefit of geographical dispersion.

WIND/SOLAR COMPLEMENTARITY A relatively neglected approach to resource assessment is the investigation of joint wind/solar availability. The type of question to be asked is whether the wind blows when the sun doesn't shine and vice versa. Rather detailed analyses are required if this type of investigation is to be useful. One might expect aggregated output to average over both the seasonal scale and the diurnal scale. The geographical dispersal effect can also be investigated for joint wind/solar availability. Data requirements

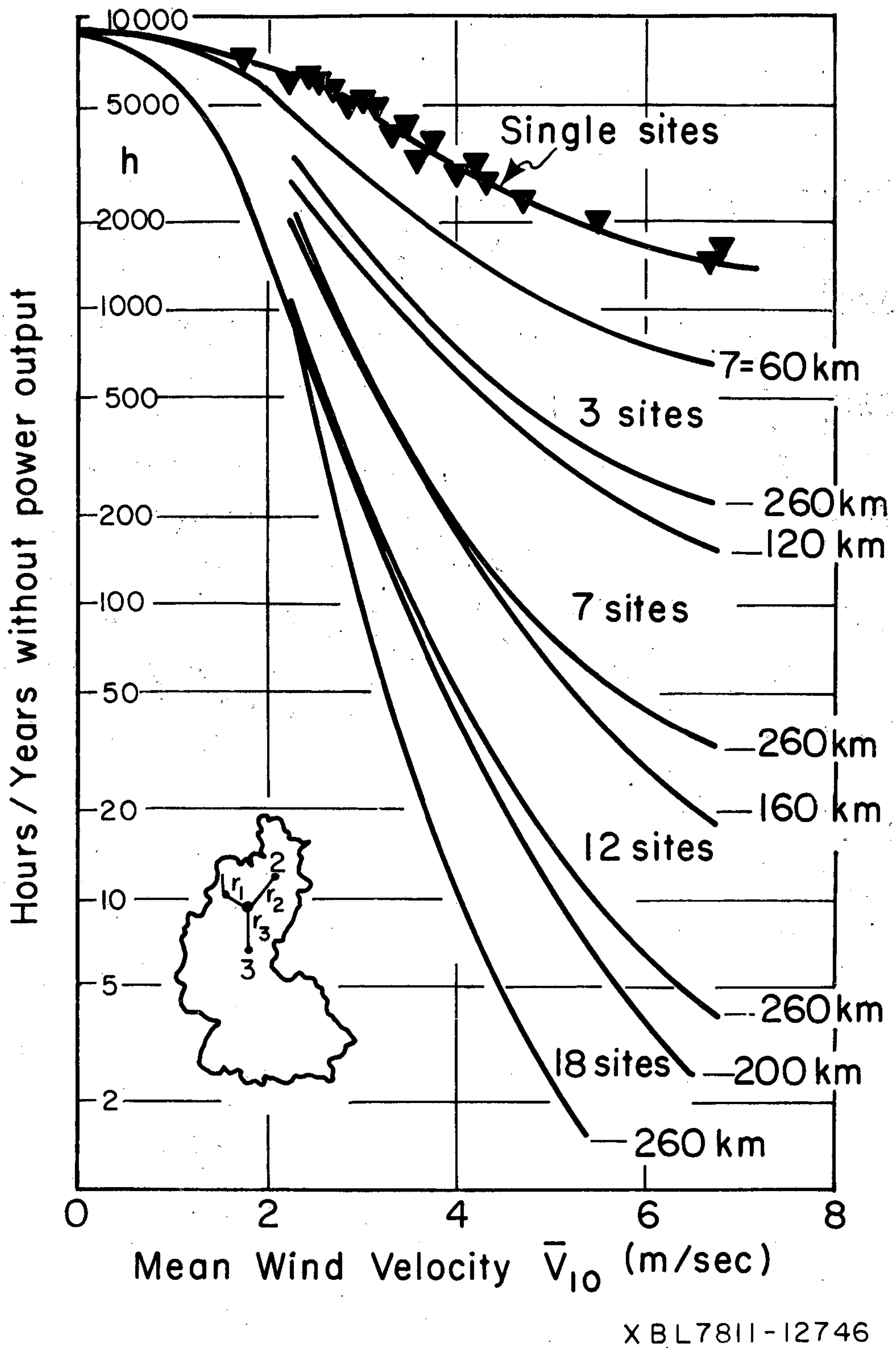


Fig. 3 Geographical Dispersal Improves Aggregate Wind Power Availability

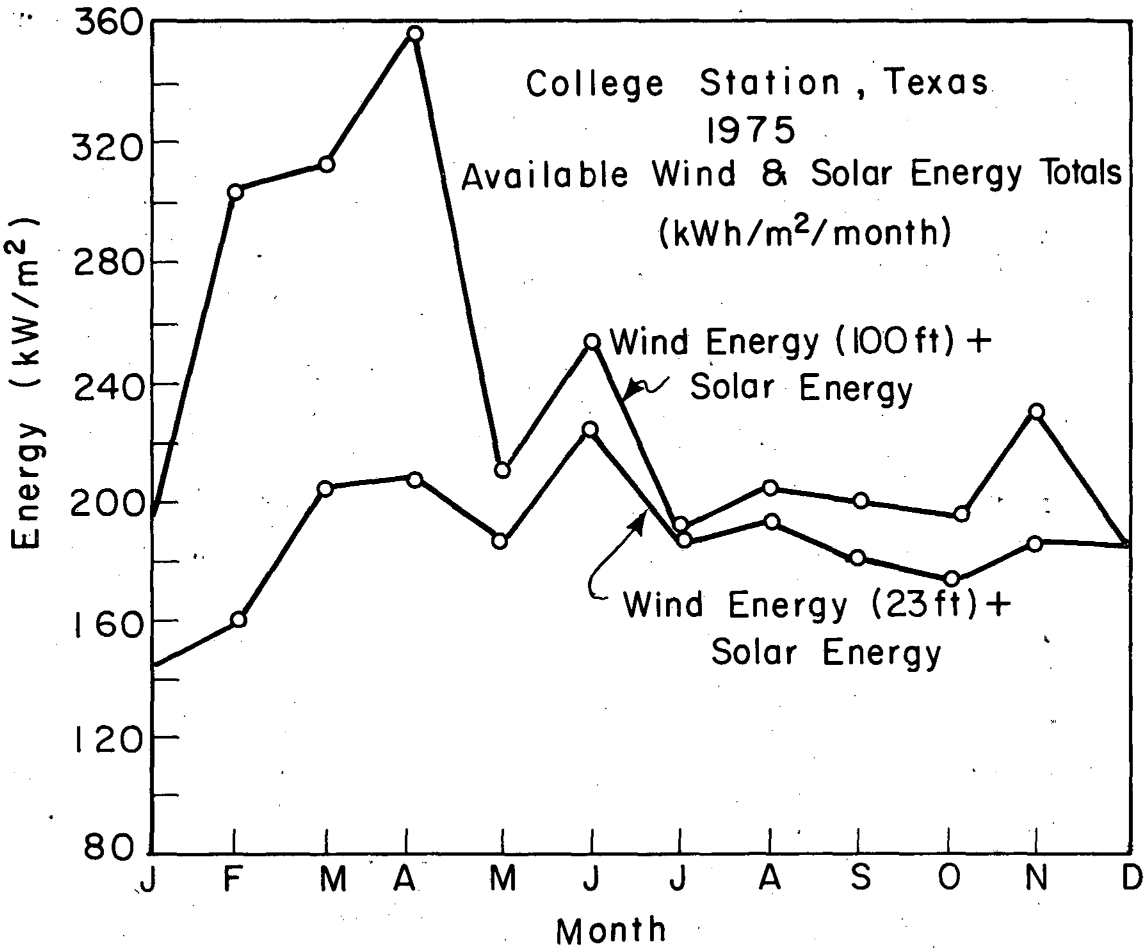


Fig. 4A Joint Wind/Solar Energy Availability

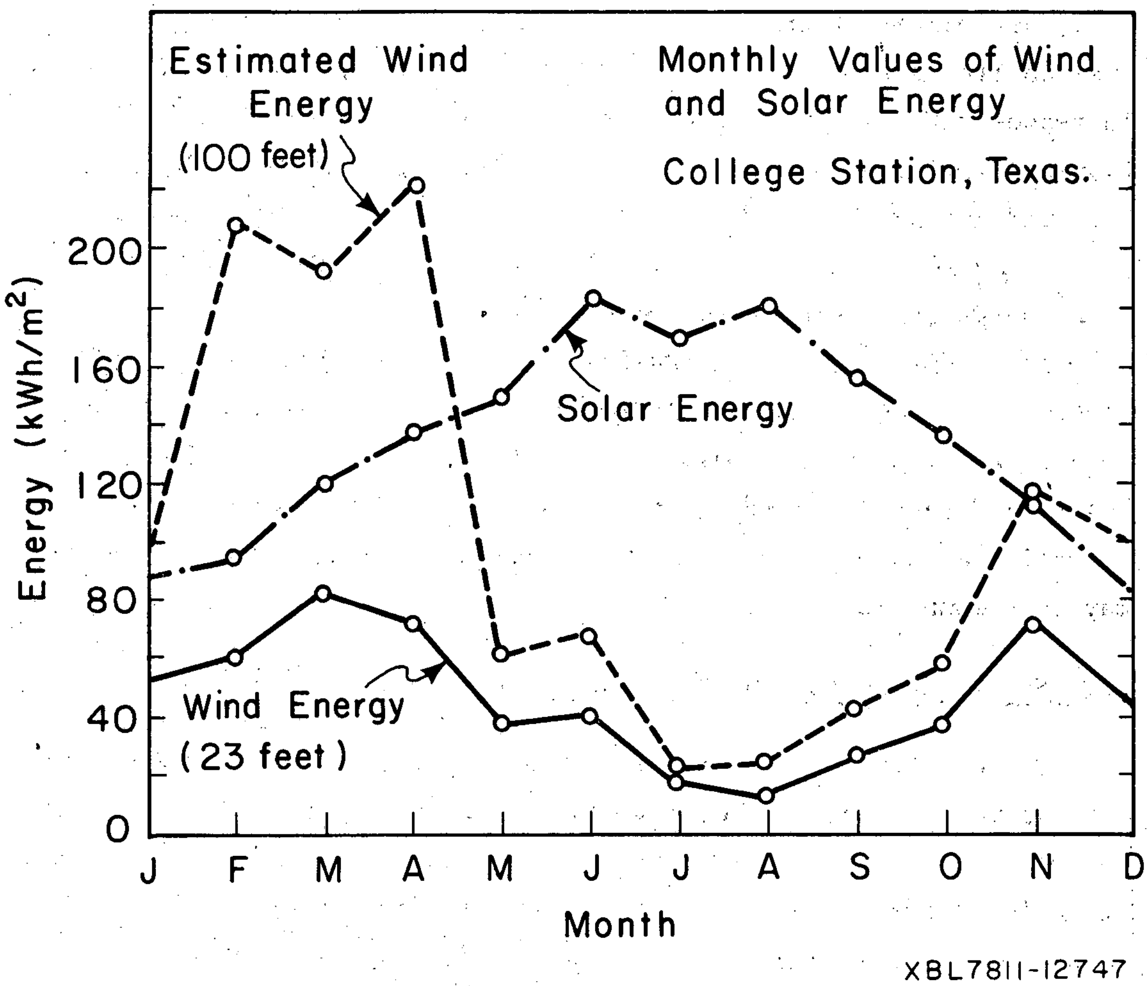


Fig. 4B Joint Wind/Solar Energy Availability for this kind of research will be large.

