Chapter V

THE RELATIONSHIP BETWEEN ONSITE GENERATION AND CONVENTIONAL PUBLIC UTILITIES

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BACKGROUND

The value of onsite energy systems cannot be addressed by examining their performance as isolated systems. While it is possible to construct onsite solar devices capable of operating with no connection to other power sources, it is seldom economically attractive to do so when other sources of power are available.

It is tautological that designing an optimum approach for providing energy in a given region requires that all equipment for installing and consuming energy be considered as components of a single integrated energy system designed to meet a fixed set of energy demands: maintaining building interiors at comfortable temperatures, providing lighting, supplying heat for industrial processes, etc. Any attempt to simplify the problem by considering the capabilities of components in isolation must result in a less efficient outcome. Moreover, it is likely that without taking this synthetic perspective, some critical aspect of the overall system will be neglected.

Performing this kind of analysis is difficult because of the complex and highly interdependent energy systems which have emerged over the past few decades, the variety of equipment which is currently in use, and the bewildering variety of devices now u rider test and development. This chapter provides a perspective on some of the major issues confronted in integrating onsite systems into larger systems for supplying energy and provides the basis for making realistic estimates of the cost of operating onsite equipment.

The design of an optimum energy network which includes onsite solar facilities requires choices in the following areas.

- How much of the backup energy should be supplied **from energy storage equipment, and** how much backup **energy should be supplied from convention l** energy sources? (This usually translates into determining **the opt i m u m size for onsite storage equipment)**
- Should conventional backup power be provided from electricity generated at a central generating facility or from fossil fuels burned onsite? (It should be noted that it is possible to use chemical fuels—oil, gas, alcohol, coal, etc.—to backup even solar electric facilities since a small emergency generator can be used when solar electricity is not available.)
- If electricity is stored, should it be in thermal, mechanical, or chemical form?
- Should the excess onsite energy be transmitted (in thermal, chemical, or electrical form) to a central or regional storage location or should it be stored where it is generated? (Energy generated at a centralized facility can be transported and stored in distributed storage facilities, and energy generated in distributed small facilities can be transported and stored in centralized storage facilities.)
- Should control over the onsite storage and generating equipment be exercised from a central point?

If it is possible to transmit energy inexpensively, overall energy costs can usually be reduced by connecting together as many energy consumers as possible. If onsite generating systems are not connected, each generating unit (solar plus backup) would have to be large enough to meet the peak demand of the building or industrial process which it is designed to serve. The load factors of individual buildings are usually very unattractive (see table V-1). Onsite load fac-

Table V-1 .—A Comparison of the Cost of Transmitting and Distributing Energy in Electrical, Chemical, and Thermal Form

Mode	Capacity	Capital cost	Efficiency	Load factor[1]	Operation and maintenance	Usable energy cost[2]
Electric transmission . (765kV, 500 miles)[3]	8.1×10^6 kW (3.25 lines equivalent)	$92/kW[4]	0.95[5]	0.7	$\$5.7 \times 10^{-4}$/kWh[6]	$\$5.2 \times 10^{-3}$/kWh[7,2]
Natural gas transmission ...... (30 inches diameter, 800 PSI, 500 miles)[8]	$8.1 + 10^6$kW (1 line)	$17.6/kW[9]	0.98[10]	0.88[11]	$\$3.8 \times 10^{-4}$/kWh[12]	$\$9.1 \times 10^{-4}$/kWh[13]
Electric distribution. . . (10,000 customers—residential/commercial)	5×10^4kW (17.2×10^3kWh per customer)[14]	$130/kW[15]	0.94[5]	0.4	$\$9.3 \times 10^{-4}$/kWh[16]	$\$9.0 \times 10^{-3}$/kWh[7] (Total electricity = 0.0142)
Natural gas distribution .... (10,000 customers—residential/commercial)	8.3×10^4kW (121 Mcf per customer)[17]	$50/kW[17]	0.98[10]	0.5	$\$3.8 \times 10^{-4}$/kWh[18]	$\$2.0 \times 10^{-3}$/kWh[13] (Total gas = 0.00291)
Hot water distribution........ (10,000 customers—residential/commercial)	7×10^4kW[19] (21.3×10^3kWh per customer)	$260/kW [19,20]	0.85[19]	0.35	$\$2.6 \times 10^{-3}$/kWh[21]	$\$1.8 \times 10^{-2}$/kWh[7]

NOTES:

1 A capital recovery factor of 0.15 is used to calculate annual capital charges.

2 Assumes a capacity of 2,500 MW for one 765 kv line.

3 Utility construction expenditures of $1,7 billion in 1975 for 3,762 additional miles or S461,000 per mile average. (*Statistical* Yearbook *of the Electric Utility Industry for 1975,* Edison Electric Institute, New York, N.Y , Oct. 1975.)

4 The 1970 *National Power Survey,* Federal power Commission, Washington, D. C., p.1-13-8, Dec. 1971.

5 Investor-owned electric utilities spent approximately $850 million on transmission O & M costs in 1975 for 1.5x10'Z kWh. *(Statistical Yearbook of the Electric Utility Industry for 1975).*

6 Assumes an end-use efficiency of 100 percent

7 *National* Gas Survey, U.S Federal Power Commission, Vol. 1, p. 34, 1975.

8 All natural gas companies spent $53 I million in 1976 for 1,845 miles of new transmission pipeline or $287,000 per mile average. (*1976* Gas Facts, American Gas Association, Arlington, Va., 1977).

9 Four percent of total natural gas consumed was used for pipeline fuel in 1976 This is equally allocated to transmission and distribution. (AGA Gas *Facts*).

10 *National* Gas Survey, U.S. Federal Power Commission, Vol. III, p.129, 1973.

11 All natural gas utilities spent $1 1 billion in 1976 on O & M for transmission for 148 trillion cubic feet (TCF).

12 Assumes end-use efficiency Of 65 percent

13 "Residential Energy Use to the Year 2000: Conservation and Economics," Oak Ridge National Lab, Report ORNL/CON-13, Oak Ridge, Term., Sept. 1977,

14 Investor-owned electric utilities spent S2.8 billion on construction of distribution facilities for 21,700 kW of new capacity in 1975. (*Statistical* Yearbook of the *Electrical Utility Industry for 1975.*)

15 Investor-owned utilities spent approximately $1.59 billion in 1975 for distribution O & M costs for 1.5x10'2 kWh. (*Statistical* Yearbook *of the Electrical Utility Industry for 1975.*)

16 Calculated from the average cost of S400 per customer (Private communication—American Gas Association) with an average hot water and space heating requirement of 36.4x10] kWh (121 MCF) per year and an assumed load factor of 0.4.

17 All natural gas utilities spent S1.1 billion on distribution O & M in 1976 for 14.8 TCF (AGA *Gas Facts*).

18 *See* volume II.

19 "Evaluation of the Feasibility for Widespread Introduction Of Coal into the Residential and Commercial Sectors. " Exxon Research and Engineering Co., Linden, N. J., Vol. 11, p. 6.11, Apr. 1977. These two studies give a construction cost of about S14 million for the size system in question, which requires a peak capacity of 70,000 kW, as shown by reference in note 20.

20 Annual O & M costs are calculated by assuming they are 3 Percent of capital costs, which is the average of the percentages for gas and electric systems.

