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# Assessment of the Load Management Potential of the Annual Cycle Energy System

M. A. Kuliasha
W. P. Poore



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# ASSESSMENT OF THE LOAD MANAGEMENT POTENTIAL OF THE ANNUAL CYCLE ENERGY SYSTEM

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## SUMMARY

Detailed comparisons of the performance and customer economics of both full and partial Annual Cycle Energy Systems (ACES) and other residential space conditioning and water heating systems have shown the ACES to exhibit the highest energy efficiency of all electrically driven systems. The ACES also had the highest life-cycle costs for most regions of the nation because the high initial cost of ACES are not completely offset by the annual operating savings under current utility rate structures.

However, the ACES has a number of load characteristics that make it attractive as a load management tool for the electric utility. These load characteristics include no on-peak compressor operation during the summer, no resistance hot water heating, and no electric resistance heat necessary to supplement the heat pump in the winter. Because of these unique ACES load characteristics, the customer economics of alternate electric space conditioning and water heating systems would improve if the electric utility were to institute time-of-day rates, demand rates, other load management rates, or higher seasonal differentials in the summer.

This study evaluates the load management potential of the ACES from the perspective of the electric utility. The primary objective of the study was to quantify the revenue requirements to serve an ACES-equipped house as compared with a house having a conventional air-to-air heat pump and electric hot water heater. If the utility revenue requirements to serve an ACES-equipped house are significantly less than for other alternatives, rate structures that reflect actual cost of service would favor ACES and could change the economic ranking of alternatives.

Two utilities, Arkansas Power and Light Company (APL) and Duke Power Company (Duke), were selected for analysis based on climatic and utility system characteristics that appear favorable for the ACES concept. The two case study utilities were selected after a screening of regional characteristics to identify relatively broad (several state) geographical areas having climatic and generating system characteristics attractive for ACES. The selection criteria included five utility characteristics: load growth, reserve margin, peak season, average energy cost, and on-peak/off-peak cost differential. Four customer demographic criteria were also considered including residential growth rates, saturation of electric space

conditioning, necessity for air conditioning, and ratio of heating to cooling requirement.

Detailed analyses were made of generation expansion plans, system reliability, and production costs for various load growth scenarios and assumed penetrations of ACES, and the total revenue requirements were calculated for each case. The four scenarios investigated were (1) normal load growth and moderate ACES penetration; (2) normal load growth and high ACES penetration; (3) low load growth and moderate ACES penetration; and (4) low load growth and high ACES penetration. The revenue requirements developed for each of these scenarios were compared with those of a base case without any ACES involving either normal or low system load growth.

The energy use characteristics of an ACES house compared with a house having a conventional heat pump and electric water heater were found to have a beneficial effect on the system load profile. For example, the annual load factor for APL in the high ACES saturation, moderate load growth case improved from 53.3 to 56.3% in the year 2000 over the base case with no ACES houses. The load shape changes also resulted in a reduction in the annual peak from 6270 to 5726 MW. For the same case in Duke's service territory, the annual load factor would improve from 61.5 to 66.4%, and annual peak load would be reduced from 21,434 to 19,148 MW in the year 2000.

In response to the load shape changes attributable to ACES, the least-cost expansion plans for the various scenarios differed slightly. The lower peak load growth and higher annual load factors of the ACES scenarios as compared with the base cases resulted in the expected decrease in new capacity. This decrease occurred through changes both in timing and the total number of generating units built during the planning horizon.

The production costs for the APL scenarios showed a slight increase in total production costs with increasing ACES penetration. This result is attributable to the decrease in new capacity that is built under the least-cost expansion plan, which results in a larger portion of the load growth being carried by more costly gas- and oil-fired cycling units.

The production costs for the Duke scenarios showed quite different behavior. In general, the production costs for the ACES scenarios were slightly lower than the corresponding base case. The differences between the two utilities' results are explained by their respective generation mixes. Arkansas Power and Light has a substantial fraction of high-cost gas- and oil-fired generation. Consequently, delays in new coal and nuclear capacity result in load growth being served by these higher cost units.

Duke, on the other hand, is already predominantly nuclear and coal-fired. Consequently, no fuel switching is involved. In fact, higher daily, seasonal, and annual load factors allowed a greater portion of the load to be supplied by more efficient base-load units, resulting in the production cost savings.

The combination of capital cost and operating cost savings attributable to the energy use characteristics of ACES compared with the conventional alternative resulted in a net reduction in utility revenue requirements over the 20-year planning horizon for all cases. The net result of a 50% saturation of ACES in new single family houses with moderate system load growth in APL was a 0.707 mills/kWh decrease in total system costs in 1981 dollars. This corresponded to a system cost savings of $892 per ACES installation over the 20-year period.

The total cost savings for Duke were similar, ranging from $842 per ACES house in the low load growth, high saturation case to $1161 per ACES house in the moderate load growth, moderate saturation case.

Cost savings per ACES installation are less for lower system load growth rates because of the decreased opportunity for capacity deferrals.

The cost savings per installation also decrease with increasing saturation of ACES houses. This classic case of diminishing returns is a result of the nature of the system load profile and of utility marginal costs. The shape of the load profile is important because it determines the amount of load relief afforded per ACES installation. The load relief per ACES installation is the difference between the diversified demand of an ACES house and the diversified demand of a conventional house at the time of the system peak. As the number of ACES installations increases, there is a point where the time of the system peak changes. Thus the load relief per house is not constant but varies with penetration. For example, for the moderate load growth scenarios for Duke, the load relief per house drops from 2.97 kW at a 50% penetration to 2.63 kW per house at a 100% penetration.

The diminishing cost savings with increasing penetration of ACES houses are also related to the nature of utility marginal costs. Generating units are dispatched in order of increasing incremental costs. Once the load during the highest cost hours has been reduced, the next increment of load would have been served by a generating unit with lower incremental cost, and the cost savings of shaving that load are correspondingly less.

Although the study results have shown that ACES does have attractive load management characteristics whose implementation would result in cost savings to the utility, the magnitude of the cost savings are such that they are unlikely to offset the higher life-cycle costs currently estimated for ACES. The high first cost of ACES, at some $11,000 compared with approximately $3500 for a conventional heat pump and electric hot water heater, would not be significantly reduced even if the utility were to flow through the full cost savings as an initial subsidy. Consequently, unless the first cost of the ACES can be significantly reduced, its prospects for widespread commercialization in residential applications appear limited.

# 1. INTRODUCTION

## 1.1 The ACES Concept

The Annual Cycle Energy System (ACES) is the most efficient electrically driven heating, ventilating, and air conditioning (HVAC) system for providing space heating, water heating, and air conditioning to a building. The large energy savings provided by the ACES concept result from the use of low-temperature thermal energy storage and the interseasonal transfer of environmental energy.

The principal components of the ACES are shown in Fig. 1.1. In the heating mode, energy is transferred into the building by an electrically driven unidirectional heat pump that obtains heat from water stored in an insulated underground tank. As heat is extracted during the heating season, most of the water in the tank is frozen, and the stored ice provides air conditioning in the summer. Thus the heat of fusion of water provides a heat source in the winter and a heat sink in the summer. Because both the heating and cooling outputs of the heat pump are used at the same time, the annual coefficient of performance (ACOP) is very high.

In addition to supplying space conditioning, the ACES heat pump incorporates a desuperheater that uses a portion of the heat pump energy to provide hot water. Producing hot water by operation of the heat pump is more than twice as efficient as production by conventional resistance heating.

The energy efficiency of the ACES concept has been fully demonstrated in residential applications at a test facility near Knoxville, Tennessee. For example, during the 1978 to 1979 heating and cooling seasons, an ACES-equipped demonstration house near Knoxville consumed 51% of the electricity for heating, cooling, and water heating that an identically constructed house with a high-efficiency air-to-air heat pump system and conventional hot water heater consumed.[1]

Detailed comparisons have been made of the performance and customer economics of both full and partial ACES and other electric HVAC systems including (1) an electric furnace with a central air conditioner and an electric resistance water heater, (2) a high-performance air-to-air heat

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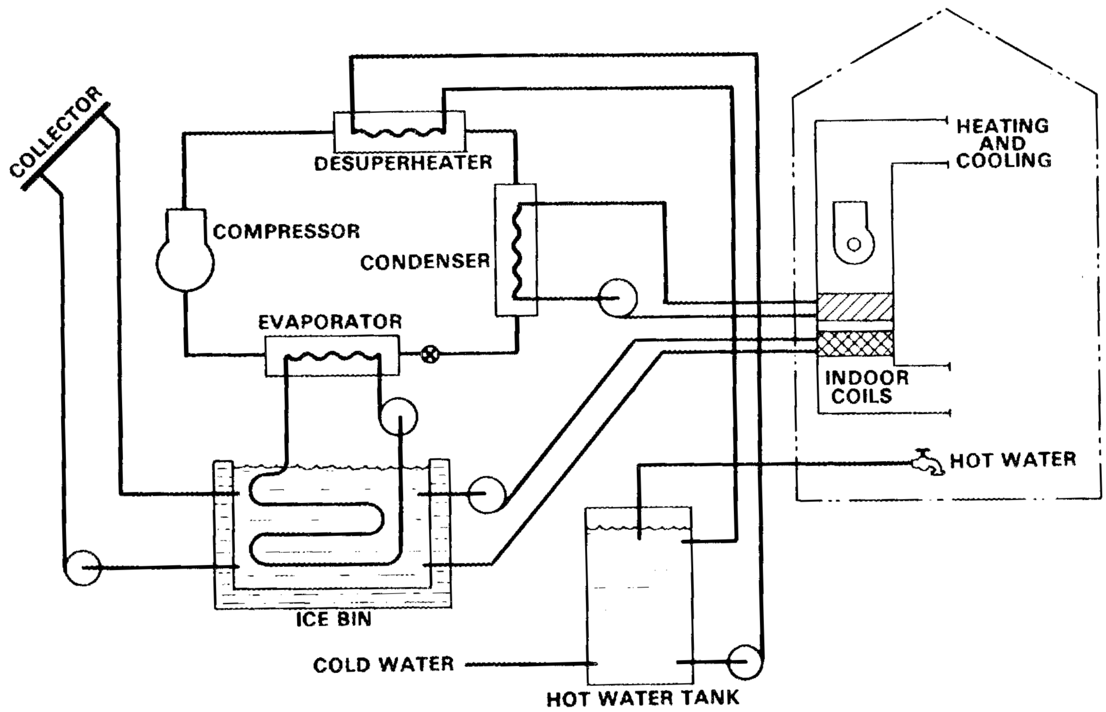



Fig. 1.1. ACES principal components.

pump with an electric resistance water heater, and (3) a high-performance air-to-air heat pump with a desuperheater unit for producing domestic hot water.[2] The results of these studies show that the ACES is the best of the five HVAC systems analyzed in terms of conserving electric energy, but that none of the five HVAC systems offers a clear-cut economic advantage over the other systems in terms of life-cycle costs. The HVAC systems with higher efficiencies tend to have higher first costs. However, the annual savings in power costs over the life of the equipment tend to offset the higher initial cost.

While the ACES may not have a clear economic advantage based on its energy conservation potential, the system has a number of characteristics that make it attractive as a load management tool for the electric utility. Depending on location, the ice produced during the winter may be sufficient to meet the house cooling needs through the summer. If the stored ice is depleted, the air conditioner can be operated at night to produce chilled water in the bin and hot water in the water heater. Thus the utility would see no on-peak compressor or water heater operation during the summer. Clearly the customer economics of alternate electric HVAC systems would change if the electric utility were to institute time-of-day rates, load management rates, or higher seasonal differentials in the summer. With some 80% (in terms of sales) of the United States served by summer-peaking utilities, the load management potential of ACES is significant.

## 1.2 Study Objectives

The objective of this study was to evaluate the load management potential of the ACES from the perspective of the electric utility. The rationale behind such an assessment is that if the utility revenue requirements to serve an ACES-equipped house are significantly less than for other electric HVAC alternatives, the utility may pass these savings through to the customer as a rate incentive. The incentive could take a variety of forms including initial subsidy, time-of-use, demand, or load management rates.

Consequently, this study is essentially a utility planning exercise to determine utility revenue requirements for various assumed market penetrations of ACES houses. These revenue requirements are then translated into utility savings per ACES installation. The load management savings to the utility (which may be passed through to the consumer) can be combined with the consumer savings that result from the higher energy efficiency of the ACES to estimate the overall potential savings of the ACES.

The approach used in this study was to calculate the difference in utility revenue requirements over a 20-year planning horizon between a base case that assumes that a certain percentage of all new homes will install a conventional electric HVAC system (air-to-air heat pump and electric hot water heater) and cases that assume that some of these homes install ACES. Revenue requirements are calculated using detailed production cost simulations and considering the utility's generation expansion plans and reliability criteria. The reason for performing the study over the entire planning horizon is to assure that both short-term and long-term effects are included. This procedure is frequently referred to as a long-run marginal avoided cost approach.

Two utilities were selected for detailed study. These utilities were selected because they have characteristics that make them likely candidates for the successful implementation of a load management system, in general, and customer demographics and weather that would favor an ACES load management approach, in particular. The reason for selecting two utilities with favorable characteristics is to provide a reasonable upper bound on the load management benefits of ACES.

## 1.3 Load Management Characteristics of ACES

The load characteristics of ACES make it attractive from the perspective of the electric utility. During the heating season, the heat pump operates from a constant temperature heat source (the ice bin) and thus does not experience the usual performance degradation that occurs at low outdoor temperatures. Because the heat pump always operates at constant capacity, the electric resistance heating normally installed to provide supplemental heat is unnecessary under normal operating conditions.

From a utility perspective, this type of heating load is desirable. Although the heat pump does operate on demand during on-peak periods, the only demand the utility sees is for the heat pump, auxiliary pumps, and fans, and not the resistance heat. Also, because the heat pump supplies domestic hot water while providing space heating, there is no resistance water heater to contribute to the utility peak.

During the cooling season, the cooling needs of the building are supplied by the ice that was formed as a by-product of heat pump operation during the heating season. Chilled brine from the ice bin heat exchanger is circulated through the indoor coil. The only electrical components in operation during this mode are the indoor air handling unit and the chilled brine pump.

If the ice formed and stored during the winter is exhausted before the end of the cooling season, supplemental cooling can be provided by nighttime heat pump operation. In any case, the heat pump does not operate during on-peak periods.

In summary, the ACES heat pump operates on demand to supply space heating but does not require electric resistance backup heaters to supply supplemental heat. While providing space heating, the system also produces hot water. Thus the maximum ACES demand seen by the utility is the demand of the heat pump and auxiliary pumps and fans, compared with the demand of the heat pump, resistance heat, and resistance water heater possible with a conventional system.

In the cooling mode, the compressor does not operate during peak periods. Cooling is provided using stored ice or chilled water produced by nighttime heat pump operation.

Throughout the year, the heat pump produces hot water two to three times more efficiently than by resistance heating. In the summer, heat pump operation to provide hot water also produces, as a by-product, ice that can be used for air conditioning.

# 2. UTILITY SELECTION CRITERIA

The approach used for this study was to assess ACES as a load management option in two different utilities that are likely to benefit from load management, in general, and ACES, in particular. The reason for selecting favorable utilities is that if no benefit is found, the issue is completely resolved. If there is a positive benefit, the upper bound for such benefits will have been established. Thus the maximum information can be gained from a limited number of case studies.

The problem of selecting utilities likely to benefit from ACES load management was approached by developing screening criteria for assessing the applicability of ACES load management to a particular utility. The screening criteria included utility and weather characteristics and customer demographics. The screening criteria are summarized in Table 2.1 and described in the following sections.

Table 2.1. Utility selection criteria

| Criteria | Explanation |
|---|---|
| Utility characteristics | |
| High load growth | ACES most suitable for new construction. Also, high load growth increases chances of capacity savings |
| Low reserve margin | Increases likelihood of capacity savings |
| Summer peaking | ACES can eliminate all on-peak compressor load |
| High average energy cost | ACES has high energy efficiency |
| High on-peak/off-peak rate differential, particularly in the summer | High differential favors shift to off-peak use |
| Customer demographics | |
| High residential growth rates | ACES most suitable for new construction |
| High saturation electric space conditioning | Increases likelihood of ACES cost-effectiveness |
| Where air conditioning is considered a necessity | Cooling is a by-product of heating operation |
| Heating-cooling requirement ratio of 2:1 to 3:2 | The ACES stores two units of cooling in the ice bin for every three units of heating supplied to the building |

## 2.1 Utility Characteristics

The most frequently cited objectives for load management are to (1) reduce the need for additional generation, transmission, and distribution investments; (2) reduce the use of imported oil (which results in production cost savings); and (3) improve the financial health of the utility. Reducing the need for new generating capacity is the objective most frequently cited for load management. The reason for focusing on generation as opposed to transmission and distribution capacity is that recently generation has accounted for 70% of the capital expenditures for a new utility plant.[3]

A utility's current and projected reserve margins and its projected load growth are two measures of the new capacity that may be required within the current planning cycle. A low reserve margin now and in the future together with a high load growth rate indicate that the utility is adding new facilities but that construction is barely keeping pace. Such utilities have more opportunities to benefit from capacity savings than those with low or negative load growth and high current reserve margins.