Interesting results on joint wind/solar availability for a single site are shown in Figure 4. This summarizes an investigation by Arnold of a single year in College Station, Texas (22). These curves show only monthly average values. Arnold distinguishes wind energy availability for two height levels. It is well known that wind speed increases with height and therefore so does energy availability. Figure 4 indicates, however, that more may not necessarily be better. The wind energy at 100 ft produces excess power that is only available seasonally, i.e. in the spring. A smoother aggregate results from wind energy conversion at a lower height.

It is difficult to generalize from these results because other smoothing effects such as geographical dispersion are likely to be important. To date the main interest in wind/solar complementarity has been directed toward "hybrid" systems at individual sites (23). Extension of this research in the direction of geographical smoothing may take some time.

Unit Size: Economies and Diseconomies of Scale

The electric utility industry has traditionally been viewed as a natural monopoly because of significant economies of scale. For the generation function (as opposed to transmission and distribution) these economies are embodied in large conversion units as opposed to small ones. Recent evidence suggests that the frontier of such economies may have been passed for conventional electric generators. Large units appear less reliable (Komanoff & Boxer (24)).impose greater reserve margin requirements (Kahn (25), Wisconsin Public Service Comm. (26)) and have financial risks (Ford, (27)) that detract from their generally lower unit variable costs. The question of optimal unit size also arises for the wind and solar electric technologies. As with conventional supply, the appropriate scale question will interact with the natural monopoly question. Let us consider the scale issue first for wind generators and then for photovoltaics.

WIND TURBINE GENERATOR RATING The unit size question arose recently in a British debate that was ostensibly about reliability issues. Ryle (28) originally suggested in a review article on the economics of alternative energy sources that wind power coupled to 150 hour storage was adequate to meet heating demand in Great Britain. This conclusion was challenged by Leicester, Newman and Wright (29) of the Central Electricity Generating Board (CEGB), who analyzed data from eight widely separated sites in England, Scotland and Wales and compared this with heating demands. The authors from the CEGB found that for the extreme weather of February - March 1975, a 38 day storage was necessary "to cover this period satisfactorily." This is more than five times the energy storage postulated by Ryle.

Anderson, Ryle and others (30) re-analyzed the data and found the important sensitivity of results to the sizing specifications of the wind turbine. In their study, three of the most widely dispersed of sites analyzed by CEGB were used. A glance at Figure 3 suggests that since average spacing goes down in this case as the number of sites go up, that the actual wind energy availability doesn't differ too much between the three site set and the eight site set. What does vary in the two studies is the type of machine postulated to convert the wind to electricity. Figure 5 shows the power output curves used in each study.

The CEGB machine is oversized with respect to the mean wind speed. This means that during the time when wind velocity is between 6 and 14 m/s, power output will vary more than two orders of magnitude. Ryle's machine on the other hand will have output fluctuation of less than a factor of three. Furthermore the CEGB machine sacrifices output on the low end of the scale to achieve the high peaks. For winds below 6 m/s the CEGB machine produces essentially no power. Thus Ryle's machine produces a less variable output and captures energy during the crucial periods of low wind.

The result of this difference is greater reliability during extreme

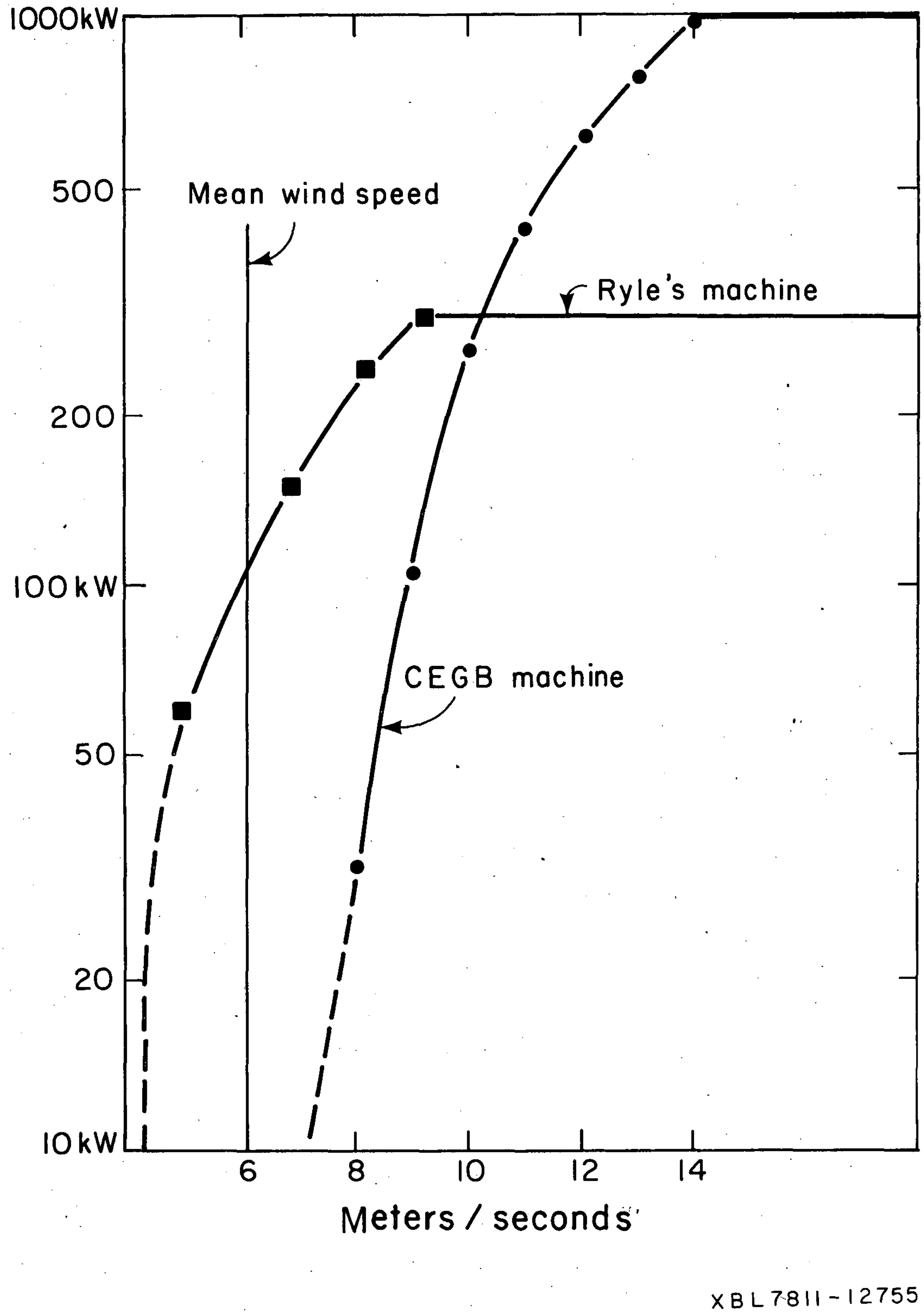


Fig. 5 Wind Turbine Power Output Curves

periods. During the two month period for which CEGB found 38 days storage was "satisfactory," Anderson, Ryle, et al found that roughly half the time the temperature of the simulated houses was 16°C or above. This is with 150 hours storage. The design temperature was 20°C. Implicit in these results is an acceptance of less than conventional power system performance, at least as measured by standard loss-of-load criteria. The conventional criteria for reliability require that deficiencies be limited to a 1 - 2% probability of occurrence. If we interpret these as frequencies, then there should be no more than 175 hours of deficiency. The data of Anderson, Ryle et al shows 1300 hours below the design temperature. This total number of hours below 20°C is identical to the CEGB results. The difference lies in how bad the mismatch is. Using the oversized machine in their simulated array, Anderson, Ryle et al found nearly half the time that the temperature of their buildings was 12°C or lower. This compares to only 50 hours in this extreme state for the smaller machine. Thus although the Anderson, Ryle et al system is not "satisfactory" in the CEGB sense, it comes closer to adequacy than the oversized wind turbine.

Relatively little research on the "optimization" of wind turbine design deals with the system reliability issues of the British debate. Sørenson (31) is aware of the trade-off between high-rated speed and power availability at low wind speed (technically, the "cut-in" speed.) He properly notes that designs such as the Anderson, Ryle et al machine are "aiming at maximizing the number of yearly operating hours (at the expense of total energy gain) for low scale applications." But Sørensen himself does not make an explicit analysis of this trade-off in his studies. He is not alone in this omission.

Finally the important theme to notice in this discussion is the role of unit size optimization in smoothing the inherent power flucations. The smaller scale wind turbine has the same general kind of averaging effect as geographic - dispersal or wind/solar complementarity. Output variations can be averaged out in a number of ways. What is particularly subtle about these and further attempts at smoothing is that there are optimalities. Too much of a good thing can be harmful.

PHOTOVOLTAIC POWER SYSTEM DESIGN The scale issue in photovoltaic technology is much more straight-forwardly economic than the reliability optimization of wind generators. Here the unit size distinction is between flat plate devices attached to individual load centers (e.g. roof tops) or sophisticated concentrating and tracking systems that are sized for larger scale utility application. The small-scale system usually requires a complex " interface" with the utility company, the sophisticated system is typically imagined as a utility-owned central station plant. To understand the engineering basis of the discussion it is useful to begin with the role played by cell efficiency in the economics of photovoltaic devices.

Many of the costs of photovoltaic systems are "area-related," the land and support structures required to hold the cells themselves. Increasing efficiency of the individual cell allows a reduction of land area per unit output. Further reductions in the area per unit output ratio can be achieved by optical concentration, (since current increases nearly linearly with intensity and voltage goes just faster than the log of intensity (32)). The price for this economy is the cost of the concentrator device. The benefit is higher allowable cost for efficient cells than for flat plate systems. These relationships were reported in Spectrolab (16) and Bradley and Costello (33). EPRI has developed a methodology for assessing the design trade-offs between cell efficiency, average insolation, and area-related costs for concentrator systems (34).

When compared to flat-plate rooftop systems, however, the advantages of concentration appear less robust. This is particularly true in light of expected trends in the cost/performance behavior of photovoltaic cells. General Electric (35), for example, found in a recent study for EPRI that it was the roof top and flat plate systems whose overall economics improved most from cell cost reductions and efficiency improvements. In three regional case studies, the flat plate systems far surpassed the estimated break-even level when "base-line" cell costs were reduced 75% and efficiency doubled. Conversely for two out of the three cases the concentrator system failed to break even under these assumptions. Furthermore the roof top systems have the potential for waste-heat utilization which may be more difficult for the concentrator systems. This difference further tips the economic balance in several estimates of comparative economics (5, 32).