21 The cost of energy lost in transmission was estimated using 0.04c/kWh for electricity y and 1.5c/kWh for thermal energy,

tors can be as low as 15 percent, while typical utility load factors are 50 to 60 percent. Moreover, each onsite facility would have to provide enough redundant equipment to achieve acceptable levels of reliability. If an interconnection is available, however, it is necessary only that the combined output of all generating units in the system be able to meet the aggregate peak demand of the region. The aggregate peak will be lower than the sum of the individual peak demands since individual peaks will occur at different times (this is usually called "diversity" in the demand). The advantage of the connection is magnified by the fact that most generating devices operate less efficiently when operated to meet an uneven demand. Interconnections also permit greater freedom in selecting generating and storage equipment (onsite and centralized facilities can be selected as they are appropriate), and it is easier to optimize the efficiency of the total system throughout the year by controlling the performance of each system in the network in response to the total load.

The problem of uneven loads is a particularly difficult one in the case of electric utilities since generating and storage equipment tends to be extremely expensive, although chemical and thermal transport systems can also benefit from balanced loads. It may prove feasible, for example, to pipe hot water generated in collectors located on a number of separate buildings to a central thermal storage facility, If this storage facility is large enough, collectors need only have an annual output large enough to provide for heating and hot water requirements and storage losses. Such systems may require less collector area per building unit than conventional solar heating and hot water systems using relatively small amounts of storage.

While connecting energy generating and consuming devices into a single energy network can lead to significant savings, the transmission and distribution systems required can be extremely expensive. The costs of several types of energy transport systems are summarized in table V-1. Comparisons of this type can be somewhat misleading because costs will vary greatly from site to site, but the table at least allows a crude ranking of alternatives. It indicates, for example, that transporting energy in chemical form is by far the least expensive approach. It is interesting to notice, however, that distributing energy in the form of hot water over distances of 1 to 2 miles is only about 30 percent more expensive than transmitting electrical energy over typical distances from generating facilities to consumers, In this comparison, no attempt was made to share the cost of the trench dug for the hot water pipe with potable water, sewer, telephone, or other lines which could be placed in the excavation, The electric distribution costs would have been significantly higher if buried cables were used.

ELECTRIC TRANSMISSION AND DISTRIBUTION

Electric transmission and distribution is an expensive undertaking. Over half of the capital invested by electric utilities in the United States is invested in a massive network of transmission and distribution equipment. In recent years, the ratio between capital investment in electric generating, transmission, and distribution equipment has fallen because of the rapid increase in the cost of generating plants [see table V-2), Each dollar now invested in generating equipment is accompanied by a 16-cent investment in transmission equipment and a 23-cent investment in distribution systems, The high cost of the electric transmission and distribution system is due in part to the fact that the lines have relatively low load

[1] *Statistics of Privately Owned Electric Utilities in the United* States, Federal Power Commission, 1974, p 40

Table V-2.—Construction Expenses of Electric Companies

	1965	1967	1969	1971	1973	1975	1977
Total Investment (billions of dollars)	4.03	6.12	8.29	11.89	14.91	15.09	19.50
Production equipment (%).	32.3	41.7	46.1	56.3	58.9	65,1	68.3
Transmission equipment	23.3	21.5	18.7	15.2	13.7	11.5	10.7
Distribution equipment.	39.4	32.3	29.2	23.3	22.6	18.7	15.7
Other	5.0	4.4	4.0	5.1	4.8	4.7	5.03

SOURCE. EBASCO 1977 Business and Economic Charts (Ebasco Services, Inc., New York, NY.)

factors. Hot water and steam distribution systems used for heating buildings typically have load factors of 33 percent (see table V-1).

The electric transmission and distribution lines now in place are typically 90-percent efficient, but it is hoped that improved technology will lead to overall efficiencies of 92.5 percent by the year 2000.[2] The improved efficiency, however, will most likely add to the capital cost of the systems. Gas pipelines are typically 90-percent efficient, the losses being due primarily to the fact that gas is withdrawn to run pumps in the pipeline.[3] No comparable information is available on the efficiency of hot water and steam transport systems. Losses are a strong function of the ground and fluid temperatures, the distances traveled, and the average size of the pipelines. Some recent steam distribution systems, however, have experienced losses on the order of 15 to 20 percent and have created serious difficulties for the systems relying on them.[4]

The cost of maintaining transmission equipment can also be substantial. In 1974, the cost of operating and maintaining the network of electric transmission and distribution lines owned by privately owned utilities in the United States exceeded the cost of operating and maintaining the generating facilities (fuel costs excepted).[5] Annual maintenance costs for a small hot water distribution system can amount to about 3 percent of the initial capital cost of the equipment.[6] Maintaining steam systems may prove to be significantly more expensive.

In addition to direct costs, transmission lines can have serious environmental consequences. It is estimated that over 3 million acres will be required for new transmission lines by 1990.[7] Much of this construction will occur in scenic areas where opposition is likely. In addition, it is possible that the large electric fields produced by high voltage transmission lines may be harmful. The question is being investigated and the results are inconclusive at this time.

[2] ERDA-48, Volume i, pp. B-10 and B-n, 1975.
[3] American Gas Association.
[4] American Public Power Association, private communication, November 1977

[5] *Statistics of Privately Owned Electric Utilities in the United States*, op. cit , pp. 35, 39,40, 42,43.
[6] W. R. Mixon, et al., Technology Assessment of Modular Integrated Utility Systems, Oak Ridge National Laboratory, ORNL/HUD/MIUS-25, pp 3-189 and 3-190.
[7] Thermo-Electron Corporation.

Table V-3.—District Heating Systems

District Heating Systems in the United States

	44 city systems	New York
Total steam sold (millions of pounds)	84,246	32,702
Total steam delivered to system (millions of pounds)	96,672	38,469
Annual system load factor	33%	37'A
Number of customers (in thousands)	14,903	2,514
Length of distribution system (in miles)	573	100
Installed air-conditioning (tons)	666,051	569,945

Note New York City has the largest American system, selling nearly 10 billion kWh per year The load Is 30 percent residences. 45 percent office bulldings, 11 percent industrles and 13 percent institutions.

SOURCE *Offlcial Proceeding,* 80th Annual Meetlng of the International District Heating Asscciation, June 1969, pp. 22-30, quoted on p 24 of ORNL-HUD-19, Ibid

District Heating Abroad

	Sweden (1973)	Denmark (1973)	W. Germany (1973)	U.S.S.R. (1971)
Energy sold for district heat (millions of kWh)	12	14	38	1,100,000
Units connected	600,000	30% of dwellings	83,000	75%

SOURCES I G C Dryden, *The Efficient Use of Energy*, IPC Science and Technology Press, 1975, p 359
Quoted In Teploengetika, Vol 18, No 12, 1971, pp 2-5
W Hausz, and C. F Meyer, Energy Conservation Is the Heat Storage Well the Key?" *Public Utilities Fortnightly* April 24 1975

THERMAL TRANSMISSION AND DISTRIBUTION

Most hot water and process steam is consumed close to where it is generated, but a number of cities have systems for distributing steam to residences and industries. In the United States, many older systems have been abandoned, and few new systems are being built. The Modular Integrated Utilities System (MI US) in Jersey City, N. J., is one of the few recent exceptions to this trend. The abandonment of steam distribution is due mostly to the overall decline of onsite generation. This tendency is reinforced by the fact that many older steam-distribution systems were not designed to return water to the generating plant, as the turbines operated on untreated water. This procedure became impractical with the addition of large, **high-pressure, steam-generating facilities requiring expensive water purification systems. Table V-3 estimates the capacities of district heating in the United States and abroad. On the other hand, district heating has been used much more extensively in Europe. For example, 30 percent of the residences in Denmark are connected to district heating systems. Sweden estimates that 70 percent of its multifamily units and 20 percent of its single family homes will be connected to district heating systems by 1980. West Germany plans to provide district heat to 25 to 30 percent of its dwellings by 1980,8**

[8] I G C Dryden (ed), *The Efficient* Use of Energy, IPC Science and Technology Press, 1975, p 358.