Capacity savings are also more likely if the load management option being considered is used during the utility's peak season (e.g., cool storage in a summer-peaking utility, heat storage in a winter-peaking utility) although exceptions exist such as a utility whose generating capacity is maintenance constrained. Consequently, the three selection criteria chosen as a measure of the opportunity for generation capacity savings were load growth, reserve margin, and peak season.

Oil conservation and production cost savings opportunities are more difficult to measure. Ideally, load management options would shift energy delivery from on-peak periods when expensive intermediate oil units and combustion turbines must be used to meet the demand to periods when more efficient, and preferably non-oil-fired, generating capacity is available. However, the degree to which this ideal can be realized is determined by the utility's generation mix, its firm purchase power agreements, and its opportunities for economy interchange.

A large number of utilities in the Northeast, West Coast, and Florida regions of the country are predominantly oil-fired.[4] The opportunities for production cost savings from load shifting for such utilities are considerably less than for utilities that have a substantial fraction of non-oil-fired base-load capacity. In predominantly oil-fired utilities, energy that is shifted off-peak is shifted from less efficient oil units to more efficient oil units, rather than to coal or nuclear capacity. Consequently, the marginal cost differential that determines production cost savings is considerably less.

Utilities with a large proportion of oil-fired generating capacity also pose a problem with respect to capacity savings due to load management. Recent studies have shown that there is an economic benefit to consumers from accelerating the replacement of economically obsolete oil-fired capacity by increasing the planning reserve margin and building new capacity.[5] These circumstances arise because increases in the price of oil since 1973 make the operating costs alone of oil-fired units more than the capital and operating costs combined of new coal or nuclear capacity. Thus any deferral of new capacity in these regions may lead to a negative capacity benefit depending on the assumptions that are made about long-term oil prices.

This complex phenomenon of generation mix and marginal production cost differentials was considered in the selection criteria through the use of average electricity costs and a simplified on-peak/off-peak rate differential. Based on previous experience with detailed production cost simulations, the portion of the on-peak and off-peak loads met by each type of generating unit was estimated. The operating costs for each type of unit were combined with the capital carrying charges to calculate a simple long-run marginal cost for each period. While not completely rigorous, the method is sufficiently accurate for the present purpose of screening candidate utilities.

Although not specifically included in the screening criteria, there is a third incentive for some utilities to institute load management — namely, the financial health of the utility. In an effort to minimize current costs, some public service commissions have not authorized a rate of return on equity sufficiently high to attract new capital and maintain the financial health of the utility. If the earnings of the utility are too low, their bond rating drops and their cost of debt capital rises. Also, the value of their stock drops, which makes it more difficult to raise equity capital. In extreme cases, the value of the stock drops below book value, so that any new stock issue dilutes the equity of existing shareholders.

Unable to raise either debt or equity capital to finance new construction, some utilities might turn to load management as the only alternative to make ends meet, even though it may not be the most economic alternative in the long run.

## 2.2 Customer Demographics and Weather

In addition to utility characteristics, the success of any load management option depends on its acceptance by the consumer. In the case of ACES, there are a number of customer and weather characteristics that will increase its likelihood of acceptance.

Because ACES has been demonstrated only in residential applications and is best suited to new construction, it would be preferable to consider a utility with a high residential growth rate. This requirement was the sixth element in the selection criteria.

Also, although ACES is the most efficient electric HVAC system, the price of natural gas makes it the preferred choice in certain regions of the country. Although the price of natural gas will rise with decontrol, it is uncertain how it will compare with electric rates in the future (particularly because much of the Southwest uses natural gas to generate electricity). Consequently, it was also desirable to select an area that currently has a growing saturation of electric space heating, because this reflects the availability and relative price of competing fuels.

The two remaining criteria involve weather characteristics that influence the likely applications of the ACES. Although the ACES is technically feasible in most of the country, it is best suited to regions of the country where air conditioning is considered a necessity. The high efficiency of an ACES comes from the fact that both the heating and cooling outputs of the heat pump are used at the same time. If summer cooling is not required, the advantage of ACES over conventional systems diminishes.

To further refine the balance of heating and cooling loads, the preferred ratio of heating to cooling requirement is on the order of 3 to 2 because for approximately every three units of heating delivered to the house, two are taken from the bin (and available for later cooling) and one is delivered by the utility. Although quite a range can be accommodated around this ratio through the use of nighttime compressor operation and a solar/convective panel, the efficiency of an ACES will be lower.

# 3. CASE STUDY SELECTION

## 3.1 Regional Characteristics

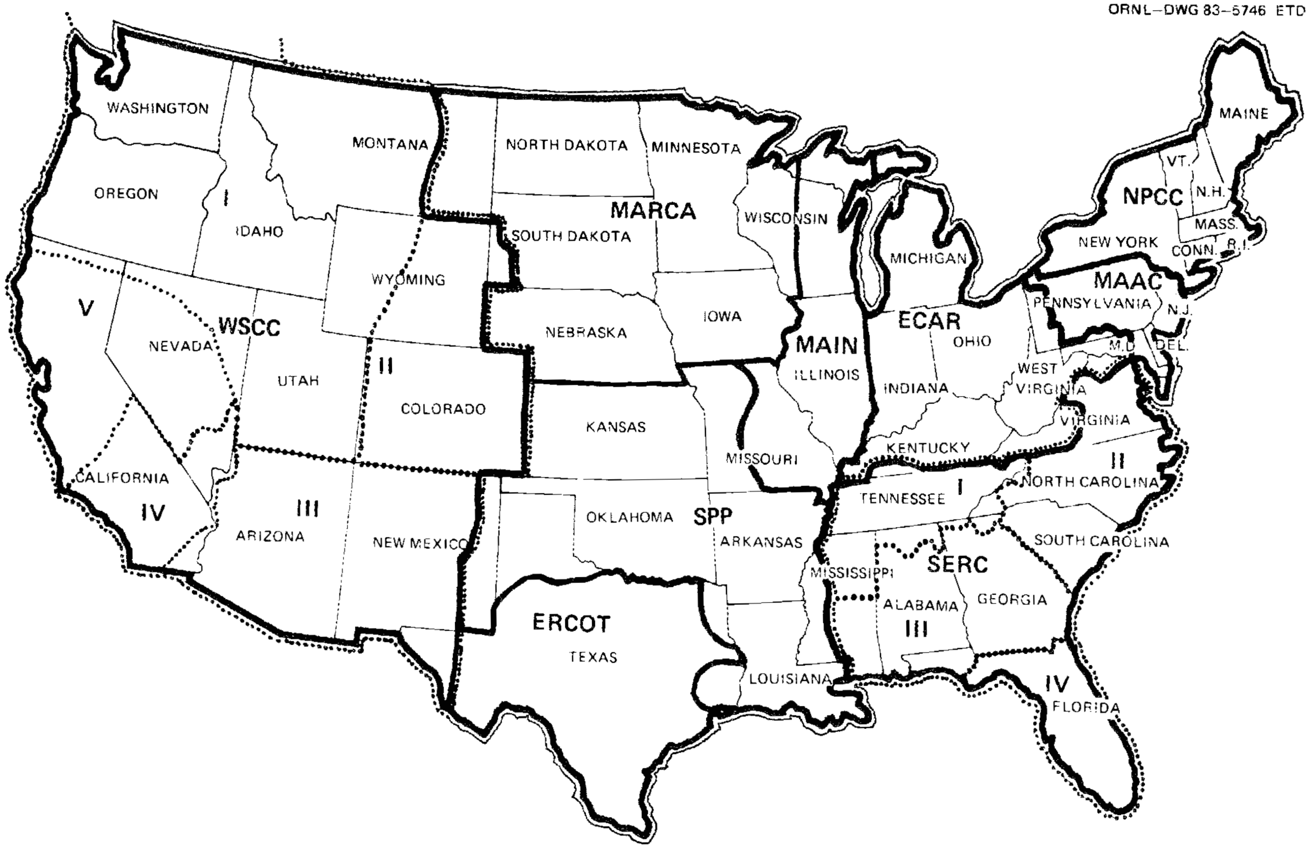
The selection of the two utilities to be used in the residential ACES evaluation began with a regional screening to identify relatively broad (several state) geographic areas having climatic and generating system characteristics attractive for ACES.

Figures 3.1—3.3 show three different regional breakdowns of the country that are used to report various types of data. The first figure shows the nine North American Electric Reliability Council (NERC), formerly National Electric Reliability Council, regions for which most of the electric utility system data were obtained. Note that three of the regions, Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC), and Western Systems Coordinating Council (WSCC), are further refined into subregions. Subregional data for these three regions were consequently used. System data included peak loads, reserve margins, generating unit inventories, and expected peak load growth rates for each NERC region or subregion. Data such as space conditioning fuel availability and expected increases in housing starts are available for the ten Department of Energy (DOE) regions shown in Fig. 3.2. Residential class electricity growth rates are reported for the nine census regions shown in Fig. 3.3.

The NERC regions and subregions were used as the reference regions in the selection process. Data from the other regional breakdowns were grouped with the NERC region or subregion that most closely corresponded.

The tables that follow show the ranking of the NERC regions with regard to the selection criteria described in Sect. 2. Table 3.1 shows relative differences in on-peak and off-peak rates based upon regional generation mix and assumed operating strategies.

The rates in Table 3.1 were based upon the following assumptions. First, it was assumed that 60% of a system's generation was required to meet base, or off-peak load. Meeting on-peak load was assumed to require 100% of the generating resources. Second, it was assumed that 75% of a system's hydro and geothermal resources were used as base load generation




ECAR – EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
ERCOT – ELECTRIC RELIABILITY COUNCIL OF TEXAS
MAAC – MID-ATLANTIC AREA COUNCIL
MAIN – MID AMERICA INTERPOOL NETWORK
MARCA – MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT
NPCC – NORTHEAST POWER COORDINATING COUNCIL
I. NEW YORK
II. NEW ENGLAND
SERC – SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
I TVA SUBREGION
II VIRGINIA – CAROLINA SUBREGION
III SOUTHERN COMPANIES SUBREGION
IV FLORIDA SUBREGION

SPP – SOUTHWEST POWER POOL
WSCC – WESTERN SYSTEMS COORDINATING COUNCIL
I. NORTHWEST POWER POOL SUBREGION
II. ROCKY MOUNTAIN SUBREGION
III. ARIZONA – NEW MEXICO SUBREGION
IV. S. CALIFORNIA – NEVADA SUBREGION
V. N. CALIFORNIA – NEVADA SUBREGION

REGIONS
SUBREGIONS

Fig. 3.1. NERC regions.

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Fig. 3.2. Department of Energy regions.

ORNL-DWG 83-5882 ETD


Fig. 3.3. Federal Bureau of Census regions.

Table 3.1. Average on- and off-peak energy costs for NERC regions (1980 ¢/kWh)

Levelized fuel costs/levelized revenue requirements[a]

| Region/subregion[b] | Off-peak | On-peak | Difference |
|---|---|---|---|
| 1. WSCC/S.CA-NV | 2.17/4.34 | 3.27/5.47 | 1.10/1.13 |
| 2. WSCC/N.CA-NV | 0.97/3.27 | 2.04/4.28 | 1.07/1.01 |
| 3. NPCC/New York | 1.20/3.51 | 2.21/4.45 | 1.01/0.94 |
| 4. SPP | 1.55/3.75 | 2.51/4.71 | 0.96/0.96 |
| 5. SERC/Florida | 2.04/4.40 | 3.02/5.30 | 0.98/0.90 |
| 6. MAAC | 0.98/3.38 | 1.84/4.15 | 0.86/0.77 |
| 7. NPCC/New England | 2.20/4.63 | 3.03/5.35 | 0.83/0.72 |
| 8. WSCC/AZ-NM | 1.17/3.31 | 1.94/4.10 | 0.77/0.79 |
| 9. ERCOT | 1.69/3.84 | 2.07/4.22 | 0.38/0.38 |
| 10. WSCC/NWPP | 0.16/2.26 | 0.45/2.55 | 0.29/0.29 |
| 11. SERC/VACAR | 0.88/3.35 | 1.27/3.62 | 0.39/0.27 |
| 12. WSCC/RMPA | 0.85/2.98 | 1.10/3.24 | 0.25/0.26 |
| 13. SERC/TVA | 0.80/3.18 | 1.08/3.38 | 0.28/0.20 |
| 14. ECAR | 1.19/3.41 | 1.40/3.60 | 0.21/0.19 |
| 15. SERC/Southern | 0.99/3.30 | 1.23/3.48 | 0.24/0.18 |
| 16. MAIN | 1.02/3.40 | 1.28/3.57 | 0.26/0.17 |
| 17. MARCA | 0.84/3.21 | 1.06/3.34 | 0.21/0.19 |

[a]Data for fuel cost and revenue requirement calculations given in Ref. 5.

[b]Generation mix taken from North American Electric Reliability Council, *1979 Summary of Projected Peak Load, Generating Capability, and Fossil Fuel Requirements, for the Regional Reliability Councils of NERC*, July 1979.

and the remaining 25% used as peaking capacity. It should be noted that this calculation of rates is not rigorous and does not include taxes, profits, or transmission and distribution system expenses. The calculations are used only to provide relative rankings of rate differentials and a qualitative evaluation of high, medium, or low rates.

Table 3.1 shows the rankings made in regard to (1) fuel costs only and (2) levelized revenue requirements. As can be seen, the rate differentials are primarily due to fuel costs.

Table 3.2 shows expected system reserve margins for the NERC regions or subregions. The regions are ranked in order of increasing reserve margin over the years of interest. These values were obtained by dividing the net generating capability by the expected peak demand for the

Table 3.2. NERC regional reserve margin[a] (%)

| Region/subregion | 1980 | 1985 | 1988 |
|---|---|---|---|
| 1. MARCA | 25 | 15 | 7 |
| 2. WSCC/N.CA-NV | 19 | 23 | 24 |
| 3. MAIN | 22 | 21 | 17 |
| 4. SERC/Southern | 20 | 23 | 19 |
| 5. SPP | 24 | 21 | 17 |
| 6. SERC/Florida | 24 | 25 | 22 |
| 7. WSCC/S.CA-NV | 27 | 24 | 21 |
| 8. SERC/VACAR | 26 | 26 | 22 |
| 9. NPCC/New England | 33 | 22 | 26 |
| 10. ERCOT | 35 | 27 | 19 |
| 11. WSCC/AZ-NM | 33 | 31 | 32 |
| 12. MAAC | 33 | 32 | 29 |
| 13. ECAR | 31 | 35 | 31 |
| 14. WSCC/RMPA | 36 | 33 | 27 |
| 15. WSCC/NWPP | 35 | 40 | 44 |
| 16. NPCC/New York | 43 | 34 | 31 |
| 17. SERC/TVA | 37 | 41 | 34 |

[a]Taken from North American Electric Reliability Council, *1979 Summary of Projected Peak Load, Generating Capability, and Fossil Fuel Requirements for the Regional Reliability Councils of NERC*, July 1979.

summer of the given years. The summer value was used because that is where the load management potential of ACES is greatest. As discussed in Sect. 2, summer peaking systems with low reserve margins would be expected to benefit from the use of ACES by deferring new capacity additions.

Table 3.3 shows the expected peak demand increases for the regions from 1980 to 1988. Systems having high growth would be most attractive for ACES, and that was the criteria used to rank the regions.

Table 3.4 gives the expected rates of growth of electric energy for the residential class.

Tables 3.5 and 3.6 can be used in conjunction with each other in estimating the penetration of electric space conditioning in new homes. Table 3.5 shows the expected new housing starts in the study regions. Table 3.6 shows a breakdown of the fuel used for space conditioning in

Table 3.3. Average NERC region peak load increase from 1980 to 1988[a]

| | Region/subregion | Increase (%/year) |
|---|---|---|
| 1. | WSCC/RMPA | 6.3 |
| 2. | SPP | 6.1 |
| 3. | SERC/VACAR | 5.8 |
| 4. | WSCC/AZ-NM | 5.5 |
| 5. | SERC/TVA | 5.3 |
| 6. | ERCOT | 5.2 |
| 7. | MARCA | 5.2 |
| 8. | SERC/Southern | 4.9 |
| 9. | SERC/Florida | 4.8 |
| 10. | WSCC/NWPP | 4.4 |
| 11. | ECAR | 4.3 |
| 12. | MAIN | 4.2 |
| 13. | NPCC/New England | 3.9 |
| 14. | WSCC/N.CA-NV | 3.8 |
| 15. | WSCC/S.CA-NV | 3.6 |
| 16. | MAAC | 3.1 |
| 17. | NPCC/New York | 2.6 |

[a]Taken from North American Electric Reliability Council, *1979 Summary of Projected Peak Load, Generating Capacity, and Fossil Fuel Requirements for the Regional Reliability Councils of NERC*, July 1979.