These analyses are clearly more suggestive than definitive. What is interesting about the apparently favorable economics of highly decentralized photovoltaic conversion is the implications this might have for the electric utility with which such systems might be interconnected. The back-up issue discussed above re-emerges with even greater complexity. Decentralized photovoltaics, like dispersed wind generators, have the potential to supply excess power to the grid as well as draw on it for back-up. This will present difficult problems of regulatory pricing. What should be the prices for utility back-up and excess energy? On what do these prices depend? How do these things vary with other system parameters? Here we are largely on unchartered territory. These issues begin to suggest that wind and solar energy will have to establish a compatability with the regulatory apparatus if their engineering economic potential is to be implemented practically. Regulators must design a pricing structure appropriate to the engineering characteristic of this unconventional technology.

Structural Optimalities

The discussion of compatability is essentially a quantification of trade-offs within a large system. Back-up demand for solar heating will affect utility load factors, but the impact of this requirement varies with building thermal design. The optimal configuration of solar design and utility prices involves a trade-off between the cost of building design improvements and the magnitude of utility revenue deterioration. It may be extremely difficult to implement such optimal configurations, but it is important to know they exist. For practical purposes it would be useful to understand the cost of specific departures from optimality, so that realistic policy can be guided by a "second best" type of analysis. In this section we will survey some results on system optimalities that are important for plausible assessment of the economics of wind and solar energy.

LOAD MANAGEMENT Underlying the discussion of the solar heating back-up problems was the concern that utility load factors whould change for the worse, i.e. decrease, as a result of the penetration of such technology. It is not widely appreciated, however, that increasing utility load factors imposes extra cost in the form of added reserve requirements. For example, increasing seasonal load factors will leave less and less "off-peak" time available for maintenance. Therefore generation which might have been available to serve demand becomes unavailable and must have back-up. This effect grows larger as the size of the largest units increases. With a large block of capacity out of service for maintenance, substantial reserve must be available. A quantitative study of this effect was conducted by the Edison Electric Institute (36). A representative formulation of the results is reproduced in Figure 6. This shows curves relating certain fractions of peak shaving to reserve margin increases for five different systems.

Examination of Figure 6 shows that there is probably such a thing as an "optimal load factor." In those cases (D and E) where the load factor is already high (65% or above), shaving 10% off the peak will double reserve requirements. This will have the net effect of <u>increasing</u> total capacity required. For example if such a system had an initial peak load of 8,000 MW and a 15% reserve margin, total capacity would be 9,200 (= 1.15 x 8,000.) Reducing the peak 10% will increase total capacity needs to 9,360 MW (= 1.30 x 7,200) if reserve margin doubles. The penalty grows if the initial reserve margin is greater than 15%.

The opposite result occurs for some lower load factor cases (A and C.) For these systems a 15% reduction in peak increases reserves

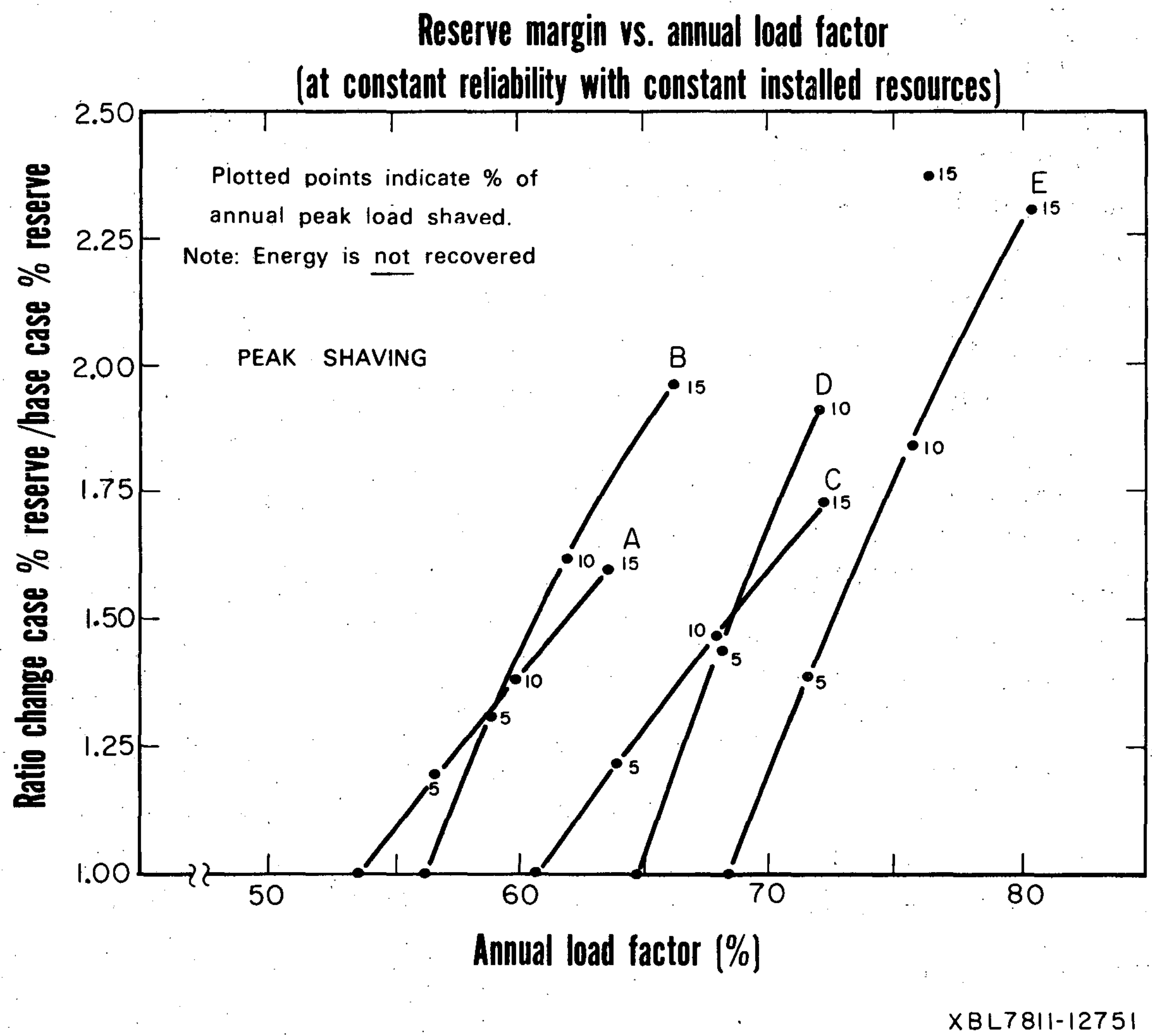

Reserve margin vs. annual load factor
(at constant reliability with constant installed resources)
Plotted points indicate % of
annual peak load shaved.
Note: Energy is not recovered
PEAK SHAVING
A
B
C
D
E
2.50
2.25
2.00
1.75
1.50
1.25
1.00
50
60
70
80
Ratio change case % reserve /base case % reserve
Annual load factor (%)
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Fig. 6

by only a factor of 1.75. This will produce overall reductions in capacity requirements. Returning to our previous hypothetical case, the original configuration of 8,000 MW peak and 15% reserve would become a system of 6,800 MW peak and 26¼% reserve. The total capacity in this case is 8,600 MW (= 1.2625 X 6,800) which is 600 MW less than the original configuration. For these relatively low (55 - 60%) load factor cases, peak shaving saves capacity. This remains true even if the initial reserve margin is as high as 25%, although the size of the benefit diminishes.

Although the load factor - reserve margin trade-off is only one aspect of load management economics (37), there are important consequences for the assessment of wind and solar energy compatability. Let us return for a moment to the load factor reductions induced by solar heating back-up demand. This problem can be ameliorated by load management, namely scheduling the back-up demand off-peak. Such a strategy is limited by the availability of off-peak power. Our solution to load factor decrease becomes limited by load factor increases. At this point we must realize that all the wind and solar technologies impose load factor changes. Unless controlled, these will all be in the direction of reduced load factor. Thus the appropriate balance of solar technology and load management becomes the kind of optimization problem we have just discussed in the case of conventional technology and the load factor-reserve margin trade-off. The optimal degree of load management will increase as more wind and solar devices enter the energy system. The problem is the counterpart in the utility capacity planning framework of the wind/solar complementarity problem. This optimization is a good deal more complex than in the conventional case. Storage is central to the wind and solar sources. Relatively little is known about this kind of problem. All that can be reviewed are a few partial results and techniques whose guidance is limited.

OPTIMAL MIX ADJUSTMENT: SCREENING CURVES When utility system load factors change, there is a change in the optimal supply mix to meet the altered load characteristics. Figure 7, which is borrowed from

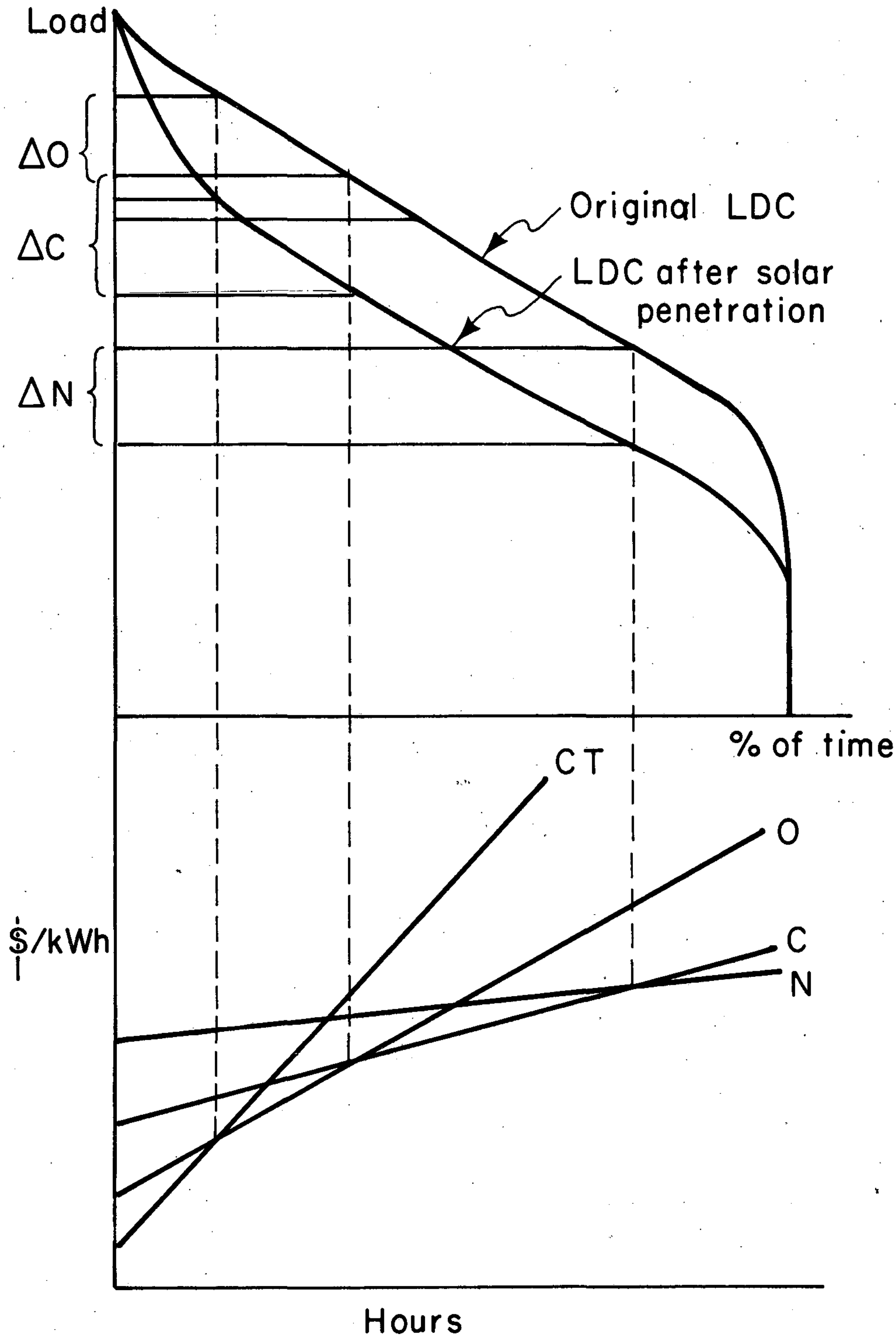

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Fig. 7 Optimal Mix Adjustment: Screening Curve