The feasibility of using district heating systems depends much on the density of dwelling units. A study conducted in connection with the MIUS project estimated that a garden apartment complex in the Philadelphia area (60 buildings with 12 apartment units per building) would cost about $410 per unit for heated water distribution and $330 per unit for chilled water,[9] A MIUS system was actually installed in Jersey City, NJ., for approximately this amount.[10] A preliminary estimate of the cost of a large district heating system capable of serving a community of *30,000* people in a mixture of apartments and single family units indicates that the cost per unit for this dispersed system would be nearly three times as great, The ability of a system to amortize these costs depends on the cost of the energy supplied and the yearly energy demand of each building. A rule-of-thumb applied until recently in West Germany was that a "break-even" housing density was one which required 44 MW_t/km^2 for existing urban areas and 28 MW_t/km^2 for new developments. Recent increases in fuel prices, however, have led them to consider areas with demands as low as 14 MW_t/km^2. The garden apartments in the MIUS study had a demand of approximately 30 MW_t/km^2.

[9] G Samuels, et al , *MIUS Systems Analysis, Initial Comparisons* of Modular *Sized Integrated Utility* Systems *and Conventional* Systems, Oak Ridge National Laboratory ORNL/HUD/MIUS-June 6, 1976, p 144

[10] Paul R Achenbach and John B Coble, Site *Analysis* for *the Application* of *Total* Energy Systems to *Housing* Developments.

[11] G.C Dryden, op cit , p 251

SALE OF POWER GENERATED ONSITE

METERING

No major technical barriers need to be overcome in designing meters for onsite energy equipment, but new types of meters may have to be developed for this purpose. If a utility owns onsite equipment with thermal output, some technique must be found for billing customers for the energy produced by the onsite device. One utility has suggested that the simplest technique would be to bill a customer on the basis of actual capital and maintenance costs, although meters capable of measuring the energy generated by solar thermal systems of various sizes are available.[12,13] An electric utility in Florida is using such Btu meters on solar hot water heaters installed under its auspices.[14]

The metering problems of onsite electric generating systems depend on the nature of the customer's relationship with the local utility, If the utility is willing to purchase energy at the same price as it sells energy to onsite users (or if it owns the generating equipment itself), it may not be necessary to change metering systems — because conventional meters can subtract from the net energy account when energy is being sold and add to the account when energy is purchased. This practice is currently permitted in several New England States on an experimental basis. " In cases where energy is sold at a different price from that purchased, dual meters will be required —with one ratchet to read sales to the customer and one ratchet to read purchases from the customer,

SAFETY

There could be risks associated with the installation of onsite electric-generating

[12] Philadelphia Electric Company in an interview reported in the General Electric study Conceptual *Design* and Systems Analysis of *Photovoltaic* Power Systems.

[13] For example, the Electron Advancement Corporation sells meters measuring 1400 to 1500 F water at flow rates of 30 to 100 gpm at a price of $400 to $500 (price list Feb 9, 1977)

[14] *Solar Energy Digest,* January 1977, p 9.

[15] Ben Wolf, Gemini Company, private communication, Apr 27, 1977.

equipment which would not automatically disconnect from utility lines when repairs are being made or when a utility line breaks in a storm or accident. As one utility put it, this "poses no problem for trained utility crewmen who treat al l lines as hot unless locally grounded The major problem can arise through exposure of laymen and children to potentially hot lines before repair crews arrive on the scene "[16] This problem can be eliminated if the onsite generating equipment is automatically taken off the line whenever the power fails. This is a standard feature in at least one design of small power-conditioning equipment now on the market.[17] The utilities Interviewed in the General Electric study indicated that any type of onsite equipment which did not incorporate such a feature could be fitted with a device al lowing the utllity to sever the connection with the utility distribution network through telemetry. Such units were estimated to cost about $100.[18] (The same units could also be used for interruptible service and for load management) It would be necessary for the utility to approve the onsite equipment connected to its grid in order to ensure that adequate safety features of this type were installed

QUALITY OF POWER FED BACK TO UTILITIES

There should be no difficulty in constructing equipment capable of providing power to utilities which meets utility standards of voltage regulation and frequency control.[19] One manufacturer of small inverter systems has sold 65 units which are integrated into utility systems, and quality of power has not been an issue 20

LOCAL DISTRIBUTION CAPACITY

One potential technical difficulty, identified in the General Electric study, is the possibility that onsite units which feed electricity back into the power distribution grld would exceed the capacity of the lines and transformers serving the area It is unlikely that onsite units would produce excess power for sale at a rate high enough to exceed the peak purchases of the onsite customer. There could be some problems in older communities, where distribution systems were installed without considering the possibility that a substantial number of residences might be equipped with al l-electric systems. A typical distribution system, however, should be able to accommodate the output of residential photovoltaic systems without major changes in transformers or lines.[21]

ECONOMIC DISPATCH

Electric utilities now control the scheduling of their generators via computer. This optimizes the efficiency of their entire system on a minute-to-minute basis throughout the day As long as a relatively small number of a utility's customers are using solar equipment which can generate electricity, no large-scale shift is necessary in current economic dispatch practices. 22 The net load to the utility would fluctuate throughout the day, but current equipment and management schemes are adequate to handle the relatively large fluctuations that already occur with daily cycles, local weather variations, and industrial energy consumption. The utilities interviewed by the General Electric Company indicated that special dispatch strategies would not be required, even if onsite generating devices were installed by 10 to 30 percent of their customers.

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[16] Pacific Gas and t lectric Company Interview publlshed ın General E lectric's photovoltaic study cited previously

[17] 'Alan W Wilkerson (President of Gemini Company), *Synchronous Inversion Techniques for Utilization of Waste Energy,* 1976

[18] "Conceptual *Design and S ystems Analysis of Photovoltaic S ystems,* General E lectric Corporation, Schenectady, N Y , Mar 19, 1977, pp 5-9

[19] "General Electric Company, op cit , pp 5-4

[20] Gemini Company, op cit

[21] "General Electric conceptual design study, pp 5-3

[22] "General E lectric conceptual design study

The Dow Chemical Company's examination of industrial cogeneration was "unable to identify any problems or potential problems of transient stability attributable to dispersed industrial generation. The effect of dispersed generation close to load centers is to improve system integration and stability problems."[23] However, if dispatching or system stability became a problem, the difficulty could be resolved by using the interruptible service devices discussed earlier. When onsite users were producing too much energy for a utility's needs, the onsite devices could simply be disconnected from the load. (The cost of this could be included in the $100 per unit cited for interruptible services meters.) It is also possible that economic dispatch of electric utilities could improve if a number of onsite generating facilities were equipped with sufficient onsite storage of a fossil backup system. Dispatch is not a problem for systems relying on chemical fuels for backup.