Table 3.4. Predicted growth rates for residential class by NERC region[a]

| | Region/subregion | Average growth (%/year) |
|---|---|---|
| 1. | WSCC/RMPA | 6.7 |
| 2. | WSCC/AZ-NM | 6.7 |
| 3. | ERCOT | 5.5 |
| 4. | SPP | 5.5 |
| 5. | ECAR | 4.6 |
| 6. | MAIN | 4.6 |
| 7. | SERC/VACAR | 4.6 |
| 8. | MAAC | 4.6 |
| 9. | SERC/Florida | 4.6 |
| 10. | SERC/TVA | 4.4 |
| 11. | SERC/Southern | 4.4 |
| 12. | WSCC/NWPP | 4.4 |
| 13. | WSCC/N.CA-NV | 4.4 |
| 14. | WSCC/S.CA-NV | 4.4 |
| 15. | NPCC/New York | 4.2 |
| 16. | MARCA | 3.9 |
| 17. | NPCC/New England | 2.4 |

[a]Based on W. S. Chern et al., *Regional Econometric Model for Forecasting Electricity Demand by Sector and State*, ORNL/NUREG-49, October 1978. The data were given for the nine census regions and carried over to the NERC region it most closely resembled.

Table 3.5. Growth rates of housing by NERC region[a]

| Region/subregion | Growth in 1980 (%) |
|---|---|
| 1. SERC/TVA | 3.3 |
| 2. SERC/Southern | 3.3 |
| 3. SERC/Florida | 3.3 |
| 4. SERC/VACAR | 3.3 |
| 5. WSCC/N.CA-NV | 3.3 |
| 6. WSCC/S.CA-NV | 3.3 |
| 7. WSCC/AZ-NM | 3.3 |
| 8. MAAC | 2.9 |
| 9. MARCA | 2.7 |
| 10. WSCC/RMPA | 2.7 |
| 11. ECAR | 2.6 |
| 12. MAIN | 2.6 |
| 13. SPP | 2.6 |
| 14. ERCOT | 2.6 |
| 15. NPCC/New England | 2.6 |
| 16. WSCC/NWPP | 2.6 |
| 17. NPCC/New York | 2.2 |

[a]Based on E. Hirst and J. B. Kurish, *Residential Energy Use to the Year 2000: A Regional Analysis*, ORNL/CON-17, November 1977. Data were given by DOE region and carried over to the NERC region that it most closely resembled.

Table 3.6. Regional availability of alternate fuels[a]

| Region/subregion | Total energy for space heating (%) | Fuel use by type of fuel (%) | | | |
|---|---|---|---|---|---|
| | | Electricity | Gas | Oil | Other |
| 1. WSCC/NWPP | 50 | 78 | 13 | 6 | 3 |
| 2. SERC/TVA | 37 | 72 | 19 | 5 | 5 |
| 3. SERC/VACAR | 37 | 72 | 29 | 5 | 5 |
| 4. SERC/Southern | 37 | 72 | 29 | 5 | 5 |
| 5. SERC/Florida | 37 | 72 | 19 | 5 | 5 |
| 6. ERCOT | 30 | 59 | 34 | 2 | 6 |
| 7. SPP | 30 | 59 | 34 | 2 | 6 |
| 8. WSCC/N.CA-NV | 32 | 51 | 46 | 1 | 2 |
| 9. WSCC/S.CA-NV | 32 | 51 | 46 | 1 | 2 |
| 10. WSCC/AZ-NM | 32 | 51 | 46 | 1 | 2 |
| 11. MAAC | 48 | 50 | 33 | 14 | 3 |
| 12. NPCC/New England | 56 | 44 | 21 | 34 | 1 |
| 13. MARCA | 56 | 44 | 46 | 5 | 6 |
| 14. WSCC/RMPA | 56 | 44 | 46 | 5 | 6 |
| 15. ECAR | 49 | 43 | 46 | 9 | 3 |
| 16. MAIN | 49 | 43 | 46 | 9 | 3 |
| 17. NPCC/New York | 52 | 36 | 34 | 29 | 2 |

[a]Based on E. Hirst and J. B. Kurish, *Residential Energy Use to the Year 2000: A Regional Analysis*, ORNL/CON-17, November 1977. Data were given by DOE region and applied to the NERC region that it most closely resembled.

existing homes. This provides an indication of the competition between electricity and other fuels in the different regions for space conditioning.

Table 3.7 shows the ratio of heating degree days (HDDs) to cooling degree days (CDDs) in each of the regions. As discussed in Sect. 2, the preferred ratio is 1.5 with both high heating and cooling requirements. Several of the regions that have close to the proper ratio have modest total heating and cooling requirements.

Table 3.7. Regional climatic characterization[a]

| Region/subregion | Heating degree days (HDD) | Cooling degree days (CDD) | HDD/CDD |
|---|---|---|---|
| SERC | 2913 | 2113 | 1.4 |
| WSCC | 2611 | 909 | 2.9 |
| SPP | 2575 | 2278 | 1.1 |
| ERCOT | 2575 | 2278 | 1.1 |
| MAAC | 5367 | 955 | 5.6 |
| NPCC/New York | 5984 | 809 | 7.4 |
| MAIN | 6677 | 806 | 8.3 |
| ECAR | 6677 | 806 | 8.3 |
| NPCC/New England | 6787 | 479 | 14.2 |
| MARCA | 7792 | 480 | 16.2 |

[a]Taken from H. M. Conway and L. L. Liston, *The Weather Handbook*, Conway Research Inc., Atlanta, 1974.

## 3.2 Case Study Utilities

Although all the regional characteristics summarized in the previous tables have a bearing on the potential for ACES, some of the criteria are more important than others. The selection criteria themselves were reviewed and classified as either (1) very important, (2) important, or (3) not very important. Criteria judged "very important" were given a numerical weighting of five. Those judged "important" were given a weight of three, and those judged "not very important" were given a weighting of one. A summary of the selection criteria weights is given in Table 3.8.

Table 3.8. Weighting factors for selection criteria

| Selection criteria | Weighting factor |
|---|---|
| On- and off-peak rate differential | 5 |
| Average electricity costs | 5 |
| Climate acceptability | 5 |
| Reserve margin | 3 |
| New housing starts | 3 |
| Peak demand growth | 3 |
| Residential energy growth | 1 |
| Alternate fuel availability | 1 |

The ranking of each region or subregion was determined with respect to each selection criterion. Areas ranking first were scored five points, areas ranking second were scored four points, and so on with a ranking of fifth scoring one point.

The overall potential for ACES based upon all the selection criteria was determined by multiplying the score on each criterion by the weight of the criterion and summing over all nine criteria. Table 3.9 shows the final results for each of the regions or subregions.

This initial assessment of regions or subregions shows five regions that appear to be particularly attractive for ACES from a load management perspective. The top ranking choice, the Southern California-Southern Nevada subregion of WSCC, obtained 50 of its 68.8 points because of a high rate differential and high average rates.

However, a more detailed look at this region shows some of the hazards associated with considering a region that is heterogeneous. The high average rates for the Southern California-Southern Nevada subregion result primarily from the high percentage of oil-fired generation in the subregion (44.7% as of 1980). The high rate differential for the subregion arose from the fact that the region's generating capability also includes 3.2% nuclear, 6.5% hydro, 16.6% gas, and 19.9% coal capacity.

Table 3.9. Results of regional evaluation

| Region/subregion | | Evaluation points |
|---|---|---|
| 1. | WSCC/S.CA-NV | 68.8 |
| 2. | SPP | 50.0 |
| 3. | WSCC/N.CA-NV | 38.3 |
| 4. | WSCC/AZ-NM | 37.8 |
| 5. | SERC/VACAR | 31.0 |
| 6. | SERC/TVA | 25.8 |
| 7. | SERC/Florida | 22.5 |
| 8. | NPCC/New England | 20.0 |
| 9. | NPCC/New York | 20.0 |
| 10. | WSCC/RMPA | 19.5 |
| 11. | SERC/Southern | 19.3 |
| 12. | MARCA | 15.0 |
| 13. | MAIN | 9.2 |
| 14. | WSCC/NWPP | 5.0 |
| 15. | ERCOT | 2.5 |
| 16. | ECAR | 0.2 |
| 17. | MAAC | 0.2 |

However, all of the coal-fired generating units are located in the Southern Nevada portion of the subregion, and most of the oil-fired units are located in the Southern California portion of the subregion. Consequently, as a whole, the subregion appears to offer much load management potential; but no single utility within the region has the mix of characteristics that support such a high score.

The second ranking region, the Southwest Power Pool (SPP), had a balanced distribution of points. It was attractive because of high residential and peak-load growth and attractive climate for ACES. Several utilities within the region also exhibit these balanced characteristics.

The third ranking region, the Northern California-Northern Nevada subregion of WSCC, got its ranking primarily because of a high rate differential and low reserve margin. This region also exhibits some of the complicating factors previously described for the Southern California-Southern Nevada region, with further complicating factors being the dependence of Northern California on large power transfers from the Pacific

Northwest and Northern California's own substantial hydro resources. Although the subregion appears to have a high rate differential, the dependence of that differential on an already energy-limited resource like hydro raises questions as to whether or not any additional benefits are available to consumers for changing their load patterns.

The Arizona-New Mexico region of WSCC rated fourth primarily because of high residential growth and an attractive climate. However, the low population density of the region, the high availability and usage of natural gas for heating and water heating, and the fact that many areas within the subregion use evaporative air conditioning instead of refrigerated air conditioning for space cooling raise questions as to the likely impact of ACES in the subregion.

The last area that scored highly was the Virginia-Carolinas (VACAR) subregion of SERC. This region received fairly balanced scoring because of high peak demand growth, housing starts, and attractive climate.

Based on their balanced scoring and the previously described problems with the other regions, the VACAR subregion of SERC and the SPP region were selected as the top candidates for a load management assessment of ACES. This by no means limits possible ACES applications to these regions, because there are numerous attractive local sites for ACES. The selection of these two regions merely indicates that they exhibit many of the characteristics that favor ACES as a load management option. The characteristics of the individual utilities within these regions were examined, and a case study utility was selected from each region. The Arkansas Power and Light Company (APL) was selected from the SPP. Duke Power Company (Duke) was selected from the VACAR subregion of SERC. These utilities exemplify the previously described characteristics favorable for ACES.

An investor-owned utility, APL serves approximately 35% of the state's area and 50% of the population. It is a summer-peaking utility with the summer peak being approximately one-third greater than the winter peak. The area has a high saturation of air conditioning (~80%) with both high latent and sensible cooling requirements. Heating degree days range from around 2500 to 4000 depending upon location in the service territory. The utility also maintains an active load management program.

Duke serves portions of both North and South Carolina. One of the largest utilities in the Southeast, Duke has a mix of hydro, coal, and nuclear generation with oil- and gas-fired peakers. It is a utility with almost equal winter and summer peaks. Like APL, Duke is in an area requiring air conditioning and is a utility actively pursuing load management opportunities.

# 4. CASE STUDY DESCRIPTIONS

## 4.1 Study Scenarios

The results of any utility planning study are sensitive in varying degrees to study assumptions. Annual revenue requirements, and hence the optimal plan, are a result of load growth, fuel costs, generating unit characteristics, capital costs, financial assumptions, and planning criteria. Because in this study the revenue requirements over the planning horizon are calculated using detailed production costing, reliability evaluation, and expansion planning, it is clearly computationally infeasible to examine the sensitivity of the study results to all combinations of study assumptions. Consequently, it is desirable to select a limited set of scenarios that will shed as much light as possible on the problem at hand — namely, the load management benefits of ACES.

Load management affects the utility's planning through the shape and magnitude of the system load profile. Therefore these parameters were selected as the basis for four scenarios that cover the range of system load profiles that might result if ACES were to be adopted on a widespread basis. The four scenarios investigated were (1) normal load growth and moderate ACES penetration, (2) normal load growth and high ACES penetration, (3) low load growth and moderate ACES penetration, and (4) low load growth and high ACES penetration.

The revenue requirements development for each of these scenarios was compared with those of a base case without any ACES involving either normal or low system load growth. The computer code used for calculating revenue requirements for the various scenarios and the data assumptions that were made are described in the following sections.

## 4.2 Supply Costs

The supply costs for the various scenarios were calculated using a modified version of the Wien Automatic System Planning Package (WASP),[6] that was developed by the Tennessee Valley Authority and Oak Ridge National Laboratory. Areas of consideration common to all generation expansion programs include generation description, load model, production costing, reliability evaluation, investment costing, and optimization method. The approach used by WASP in each of these areas is described in the following paragraphs.

WASP considers the existing generation system, firm additions to and retirements from the existing system, and the candidate units being considered for expansion. Thermal generating units are described in terms of minimum and maximum operating levels, heat rate at minimum operating level, average incremental heat rate, fuel cost, plant type, spinning reserve capability, forced outage rate, scheduled maintenance requirements, fixed component of nonfuel operation and maintenance (O&M) costs, and variable component of nonfuel O&M costs. Hydroelectric generating units can be either normal or emergency plants and are described by their minimum and maximum operating capacities, spinning reserve capability, annual energy availability, fixed nonfuel O&M costs, and variable nonfuel O&M costs. Pumped storage units are characterized by their maximum pumping load, maximum generating capacity, maximum feasible energy per period, round trip efficiency, fixed nonfuel O&M costs, and variable nonfuel O&M costs. In addition to the description of individual generating units, hydroelectric units can be further characterized by anticipated hydro conditions. Up to five hydrological conditions can be considered with their corresponding probabilities, capacities, and energies.

Firm additions to and retirements from the existing system can be specified at the start of the study. The investment costs for these committed units are not included in the calculated system costs, because they are prespecified in the plan, and hence similar to the existing system.

The load model in WASP is used for both the production cost and reliability calculations. The model consists of a separate hourly load duration curve for each processing period. The load duration curve must already include any firm scheduled economy interchanges because all calculations are done on an isolated system basis. The processing period can range from one month to one year and is selected by the user. The load duration curve is described by a fifth-order polynominal

$$y = a_0 + a_1X + a_2X^2 + a_3X^3 + a_4X^4 + a_5X^5$$

where X is the fraction of time during the period that the load equals or exceeds the fraction y of the peak period demand. The shape, as well as the magnitude, of the load curve can be varied for every period throughout the study horizon.

The production costs and reliability calculations for the existing system and each allowed set of generating unit additions are calculated for each period of the study using a simulation technique based on probability analysis. A detailed description of the basic techniques of probabilistic simulation has been given by others[6,7] and will not be repeated here. Briefly, the technique involves the assignment of each generating unit to supply the energy related to a given portion of the load duration curve. The shape of the curve is adjusted so that each unit generates the energy expected of it when outages of all units in the system have been considered. The procedure provides a systematic means for combining the probability density functions describing the loads to be met and the capacity on outage. The output of the probabilistic simulation is the expected energy generated by each unit, production costs by fuel type, the total expected operating costs, the period loss of load probability, and the expected unserved energy.

The reliability indices calculated by WASP are loss of load probability (LOLP) and loss of load expectation (LOLE). Reliability can be used as a constraint on selecting feasible unit addition schedules.

Maintenance is scheduled to levelize reserves for the system during the year. Because it is not possible to subdivide a time period in probabilistic simulation, if a generating unit requires maintenance for only a fraction of the period, the fractional contribution is represented by unit derating. This maintains the proper total maintenance but slightly distorts the amount of capacity that is removed from the system.

The version of WASP used in this study has been modified so that either minimum discounted expenditures or minimum present value of annual revenue requirements can be used as the criterion for selecting the least-cost plan over the planning horizon. The former criterion is commonly used by publicly owned utilities, while the latter is most frequently used by private investor-owned utilities. If minimum discounted expenditure is used as the objective function, the system is charged for the full installation cost of a unit in the year the unit goes on line. The unit is depreciated throughout the study period, using either straight line or sinking fund depreciation, until the last year of the study when the system is credited with the unit's "salvage value." The salvage value is to account for the useful life of the unit that extends beyond the planning horizon. All operating costs are discounted from the year in which they occur.

If present value of revenue requirements is used as the objective function, the fixed portion of the annual revenue requirements is calculated using a levelized annual fixed charge rate that is calculated for each expansion alternative. When fixed charges are used to determine revenue requirements, the depreciation component of the fixed charge rate takes into account the life of the facility, and therefore calculation of salvage value is unnecessary. Again, operating costs are discounted from the year in which they occur.