Miles, Badertscher, and Peschon (38), shows one approach to studying these changes. This approach is called the screeening curve (30). It is a formal representation of the intuition that solar reduces load factor, i.e. makes the rest of the utility more of a peaking system. Starting from a load duration curve (LDC) at the top of Figure 7 and cost curves for various technologies at the bottom of Figure 7, one can estimate the optimal supply mix. The LDC is just a representation of the annual fraction of various load levels. The cost curves show the relation between fixed and variable costs for different technologies. Nuclear (N in Figure 7) has higher fixed costs (y-axis intercept) and lower variable costs (slope of line) than the fossil fuel technologies (C = coal, O= oil, CT = combustion turbine.) The intersection of the cost curves mark the "break points" for the different technologies in the optimal mix. Projecting these upward to the LDC (dotted lines) will show which fraction of the load should be served by each resource.

Figure 7 shows changes in optimal mix after the LDC shifts due to solar penetration. These are shown as ΔN, ΔC and ΔO. Each resource moves "down" the LDC, with the "base load" nuclear being displaced as the system becomes more "peak" and "intermediate" in its load requirements. This particular outcome is due to the shape of the new LDC.

There are important limitations to this approach. First, screening curves are applicable only if there are no other technical constraints to be considered. Reliability is one such neglected factor. As long as the solar penetration is relatively limited it can be treated as in effect a reduction of an originial LDC. At large penetration, or where bulk power storage must be treated, further adjustments are necessary. Second, the screening curve approach says nothing about the dynamics of adjustment. R. A. Meyer (personal communication) suggests that very rapid penetration of solar technologies may have harmful financial consequences by displacing unamortized investments. Thus the benefits of displacing conventional investments by wind and solar are limited by the time necessary to write off the capital plant that will become obsolete or suboptimal. This barrier to solar energy belongs in the category of large penetration problems that are not well understood.

Finally the wind and solar energy technologies are not easily placed on the supply side of the screening curve. Although it is convenient to try to classify them as "base", "intermediate", or "peaking" (40), these characteristics cannot be translated into the cost curves on the bottom of Figure 7 to project optimal mix.

OPTIMAL MIX: RELIABILITY CONSTRAINT A considerably less well understood aspect of optimal electricity supply mix is the reliability constraint. For conventional technology it has been shown that unit size impacts reserve requirements and therefore comparative project economics (25,26). There is no very satisfying treatment of the general reserve margin problem, however, which could be brought to bear on the more complicated reliability problems of wind and solar energy. One exception of the general lack of theory is the recent paper of Sharkey (41) which formulates an interesting first approximation.

Sharkey poses the problem of optimizing the distribution of plant size when the demand faced by the industry in question is uncertain. To formulate the problem in a welfare setting which considers both the benefit of satisfied demand and the cost of unsatisfied demand, Sharkey makes simplifying assumptions about cost structure. Both the variable cost per unit output and the benefit of satisfied demand per unit output are considered to be fixed constraints (the latter being larger than the former). Under these assumptions and given a uniform distribution of demand, Sharkey demonstrates that there is an optimal distribution of plant size. This distribution has roughly the following properties. The largest plant constitutes about half the total capacity. The second largest is half that size, the third is half the size of the second largest, and so on. The distribution is calibrated by a relation among the variable cost, unit benefit and fixed cost.

This result cannot be translated into the language of power systems economics without certain adjustments. Nonetheless it offers a plausible interpretation of some otherwise anomalous results and a guide to large wind/solar penetration problems. Wind and solar energy devices, even if distributed over a wide geographical region, have outputs that are correlated. In effect this makes an array of such devices act as a single large unit. When it is cloudy, all solar units are unavailable to meet demand; similarly for wind lulls. Thus for reliability analysis, all wind generators and all solar devices must be treated as an aggregate. Sharkey's theorem, which can be interpreted as a result on reliability, says that the effectiveness of such arrays will depend on the unit size distribution of the other generators in the system of which they are a part. A concrete example of this effect is shown on Figure 8.

Figure 8 is derived from a study of wind generation assumed to penetrate various California power systems (42). The graph plots effective capacity versus penetration for two configurations. Effective capacity, expressed as a fraction of rated capacity, is defined as the amount of extra load a power system can carry at the specific reliability criterion per unit installed capacity. This notion was first introduced by Garver (43). It is the only rigorous way to express the notion of capacity credit or back-up requirements. Effective capacity is a marginal notion. It expresses the impact of a given addition to some fixed system. It can be used to give some global insight, however, into the reliability properties of entire systems.

Figure 8 shows curves for two different power systems. One represents the existing hydro-thermal system of Northern California supplemented by wind generation characterized by that region's wind resource. The other curve represents a hypothetical fully integrated power pool for all of California. Into this system wind generation is added, but this time using statistics representing the wind regime of the larger region. The larger geographic region has a higher mean wind speed and smaller standard deviation than the smaller region. Yet Figure 8 says that as far as power system reliability is concerned, the smaller region with less reliable wind is better. From the marginal point of view this is anomalous. From a global perspective, however, it makes more sense. As the wind penetration increases in this analysis, the overall generator size distribution becomes

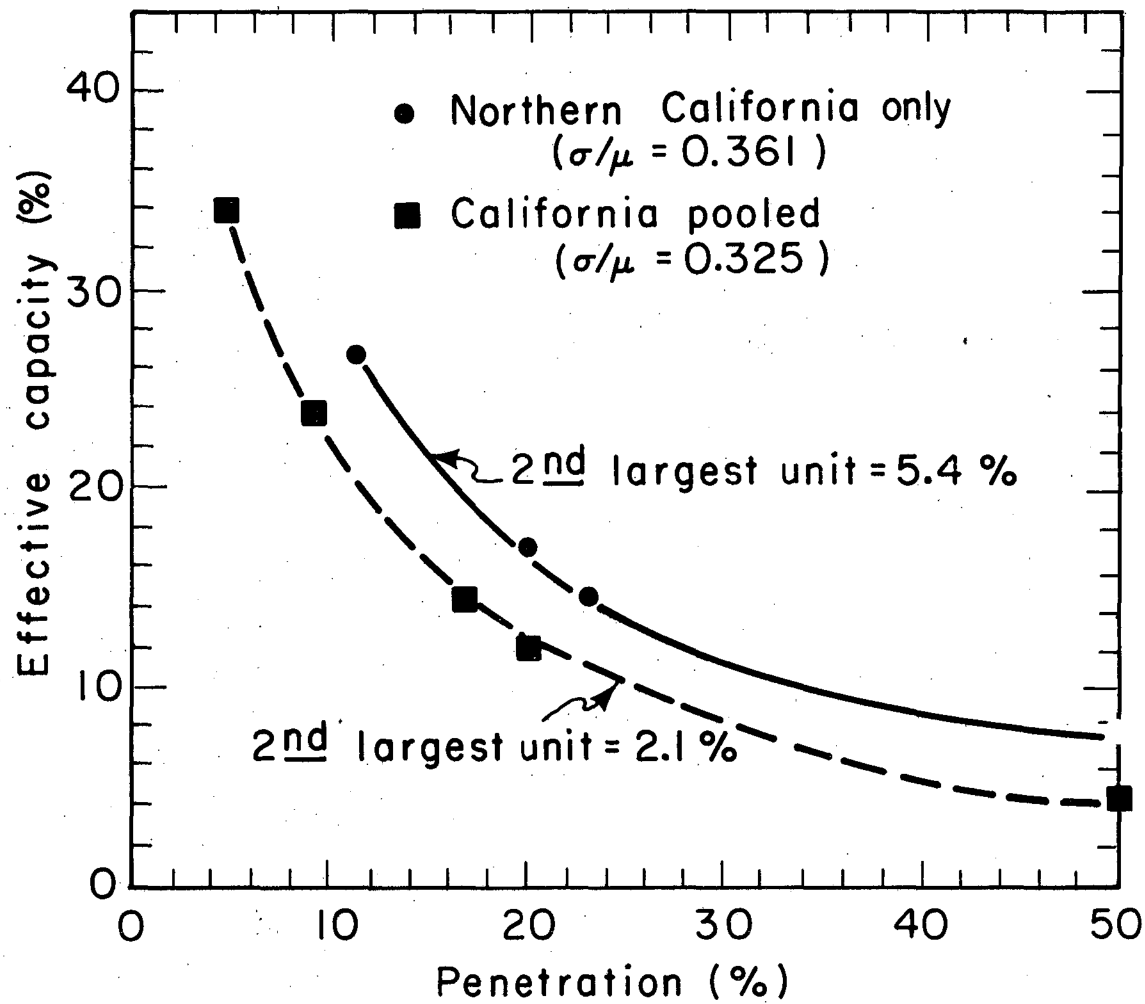

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Fig. 8 Influence of Optimal Unit Size Mix Dominates Influence of Wind Resource increasingly sub-optimal. The second largest unit in the small system is a bigger fraction of the mix than in the large system (5.4% vs 2.1%). This may be small in terms of Sharkey's result, however, it is enough to dominate the opposite difference in the reliability of the wind resource alone.

Results such as this lend support to the theory that wind and hydro power have a special technical compatability that is strengthened by increases in the generator capacity at existing dams (44). The structural properties of wind-hydro systems that are optimized by "over-machining" the hydro are a promising research subject. This approach will involve complicated analysis of regional economies of scale from several points of view; wind resource, transmission line costs, hydro availability, etc. The analysis of Figure 8 suggests there are dis-economies of scale also. Trade-offs among these factors are not well understood.

STORAGE ECONOMICS Storage in one form or another is essential for the use of wind and solar energy. The determinants of storage economics are fairly well known. Relatively few technologies are likely to be available for energy storage at reasonable cost, and only conventional pumped hydro is now in widespread use (45). Because major technological and economic breakthroughs in storage are not expected (46), attention has begun to focus on the comparative economics of different storage use patterns. The main result that has emerged from this research is that there is an economy of scale for utility systemwide use of storage as opposed to independent decentralized applications. This conclusion can be expressed in terms of break-even costs, the cost at which a technology becomes "competitive." This can be a confusing concept because the higher a breakeven cost, the more attractive is the option. Essentially it means that a technology will not have to be "cheap" to compete effectively.