CONTROL

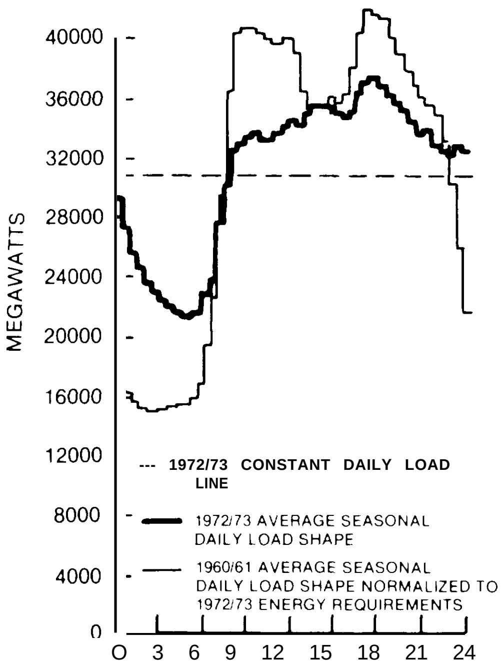
TIME-OF-DAY PRICING

Some of the advantages of connecting energy generating and consuming devices with a common energy transport system cannot be realized if control over the equipment is not exercised by a central authority capable of optimizing the performance of the integrated system. This control can be exercised directly by a utility if it owns all of the storage and generating equipment in a system, but it can be exercised indirectly by such approaches as time-of-day pricing. For example, with time-of-day pricing, the costs of nonoptimum performance of equipment not owned by the utility would be communicated to the owners of this equipment through higher prices for energy consumed for backup power and lower rates for any energy sold to the utility. The electric rates now in effect in most parts of the United States, however, do not have the effect of enforcing optimum al locations between onsite and centralized generating equipment. I n fact, many of the current rates tend to discourage onsite generation in spite of potential cost savings. (This problem is treated in chapter VI Legal *and Regulatory Issues.*)

Figure V-1 illustrates the dramatic change in electricity consumption in Great Britain which occurred after a time-of-day electric rate was imposed. Before the rate was introduced, very little electricity was consumed during the night and an enormous in-

[23] 'The Dow Chemical Company, et al , *Energy Industrial Center Study.* NSF Grant #OEP 74-2042, June 1975, p70

Figure V-1 .— Improvement in the Pattern of Electricity Consumption in England's South Western Electricity Board Resulting From a Shift to Time-of-Day Electricity Rates



Winter-average Weekday Load Curve

SOURCE
Ash bury, J G and A. Kouvalis, *Electric Storage Heating The Experience in England and Wales and in the Federal Republic of Germany'* Argonne National Laboratory, Energy and Environmental Systems Division A N LJES 50 1976 p 14

crease occurred in the morning when electric heaters and other equipment were turned on. After the variable rate was introduced, many consumers purchased onsite thermal storage devices which could be charged during the night and used to heat buildings during the day. The result was a much more uniform pattern of energy consumption.

STORAGE STRATEGY

Onsite solar electric devices integrated into electric utility grids provide a good example of some of the difficulties which can arise from local control over storage equipment, A solar electric system which is not connected to a utility grid would charge its batteries during the day and discharge its batteries during the night. This is precisely the wrong strategy of operation from the perspective of the electric utility since storage devices owned by the utility would be charged during the night, when demands are low, and discharged during the day when demands are greatest.

There will be some overlap between the two operating strategies since both types of storage would be discharging near sunset and during cloudy days, but it is clear that the storage equipment would be used to best effect if it were controlled by the utility. The advantage of using the solar electric devices to meet utility electric demands directly during the day (instead of sending it to be stored) is arnplified by the fact that storage devices are typically only about 75-percent efficient This logic would apply even if a very large fraction of the utility's energy were derived from solar sources, although in this case the strategy of operating individual storage systems would closely parallel the operation of utility storage. (A quantitative evaluation of this issue appears in the final section of this chapter,)

LOAD MANAGEMENT

The performance of isolated and interconnected energy systems can be improved if control is exercised over devices which consume energy as well as over energy storage and generating equipment. Clearly, energy consumers will want to exercise as much discretion as possible over the amount of energy they use and when they use the energy, but they also may be willing to change their consuming habits to some extent if they are required to pay large premiums for energy consumed during periods when energy is relatively expensive to produce. Consumers may be willing to postpone or defer the use of appliances such as dishwashers, disposals, clothes washers and dryers, and other equipment when electricity is expensive.

The utility can exercise control through the use of "interruptible service" equipment when onsite equipment includes onsite storage, Such devices would permit the utility to turn off water heaters and other appliances with storage capabilities during periods of peak demand. Equipment of this type has been installed for relatively large-scale testing by the Detroit Edison Co. If this equipment could ensure that onsite generating equipment (whether thermal or electric) purchases backup power only during off peak periods, the cost of backup energy to the onsite customer might be reduced — perhaps to the point where energy could be bought and sold at the same rate. An experiment was recently conducted in Vermont in which these appliances were automatically turned off when utility rates were high. The customers were able to switch them back on again, but in most cases were willing to wait until rates fell.[24] Well-insulated water heaters and freezers are able to operate effectively even if their supplies of electricity are automatically shut off during the day when electricity prices are high. Several cities in Germany have utilities which are able to exercise elaborate control over energy-consuming equipment The central load-management

[24] J G Ashbury and A Kouvalis, *Electric Storage Heating The Experience in England and Wales and in the Federal Republic of Germany,* Argonne National Laboratory, Energy and Environmental Systems Division, ANL ES-50, 1976, p 20

computer can control both the generating equipment and electricity-consuming devices. The computer sends a signal down the electric wires which automatically shuts off industrial equipment, refrigerators, water heaters, and other equipment where energy use can be deferred during peak periods. 25

As was the case with the control over storage, however, the strategy of deferring demand for energy will depend strongly on how the solar devices are connected with other energy equipment. If the solar device operates in isolation, an attempt should be made to shift all demands for energy to periods when the sun is shining, If an electric utility is used for backup power, however, it will usually be preferable to shift the demands which would require backup power to the late evening.

OFFPEAK ELECTRICITY

It is sometimes argued that electric utilities will be able to sell "off peak" electricity at a rate which covers only the cost of operating a large "baseload" plant and the relatively inexpensive fuels which can be used in these plants. Such rates are possible, but they must be considered promotional since, in effect, they subsidize the price of electricity during the night by charging daytime customers for all other utility costs. These costs are capital charges on generating plants and transmission and distribution systems, the costs of maintaining the transmission and distribution lines, and all other overhead costs — including the added cost of maintaining dual meters for daytime and nighttime rates.

It is also important to recognize that there is not an unlimited supply of "off peak" power available in a given utility. There are many possible uses for the power available at night, in addition to storing heat for buildings. The power can be used to charge batteries for electric vehicles and in other industrial procedures which can be deferred to use night rates. The utilities may find that they require the "off peak" nighttime energy themselves to charge their own storage devices, if utility storage must be used as a replacement for the oil- and gas-fired generators now used to meet utility peaks. (The National Energy Plan places major emphasis on eliminating utility use of oil and gas.) And utilities must also make some use of off peak periods to maintain their equipment.