The WASP Code uses dynamic programming to determine what unit additions over the planning horizon will result in a system with the desired reliability at minimum cost. In WASP, each year of the planning study has a number of system configurations, represented by various combinations of generating unit additions, which meet the constraints (such as reliability) stated in the problem. The production costs for each configuration in each year are then computed. The dynamic program combines the present values of production costs with the fixed costs for the alternative plans to find the set of unit additions for each year of the study that result in the least total cost. Note that a dynamic program considers the entire planning horizon when making each investment decision; thus, there is no need to make special adjustments for changing conditions such as varying rates of capital cost escalation, fuel cost escalation, or changes in load growth over the planning horizon.

## 4.3 Study Assumptions

### 4.3.1 System loads

The objective of all load management options is to modify the system load to a shape and magnitude that can be supplied at a lower total cost.

Thus, assumptions about load growth and load shape are particularly critical to a load management assessment. Because the focus of this study is on load shapes, the parameters that affect that shape, namely load growth and ACES penetration rate, were varied for the different scenarios studied.

Hourly load data for 1980 were supplied by both Duke and APL. These load profiles were used to calculate the base case expansion plans and costs both for a moderate and a low load growth scenario for Duke and a moderate load growth scenario for APL.

The load profiles for the scenarios involving various penetrations of ACES and load growth rates were derived from the hourly utility loads, hourly weather data, and the performance results from the ACES demonstration home near Knoxville, Tennessee. The ACES demonstration home, a well-insulated 149-$m^2$ (1600-$ft^2$) single family dwelling, has operated several years and detailed electricity demand data and weather data (e.g., outdoor temperature, humidity ratio, and solar insolation) have been collected. Similar demand data are available for a control home, which uses a conventional HVAC system (air-to-air heat pump and resistance hot water heater), that was built to the same specifications as the ACES house and is located on the same site. Statistical correlations were made between local weather variables and the loads in both the ACES and control house using multivariable regression analysis.

The model developed to correlate ACES and conventional house heating and cooling load to weather variables uses indoor temperature change during an hour as the dependent variable. The statistical correlations between the various weather variables and indoor temperature change are summarized in Table 4.1. Once the indoor temperature change is calculated, the new indoor temperature can be compared with the indoor thermostat upper and lower set points to determine if heating or cooling is needed. If the indoor temperature is below the thermostat lower set point, heat is added to the house and the electric loads calculated considering the relative efficiency of the ACES and conventional heating systems. If the indoor temperature is above the thermostat upper set point, the cooling energy required by the ACES and conventional houses is calculated using both the indoor temperature and the outdoor relative

Table 4.1. Statistical correlations between weather parameters and ACES and control house indoor temperature change

$$PD = a_1 + a_2 \times SOLR + a_3 \times YWS + a_4 \times YWS \times YOT + a_5 \times SOLRA + a_6 \times IOA + a_7 \times DAT1 + a_8 \times DAT2 + a_9 \times YWS \times SOLR$$

PD = Inside temperature change (°C)

SOLR = Solar radiation ($Wh/m^2$)
(determined by sun's position based on latitude, hour of the day, day of the year, and cloud cover)

YWS = Wind speed (m/h)

YOT = Outdoor temperature (°C)

SOLRA = Weighted average of current and previous solar radiation ($Wh/m^2$)

IOA = Weighted average of current and previous temperature differences (°C)

DAT1 = Time of year parameter that varies as a sine function

DAT2 = Time of year parameter that varies as a cosine function

The calculated values of the coefficients are as follows:

| | |
|---|---|
| $a_1 = 0.347$ | $a_6 = -6.654 \times 10^{-2}$ |
| $a_2 = 4.604 \times 10^{14}$ | $a_7 = -1.326 \times 10^{-1}$ |
| $a_3 = 1.327 \times 10^{-2}$ | $a_8 = 1.291 \times 10^{-2}$ |
| $a_4 = 4.895 \times 10^{-4}$ | $a_9 = -1.029 \times 10^{-5}$ |
| $a_5 = 1.167 \times 10^{-4}$ | |

humidity (to account for the fact that a portion of the cooling load is latent cooling) and the relative efficiency of the two systems.

This model specification allows different indoor thermostat settings for heating and cooling and recognizes the temperature range around the comfort zone where no heating or cooling is required.

Table 4.2 summarizes the average annual heating and cooling degree days for Little Rock, Arkansas; Charlotte, North Carolina; and Knoxville.[8] Statistics for 1980 are also shown in the table for comparison. Note that the weather conditions for Duke's and APL's service territory are similar to those of Knoxville where the actual performance data were collected.

Table 4.2. Average climatic conditions for major cities in study areas

| City | Average degree days[a] | | 1980 degree days[a] | |
|---|---|---|---|---|
| | Heating | Cooling | Heating | Cooling |
| Little Rock | 3354 | 1725 | 3049 | 2579 |
| Charlotte | 3218 | 1596 | 3436 | 1760 |
| Knoxville[b] | 3478 | 1569 | 3010 | 1773 |

[a]18.3°C (65°F) base.

[b]Location of ACES demonstration house.

Source: National Oceanic and Atmospheric Administration, *Local Climatological Data: Annual Summary with Comparative Data, 1980*.

The predicted demand as a function of weather for the ACES and control homes was then used with hourly weather data for 1980 obtained from the National Weather Service for the largest city in each of the two utility service territories to generate a typical annual load profile for each type of HVAC installation. Figures 4.1—4.4 show the typical annual space conditioning profiles for the control and ACES houses in the APL and Duke service areas, respectively. Weather data from Little Rock were used for APL, while data from Charlotte were used for Duke. (A single year's weather data were used in the analysis rather than a multiple year average to preserve the correlation between local weather and utility system load, and because averaging tends to smooth the peaks and valleys in the temperature profiles, which are so important from a reliability perspective.)

The predicted energy consumptions, based on the modeling procedure outlined above, are summarized in Table 4.3. The ACES house in Little Rock consumed 6,758 kWh annually for space conditioning compared with 12,984 kWh for the control house: a 48% energy savings. An ACES house in Duke's service area would consume 7,024 kWh annually compared with 11,827 kWh for a conventional house for a 41% energy savings.

ORNL--DWG 83-5747 ETD

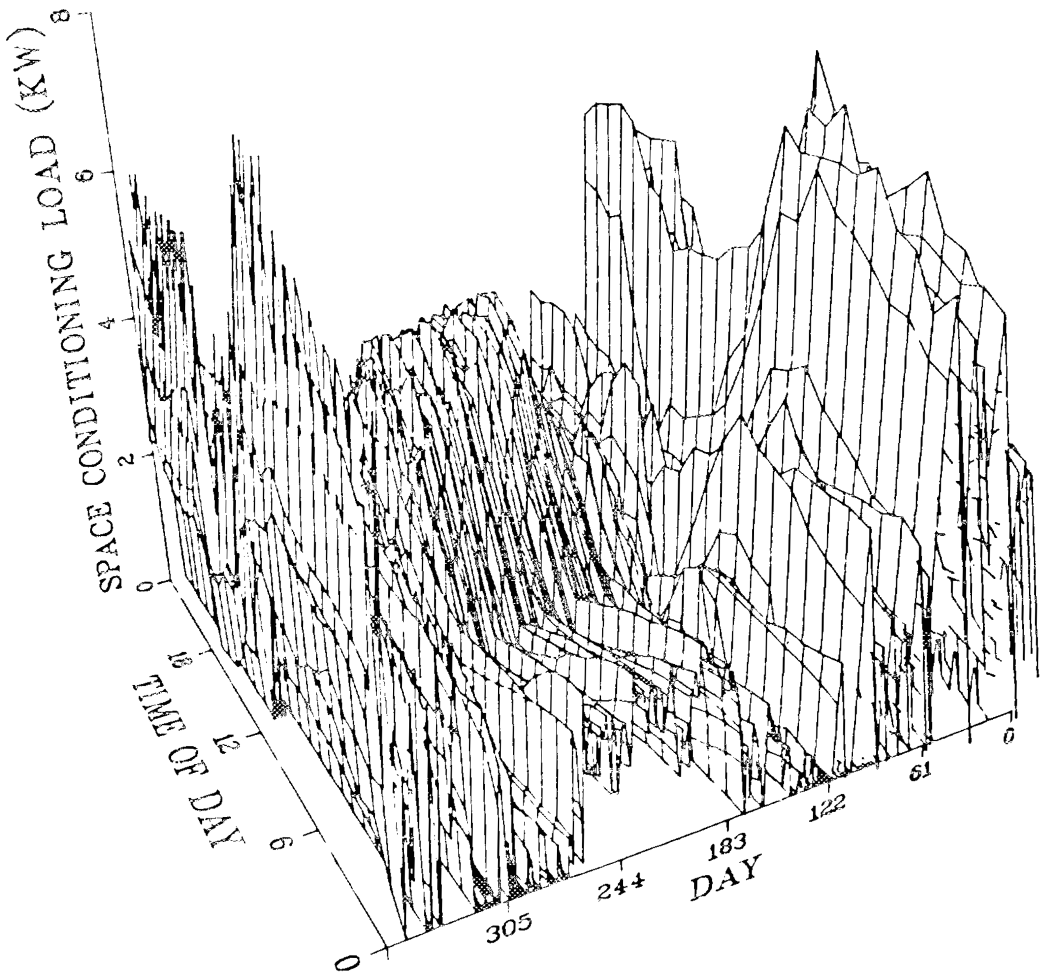


Fig. 4.1. Little Rock control house space conditioning profile.

Table 4.3. Predicted annual space conditioning energy usage

| City | Control house (kWh) | ACES house (kWh) | ACES energy saving (%) |
|---|---|---|---|
| Little Rock | 12,984 | 6,758 | 48 |
| Charlotte | 11,827 | 7,024 | 41 |

ORNL-DWG 83-5748 ETD

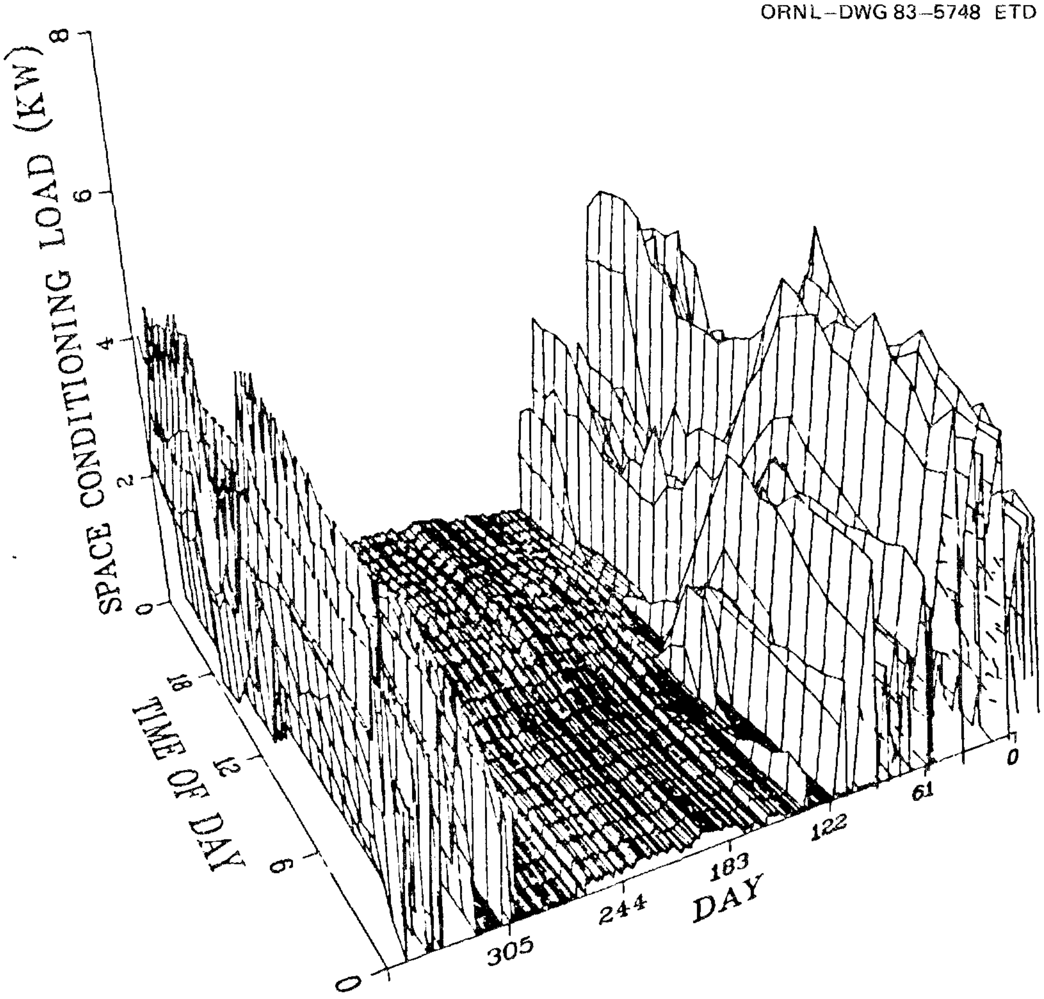


Fig. 4.2. Little Rock ACES house space conditioning profile.

Two scenarios for ACES penetration were considered: 50% and 100% of all new single family dwellings. These substantial penetrations were assumed because low penetrations would not produce any significant changes in system load. The number of residential customers in each utility were taken from utility data.[9,10] The percentage of single family residences among all residential customers was taken from data on the Federal Energy Administration regions containing the service areas.[11] The growth rate of residential customers was assumed to be the same as the utility system load growth rate for that scenario. This assumes that the relative mix of industrial, commercial, and residential customers

ORNL–DWG 83–5749 ETD

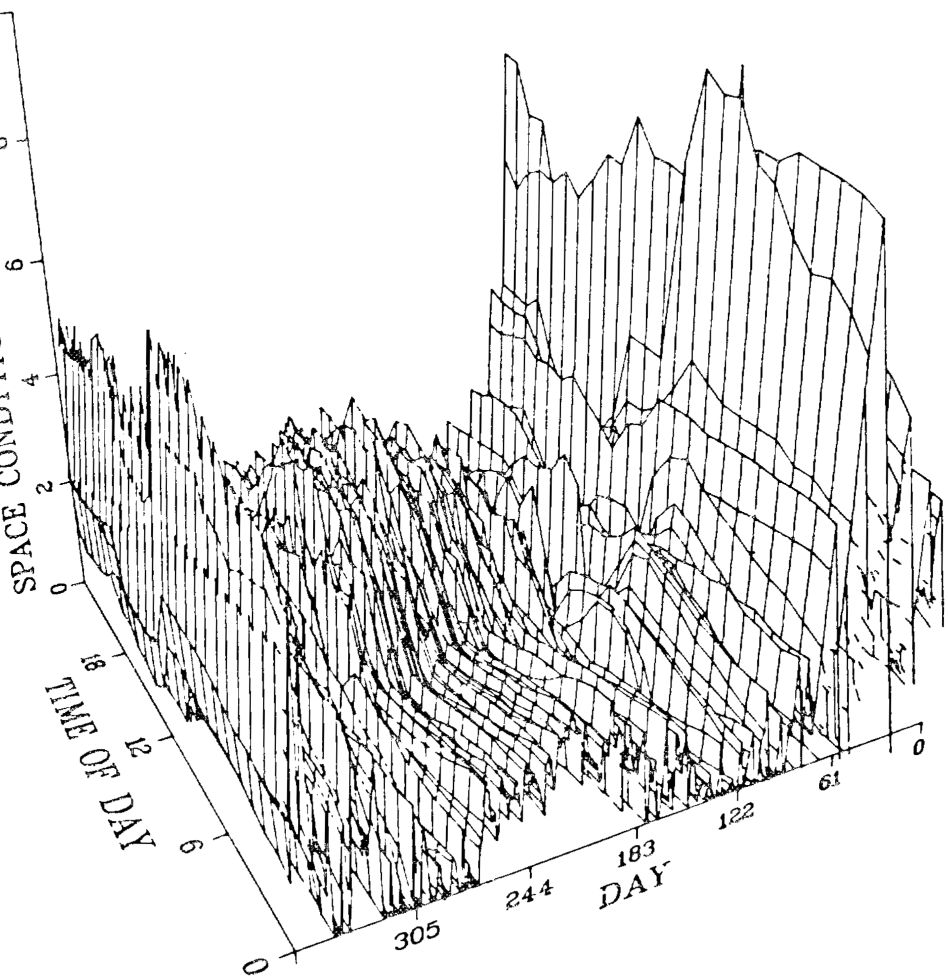


Fig. 4.3. Charlotte control house space conditioning profile.

does not change over the study horizon. The assumption is consistent with the assumption of a constant load shape over the study horizon for the base case. The expected number of ACES houses was estimated by multiplying the expected number of new single family dwellings by the assumed ACES penetration. The number of installed ACES for each scenario in various years is shown in Table 4.4.