A recent study by General Electric (46) found that break-even costs were roughly four times higher for the centralized application than the independent decentralized ones. A centralized application of storage is something like pumped hydro which can be charged by any unit on the system. Decentralized storage is a smaller device that is dedicated to one or two small group of users, e.g. thermal storage. The considerable cost advantage results primarily from the greater flexibility of the centralized application. The benefit of various kinds of averaging requires central integration. Although this conclusion is sensitive to assumptions about rate structures and tax law, it is quite plausible and likely to be robust (i.e. not change qualitatively when assumptions are varied.) Just as the storage function in agriculture is most efficiently provided by centralized facilities such as grain elevators, energy will probably also be stored most economically in bulk. This conclusion has important implications for the debate over energy decentralization and the future role of today's utilities.

ECONOMICS

Financial Risk

The discussion of comparative economics for various energy technologies is typically carried out in a static framework. For electric generating technologies the simplest measure of economic value is the busbar energy cost. This is the annual sum of fixed and variable costs divided by the kilowatt-hours generated. Busbar cost is inappropriate for solar technologies becuase they are only comparable with conventional power generators after the reliability differences have been accounted for. Even the more elaborate utility simulations, however, despite inclusion of availability analysis are conducted under stylized assumptions about the economic and finanacial climate. Demands are assumed to be known with certainty, regulation is assumed always to work perfectly and adjustment to macro-economic flucations are assumed to be without cost. Thus whole classes of risk are typically ignored in the conventional engineering-economics where a world of certainties is assumed.

There has been growing interest recently, however, in the analysis of uncertainty as it impacts the relative economics of energy projects. Engineering parameters of energy technologies translate ultimately into different levels of financial risk. Financial risk analysis assumes a "mature" technology. That is, the dominant uncertainties are not technological, but are features of the economic system. Economic activity has its own random and cyclic fluctuations. Projects whose cash flows are less vulnerable to these movements are less risky. Only some solar and wind energy technologies can be considered sufficiently "mature" to be analyzed in this way. Photovoltaics and solar thermal electric plants are clearly "immature". In the discussion which follows we will review several approaches to financial risk analysis in energy project evaluation. Since the most specific results in this area involve conventional technologies, we will look for analogies between the risk elements of these devices and the properties of wind and solar energy conversion. We begin with the interaction of construction lead time and demand uncertainty in the electric utility industry.

CONSTRUCTION LEAD TIME AND DEMAND UNCERTAINTY Electric utilitie must forecast the demand for power years in advance of its occurrence. These forecasts have become considerably less accurate in the years following the OPEC embargo (47). The utility planner faces a less and less certain demand the further he looks into the future. The uncertainty increases the risk of long lead time projects, because there is decreasing assurance over the construction time that forecasted demand will actually be realized. This means the cash flow necessary to amortize the investment is less certain as lead time grows. This interaction has been modelled from several points of view.

Ford (27) approaches the demand uncertainty problem from the perspective of macro-economic fluctuations. Unanticipated recessions reduce the demand for electricity. Presumably this case is more interesting than the symmetric case of unanticipated economic booms and increased demand for power, because economic growth rate expectations are now lower than in the past. Given the unanticipated recession scenario, Ford compares small plants with roughly five year lead times to large plants with roughly ten year lead times. Two factors favor the former alternative over the latter. First, forecast error is reduced since the forecast period is shorter. This is due to the shorter lead time of smaller plants. Second, supply adjustment is easier since the short lead time plant comes in smaller sizes. The magnitude of the differences in financial burden to customers is also reflected in realized rate of return to the utility. The realized rate of return penalty is roughly twice as large for the long lead time case compared to the short lead time case.

Boyd and Thompson (48) approach the problem of optimizing investment in the face of uncertain demand using a dynamic programming model. The output of their analysis is a pairing of demand probability distributions with the cost ratios that would favor long lead time plants over short lead time plants. For example, in the simplest case where demand is equally likely to grow one, two, or three units over the planning period it will always be optimal to build at least one long lead time plant. If the cost advantage of such plants is at least 12% over the short lead time plant, then it is optimal to build two such units. It requires a cost advantage of 42%, however, to make three long lead time plants optimal. While suggestive in its results, this study is somewhat stylized in its assumptions. This makes it more of conceptual value than a practical guide to particular regulatory decisions

APPLICATION TO SOLAR INVESTMENTS The preceding analyses are not explicitly addressed to the economics of solar investment. This question has been examined in part by W.R.Z.Willey in two case studies (49, 50). Willey does not address the demand uncertainty problem posed above, but he does model the financial consequences of lead time differences between alternative approaches to energy supply. Both case studies compare the financial burden to rate-payer and utility stockholder of a supply plan based on long lead time technology to one based on solar heating, end-use conservation investment, co-generation and other short lead time technologies. These calculations are based upon equal regulatory treatment for the two alternative approaches. Although plausible logically, this assumption amount to allowing utilities to capitalize end use conservation and solar investments and capture the tax benefits. It is not clear, however, whether the tax treatment would be allowable (G. Amaroli, California Public Utilities Comm., personal communication.) There is also some doubt concerning the legality of utilities owning solar and conservation devices (5).

Subject to these important cavaets, the results of the analysis are still interesting. Willey finds that utility revenue requirements, i.e. customers rates, remain the same for both the long lead time supply plan and the solar/conservation/short lead time plan. Utility earnings available for dividends, however, actually increase in the solar/conservation/alternatives case. These extra earnings could either be allocated to stockholders or shared with rate-payers by reducing revenue requirements. Regardless of the allocation of the financial benefits, the financial pressures on the utility diminish in the conservation/solar case. Key indicators of financial health improve. Interest coverage of debt improves in quantity and quality. Internal finance increases and common stock issuances drop. The main reason for these results isthe lead time difference between conventional plants and the alternative investments.

MARKET INDICATORS OF UTILITY RISK: AFDC AND EQUITY BETA; Willey's analysis suggests that the cost-of-capital for the solar/conservation investments should be less than for conventional plants. Improved financial ratios should make stock prices more attractive and debt cheaper. To substantiate the argument that solar investment bears less financial risk than conventional alternatives, we need to survey empirical indicators of risk in financial markets. One important indicator of financial risk is AFDC (allowance for funds used during construction). AFDC is an accounting adjustment for long term construction expenditures which capitalizes interest costs when such projects become useful and enter the utility rate base. During the construction period AFDC expenses must be underwritten by external capital, and they are treated as current income for interest coverage ratios (51). Since AFDC is not backed up by income producing assets, it represents a risky type of borrowing. Solar investments, because they have short lead times will not require AFDC. The impact of the lead time risk can be measured by looking for discounts on utility stock prices which reflect market evaluations.

Two recent studies have attempted to estimate this effect by looking at the determinants of the market to book value ratio of utility stock. Fitzpatrick and Stitzel (52) found that AFDC has a statistically significant negative impact on the market to book value ratio. This factor became significant in their model starting in 1972 when AFDC represented roughly 25% of net income in the electric utility industry. The results of Burkhardt and Viren (53) are more ambiguous They did not find AFDC a statistically significant determinant of the market discount. However, several of their significant variables such as bond rating and regulatory ranking are correlated with AFDC.

A more aggregate measure of utility financial risk is the beta-co-efficient of the common equity. Beta is the main parameter of the capital asset pricing model (CAPM). Basically beta measures the volatility of a security return in comparison with the capital market in general. The more that retunrs on a given security fluctuate in response to macro-economic movements, the higher a value of beta. The basic theory underlying this point of view is an equilibrium analysis of capital markets postulating risk-averse investors. As originally formulated by Sharpe (54) and Lintner (55) this beta parameter is just a regression co-efficient. As such one cannot easily disentangle effects such as lead time and demand uncertainty or AFDC from other factors. Nonetheless, beta does seem to be positively correlated with utility rate of return (56). As yet there is no model which has plausibly linked such fundamental determinants of beta as lead time and forecast uncertainty to measured values of this co-efficient.

Rosenberg and Guy (57) have presented a rather general framework for such an approach, but detailed model building has yet to be attempted.

CAPM AND ENERGY PROJECT EVALUATION; When the risk of energy projects is evaluated for technologies that are not in widespread use, the analyst will typically look only at the variance or uncertainty of return on investment associated with certain assumed engineering parameter values. Manri and Fujita (58), for example, use Monte Carlo simulation to analyze the trade-off between risk of engineering-economic failure versus the potential for large gains in the design of solar thermal power plants. English et al (59) use portfolio techniques to analyze the risk of various combinations of synthetic fuel plant demonstration projects. Although these authors are aware of economic risks originating outside the engineering processes themselves, their portfolio model is confined to a purely static and technical formulation of these factors. Thus construction and labor cost escalation or construction schedule slippage are treated as engineering uncertainties, not as fluctuating economic forces impinging somewhat randomly on the project returns. This point of view is reasonable for projects where major technical uncertainties exist. But for the purpose of assessing market penetration of "commercializable" technologies, it is the financial not technical risks that dominate.

In simplest terms the financial risk of an energy project is or should be reflected in its discount rate. The more uncertain the return on the project, the higher should be the fixed or capital charge associated with it. Using some fixed average cost of capital to compare the value of competing projects for a given actor obscures the differences among projects in the firm's portfolio of investments. The measure of financial risk which is most useful for this purpose is the beta co-efficient of the CAPM. Although originally introduced as a way to understand the valuation of securities, CAPM and the beta measure have been extended to project valuation. In this paradigm, the risk, i.e. the project beta, sets the "hurdle-rate" for accepting or rejecting a project. This amounts to setting the discount rate endogenously rather than exongenously. These extensions of CAPM are described from the financial viewpoint by Mossin (60) and from the perspective of engineering economics by Bussey (61).

There has been relatively little published literature on the use of CAPM techniques in energy project evaluation. A recent survey of industrial investment analysis found that probabilistic risk assessment techniques with variable hurdle rates were in fairly widespread use (62). The CAPM is growing in importance within this kind of analysis. The most interesting result of the survey study was the finding that many industrial firms view energy conservation investments as less risky than their "mainstream" investments and consequently subject them to lower hurdle rates than the average cost of capital to the firm.

Kahn and Schutz (63) reached a similar conclusion in their analysis of the financial risk associated with utility investment in on site solar. This study found significant differences in the financial risk of utility projects. Long lead time projects appear to be increasing the entire risk structure of industry (64). On-site solar investments for space and water heating however face relatively little elasticity of demand, unlike other markets for energy. There is little reason to believe that the revenue generated by these investments will exhibit the "beta" type risk. That is, regardless of macro-economic fluctuations, people will use heat and hot water, paying their utility bill (or its substitute) for these services. The utility has a lower default risk in financing on-site solar than other agents because it has the ultimate lever, disconnection. Thus solar investments will diversify a utility's portfolio of investments because that portion of the total cash flow will be relatively certain. This is an insurance benefit, in effect, and should be reflected in a lower than average discount or capital charge rate.

The social price of this benefit to the utility is increasing its market power. This could be a net social cost, because utility investment in on site solar could structure the vendor market in a way that would reduce competition. This danger must be assessed by the regulatory agenecies who will ultimately make policy in this area (65). Nonetheless, Schmalensee (66) argues persuasively that any scheme which accelerates the use of solar technology will reduce competition. Policy choice may amount to deciding how that should be done.