OWNERSHIP

The complex rates required to encourage design of onsite equipment best suited for the energy network of which it is a part, would, of course, be obviated if utilities owned the onsite systems outright. While there clearly are disadvantages associated with expanding the monopoly position of utilities, there are a number of reasons for believing that utility ownership of onsite solar equipment may be attractive in many circumstances:

- Utilities are uniquely able to optimize the mix of generating and storage equipment in their service area and to develop control strategies for minimizing overall utility costs. (This could, of course, also be done by a company owning only transmission and distribution equipment,)
- Utilities compare the cost of energy derived from new solar equipment to the cost of generating energy from new electric-generating equipment or the marginal cost of gas from new sources, while all other solar owners must compare solar costs to the lower imbedded costs of energy which determine commercial rates.
- Utilities are probably better able to raise large amounts of capital for long-

" J G Ashbury, op cit , p 20

term energy investments than any other type of organization. As the statistics in table V-4 indicate, electric utilities require several times more capital per dollar of sales than typical industrial firms (although the capital intensity has declined rapidly in recent years because of the rapid increase in fuel costs) At the end of 1974, electric utilities owned approximately $150 billion in plants and equipment— nearly 20 percent of all business plant equipment in the United States.[26]

Table V-4. —The Capital Intensity of Major U.S. Industries
[Dollars of plant to secure $1.00 of revenue]

	$
Investor-owned electric companies:	
(1965)	4.51
(1970)	4.39
(1975)	3.20
(1977) (est.)	2.96
Bell Telephone System (1971)	2.95
10 major railroads (1971)	2.48
Gas transmission companies (1971)	2.43
Gas distribution companies (1971)	1.62
10 major integrated oil companies (1971)	1.25
500 diversified industrial companies (1971)	0.87
50 major retailers (1971)	0.43

SOURCES *National* Gas Survey U S Federal Power Commission Ebasco Services Incorporated (New York, N Y), *1977 Business and Economic Charts* p 28

An ability to raise capital for long-term investments is particularly critical for solar energy devices since solar energy is very capital-intensive and typically requires a number of years to return the initial investment. Utilities, therefore, may be uniquely able to provide initial capital for solar devices in situations where individuals (particularly individuals in lower income groups) and organizations may find the capital requirements prohibitive. Reverses in the stock market, uncertainties about the future of the energy industry, and difficulties in obtaining rate changes from utility commissions have, however, made it progressively more difficult for utilities to raise capital in recent years,

- Utility capital tends to be less expensive than capital required by more speculative industries. A typical utility can raise 50 percent of its capital from debt–while most manufacturers rely on debt for only 10 to 15 percent of new investment capital, the remainder of the capital being purchased at higher rates from investors, 27 Utility capital costs may, however, be higher than those experienced by homeowners and can be higher than the cost of capital available for financing typical residential and commercial buildings. A home owner earning a tax-free return of 10 percent on capital invested in solar energy equipment may be well satisfied. This advantage is moot, of course, if the individual is unable to raise any capital for the project at al 1.
- Utilities are already in the business of selling energy and have the required infrastructure for billing, marketing, and repairing equipment, Some potential owners of onsite devices have been wary of investing in equiprnent which might lead them to unfamiliar maintenance problems or the hiring of specialized personnel,
- Utility ownership or marketing of solar equipment and a willingness to stand behind the equipment once installed could increase consumer confidence in the equipment.

There is some ambiguity, however, about whether utility ownership of small solar energy equipment would be permitted by Federal antitrust statutes. The legal issues of

[26]Federal Power Commission, National Power Survey, *Financial Outlook for the Electric Power Industry. Report and Recommendations of the Technical Advisory Committee on Finance*, December 1974, p 50

[27]Paul J Garfield and W F Lovejoy, *Public Utility Economics*, Prentice Hall, Inc, Englewood Cliffs, N J, 1964, p 25

ownership are discussed in greater detail in chapter V 1, Legal and *Regulatory Issues.*

UTILITY ATTITUDES

There is no industrywide position either on the issue of onsite generation or on the question of utility ownership of such facilities, Industry attitudes vary company by company, and the diversity of attitudes is due, at least in part, to the fact that many utility companies simply have not taken a close look at the issue.

Natural gas utilities have expressed the greatest recent interest in onsite solar facilities since supplies of gas are diminishing and the companies are looking for new energy sources to replace natural gas in the future. Southern California Gas Co., for example, has tested solar-assisted gas heating for apartment buildings as one means of conserving supplies and extending the life of the company's resources .28 Interest is not confined to gas companies. A recent survey found nearly 100 electric utilities which were initiating projects in solar heating and cooling.[29 30] The Electric Power Research Institute has an extensive program in solar energy equipment.[31] At least one electric utility has entered into an agreement with a local installer of solar hot water heaters, and a gas utility has proposed changes in regulations that would permit it to operate as a combined gas and solar utility.[32 33]

On the other hand, most of the utility companies surveyed for a General Electric study referred to earlier said they were reluctant to enter the business of selling thermal energy systems. Some indicated that it would require too much diversification; others cited problems with metering and other technical difficulties.

A study conducted for the Federal Energy Administration found mixed opinions among utilities on expanding capacity by using conventional onsite generating equipment, primarily cogeneration systems in factories and other generators of process heat. Examples include:

- A west-south-central utility which sells both steam and electricity.
- A Pacific coast utility, which has installed turbines at a paper mill, returns low-temperature steam to the mill and pays $0,01 per kWh for the electricity generated.
- A Vermont utility actively searching for cogeneration opportunities.
- A Texas utility which stated flatly that they were "not in the business of selling steam, " and which turned down several opportunities.

Although utility attitudes may be changing, there have been scattered complaints that utilities have tried to thwart private companies intending to install onsite generating equipment. The Dow Chemical Co. reports that onsite industrial cogeneration "has been consistently discouraged by longstanding policies on the part of most privately owned electric utilities that have discouraged in every way possible the generation of electricity by any other type of organization. Relevant here are rate schedules

[28] Alan Hirshberg, *Public Policy for Solar Heating and Cooling,* October 1976, p 37

[29] *Solar Energy Intelligence Report,* Feb. 14, 1977, p 31

[30] Electric Power Research Institute, *Survey of Electric Utility Solar Projects,* Palo Alto, Calif , ER 321 -SR, 1977

[31] Electric Power Research Institute, *Electric Power Research Institute: Solar Energy Program,* fall of 1976, E PRI RP 549, 1976

"E S Davis, *Commercializing Solar Energy: The Case for Gas Utility Ownership,* mimeo, Jet Propulsion Laboratory report, California Institute of Technology, June 1976

"General Electric Corporation, conceptual design study.

[34] Dow Chemical Co , et al , *Energy Industrial Center Study,* June 1975, p 23

[35] Thermo Electron Corp., *A Study of /rip/ant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries,* June 1976

that favor large industrial users (whether justified or not by "cost of service"), and heavy demand charges (charges levied even if no power is used) that make it uneconomical to use the utility as a standby source backing up industrial power generation "'b

THE COST OF PROVIDING BACKUP POWER FROM AN ELECTRIC UTILITY

There is no easy way to compute the cost of providing backup power to an onsite system from a conventional electric utility since electric utility costs are very sensitive to the cost of equipment and fuels in the area being served and to the times when electric backup power is demanded. A simple technique for computing these costs is presented here to illustrate some of the major trends, to exhibit several different ways of looking at the major trends, and to exhibit several different ways of looking at the issue of rates. It must be emphasized from the onset that the method cannot be taken to be a precise calculation of the costs of electric utilities actually operating in the regions covered. The results are so sensitive to local conditions that each utility must make its own analysis of the costs. The following analysis shows that utility costs are extremely sensitive to four variables:

- The regional cost of equipment, the available financing, and the local cost of fuels;
- Local climatic conditions [for example, solar backup costs are lower if peak heating and cooling periods are correlated with periods of clear skies);
- The type of solar equipment installed (collector area, storage capacity, etc.); and
- The number of buildings in a utility service area equipped with solar energy devices (a relatively small number of solar facilities will contribute to load diversity, but a large number will reverse this result).