The effect of the various penetrations of ACES installations on the total utility load was calculated by taking the expected hourly system load for the year in the absence of ACES and subtracting the product of the number of ACES installations and the difference between the ACES and

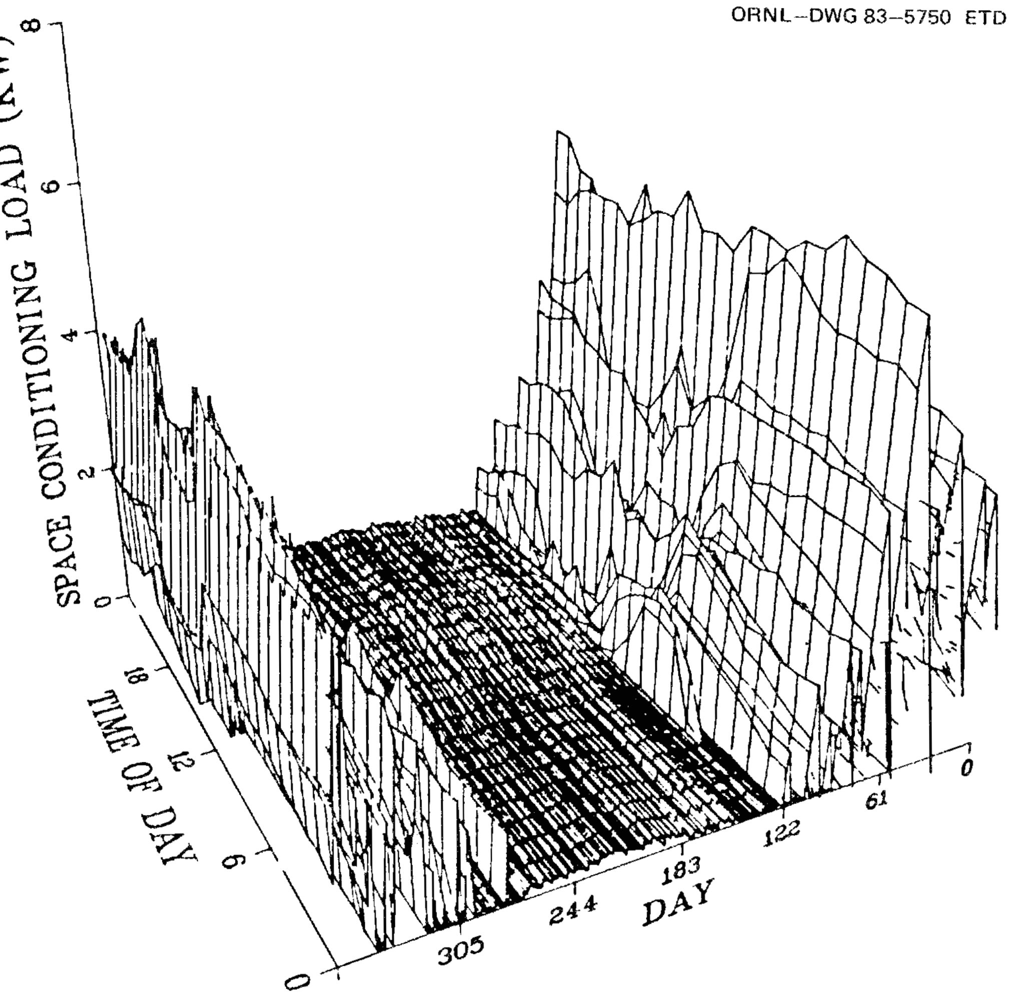


Fig. 4.4. Charlotte ACES house space conditioning profile.

Table 4.4. Cumulative number of ACES installations for study scenarios (thousands)

| | Arkansas Power and Light | | Duke Power Company | | | | | |
|---|---|---|---|---|---|---|---|---|
| Load growth: | Moderate | | Moderate | | | Low | | |
| ACES penetration (%): | 0 | 50 | 0 | 50 | 100 | 0 | 50 | 100 |
| Year | | | | | | | | |
| 1980 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1985 | 0 | 20.7 | 0 | 83.4 | 166.7 | 0 | 60.2 | 120.4 |
| 1990 | 0 | 44.1 | 0 | 183.7 | 367.6 | 0 | 129.3 | 258.7 |
| 1995 | 0 | 60.7 | 0 | 298.0 | 596.0 | 0 | 202.7 | 404.5 |
| 2000 | 0 | 78.8 | 0 | 434.3 | 868.7 | 0 | 286.2 | 572.4 |

control house hourly load profiles. (It is assumed that ACES has been installed rather than air-to-air heat pumps and resistance water heaters.)

### 4.3.2 Load growth

Two load growth scenarios were also considered. The first scenario assumes that system load (both peak and total energy) grows according to the latest utility forecast. These forecasts already assume that the utility's current load management efforts are successful. For example Duke's current forecast anticipates that their current load management efforts will reduce the system peak in 1995 by 4769 MW in the summer and 5992 MW in the winter over and above those things that their customers would have done in the absence of the program.[12]

The most recent forecast available from Duke projects an average annual growth for peak load and energy of 3.8% through 1990 and 3.6% for the 1991—2000 period. Arkansas Power and Light projects growth of 2.5% through 1990 and 1.6% for 1991—2000. Both of these forecasts are substantially lower than previously published forecasts[9,10,13,14] and the historical growth rates for these utilities.

A second set of scenarios that assume that load grows slower than the utility forecasts was also studied for Duke. It was assumed that Duke's load growth averages 2.8% through 1990 and 2.6% for the 1991—2000 period. The fact that load growths lower than the utilities' forecasts were chosen for the second set of scenarios is not to say that actual growth may not be higher than the forecast. There are any number of events including economic recovery, load management programs being unsuccessful, electric vehicles, gas deregulation, and extreme weather, which might boost load growth. (For example, Duke's 1981 summer peak was 10,602 MW as opposed to a 1980 forecast of 10,460 MW.) The reason for choosing a lower estimate was that the historical trend in recent years has been towards reduced growth estimates.

Table 4.5 summarizes the base case peak loads for both utilities for the two cases.

Table 4.5. Base case peak loads (MW)

| Year | Arkansas Power and Light | Duke Power Company | |
|---|---|---|---|
| | Moderate | Low | Moderate |
| 1981 | 4,292 | 10,654 | 10,758 |
| 1982 | 4,399 | 10,953 | 11,167 |
| 1983 | 4,509 | 11,259 | 11,591 |
| 1984 | 4,622 | 11,574 | 12,031 |
| 1985 | 4,737 | 11,899 | 12,489 |
| 1986 | 4,856 | 12,232 | 12,963 |
| 1987 | 4,977 | 12,574 | 13,456 |
| 1988 | 5,101 | 12,929 | 13,967 |
| 1989 | 5,229 | 13,288 | 14,498 |
| 1990 | 5,360 | 13,660 | 15,049 |
| 1991 | 5,446 | 14,015 | 15,591 |
| 1992 | 5,533 | 14,380 | 15,152 |
| 1993 | 5,621 | 14,753 | 16,734 |
| 1994 | 5,711 | 15,137 | 17,336 |
| 1995 | 5,803 | 15,531 | 17,960 |
| 1996 | 5,896 | 15,934 | 18,607 |
| 1997 | 5,990 | 16,349 | 19,276 |
| 1998 | 6,087 | 16,774 | 19,970 |
| 1999 | 6,183 | 17,210 | 20,689 |
| 2000 | 6,282 | 17,657 | 21,434 |

### 4.3.3 Fuel prices

Table 4.6 summarizes the assumptions that were made with respect to fuel prices for this study. The 1981 values are typical of the prices paid by utilities for contract fuel delivered in late 1980 in Arkansas, North Carolina, and South Carolina.[15] The escalation rate of all fuels includes an assumed overall inflation rate of 7% during the study period.

The uranium price used in this analysis assumes modest expansion of nuclear generating capacity above current commitments. The 2.8% real escalation in the cost of nuclear fuel is based on the assumption that the currently depressed market for yellowcake ($25/lb) gradually recovers during the study period and that enrichment costs will increase.

Table 4.6. Fuel prices

| | Arkansas Power and Light | Duke Power Company |
|---|---|---|
| **Nuclear** | | |
| Beginning 1981 price (¢/MBtu) | 66.0 | 66.0 |
| Escalation rate (%/year)[a] | 10 | 10 |
| **Coal** | | |
| Beginning 1981 price (¢/MBtu) | 147.3 | 164.4 |
| Escalation rate (%/year)[a] | 9 | 9 |
| **Oil** | | |
| Beginning 1980 price (No. 6) (¢/MBtu) | 448.8 | NA |
| Beginning 1980 price (No. 2) (¢/MBtu) | 630.2 | 749.5 |
| Escalation rate (%/year)[a] | 12 | 12 |
| **Natural gas** | | |
| Beginning 1981 price (¢/MBtu) | 248.2 | NA |
| Escalation rate (%/year) 1981–1990[a] | 17.4 | NA |
| 1991–2000 | 12 | NA |

[a]Includes 7% general inflation.

The cost of coal presently exhibits wide regional variations that will continue into the future. The price utilities pay for coal generally consists of two components: a mine mouth price and a transport price. The 9% overall escalation used in this study was applied to both Eastern coal (Duke) and Western coal (APL); however, the components of the escalation are different for the two cases. The 1.9% real escalation in Eastern coal will be attributable primarily to increases in the mine mouth price as the demand for this fuel increases and new, more expensive mines are opened. The mine mouth price of Western coal is not likely to rise as fast as that of Eastern coal; however, the transportation charges are likely to escalate at a higher rate due to their dependence on oil and the longer distances involved. Thus the same overall rate was used for both cases, maintaining the regional variation in coal costs.

The future price of oil is by far the most volatile projection and will have a substantial impact on the projected price of all other fuels. The 12% rate used in this study is based on an oil price tied to real growth in gross national product (GNP), inflation, and real cost escalation relative to competing fuels. These indices have been proposed to the Organization of Petroleum Exporting Countries (OPEC) by Saudi Arabia as a suitable basis for future prices. Of course, such rates will be possible only if the current problems in the Middle East are resolved and there are no future gross disruptions.

The price of natural gas after deregulation will be closely tied to the price of oil because of the substitutability of the fuels in many applications. The escalation rates used in this study assume that natural gas will reach parity with No. 6 oil by 1990. (No. 6 was used instead of No. 2 because it was felt that natural gas would not see widespread usage in the transportation sector, which would maintain a premium for No. 2.)

All the fuel price assumptions used in this study fall within the range of values currently projected by the Energy Information Administration[16] and are believed to be consistent with the capital cost and financial assumptions used for the study.

#### 4.3.4 Capital costs

Table 4.7 shows the economic ground rules and capital costs for new coal and nuclear plants that were used for this study.[17] The estimates are based on detailed engineering designs for plants conforming to safety and environmental regulations in effect as of January 1980. Depending on what economic ground rules are assumed (e.g., escalation rate, interest rate), the estimated cost of a nuclear plant for first commercial operation in 1995 is from $4300 to $4500/kW(e) in 1995 dollars.

Similarly, coal plants are expected to range from $3000 to $3300/kW(e). Of course, actual costs will vary significantly depending on construction lead time, interest and escalation rates, and year of commercial operation.

Combustion turbines were considered as the third expansion alternative for the two utilities at a cost of $267/kW(e) for commercial operation in 1983.

Table 4.7. Generation expansion candidates

| Property | 1200 MW LWR | 800 MW coal | 150 MW combustion turbine |
|---|---|---|---|
| Licensing and construction lead time (year) | 12 | 8 | 2 |
| Capital cost (millions of dollars): | | | |
| Direct and indirect costs[a] | 1535 | 787 | 33 |
| Allowance for escalation | 1595 | 993 | 4 |
| Allowance for interest | 2220 | 870 | 3 |
| Plant capital cost at commercial[b] operation | | | |
| Millions of dollars | 5350 | 2550 | 40 |
| Dollars per kilowatt | 4458 | 3312 | 267 |
| Possible commercial Operation | 1993 (APL)<br>1990 (Duke) | 1989 | 1983 |
| Escalation rate for capital costs | 9 | 9 | 9 |
| Book life | 30 | 30 | 20 |
| Tax life (ACRS) | 10 | 10 (APL)<br>15 (Duke) | 10 |

[a]In January 1982 dollars.

[b]1995 start-up year for nuclear and coal, 1983 start-up year for combustion turbines. Current dollars.

The earliest possible year of commercial operation is based on the plant licensing and construction lead time assuming a decision made in 1981, except for the case of new nuclear units for Duke. The 1990 operation date for a new nuclear unit in Duke is based on the fact that Duke has already started construction on the Cherokee plant. Construction on unit one is currently halted at 18% completed.[18] The 1990 date for Duke assumes that construction on this unit would be resumed if another new plant beyond McGuire and Catawba were needed.

### 4.3.5 Generating unit characteristics

Data describing individual generating unit performance in the two utilities were taken from a variety of sources. The heat rate curves for each thermal generating unit were taken from published utility sources.[9,10,19–21] The data characterizing each hydroelectric unit were likewise taken from annual performance records.[14,15,22] Average flow conditions were used for all production cost and reliability calculations.

The net maximum dependable capability used for each generating unit was the observed capability at time of the summer peak. This number can vary significantly from the nameplate rating or winter capability due to such things as cooling water temperatures, thermal discharge and ambient air quality restrictions, or in the case of hydro units, reservoir levels and recreational considerations.

Generating unit maintenance requirements and forced outage rates were taken from the NERC ten-year reports on equipment availability.[23] The reason for using these data instead of actual unit operating histories from the generating units in the two utilities is that for many of these units insufficient operating history has been accumulated to project long-run reliability. For example, APL's two nuclear units (Arkansas Nuclear One Units 1 and 2) have accumulated only about 8 unit-years of operation. Likewise APL's only coal plant, White Bluff, had units come on line in 1980 and 1981. Because forced outage rates are defined to be a long-run average, it was felt that the many unit-years of data represented in the NERC ten-year averages were more suitable.

Equivalent forced outage rates were used to include the effects of partial unit outages. Maintenance requirements were calculated on the basis that the total unit unavailability due to full outages, partial outages, and maintenance resulted in the equivalent availability reported in the NERC data. The NERC data are reported by unit size and primary fuel type. In the case of units that burn multiple fuels (e.g., oil-natural gas), a weighted average based on the amount of each fuel burned was used.

### 4.3.6 Financial

Tables 4.8 and 4.9 summarize the economic ground rules used for the study. The capitalizations of APL and Duke as of the end of 1980[24] are assumed to continue into the future. The cost of debt and equity capital is based on an assumed 7% inflation rate over the 20-year study period.

The levelized fixed charge rates used for the study reflect the tax law changes contained in the Economic Recovery Tax Act of 1981 as they

Table 4.8. Financial parameters

| | | |
|---|---|---|
| APL: | Debt ratio, % | 51.7 |
| | Preferred equity, % | 16.7 |
| | Common equity, % | 31.6 |
| Duke: | Debt ratio,% | 49.2 |
| | Preferred equity, % | 13.5 |
| | Common equity, % | 37.3 |
| Debt cost, % | | 10 |
| Preferred return, % | | 10 |
| Common return, % | | 15 |
| Federal income tax rate, % | | 46 |
| State income tax rate, % | | 4 |
| Property tax and insurance, % | | 2.5 |
| Tax depreciation method | | ACRS |
| 10% investment tax credit | | |

apply to new public utility property. Depreciation on new assets was calculated using the new accelerated cost recovery system (ACRS). This system replaces the old asset depreciation range (ADR) guidelines used with either straight line or accelerated depreciation.

Information currently available indicates that new nuclear units and combustion turbines will qualify as 10-year property under ACRS, while new coal units will be classified as 15-year property unless the coal unit is being used to displace oil or natural gas in which case the 10-year rates are used. The question of whether a new generating unit is displacing oil or natural gas, as opposed to serving load growth, is certainly open to interpretation, and new guidelines will probably develop. For this study, it was assumed that coal units would qualify as 10-year ACRS property in APL by virtue of APL's substantial existing oil- and gas-fired capacity. New coal units planned by Duke were treated as 15-year ACRS property.

The new depreciation guidelines specify that utilities using the ACRS method of depreciation must normalize all tax benefits. Consequently, normalized accounting was used throughout this study.