Finally, not all solar technologies would appear to have the low financial risk of solar heating. Although the lead time risk can be expected to minimal in all cases, the uncertainties associated with energy availability from wind and solar devices can become important with large market penetration of these technologies. Energy systems which depend strongly on intermittent output could produce the kind of market risk measured by the beta parameter of CAPM. In short the economy might become sufficiently dependent on fluctuating output resources, that correlation of economic activity with meteorological changes is non-trivial. It is difficult to estimate this effect, but the logical possibility cannot be ignored.

Reliability Critera

The previous discussion has emphasized technical aspects of energy reliability from wind and solar conversion devices. There is, however, an equally important economic aspect of reliability. Reliability of power supply costs money for back-up capacity (reserve margin). Wind and solar energy are more economically competitive at lower standards of reliability. Since the seminal article by Telson (67) there has been increasing interest in the proposition that current criteria for power reliability may be uneconomically high. Indeed in 1976 the New York Public Service Commission (68) adopted a standard of eight days in ten years instead of the traditional one day in ten years loss of load criterion. This decision was based on a finding that the lower reliability level was cost-justified. It was noted, however, that such a change would have no practical impact for five years due to slow demand growth and construction in progress. During that period the Commission is open to changing its policy.

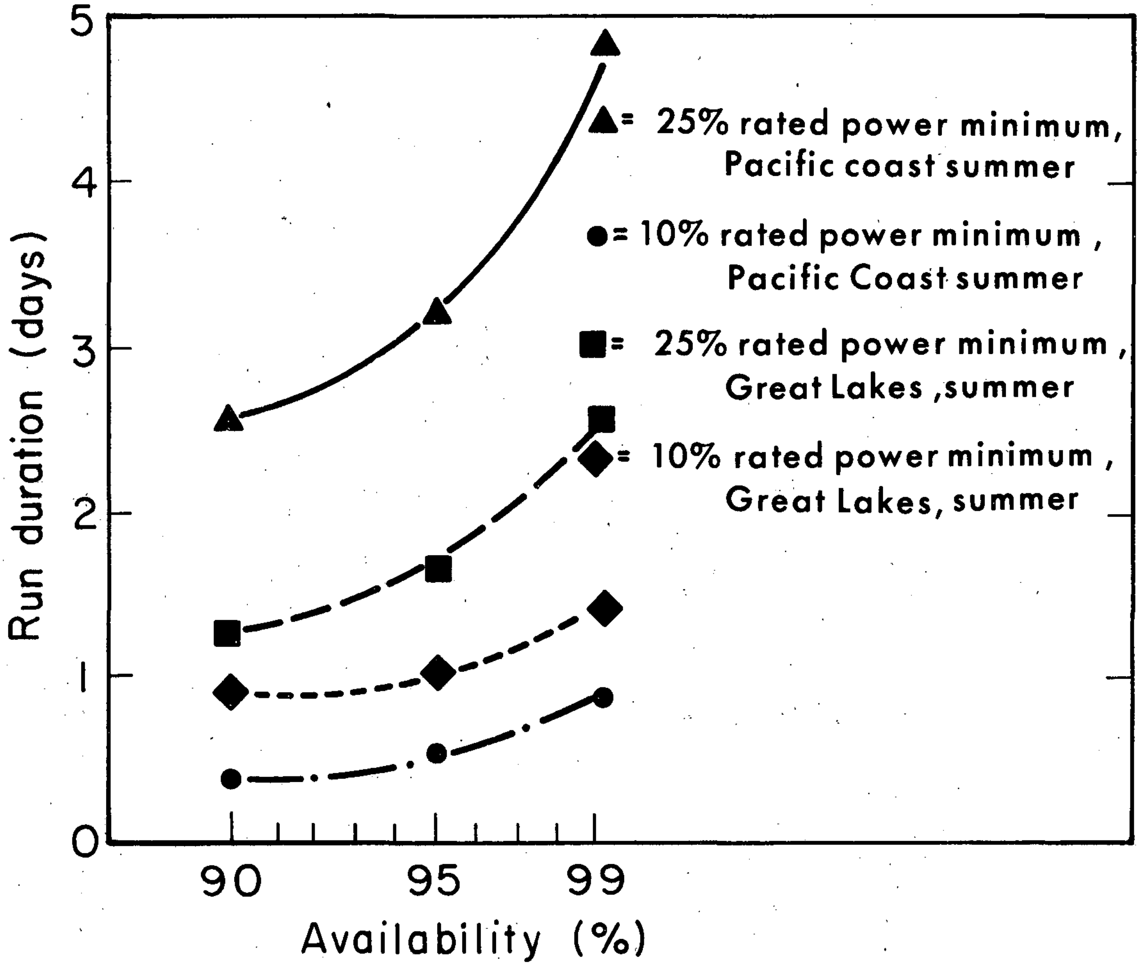

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Fig. 9 Wind Power Lulls vs Expected Power Availability

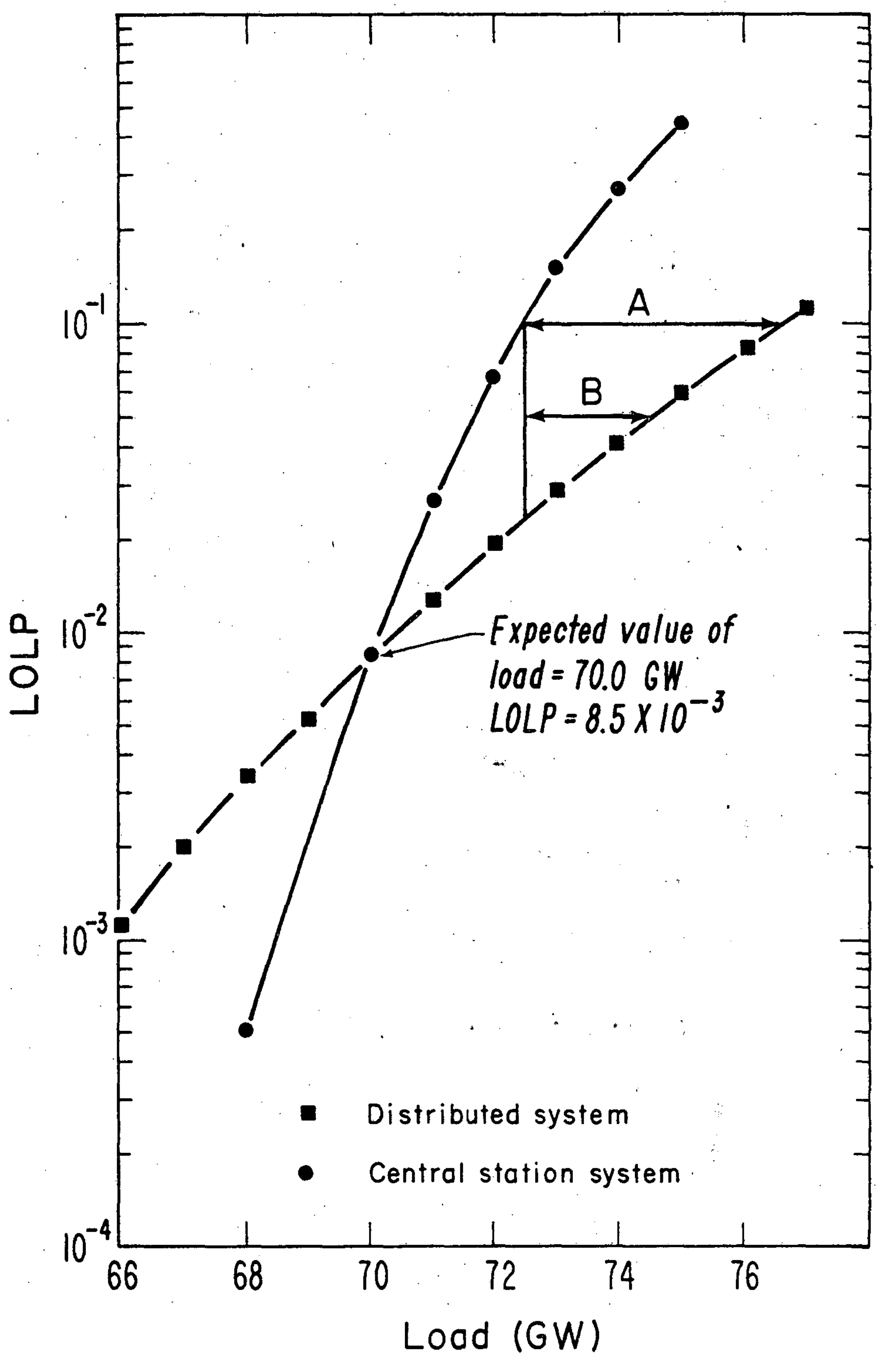

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Fig. 10 Risk Structure as a Function of Technology

These issues are complicated in many respects, not the least of which is formulating a clear definition of reliability. For the purpose of this discussion reliability refers only to the generation system. The 1977 blackout in New York City, for example, did not result from lack of reserve capacity, but from failures in the transmission system and power control center (69). Even within the generation system itself there are a variety of indices measuring reliability (70) What is generally lacking is a common language for both the engineering measures and an economic evaluation of cost and worth. This is a theme that will emerge from the subsequent discussion. Before exploring this theme, it will be useful to review some evidence on the relations between reliability criteria and the economics of wind and solar energy.

LOWER RELIABILITY STANDARDS FAVOR WIND AND SOLAR; The evidence for the proposition in this section's title is clear-cut for wind generators. Justus, for example, has calculated data showing the expected length of wind power lulls from array configurations parameterized by a probabilistic availability (20). This is shown in Figure 9. This figure shows for example that if 25% of array rated power is expected to be available 99% of the time, then the average lull would last 4.9 days in the Pacific Coast region and 2.6 days in the Great Lakes. If availability is desired only at the 90% level, the expected lull drops to 2.6 and 1.3 days respectively.

These data show that wind power availability improves in an absolute sense with a relaxed reliability criterion. There is an equally interesting comparative problem. How does the reliability criterion affect the relative reliability of wind power versus conventional plants? An answer to this kind of question is illustrated in Figure 10 taken from Kahn (71). This figure shows two risk curves, one for a system dominated by wind generators, the other for a system dominated by central station power plants. The curves intersect at a point corresponding to the "one day in ten years" criterion for loss of load probability. (LOLP). Extending these curves up to the level of LOLP corresponding to roughly one day in one year, we find that the wind based system can carry more extra load for the same risk compared to the central station system. The line segment A is one measure of the additional extra performance. For technical reasons, the actual benefit should probably be measured by the line segment B.

The basic point illustrated by Figures 9 and 10 can also be expressed in the language of reserve margins. In a Westinghouse study of photovoltaic performance (72), the sensitivity of reserve margin to reliability criterion was analyzed. The authors found that 400 MW of photovoltaic capacity reduced margin requirements in the two-axis tracking configuration 142 MW at reduced reliability compared to only 127 MW of standard reliability. The size of the effect here appears smaller than in the wind case. Aerospace Corp., on the other hand, found that reduced reliability criteria did not reduce the reserve requirements for photovoltaics (73). This result is somewhat anomalous, but its formulation is sufficiently ambiguous technically so that it is difficult to accept it at face value.