The details of the technique used to compute utility costs, and detailed assumptions made about the costs of equipment and fuels experienced by each utility, are described in detail in appendix A of this chapter, but the basic method is straightforward:

1. A "baseline" utility was constructed by combining the electric demands of a number of buildings and industrial processes using a mixture of energy-consuming equipment which was typical for the city under examination. The cost of providing electricity for the combined utility load was then computed, assuming that the utility was optimized to meet the demands. (Both the cost of energy attributable only to the generating units, the so-called "busbar costs," and the cost of energy delivered to customers were computed).
2. The cost of meeting a new set of electric demands resulting from adding a specified number of solar and nonsolar buildings to the utility was computed, assuming that the utility was optimized to meet the new demand pattern.
3. The effective cost of providing backup power for different types of buildings could then be computed by examining the incremental costs and the incremental utility costs which resulted when the new buildings were added,

Since it was assumed that all of the equipment in the utility was new, and the costs computed are all essentially marginal costs, the actual utility costs in the region would be lower because some fraction of the ener-

"Dow Chemical Co, et al, *Energy Industrial Center Study*, June 1975, p 23 gy would be generated from less-expensive, older plants. There are a number of other artificial ities in the technique:

- The choice of an "optimum" set of utility equipment does not use a detailed analysis of overall system reliability and maintenance schedules— it instead simply assumes that the utility will purchase 20 percent more in each generating capacity than the peak required in , that category to meet the load;
- Utilities will seldom be able to deploy equipment which is optimally suited to load patterns because of regulatory delays, an inability to precisely predict demands, and the need to use older equipment; and
- I t was assumed that none of the utilities evaluated owned storage equipment. In the future, utility storage devices may play a major role in replacing the oil- and gas-burning devices now used to meet real demands. The impact of storage on the cost of backup power for solar systems will need to be carefully examined. One would expect that low-cost storage would minimize the negative impacts of solar equipment.

This technique has been used to compute the cost of providing electric power to a number of different single family houses, and the results are summarized in table V-5. This table compares the cost per kWh of providing electricity to the building described to the cost per kWh of providing electricity to a similar building using an electric heat pump. All comparisons are between delivered costs. Greater detail on the utility costs and the capacity of equipment installed is presented in volume I I.) For example, the table indicates that the electricity required by a single family house using gas for heating, water heating, and air-conditioning in Albuquerque, N. Mex., costs the utility 2 percent more than the electricity used to provide power for a conventional single family house in the same city using a heat pump and electric hot water.

An examination of table V-5 reveals several features:

- Electricity for conventional houses using gas for everything other than fans and miscellaneous electric loads costs the utility approximately the same amount as electricity for a heat-pump house.
- Electricity costs are lower for houses using electric resistance heat (presumably because they use more electricity during periods of mild winter weather when utility demands are relatively low) and are higher for houses using gas heat and electric air-conditioning. (All of the utilities examined have peaks in the summer, and these peaks are increased by the added air-conditioning. But the added equipment is underutilized since the new houses do not use much electricity during the winter.)
- The houses using solar energy for heating and hot water and a heat-pump backup cost the utility more per kWh than the conventional houses using baseboard heat, but less than the houses using gas heat.
- The photovoltaic houses cost some what more than the houses equipped only with solar heating and hot water, but in no case is the utility cost significantly larger than the cost of providing backup power for a heat-pump house– in several instances, the utility costs are lower in the solar cases. The relatively favorable appearance of these solar systems results in part from the fact that some of the utility air-conditioning peaks can be reduced by the solar devices. (About 50 percent of the total building energy requirement is provided by the photovoltaic devices, and about 30 percent of the total energy requirement of the house is provided by the heating and hot water systems.)
- Utility costs per kWh of backup power delivered are increased slightly if sales to the utility are permitted.

Table V-5.—The Fractional Difference Between the Utility Costs [¢/kWh] Required to Provide Backup Power to the Systems Shown and the Costs to Provide Power to a Residence Equipped With an Electric Heat Pump [see note for explanation]

	Albuquerque	Boston	Fort Worth	Omaha
1. Single family house with gas heat, hot water, and alr-conditioning" . .	**0.02**	**-0.09**	**-0.15**	**0.03**
2 Single family house with gas heat and hot water, and central electric air-conditioning •.	0.26	0.28	0.15	0.32
3. Single family house with baseboard heat, electric hot water, and window air-conditioning"	– 0.14	-0.14	-0.15	-0.10
4. Single family house with solar heat and hot water backed up with a heat pump and electric hot water*	0.01	-0.13	0.06	-0.07
5. Single family house with extra insulation, electric hot water, and heat pump with:..				
a. Photovoltaic system with no battery and no sale to the utility	-0.06	-0.27	**'0.02**	**-0.07**
b. Photovoltaic system with no battery and sales to utility permitted, ...	0.07	-0.23	0.03	-0.01
c. Photovoltaic system with battery and no sales to utility.	-0.30	-0.27	0.01	-0.05

* Compared with single family house with electric hot water and heat pump.
"' Compared with single family house with extra insulation, electric not water, and heat pump,

NOTE: let C_r = Incremental utility costs resulting from adding 1,000 reference houses with heat pumps.
let K_r = the Incremental number of kWh generated when 1,000 reference houses with heat pumps are added to the utility
let C_t and K_t be the equivalent quantities resulting from adding 1,000 houses with a different kind of energy equipment
Then the fractional change *Illustrated* **above Is** given as follows: $F = \frac{C_t/K_t - C_r/K_r}{C_r/K_r}$

Table V-6 indicates the levelized monthly costs which would be experienced by consumers if they were charged electric rates reflecting the marginal cost of providing energy to several types of energy systems. Levelized costs assuming a moderate rate of increase in electric prices are shown for comparison. In these cases, it is assumed that an electric utility will purchase electricity from the onsite generating facility for 50 percent of the price at which it sells electricity. (In the cases when the electric price was assumed to be the marginal cost of providing backup — giving credit to the value of electricity sold to the utility— it was assumed that electricity is bought and sold at the same price.)