Table 4.9. Levelized fixed charge rates
(%/year)

| | Arkansas Power and Light | | | Duke Power Company | | |
|---|---|---|---|---|---|---|
| | Nuclear | Coal | Combustion turbines | Nuclear | Coal | Combustion turbines |
| Annual level premium[a,b] | 11.34 | 11.34 | 12.91 | 11.92 | 12.97 | 13.45 |
| Property tax and insurance | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| Interim replacement[c] | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Backfitting (regulatory) cost[c] | 2.0 | 1.0 | 0 | 2.0 | 1.0 | 0 |
| Decommissioning sinking fund[d] | 0.32 | 0 | 0 | 0.32 | 0 | 0 |
| Levelized fixed charge rate | 17.16 | 15.84 | 16.41 | 17.74 | 17.47 | 16.95 |

[a]Book life of 30 years for nuclear and coal, 20 years for combustion turbines.

[b]ACRS - Nuclear and combustion turbines 10 year property;
Coal - 15 year property in Duke, 10 year in APL (natural gas backout).

[c]Levelized - payments escalate at 7%/year.

[d]Decommissioning cost equal to 10% of initial investment in constant dollars. Actual dollar cost is 76% [$(1.07)^{30}$ (0.10)] of initial investment in current dollars.

### 4.3.7 Planning criteria

The planning criteria that utilities use to determine the type and timing of generating unit additions has been the subject of considerable controversy. The problem has historically been one of providing adequate reliability at the lowest possible cost, which was synonymous with maintaining the lowest possible reserve margin. However, changes in the cost of producing power, most notably the tremendous increases in the cost of oil, have changed the economics of power system reliability. Detailed studies have shown that in many parts of the country consumer costs can actually be lowered by increasing the planning reserve margin to accelerate the replacement of economically obsolete generating units.[5] The principal problem with achieving these economies is the strain that such an ambitious construction program places on the financial resources of the utility.

Rather than addressing the issue of what constitutes an appropriate planning criteria, where possible the planning criteria adopted by the regional reliability councils containing the case study utilities were used. The generation capacity planning criterion of the SPP, of which APL is a member, states that available reserves shall exceed the predicted annual peak load obligation by a margin of 15%. Alternately, a probability study can be made to determine capacity requirements such that the LOLE does not exceed 1 d in 10 years provided that in no case shall the reserve be less than 12% of the peak load obligation.[13]

The VACAR subregion of the SERC, of which Duke is a member, does not specifically state what planning criteria are used to determine generation capacity requirements.[14] However, a review of all the reliability regions that do describe their planning criteria[25] shows that the SPP criteria are fairly typical and the same criteria were applied to Duke.

# 5. RESULTS

## 5.1 Load Profiles

Figures 5.1 and 5.2 show the normalized annual load profiles for APL and Duke, respectively, for 1980. These load shapes were used as the base cases with which the various ACES penetration scenarios were compared. The figures clearly show the reasons why these utilities might be interested in load management, in general, and ACES, in particular. The severe summer peaking problem of APL is readily apparent in Fig. 5.1.

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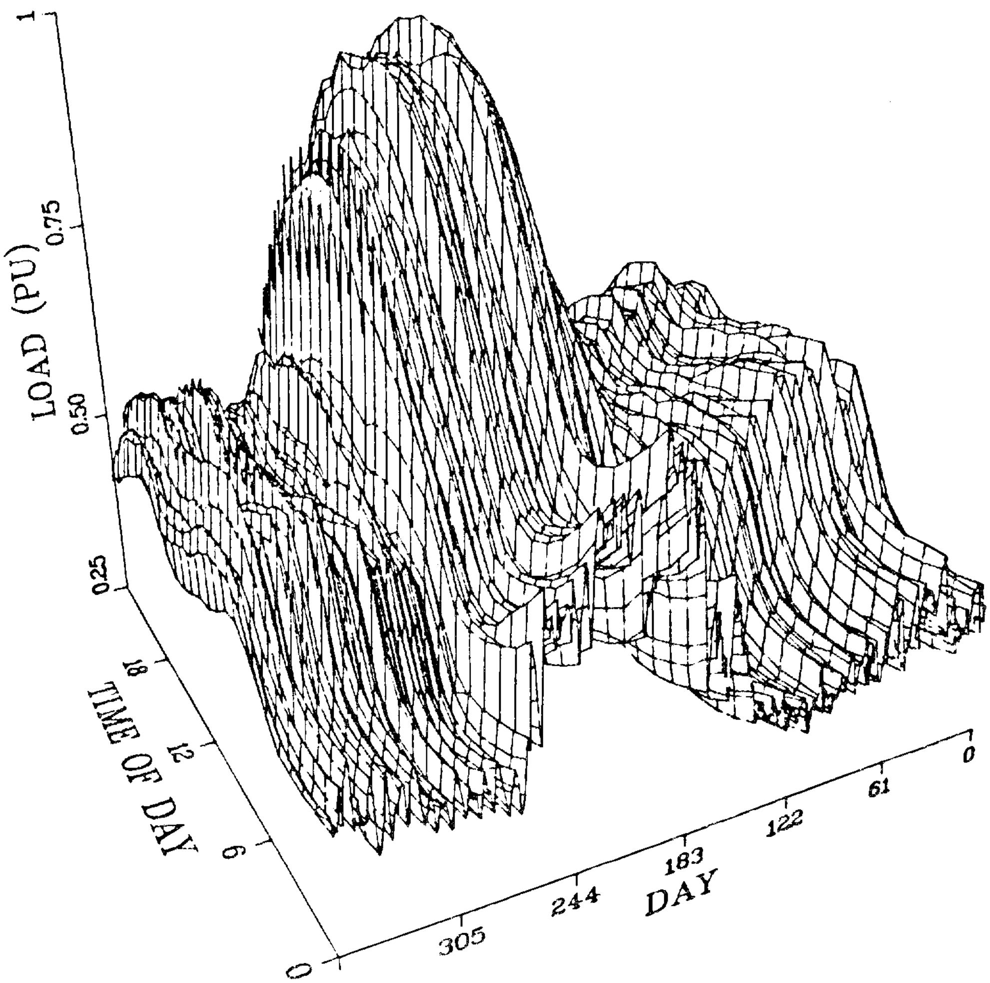


Fig. 5.1. APL base case annual load profile.

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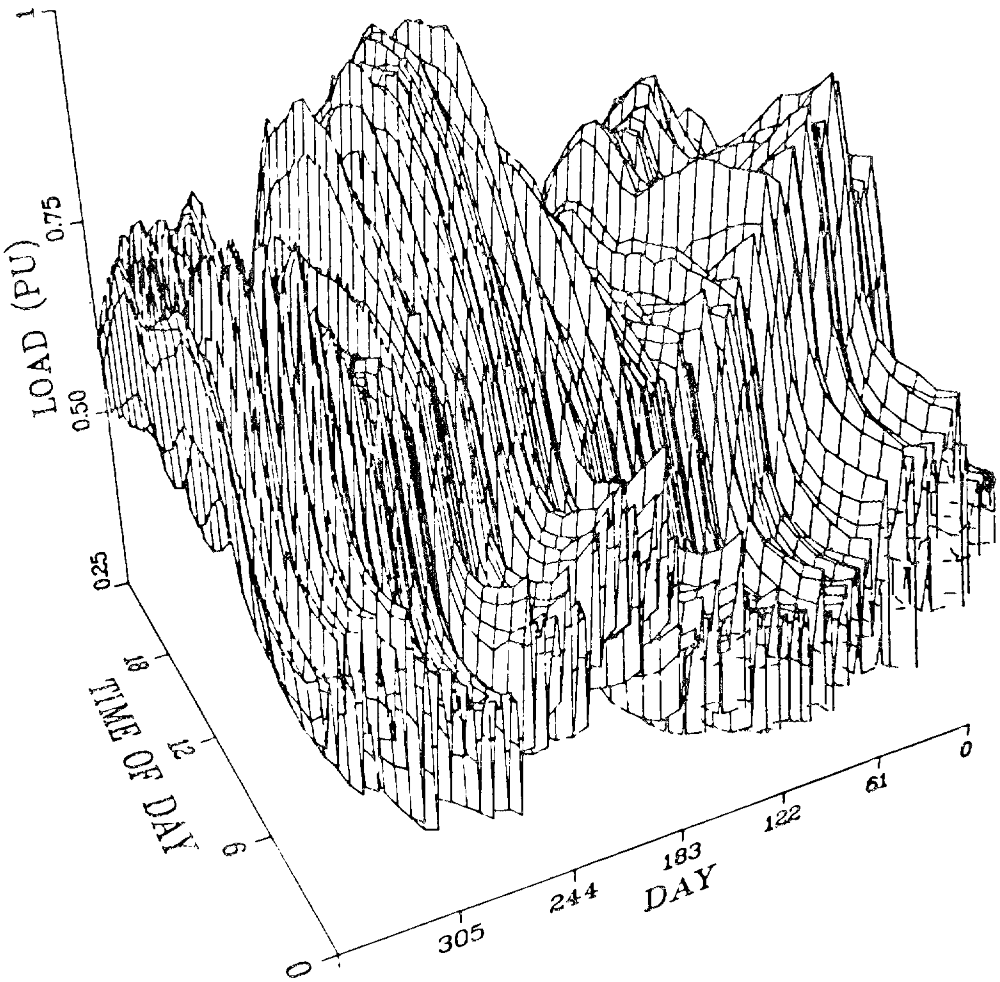


Fig. 5.2. Duke base case annual load profile.

Arkansas Power and Light's 1980 annual load factor was 53.3%, and its winter peak was only 65% of the 4179-MW summer peak. Of total annual energy sale of 19.6 TWh, 8.1 TWh were produced during May through August. The summer of 1980 was unusually hot, with Little Rock experiencing 2579 degree-days of cooling compared with an average of 1925 degree-days.

Duke's 1980 annual load profile does not exhibit the marked summer peaking of APL. The winter peak is 95% of the 10,364-MW summer peak. However, the 1980 system annual load factor was still only 61.5%. The winter daily load profile shows the characteristic early morning peak and midday valley common to many utilities' winter load profile. Annual energy production was 56.0 TWh.

As discussed in Sect. 4.3, one load growth scenario was investigated for APL and two load growth scenarios for Duke. These load growth scenarios were combined with three ACES penetration scenarios, 0, 50, and 100% ACES in new single family residences, to yield a total of nine load profile scenarios.

Figure 5.3 shows APL's year 2000 annual load profile for the 100% ACES penetration, moderate load growth case. While this annual profile is substantially similar to the base case load profile shown in Fig. 5.1, there are some discernible differences. Comparing Figs. 5.1 and 5.3, the summer peaking season in Fig. 5.3 is less accentuated, as is the early

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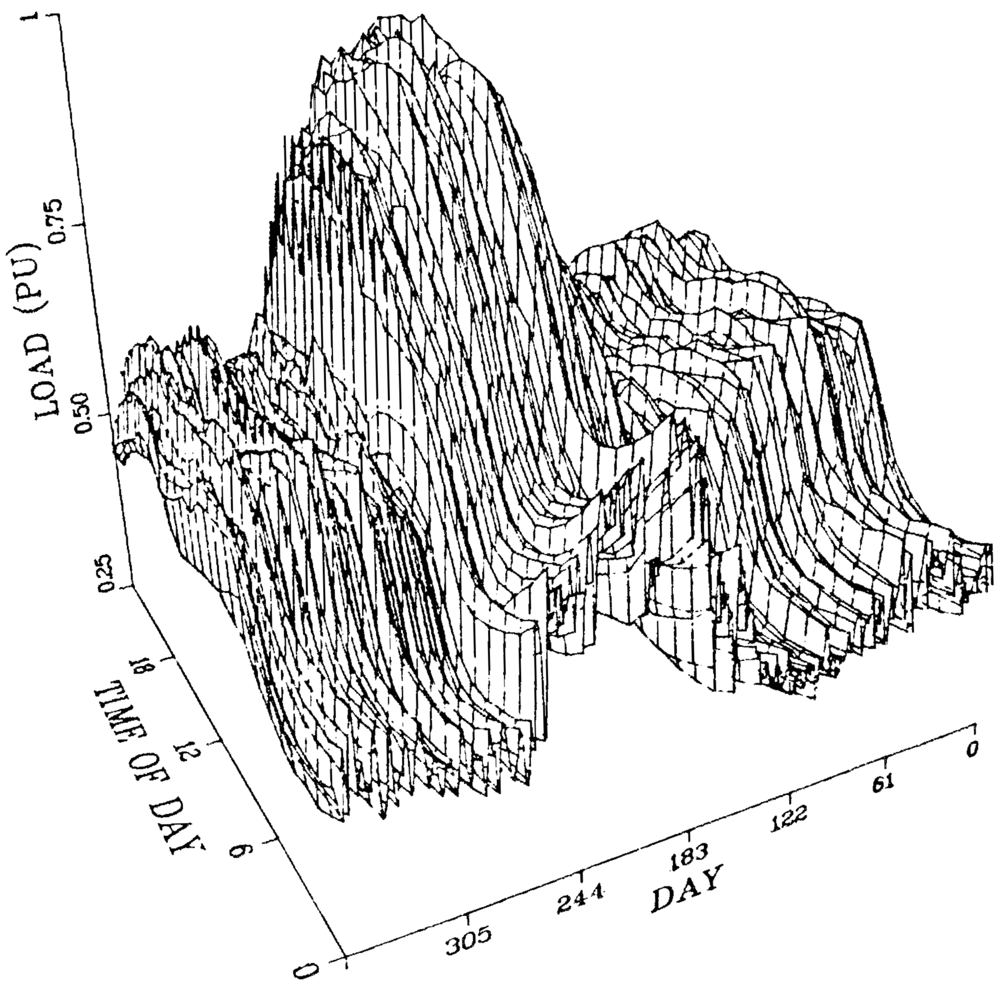


Fig. 5.3. APL 100% ACES saturation year 2000 annual load profile.

evening peak during winter days. The net result of the differing load characteristic of an ACES house compared with a conventional house would be to improve the system annual load factor from 53.3 to 56.3%. The annual peak would be reduced from 6270 to 5726 MW, and total annual energy production would be 28.5 TWh instead of 29.3 TWh.

The load shape changes due to ACES are more pronounced for Duke. Figure 5.4 shows the year 2000 annual load profile for Duke for the moderate load growth, 100% ACES penetration scenario. Comparing Figs. 5.2 and 5.4, the summer peak has been reduced almost to the winter peak and

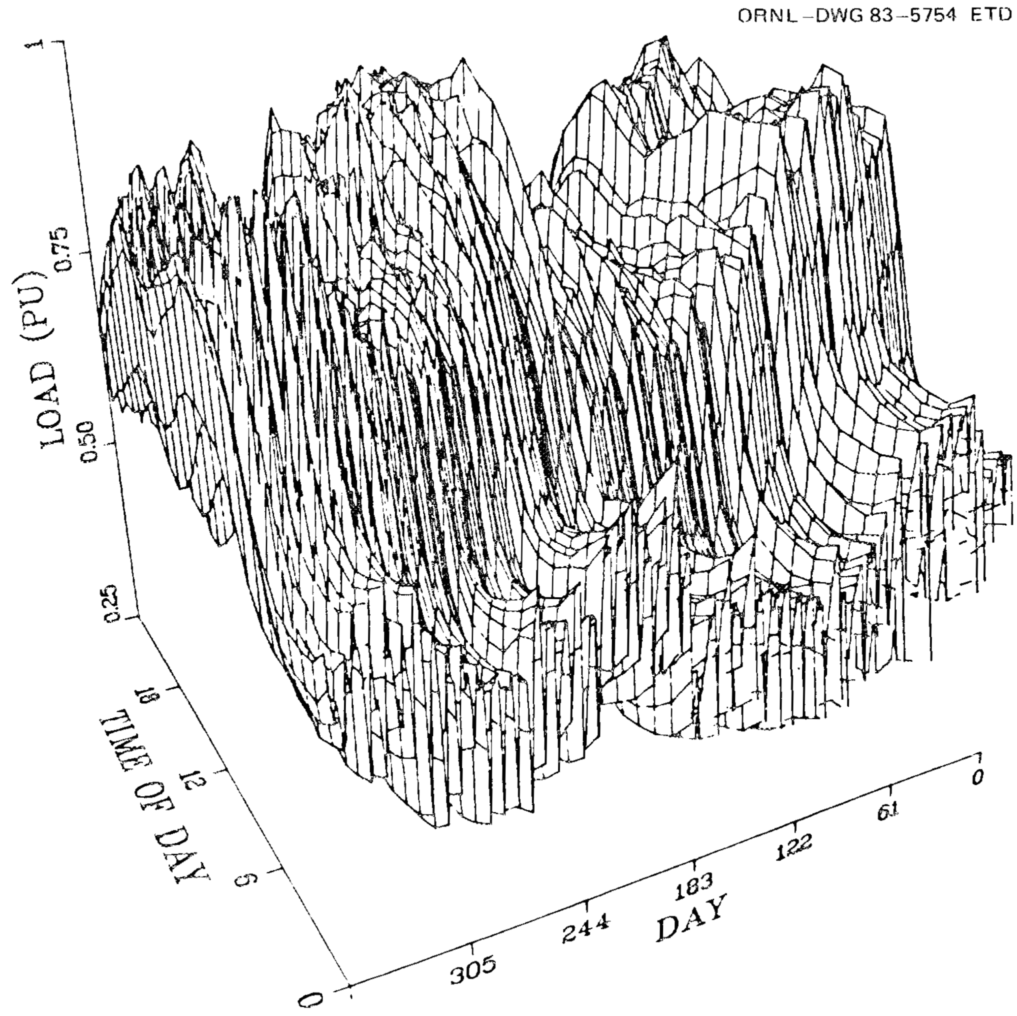


Fig. 5.4. Duke 100% ACES saturation year 2000 annual load profile.

both the summer daily and winter daily load profiles have been substantially flattened. Also, the early morning daily winter peak has been reduced. The load profile for this scenario shows that the annual load factor improved from 61.5 to 66.4%, the annual peak has been reduced by 2286 MW, and total energy consumption has been reduced from 115.9 to 111.7 TWh. The load statistics for the year 2000 for all nine cases are summarized in Table 5.1.