THE WELFARE ECONOMICS OF RELIABILITY; Economists have shown increasing interest in the welfare economics of reliability. Because the problem is difficult to formulate, however, results have been ambiguous and difficult to apply practically. One line of approach is to treat reliability as a "quality" of the product delivered, whether that product is energy, communication services or transportation. An illustrative treatment is the formulation of Spence (74). He shows that unregulated monopolists will set the level of quality below the socially optimal level because of profit maximization. Rate of return regulation will create a tendency in the opposite direction, at least in those cases where quality is capital intensive. This tendency is basically due to the bias toward capital that is induced by rate of return regulation. This bias was first described by Averch and Johnson (75). Induced capital intensive reliability may or may not be socially optimal. The difficulty lies in determining the value of this quality to consumers. This valuation problem requires both specification of a rationing scheme and a characterization of the welfare losses to those curtailed.

If this were not complex enough already, the problem grows larger when risk and uncertainty are added as essential elements. We have discussed the financial aspect of risk in the previous section from a fairly concrete point of view. In the welfare setting, risk and uncertainty complicate the search for optima. One line of inquiry has postulated the creation of a market in reliability, to sell electricity as if it were also insurance (76, 77). Although these authors show that welfare optimality result from such arrangements, there are formidable problems associated with implementing a market for service reliability. Not the least of these problems is the "income effect", those who can least afford to pay may well bear the burden of the inconvenience.

A more modest line of inquiry is directed toward the analysis of pricing choices under uncertainty (78 -80). Here the uncertainty can be interpreted as a reliability problem (78), although essentially this literature is addressed to the peak-load pricing problem. Of practical interest in this literature is Dansby's result that physical load management devices are superior to pricing mechanisms in maximizing utility corporate profit and minimizing service interruptions (80). The argument here, essentially that price incentives produce responses with more variance than physical control, may not carry over when engineering parameters are integrated into the simplified formulation of technical behavior.

EMPIRICAL LITERATURE ON THE VALUE OF RELIABILITY; The welfare economics literature is generally quite removed from both the engineering aspect of reliability and empirical measures of the value of availability. Precise definition of reliability, however, cannot be avoided when reviewing studies of its value in different settings. For conceptual purposes it is useful to classify the different events that might come under the general heading of power outage. Capacity deficits can refer to either acute or to chronic situations. A chronic condition in turn may be thought of as a persistent shortage which can be planned for by explicit rationing or as a stochastic condition of recurring random outages. In the acute category, we may think of either of single catastrophic blackouts or temporary but not radical shortage in capacity. Empirical measures of the cost of outages must include a characterization of the event studies.

There is a survey literature (81 - 84) which is addressed primarily to short-term outage events. Users are asked to quantify their "costs" during planned and unplanned outages as a function of how long the outage lasts. The time scale ranges up to one day, perhaps even a week. The most interesting conclusion of the few published surveys is the wide range of variation in outage costs. Most discussions of the value of reliability express this as an average dollar per kWh not supplied. These averages, however, mask a collection of cases where losses were either severe or minimal. For example, the IEEE survey of outage costs in commercial buildings (81) found that in their sample of 13 large office buildings the one hour cost per kWh lost ranged from \$100 to \$0.16. The average value was \$16.16. Clearly some buildings are more vulnerable than others, but we know relatively little about what accounts for the large differences in impact.

Some other qualitative conclusions emerge from these surveys. Large industrial users seem less vulnerable to power outages than small industrial users (83, 84). Perhaps the former have more flexibility. Ontario Hydro found that planned outages were easier to adapt to than random failures, also a plausible conclusion (83). The IEEE survey on commercial building outage costs (81) looks only a electricity-intensive structures that are not representative of this whole sector. Yet this is the only survey that is currently available. The survey approach, however, is not particularly suitable for residential customers. They do not have a cost accounting structure that can easily be used to quantify losses due to outages. For these users the problem is more difficult to conceptualize.

One approach to the study of outage costs for non-business users is a recent analysis of the 1977 New York City blackout (85). Indirect or social costs of the blackout are estimated. These include insurance costs, public health expenses and other costs incurred by public agencies in coping with the ensuing civil disturbances. Moreover, the new capital investment by Consolidated Edison in response to criticism of their performance is counted as an indirect cost. To call these latter expenses part of the value of reliability, however, is a conceptual leap unjustified by the authors. The cost of system re-inforcements might also be called the price of poor planning and operation.

The New York case is extreme. Looting and arson are not inevitable consequences of outage events. The more likely indirect consequence of reliability degradation is economic loss due to reduced economic activity. This perspective is oriented less to the single catastrophic outage than to chronic outages or temporary rationing. Industry may decide to re-locate from such a region or reduce its planned activity. There have been some studies of this effect (86 - 89). To quantify these effects, impacts must be aggregated to the point where the fine detail of the surveys and case studies is lost. These aggregated studies typically use asympototic values of cost per kWh lost that are much lower than what is found in the survey literature. Nonetheless, the usual conclusion of such studies is that the net costs of outages or rationing is high.

Were these studies sufficiently convincing, the interest in reliability criteria would not be so great. The matter would be settled. The more reliability the better. That this is not the case indicates that these aggregated approaches rely excessively on averages. There are users with significantly lower reliability requirements than average. This market is relatively unexploited. We do not know the size or structure of the market, however, and that is what lies behind the aggregated valuation approach. This conventional approach to reliability appears to be a barrier to certain applications of wind and solar energy. What is needed is a more detailed analysis of the range and structure of end-user reliability requirements. In the final part of this discussion we will return to the engineering language to pose a further, more subtle valuation problem for the economist, the pricing of different kinds of failure.

RESILIENCE: A QUALITY OF FAILURE MODES The economic literature typically ignores the kinds of differences in supply technology that have concerned us here. The special availability characteristics of wind and solar energy produce a structure of risk that differs strongly from what is typical with conventional technology. Figure 10 gives one indication of this difference. The risk curve for conventional technology is more peaked; it rises more quickly and steeply than for the distributed, i.e. wind-based system. The implications of this difference are further illustrated in Figure 11, also from Kahn (71). Here we show the impact of unusual or extreme circumstances on the risk structure. These extreme conditions are modelled as extra variance or uncertainty. The figure shows that exogenous, unplanned risks have a smaller impact on the wind energy system than on the conventional one. Analytically it doesn't matter if we think of these uncertainties as supply side or demand side phenomena. What is important is the greater ability of one system to absorb risk.

This property has been called resilience by Lovins (90), and it appears in the control-theoretic literature in power systems (91). The results of Ryle on wind turbine unit size are analogous. In that case the absolute reliability of the small wind turbine system was not better than the CEGB system in the extreme period studied, but the degree of failure was superior. Instead of failing by a drastic shortfall from the design criteria, the resilient system minimizes the impact of extreme conditions by failing relatively less than its over-designed counterpart. This property may be viewed as a kind of insurance, but one which is particularly hard to price.

Nonetheless resilience has important consequences. It means, for example, that exogenous uncertainties have less impact on the margin. In some sense this is because they have already been built into the

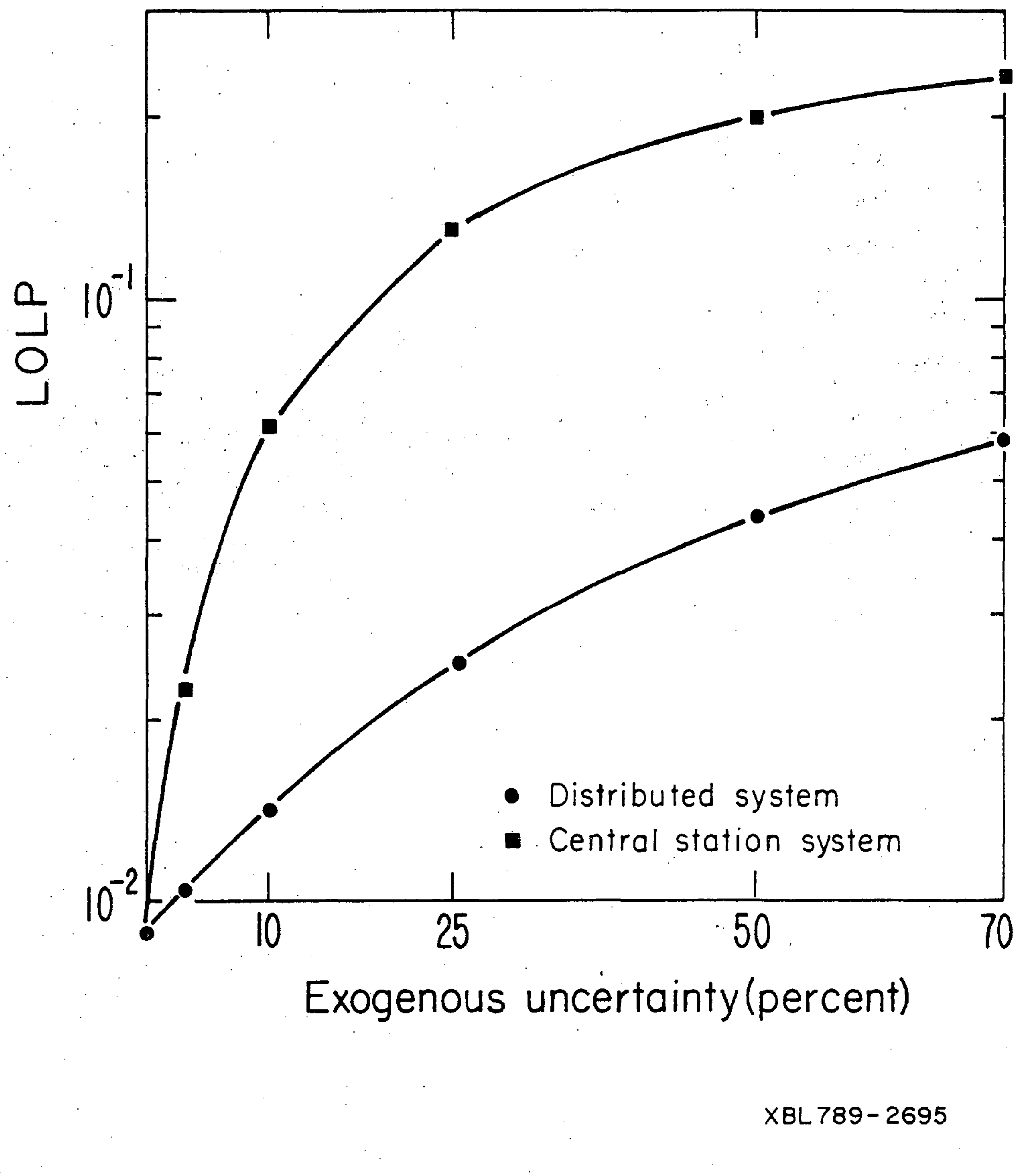

Fig. 11 Impact of Exogenous Uncertainty

system. Therefore the impact of the marginal risk goes down. Thus the difference with respect to risk between peak load pricing and physical load control that Dansby (80) found in a technically unsophisticated model will tend to diminish. This means in general that the pricing vs load management debate has a dimension of compatability or incompatability with given technologies. Needless to say conventional engineering economics has little to say on this subject.