Except for Boston, the two techniques for computing levelized energy costs produce similar estimates of levelized energy charges. (It is likely that the techniques used to compute the marginal costs of electricity are overly optimistic about the costs of new

Table V-6.—Levelized Monthly Costs for a Well-Insulated Single Family House Showing the Effect of Marginal Costing for Backup Power

	Electricity rates assumed to increase by BNL forecast		Electricity rates reflect marginal utility rates (see appendix for methodology)	
	No credits given	20% ITC on solar equipment	No credits given	20% ITC on solar equipment
I. ALBUQUERQUE				
—no solar	183	183	204	204
—59 m^2 silicon photovoltaics, no batteries, no sales to the the utility	213(255)	202(246)	21 4(257)	204(248)
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	197(240)	187(231)	190(232)	179(223)
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	216(267)	204(257)	194(245)	181 (234)
II. BOSTON				
—no solar	300	300	215	215
—59 m^2 silicon photovoltaics, no batteries, no sales to the Utility	319(362)	308(353)	215(259)	204(249)
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	305(348)	294(339)	200(244)	189(234)
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	324(376)	311 (365)	227(279)	21 3(267)
III. FORT WORTH				
—no solar	190	190	191	191
—59 m^2 silicon photovoltaics, no batteries, no sales to the utility	228(272)	216(262)	227(272)	216(262)
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	218(263)	207(253)	212(257)	201 (247)
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	240(293)	226(281)	242(295)	228(283)
IV. OMAHA				
—no solar	211	211	219	219
—59 m^2 silicon photovoltaics, no batteries, no sales to the utility	241 (284)	230(275)	238(282)	228(273
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	231 (275)	220(265)	223(267)	21 2(258
—59 m^2 silicon photovoltaics, no batteries, sales to utility permitted	253(305)	239(294)	250(303)	237(291)

NOTES: (1) All houses use heat pumps for space conditioning and electric resistance hot water heaters
(2) Parenthesis ( ) indicates utility ownership.
(3) ITC = Investment Tax Credit

equipment in that region.) More importantly, however, the ranking of the levelized costs of the four systems appears not to depend on whether marginal costs or average costs are used to make estimates.

The same methods can be used to estimate the price a utility should be able to pay for electricity produced by an onsite device which exceeds onsite demands. This can be done simply by computing the difference in utility costs which results when a group of solar buildings is permitted to sell energy and dividing this cost by the total amount of kWh sold. The results are presented in table V-7 as a ratio between the value of the electricity available for purchase and the average cost of electricity generated by the utility. Since all costs in the utility used in this analysis are effectively "marginal costs," the onsite devices are

Table V-7.—Ratio of Price Utilities Can Pay for Solar Energy Generated Onsite to the Price Charged by Utilities for Electricity

	Albuquerque		Boston		Fort Worth		Omaha	
	Purchase base	Purchase reference	Purchase base	Purchase reference	Purchase base	Purchase reference	Purchase base	Purchase reference
1. Single family house with no onsite batteries	0.67	0.65	0.62	0.55	0.31	0.28	0.57	0.59
2. Single family house with onsite batteries	0.40	0.39	1.09	0.98	0.29	0.26	0.64	0.66
3. Single family house with extra insulation and no onsite batteries	0.64	0.62	0.58	0.49	0.66	0.64	0.50	0.50
4. High rise apartment with no onsite batteries	0.64	0.66	0.51	0.48	0.29	0.29	0.42	0.44
5. High rise apartment with onsite batteries	0.41	0.43	0.38	0.36	0.29	0.28	0.36	0.38

Let x = (utility cost supplying building not selling electricity minus utility costs for building selling excess electricity to the utility)

Let y = (kWh generated by utility in supplying building not selling electricity minus utility costs in supplying building selling excess electricity)

Let z = (added utility cost incurred in supplying building with no solar equipment) divided by **(added kWh required to supply the building)**

Let w = (total utility costs) divided by (total kWh produced by the utility)—no additional buildings

$$\frac{\text{Purchase}}{\text{Base}} = \frac{x/y}{w} \qquad \frac{\text{Purchase}}{\text{Reference}} = \frac{x/y}{x}$$

All utility costs are delivered costs

not given credit for the difference between the imbedded average utility costs used to determine selling prices and the fact that new solar systems will displace relatively expensive "new" generating facilities.

Table V-8 shows information for high rise apartment buildings which is equivalent to the data for single family houses shown in table V-7. It can be seen that the solar devices are less attractive to the utility in these cases, in part because the reference case chosen for the high rise building uses electric baseboard heating—which produces a more even load than the heat pumps used for the single family reference case.

As noted earlier in this chapter, the costs of providing electricity can be reduced if onsite storage is available at each building site which permits the building to purchase energy during periods when the demand on the utility is relatively low. Solar equipment, of course, is typically already equipped with a thermal storage device, and these devices can be converted to allow the system to purchase energy only during off peak periods with a relatively simple change in their control systems. The result of installing off peak storage devices in a number of different types of buildings is shown in tables V-9 and V-10. Chilled water can also be produced during the night and stored in tanks to reduce cooling loads during the day. The use of "off peak cooling" has the additional advantage of allowing the chilling equipment to operate at night when it is more efficient. In computing the load pattern, it was assumed that the storage devices are charged between midnight and 5 a.m. and that the amount stored is equal to the amount of backup energy for heating, hot water, and cooling which would have been required for the previous day with no off peak storage.

An examination of tables V-9 and V-10 shows that the savings to the utility can be considerable if off peak storage is used onsite. In the case of off peak storage of cooling, utility costs per kWh attributable to the house are reduced by nearly 50 percent. In all cases, the reduction in costs is lower if solar equipment is installed, but in many instances the difference is not very large. Typically, the utility cost per kWh to provide backup power for the solar houses with offpeak storage is about 10 percent greater

Table V-8.—The Fractional Difference Between the Utility Costs Required To Provide Backup to the Systems Shown and the Costs of Providing Power to a High Rise Apartment Equipped With Central Electric Air-Conditioning, Electric Hot Water, and Baseboard Resistance Heating
[see notes on previous table for explanation of how these fractional changes are computed]

Building equipment	Albuquerque	Boston	Fort Worth	Omaha
1. **Gas heat, gas** hot water, and gas air-conditioning	0	-0.11	-0.12	-0.05
2. Gas heat, gas hot water, electric air-conditioning	0.02	0.32	0.21	0.26
3. Electric hot water, electric baseboard heat, central electric air-conditioning, and a photovoltaic system:				
a. No batteries onsite, no sales to grid	0.27	-0.01	0.21	0.03
b. No batteries onsite, sales to grid allowed	0.31	-0.02	0.23	0.09
c. Batteries onsite, no sales to grid	0.28	-0.02	0.22	0.08
d. Batteries used onsite, sales to grid allowed	0.31	-0.02	0.22	0.08

Table V-9.—The Impact of Off peak Storage on Utility Costs
[fractional increase or decrease in backup costs per kWh–see notes]

	Albuquerque	Boston	Fort Worth	Omaha
Nonsolar houses				
• Off peak storage for heat and hot water	-0.37	-0.38	-0.29	-0.34
• Off peak storage for heat, hot water, and cooling	-0.47	-0.45	-0.48	-0.44
Houses with solar heating and hot water				
• No off peak storage	**0.03**	-0.11	0.12	-0.06
• Off peak storage for heating and hot water	-0.11	-0.24	0.003	-0.21
• Off peak storage of heating, hot water, and cooling	-0.30	-0.35	-0.32	-0.36

Notes The "reference house' is a single family house using electric resistance heating and hot water and window air-conditioners
All solar houses generate only heating and hot water from solar energy.

Let C_r = added utility costs resulting from the addition of 1,000 reference houses

K_r = added kWh resulting from the addition of 1,000 reference houses

C_t = added utility costs resulting from the addition of 1,000 test houses (type noted in left column above)

K_t = added utility costs resulting from the addition of 1,000 test houses

The fractional change ratio shown above is calculated as follows:

$$F = \frac{(C_t/K_t) - (C_r/K_r)}{(C_r/K_r)}$$

than the utility cost per kWh attributable to conventional houses with off peak storage.