Table 5.1. Year 2000 annual load statistics for study scenarios

| Utility | Scenario load growth | ACES penetration (%) | Peak (MW) | Energy (TWh) | Load factor (%) |
|---|---|---|---|---|---|
| APL | Moderate | 0 | 6,270 | 29.3 | 53.3 |
| APL | Moderate | 50 | 5,998 | 28.9 | 54.8 |
| APL | Moderate | 100 | 5,726 | 28.5 | 56.3 |
| Duke | Moderate | 0 | 21,434 | 115.9 | 61.5 |
| Duke | Moderate | 50 | 20,143 | 113.8 | 64.3 |
| Duke | Moderate | 100 | 19,148 | 111.7 | 66.4 |
| Duke | Low | 0 | 17,657 | 95.5 | 61.5 |
| Duke | Low | 50 | 16,758 | 94.1 | 63.9 |
| Duke | Low | 100 | 16,103 | 92.7 | 65.5 |

These load shape changes are the culmination of gradual changes over the 20-year planning horizon. Figures 5.5—5.7 summarize the annual peak loads for the various ACES penetrations for the APL moderate load growth, Duke moderate load growth, and Duke low load growth cases, respectively. Note that Fig. 5.5 does not contain the curve for the 100% ACES case for APL. This case was not fully analyzed because it was felt at the end of the APL 50% ACES saturation case that no additional information would be gained by completing this case.

Figure 5.5 clearly shows the lower rate of load growth that is currently forecast for APL in the 1991—2000 time frame. The forecast used

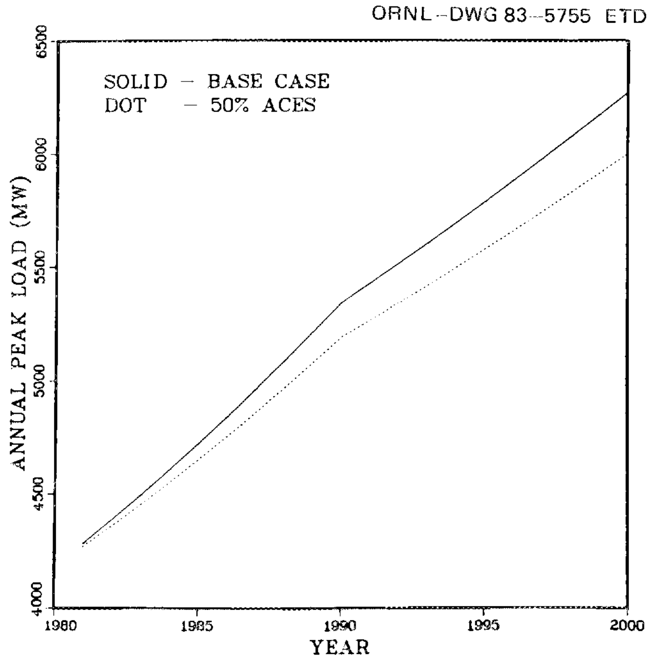


Fig. 5.5. APL moderate load growth cases annual peak loads.

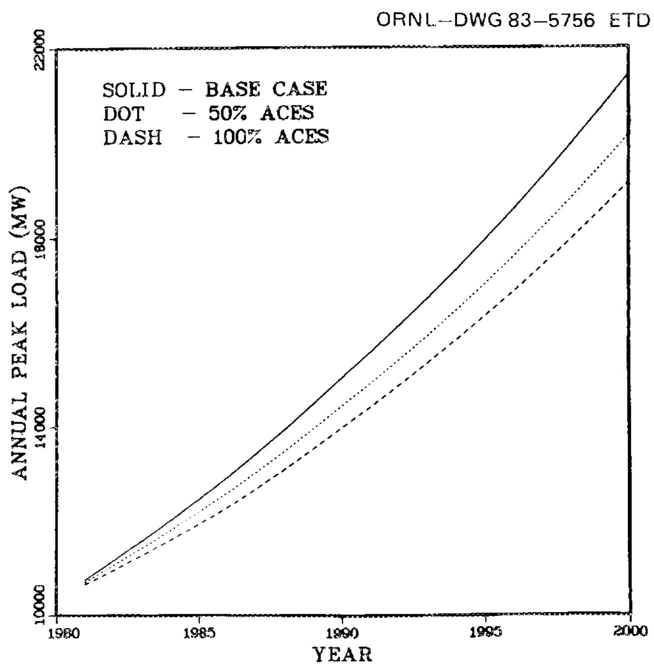


Fig. 5.6. Duke moderate load growth cases annual peak loads.

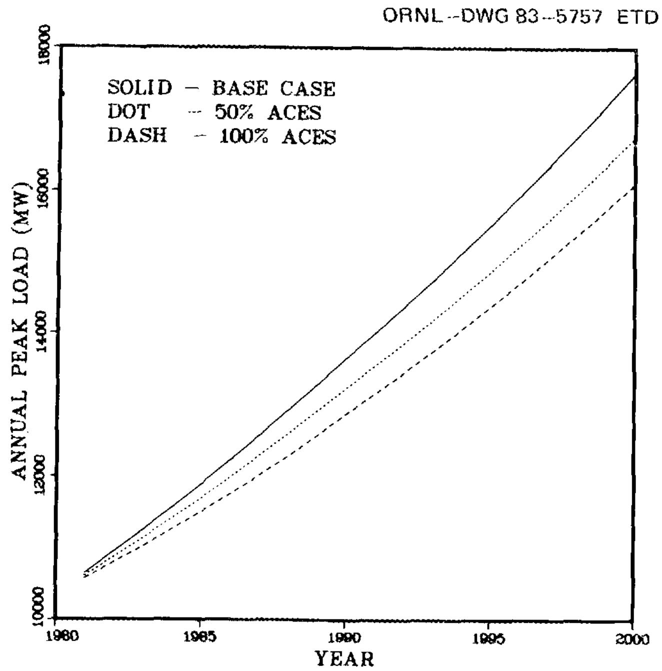


Fig. 5.7. Duke low load growth cases annual peak loads.

for this study predicts 2.5% average annual load growth for the 1981—90 time frame dropping to 1.6% per year during the 1991—2000 period. This growth rate change shows up as a sharp break in the slope of the load growth curve.

The figure also shows the annual peak load reductions attributable to ACES, which grow to a peak reduction of 272 MW by the year 2000. The corresponding number of ACES installations in this case would be 78,755 for that year or a peak load reduction per ACES installation of about 3.45 kW.

Similar results for Duke are evident in Figs. 5.6 and 5.7. The load forecast used for the moderate load growth cases predicts average load growth of 3.8% per year from 1981—90 and 3.6% for 1991—2000. The low load growth case assumes 2.8% growth per year for 1981—90 and 2.6% for 1991—2000. It is interesting to note that the peak load reduction from the moderate load growth base case attributable to a 50% saturation of ACES is 1293 MW, while the next 50% removes only 995 MW more. This is because between these two saturation levels, the time of the annual peak changes due to the load profile changes. These peak reductions correspond to 2.97 kW/installation for a 50% saturation and 2.63 kW/installation for a 100% saturation. This is a clear example of diminishing returns.

Figures 5.8—5.10 show the annual load factors for the eight cases. As in the case of peak loads, the first 50% of ACES houses produces a greater improvement in annual load factor than the next 50%.

Finally, Figs. 5.11—5.13 show the energy under the annual load curves for the various cases. Because ACES is more efficient than the conventional air-to-air heat pump and electric water heater it is assumed to replace, the utility is required to produce less energy. However, a comparison of Figs. 5.5—5.7 with Figs. 5.11—5.13 shows that the impacts on load shape are much more dramatic than those on total energy production. For example, a 100% ACES saturation in the Duke moderate load growth case reduces system peak load by 10.67%, while reducing total annual energy by only 3.62%.

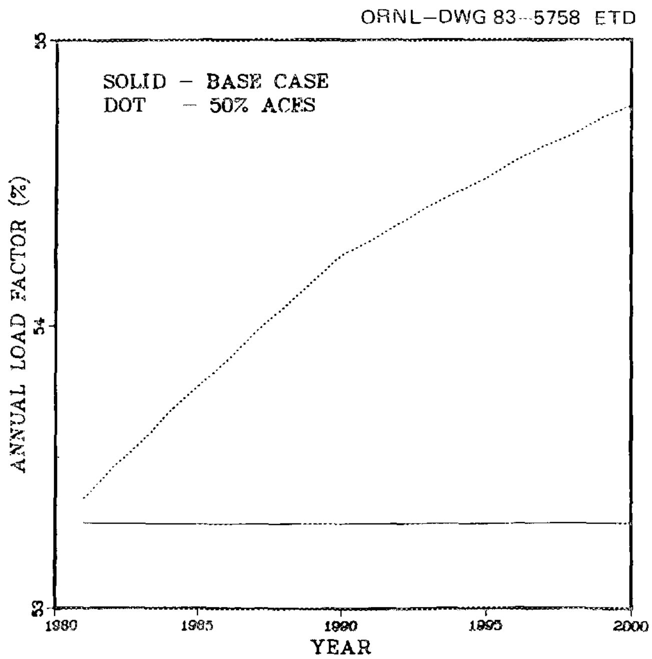


Fig. 5.8. APL moderate load growth cases annual load factors.

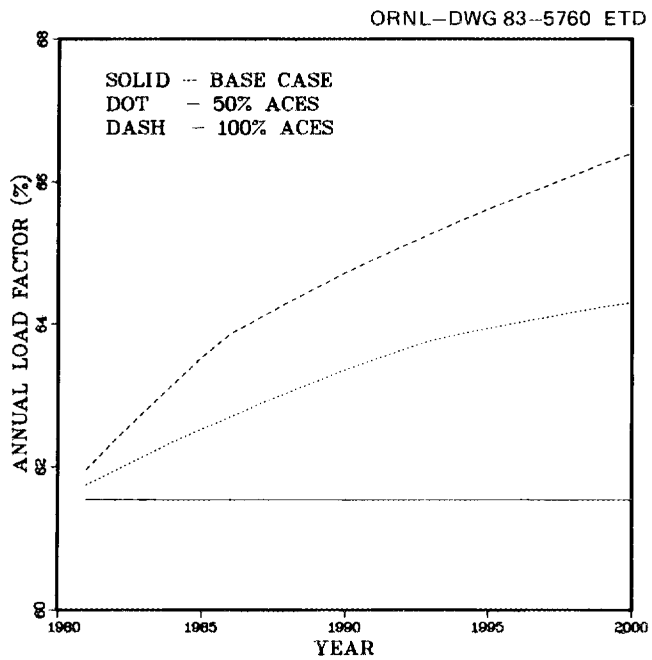


Fig. 5.9. Duke moderate load growth cases annual load factors.

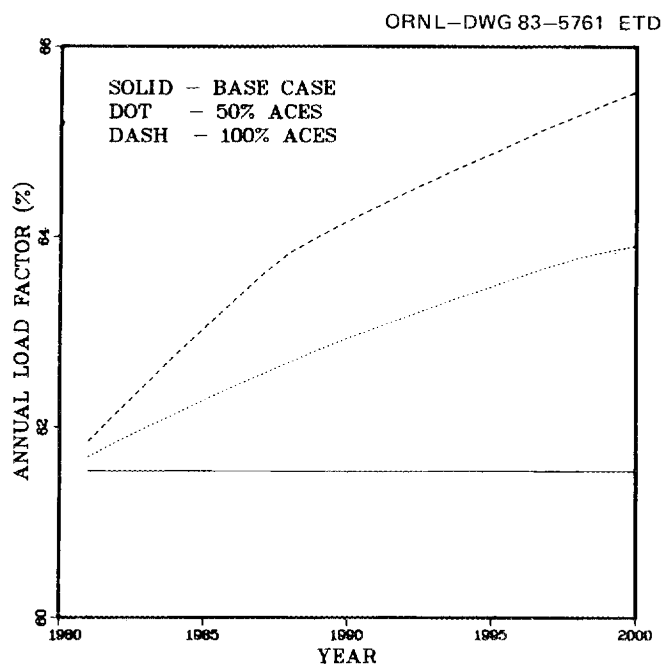


Fig. 5.10. Duke low load growth cases annual load factors.

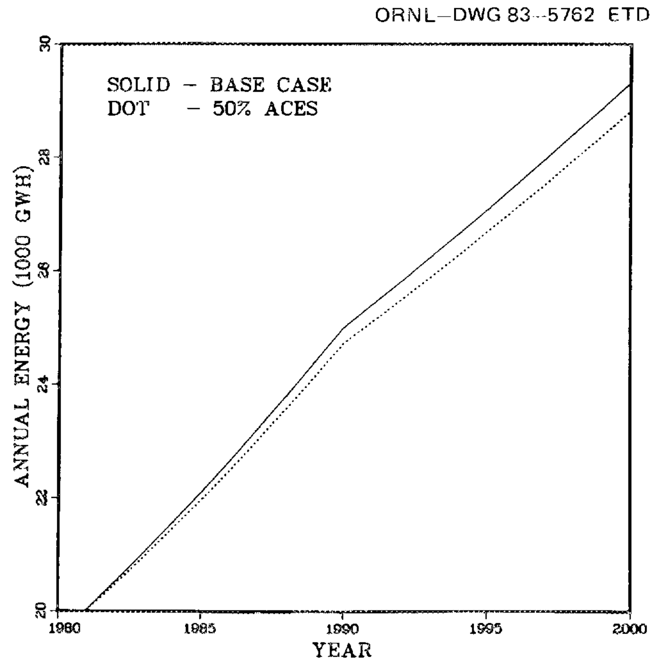


Fig. 5.11. APL moderate load growth cases annual energy production.

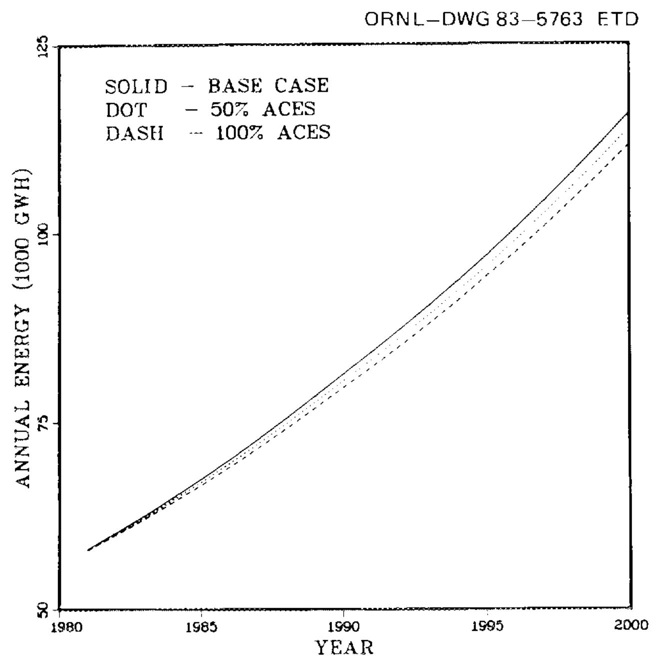


Fig. 5.12. Duke moderate load growth cases annual energy production.