We are left then with a research agenda, a list of unsolved problems. Some are empirical, some conceptual. We can expect some resolution of the factual uncertainties. More data and analysis will determine the extent and substance of the resilience property. Customer valuations of reliability will be refined. Once our knowledge is improved, however, it will ultimately be in the regulatory arena that policy strongly influencing the economic viability of solar and wind energy will be made. This review will conclude with a survey of the economic regulatory issues that will have to be decided.

Regulatory Structure

The electric utility industry is regulated at two different levels. Its financial environment is constrained by federal tax and energy incentive policies. These federal policies are often embodied in accounting procedures for depreciation of assets and investment tax credit (92). State regulation of electricity pricing and facility siting is a more severe constraint. In this arena every detail of the planning and power production process is, in principle, subject to regulatory control. Traditionally state regulation of the electric utilities had been limited to price setting activities, with only qualitative attention to service standards and utility investment decisions. The scope of state regulation has broadened in the last decade, however, to encompass both facility siting and basic planning issues such as forecasting demand, analyzing supply alternatives, etc. (93). In this last section, we will review the impact of regulation at the state and federal level on wind and solar compatability issues.

FEDERAL TAX POLICY In our discussion of financial risk, we presented the results of Willey (49, 50) which showed economic advantages to utility stockholders and ratepayers if conservation and solar investments displaced central station power plants in the utility portfolio. These results depend critically on a postulated equal tax treatment for the two types of investment. Under private ownership by individuals, solar energy is at an economic disadvantage because tax incentives are not capturable. Chapman has analyzed the impact of tax subsidies to conventional fuels and compared this to various subsidy proposals for solar energy (74). This analysis concludes that for homes to be occupied in 1985 in Southern California solar energy is more economically efficient than electric heating or Alaskan gas. Present tax and pricing policies, however, make the market costs appear greater for solar than these alternatives. Even the California 55% state tax credit only partially offsets the subsidies to conventional heating sources. These results will change, however, where the potential solar investor can depreciate his investment. Multi-unit apartment owners and commercial building owners can capture these benefits. In the case of commercial buildings, however, utility bills are deductible expenses for tax purposes. This will remove the incentive to invest in solar energy, since only interest on the financing will qualify for tax deduction.

RATE OF RETURN REGULATION: INVESTMENT BIAS There is a substantial literature on various biases built into the regulatory structure. We have already referred to the best documented of these, the bias toward excessive capitalization first formulated by Averch and Johnson (75) that is induced by rate of return regulation. There have been recent extensions of this literature to the case where uncertainty is an inherent and systematic feature of the regulated industry. Peles and Stein (95) find that where uncertainty is large and the monopolist is risk-neutral, then an anti-Averch-Johnson result emerges. There is a bias against capital because the monopolist is unwilling to risk the burden of incurring the fixed cost of capital investment. Only by allowing the rate of return to rise above the cost of capital will this "under capitalization" be ameliorated. Meyer (96) considers the case of a risk-averse monopolist. In this setting the Averch-Johnson effect operates in a socially beneficial manner; increasing the capital stock is a movement in the direction of welfare optimality. This literature then says once more that it is the attitude of the monopolist, or his regulator, toward risk that must be explicitly determined. Only with such a policy toward risk can the significance of rate-of return distortions be evaluated.

Wind and solar energy investment by utilities would be encouraged by a bias toward capital. These devices displace fuel with capital. The question remains, however, whether rate of return regulation will influence the rate and direction of such technical change. Magat (97) has examined this general question with inconclusive results. On a less theoretical level, however, there is a fairly widespread perception that utilities are and will remain hostile to these new technologies and are inappropriate users of them (97). The question of appropriateness really brings us back to the issue of scale economies. If wind and solar energy devices have no significanteconomies of scale (or even dis-economies) then the rationale for monopoly exploitation of these technologies will disappear. There is reason to believe that this may be the case for photovoltaics (98). There is also evidence of scale diseconomy for wind generators (large towers may not economically justify the extra energy captured (99)). The consequences of such an eventuality require special attention.

Finally the current environment of high capital costs and increasing marginal cost of new capacity militate against the Averch-Johnson effect. The combination of automatic adjustment for fuel costs and regulatory lag for capital costs creates a bias away from capital (40). This combination of circumstances can be seen as a particular embodiment of the Peles and Stein result. As conditions change, the bias toward capital may well re-emerge.

FREE ENTRY AND CREAM SKIMMING: REGULATION AND TECHNICAL CHANGE; The general subject of market-restructuring when technical change impacts a regulated industry has been analyzed extensively in the treatise of Alfred Kahn (100). The regulatory options in the case of solar energy have been well delineated by Noll (101). The most relevant analogues to our problem are changes in the telecommunications industry which occurred in the decade of the 1960's. In several cases decided by the FCC, AT&T was forced to share new facilities with competitors and make their own facilities available to these competitors for back-up and interface. From the monopolist's perspective allowing this kind of entry amounted to skimming the cream off the market and leaving the less profitable arena to the monopolist. In Figure 12 we give a graphic representation of de-regulation and market restructuring for electricity.

Figure 12 is a load duration curve segmented to represent a potential market re-configuration. There are two slices taken out of

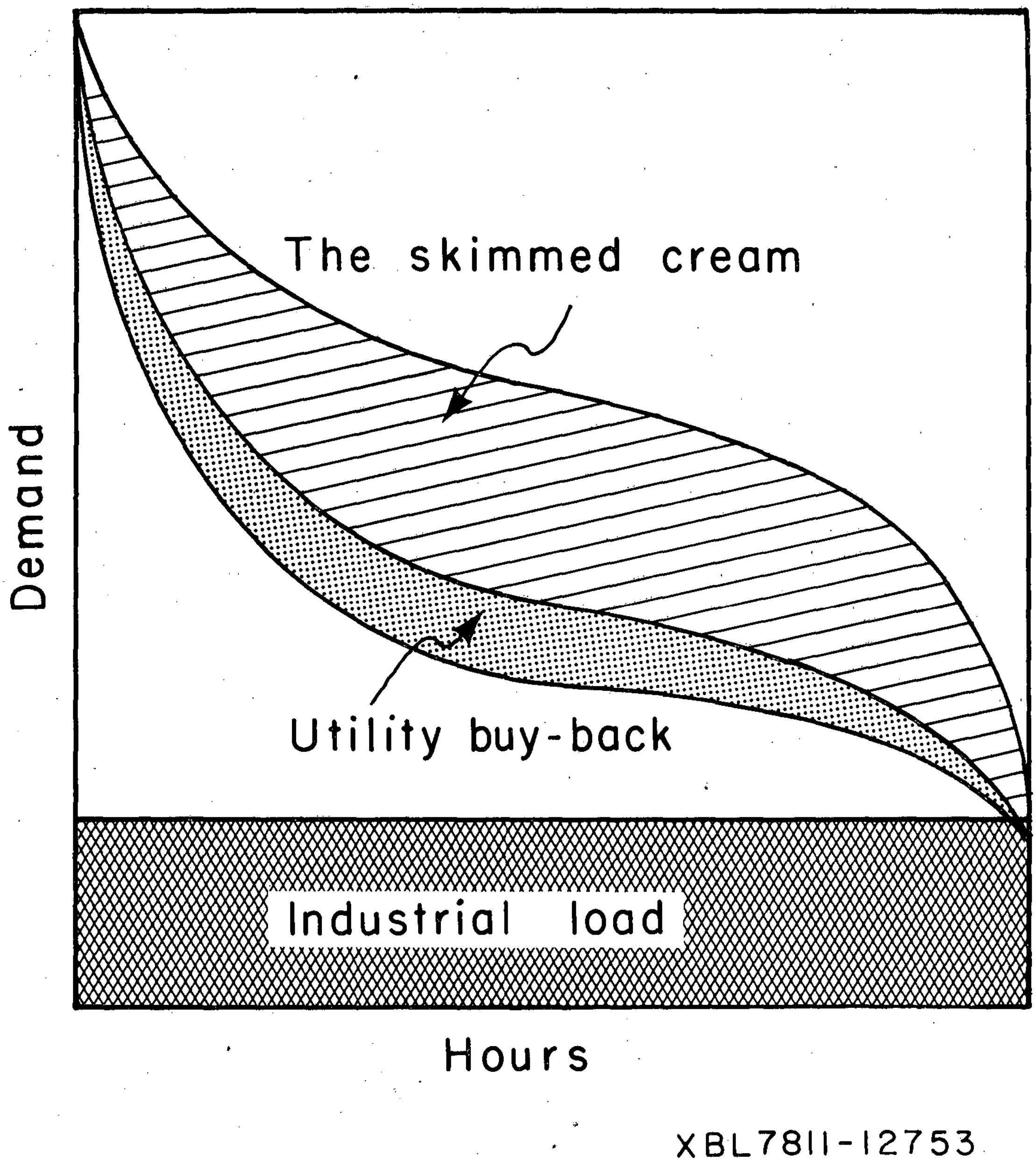

Fig. 12 Cream Skimming

the mainly variable portion of this curve which represent the impact of widespread, decentralized, low-scale wind and solar energy. Because of sizing economics and load mismatch it is anticipated that the utility will find it economic to purchase a modest fraction of energy from the decentralized producer. Figure 12 also represents a portion of the load duration curve that is fairly constant in its demands, an industrial base load. The industrial market is segmented because it should not be directly impacted by decentralized energy production assuming that industrial customers do not produce their own power. The remaining area under the curve represents back-up energy and the demands of non-energy producers. It will likely exhibit a very different cost structure than the original load duration curve. With a large peak and a diminished base, the utility's remaining demand structure ("the skimmed milk") would probably result in higher unit costs for that service than if the "cream" remained to lower average costs. This result would still be preferable to creation of entry barriers that would prevent capture of economies in the cream market.

Regulators will eventually have to face the pricing and entry issues associated with decentralized application of wind and solar energy conversion. Even if these technologies do not exhibit dis-economies of scale, their introduction may have potentially de-stabilizing impacts on the electric utility industry. In a stylized model, Panzar and Willig (102) have found that unrestricted entry may reduce the full product set without diminishing total average costs. These risks must be traded-off against the benefits of competition. This kind of policy choice will shape the market for wind and solar energy as much as the enegineering constraints of these technologies.

CONCLUSION

This review has inventoried a wide range of issues in the engineering-economics of wind and solar energy. The various effects of introducing these devices into conventional energy systems are only partially understood. The clearest conclusion to emerge from this survey is that our present analytic tools are rather limited in their ability to grasp the total problem. We can, however, classify the various issues discussed into those which are long range in nature and those which are of more immediate concern. In the short run, engineering issues involving resource assessment and appropriate scale seem particularly important. The more complex problems of structural optimality in energy systems only emerge in a longer range perspective. Economic analysis should probably concentrate first on financial risk. The economics of reliability criteria will only be understood when greater understanding of end use requirements emerges. Regulatory structure is an ongoing area where policy research will be fruitful.

The research directions reviewed here cross traditional boundaries of analysis. This is to be expected. Understanding new technologies capturing energy directly from the sun and wind will require new analytic tools. Compatability analysis will require a closer integration of engineering and economics than we have been accustomed to in the past.

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