It is apparent that the solar systems have more difficulty competing with conventional electric heating systems if the conventional devices use off peak storage and are able to buy electricity during off peak periods at reduced rates. There are, however, still a number of cases in the examples shown where solar devices are able to compete. Off peak storage equipment, while not as expensive as solar devices, can still be costly: they require the installation of heating (or chilling) equipment which is larger in capacity than conventional equipment by the ratio of 24 hours to the number of hours used to charge storage; with existing technology, heat pumps cannot be used to charge off peak heat storage and resistance heating must be used; and the devices require more sophisticated controls than ordinary heating systems. Another difficulty with storage of off peak electricity in the form of thermal energy to be used for space heating is that, in the climates examined in this study, the use of off peak storage led to a significant increase in the electricity consumed by each building—which would reduce the economic advantage to the building owner of using off peak storage. It must also be recognized that the costs shown in the tables implicity assume that an ideal "marginal rate" is charged in which the utility is able to charge each customer precisely the real incremental cost incurred by the utility in supplying that customer. In this sense, the costs represent a "best case" for off peak power. The rates also do not include additional charges which might result from additional metering and billing. The results may indicate, however, that in the long-run conventional electric utilities may prove to be poor choices for providing backup power to onsite solar installations.

Table V-10.—Levelized Monthly Costs for a Single Family House Showing the Effect of Marginal Costing and Buying of Off peak Power

	Electricity rates assumed to increase by BNL forecast		Electricity rates reflect marginal utility rates (see appendix for methodology)	
	No credits	200% ITC on solar & off peak equipment	No credits	20% ITC on solar & off peak equipment
i. Albuquerque				
—No solar or off peak buying:				
. Electric resistance heat. . . .	239	239	241	241
• Heat pump heat	204	204	229	229
—Solar only:				
• Low cost coils . . , ...	185(21 1)	179(205)	183(209)	177(203
Ž High cost	205(240)	196(232)	203(238)	194(230)
—Offpeak heating, & hot water only	N/A	N/A	185(205)	181 (201)
—Offpeak heating, cooling & hot water only.	N 1A	N/A	198(232)	189(225)
—Solar & off peak heating & hot water				
• Low Cost coils	N/A	N/A	177(207)	169(200)
• High cost coils	N/A	N/A	197(236)	186(227)
—Solar & off peak heating, cooling & hot water				
• Low Cost coils	N/A	N/A	194(242)	181 (231)
• High cost coils.	**N/A**	N/A	214(272)	198(258)
II. **Omaha**				
—No solar or off peak buying:				
• Electric resistance heat. . . .	**278**	278	278	278
• Heat pump heat	**250**	250	268	268
—Solar only				
• Low Cost coils	**252(282)**	244(276)	234(265)	227(259)
Ž High cost coils	**278(320)**	267(31 1)	261 (303)	250(294)
—Offpeak heating & hot water only	**N/A**	**N/A**	219(241)	21 4(237)
—Offpeak heating, cooling & hot water only.	N/A	N/A	237(278)	227(270)
—Solar & off peak heating & hot water				
• Low COSt Coils	N/A	N/A	221 (258)	211 (250)
. High cost colts.	N/A	N/A	247(296)	234(284)
—Solar & off peak heating cooling & hot water				
• Low Cost Coils	N/A	**N/A**	244(303)	228(289)
Ž High cost coiLs.	N/A	**N/A**	270(341)	250(324)

NOTE: Solar systems are thermal only; Houses are SF-3

Table V-1 O also shows that when contemporary rate schedules are used, it costs less to heat a single family house with a heat pump than with electric resistance baseboard heat. The difference in costs narrows considerably, however, if marginal costs are charged. The resistance system actually is less expensive if off peak storage is used in connection with the resistance heating. The disadvantages of heat-pump systems would be magnified if a large number of customers in the regions examined used electric heating and the utility peak occurred in the winter (both utilities examined have summer peaks). The heat-pump systems would be more attractive, if their performance were improved or a technique could be developed for storing off peak energy for use during periods when the heat-pump capacity is inadequate to meet the load; in current systems, straight resistance heating is used in such situations. Clearly, more analysis is required in this area.

BACKUP POWER WITH ENERGY SOURCES OTHER THAN ELECTRICITY

It was noted earlier that the cost of providing backup for solar equipment from relatively expensive electric-generating equipment may be so great that it would be preferable to provide backup by using seasonal storage systems or relying on gas I n fact, it has been suggested that electric utilities, with their high capital costs, are uniquely unsuited to providing backup for solar equipment.[37] Analysis presented in volume II shows that for large buildings (and for single family structures which can pipe thermal energy to a central storage site), solar heating and hot water systems capable of providing 100 percent of local requirements may become economically competitive with electric heating and hot water in many parts of the country in the relatively near future.

Table V-11 indicates some comparisons between gas and electric backup. In the gas cases, it is assumed that the system is not connected to an electric grid. Backup is provided by a small, 32-percent efficient engine burning natural gas to power a heat pump Electricity for lighting and other uses is provided from a generator attached to the heat-pump engine The table indicates that the gas backup alternative may be attractive even if gas prices increase drastically over the next few decades This possibility may make it interesting *to* consider the possibility of granting preferential allocation of gas to facilities using gas to backup solar facilities and permitting new gas hookups in regions where such hookups are now permitted if the gas is used as a solar backup

[37] Joseph G Ashbury and Ronald O Mueller, "Solar Energy and Electric Utilities Should They be Interfaced?" *Science*, 1954127, p 445 (1977)

Table V-n.—Levelized Monthly Costs of Several Kinds of Energy Equipment in a Single Family Detached Residence in Albuquerque, N. Mex. (dollars per month)

Gas price in 2000 (¢/kWh)	0.005	0.011	0.015	0.03	Percent of total energy usage supplied by solar energy
Electric price in 2000 (¢/kWh)	3	4.5	10	—	
Incentive	none	none	20% tax credit	20% tax credit	
1. Heat pump, electric hot water	156	203	395	—	o
2. Solar heat and hot water, electric heat pump backup					
—High	187(223)	213(250)	309(354)	—	28
—Low	158(1 83)	184(210)	284(315)	—	28
3. Extra insulation, 59 m^2 photovoltaics at $500 kW, electric heat pump backup					
—No batteries	169(207)	196(233)	294(338)	—	52
—20 kWh batteries at $70/kWh	190(228)	215(253)	303(349)	—	45
4. Gas heat and hot water, central electric air-conditioning	116	173	287	500	0
5. Solar heat and hot water backup, electric air-conditioning					
—High	172(21 O)	201 (239)	276(323)	422(469)	41
—Low	1 43(1 70)	172(1 99)	251 (284)	379(430)	41
6. Extra insulation, 50 m^2 photovoltaics at $500/kW, gasfired heat pump/generator backup	157(1 96)	177(21 5)	182(230)	203(277)	50
7. Solar heat with central seasonal storage, homes connected with hot water piping, electric air-conditioning in each house					
—High	21 4(292)	233(31 1)	290(383)	—	65
—Low	164(21 2)	184(231)	249(306)	—	65

Notes: All costs in 1976 dollars
( ) = utility ownership