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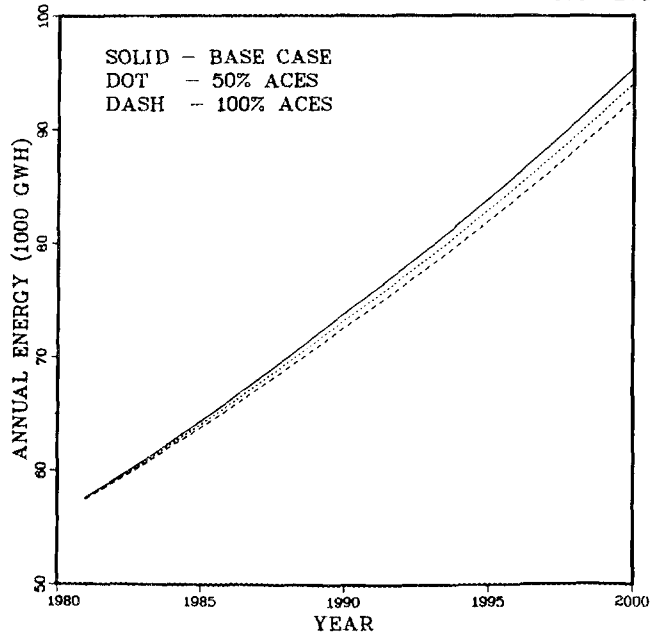


Fig. 5.13. Duke low load growth cases annual energy production.

## 5.2 Revenue Requirements

Two of the most frequently cited objectives of load management are to increase the utilization of existing equipment and to reduce the need for new capital expenditures. The next step in this study was to determine the effects of the load shape changes attributable to ACES on the utilization of existing generating units and the need for new units. As discussed in Sect. 4.1, this was done using a dynamic programming generation expansion planning package (WASP), which includes probabilistic simulation of production costs, reliability evaluation, and traditional engineering economic treatment of all capital and operating expenditures.

The principal outputs of the WASP code are the least-cost expansion plan over the planning horizon for the given conditions, the expected annual production costs for each generating unit (which can be aggregated by fuel type), the reliability (measured by LOLP) of each generating unit configuration, and the capital expenditures associated with the plan. A useful feature of dynamic programming for solving the generation expansion planning problem is that, in finding the least-cost plan, the costs of all suboptimal plans are also calculated. Thus, in addition to the best plan, the second best, third best, etc., plan can also be examined. This is a useful feature that can be used to judge the sensitivity of the solution to key study assumptions.

The WASP package considers the existing generating system, firm additions to and retirements from the existing system, and up to 20 different types of new generating units as expansion candidates. In this study, the existing system and all firm additions to and retirements from the system were considered to be fixed and are common to all scenarios. A generating unit addition was considered to be fixed only if it was already under construction as of the beginning of 1981. All unit additions are assumed to occur at the beginning of the year.

In the case of APL, the fixed unit additions included APL's share of the coal-fired White Bluff Unit 2 (57% or 465 MW), assumed to come on-line in 1982, and its share of the coal-fired Independence Units 1 and 2 (56.5% or 461 MW each) assumed to come on-line in 1983 and 1985, respectively. APL is also planning to retire ten older generating units during the 1981—90 period.[13]

The firm additions considered for Duke Power Company include the Maguire nuclear units coming on-line in 1982 and 1983 and Duke's share of nuclear units Catawba 1 and 2 in 1984 and 1986. Cherokee Unit 1 (nuclear) was not considered to be a firm addition even though it is 18% complete, because construction on the unit was stopped on September 30, 1981.[18] Although the unit was not considered to be a firm addition, it was assumed that if a decision were made in 1981, the unit could be completed by 1990 instead of the 12-year lead time assumed for other nuclear units. Also, the capital cost estimate for Cherokee Unit 1 was credited for the expenditures made to date.

Before the expansion plans for each scenario are discussed, some words of caution are in order. First, the least-cost generation expansion plan for a utility is sensitive to load shape, load growth, capital cost estimates, operation and maintenance expense estimates, fuel cost assumptions, assumed unit performance characteristics (forced outage rates, maintenance requirements, heat rates, minimum and maximum operating levels, ramp rates, minimum up and down times, spinning reserve requirements), and financial assumptions. The objective of this study is to analyze the changes in plans due to load shape and load growth changes that might occur if ACES were installed holding all other parameters constant. Every effort has been made to make reasonable, internally consistent assumptions throughout this study; however, a different set of assumptions would produce different results. However, it is the difference between two plans that is of interest in this study. Assumptions that consistently change the magnitude of a result tend to have a lesser impact on the difference between two results.

A second word of caution has to do with the continuing coal vs nuclear controversy. Both utilities in this study have both coal and nuclear units in their current systems and continue to be good candidates for a mix of new base load units. The capital cost estimates used in this study assume post-Three Mile Island design modifications for nuclear units and new source performance standards for pollution controls for coal units. These assumptions, together with current fuel cost estimates, result in substantially similar total generating costs for these two base load options. There are a number of circumstances unique to each utility (such as the multiple nuclear units planned at Cherokee and the proposed Bad Creek pumped storage plant in the case of Duke or the planned Arkansas Lignite Energy Center for APL), which might shift the advantage one way or the other. As far as this study is concerned, either option could be read as "base load plant" with little loss of precision.

Table 5.2 summarizes the least-cost expansion plans for the two APL scenarios. The base case plan calls for APL to add two jointly owned coal-fired units in 1989, one nuclear unit in 1993, and a third coal-fired unit in 1999. (Note that these are in addition to White Bluff 2 and Independence 1 and 2 and considering ten unit retirements.) The second best plan for this scenario called for two coal units in 1989, a nuclear unit in 1993, and a second nuclear unit in the year 2000 at an increase in total revenue requirements of 0.0525%.

The total system production costs for the two plans by fuel type are summarized in Figs. 5.14 and 5.15. As shown in the two figures, the

Table 5.2. APL moderate load growth optimal generation expansion plans

| Expansion candidate | Year of commercial operation | |
|---|---|---|
| | Base case | 50% ACES |
| Nuclear (600 MW)[a] | 1993 | |
| Coal (480 MW)[a] | 1989-2, 1999 | 1989-2, 1994, 1999 |
| Combustion turbine (150 MW) | | |

[a] Unit sizing assumes joint ownership with other utilities of a 1200-MW nuclear unit or an 800-MW coal-fired unit. Capacity represents APL's share.

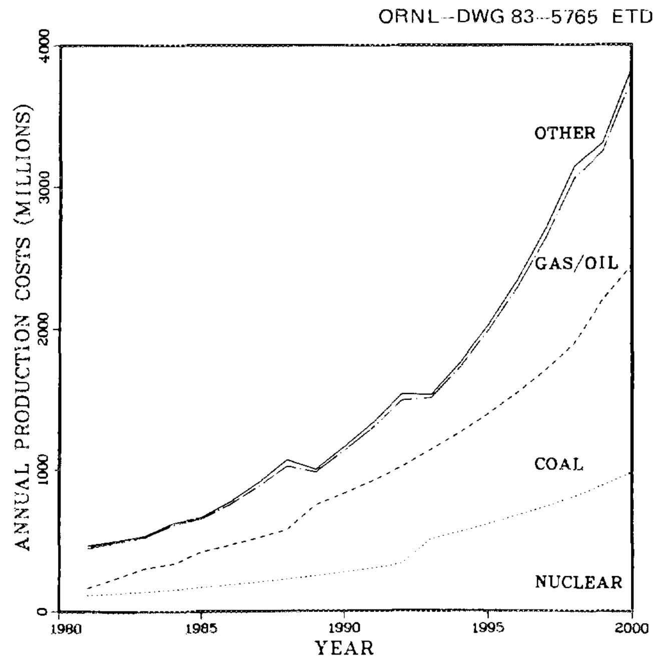


Fig. 5.14. APL annual production cost components: Moderate load growth/0% ACES.

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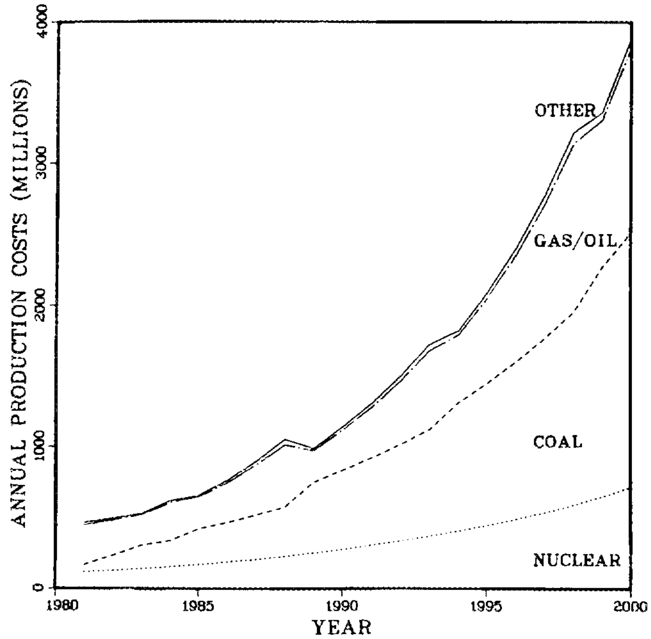


Fig. 5.15. APL annual production cost components: Moderate load growth/50% ACES.

relatively large contribution to current production costs of APL's gas- and oil-fired units will be shrinking as new base load generating units come on-line. The two sets of curves are identical until 1993, when a nuclear unit would be scheduled for operation in the base case. The dips in the total production cost curve as new, more cost-efficient generators come on-line is clearly discernable. By the year 2000, the two curves are again virtually identical.

However, the 50% ACES case has resulted in a 120-MW decrease in new capacity and a 1-year deferral of the need for new capacity. Table 5.3 summarizes the levelized revenue requirements for the two cases in 1981 dollars. As shown in the table, the 50% ACES scenario results in a slight increase in production costs due to the decrease in new base load capacity. However, the capital cost savings more than compensate for the production cost increase resulting in a net savings of 0.707 mills/kWh, or $892 per ACES installation levelized over the 20-year planning horizon. Note that this $892 system savings per ACES installation is in addition to the savings that accrue to individual homeowners due to the

Table 5.3. Levelized revenue requirements for APL scenarios[a]

| Scenario | Operating costs (mills/kWh) | Capital costs[b] (mills/kWh) | Total revenue requirements (mills/kWh) | Cost savings (mills/kWh) | Cost savings ($/ACES house) |
|---|---|---|---|---|---|
| Base case | 45.281 | 8.161 | 53.442 | | |
| 50% ACES | 45.878 | 6.856 | 52.735 | 0.707 | 892 |

[a]1981 dollars.

[b]Incremental above fixed unit additions and existing system.

higher efficiency of their space conditioning and water heating system. While the cost savings per kilowatt-hour or per ACES installation may sound insignificant, it is important to bear in mind that the total difference in revenue requirements between the two cases is $212.8 million in 1981 dollars.

Table 5.4 summarizes the expansion plans for the six Duke scenarios. The base case for the moderate load growth scenarios resulted in a least-cost plan that calls for Cherokee Unit 1 to be completed by 1990; coal units in 1991, 1993, and 1994; a second nuclear unit in 1995; and four more coal units in 1997, 1998, 1999, and 2000. For comparison, the second best plan called for a third nuclear unit to be substituted for the coal unit in the year 2000 at a cost premium of 0.226% over the best plan.

The two ACES scenarios result in changes both in timing and the total number of generating units built during the planning horizon. In the 50% ACES scenario, Cherokee Unit 1 would be deferred one year to 1991, two nuclear units would be built in 1993 and 1997, and four coal units in 1995, 1996, 1999, and 2000. The 100% ACES case resulted in a least-cost plant whereby Cherokee Unit 1 would come on-line in 1992, a second nuclear unit in 1997, and coal units in 1994, 1996, 1999, and 2000.

The three low load growth scenarios for Duke show a similar pattern to the moderate load growth scenarios. A higher penetration of ACES delays the preferred date for Cherokee Unit 1 to 1996 and results in one or two fewer coal units in the 50% or 100% ACES cases, respectively. In addition, the combustion turbine plant, which was economic in the base case, would not be built.

Duke, whose primary energy sources are already coal and nuclear power, does not exhibit the same production cost behavior as APL. For APL's existing generation mix, the ACES case led to higher production costs in later years due to the deferral and reduced construction of new base-load capacity. Figures 5.16 and 5.17 show total annual production costs for the six Duke scenarios. In the moderate load growth cases, the 50% ACES penetration results in the lowest annual production costs starting in 1993, with the 100% ACES case slightly higher and the base case

Table 5.4. Duke optimal generation expansion plans

| Expansion candidate | Year of commercial operation | | |
|---|---|---|---|
| | Base case | 50% ACES | 100% ACES |
| | **Moderate load growth** | | |
| Cherokee Unit 1 (1280 MW) | 1990 | 1991 | 1992 |
| Nuclear (1200 MW) | 1995 | 1993, 1997 | 1997 |
| Coal (800 MW) | 1991, 1993, 1994, 1997, 1998, 1999, 2000 | 1995, 1996, 1999, 2000 | 1994, 1996, 1999, 2000 |
| Combustion turbine (150 MW) | | | |
| | **Low load growth** | | |
| Cherokee Unit 1 (1280 MW) | 1993 | 1995 | 1996 |
| Nuclear (1200 MW) | | | |
| Coal (800 MW) | 1996, 1998, 1999 | 1998, 1999 | 1999 |
| Combustion turbine (150 MW) | 1997 | | |

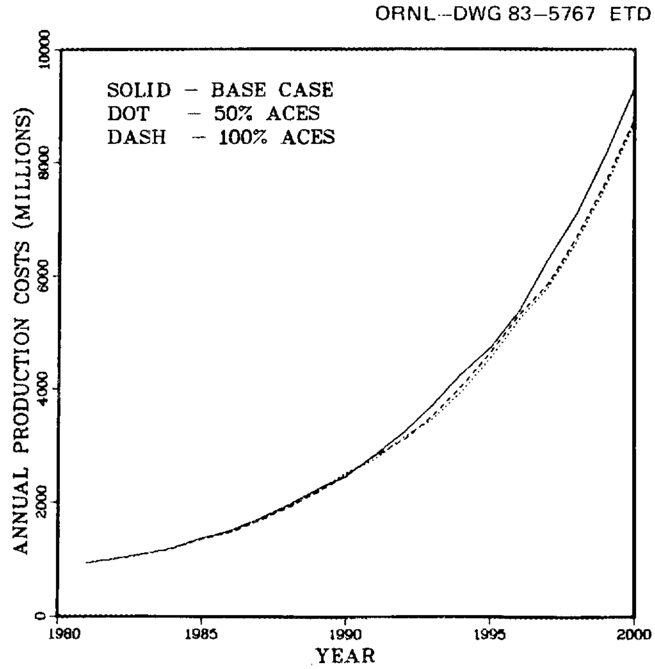


Fig. 5.16. Duke moderate load growth cases annual production costs.

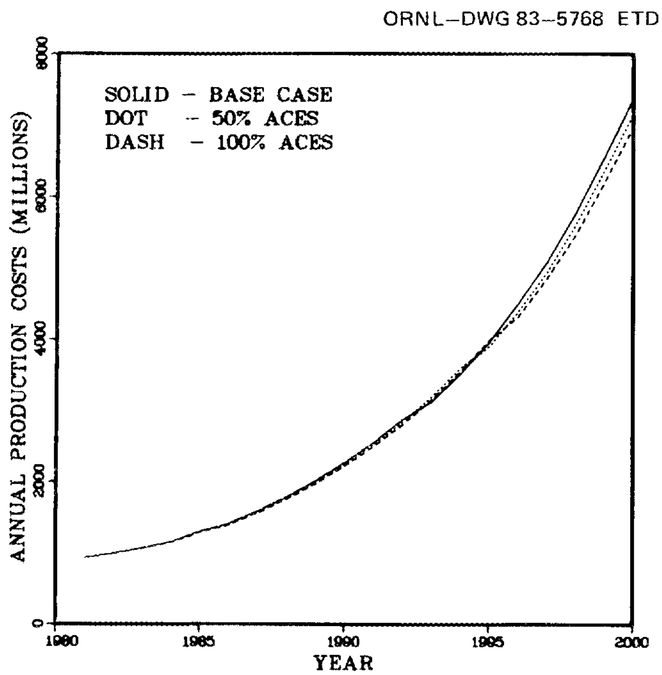


Fig. 5.17. Duke low load growth cases annual production costs.

plan the most expensive. For the low load growth scenarios, the 100% ACES case results in the lowest annual production cost starting in 1995, with the 50% ACES case slightly higher and the base case slightly higher still. On a cost per kilowatt-hour basis, the six scenarios result in similar operating costs, and the main effect shown in Figs. 5.16 and 5.17 is the difference in total energy generated.

The breakdown in production costs by fuel type for two of the cases is shown in Figs. 5.18 and 5.19. Comparing the two figures, the slight differences in generating unit timing are apparent, but there are no significant changes in the mix of fuels. The 100% ACES case does result in a higher fraction of the load being supplied by other than coal or nuclear power in later years (mainly distillate and purchased power), due to fewer new generating units being built. However, the decrease in total energy more than offsets the increase in per unit cost in these later years.

Table 5.5 summarizes the revenue requirements for the six Duke cases studied. The net result of a 100% saturation of ACES in new single

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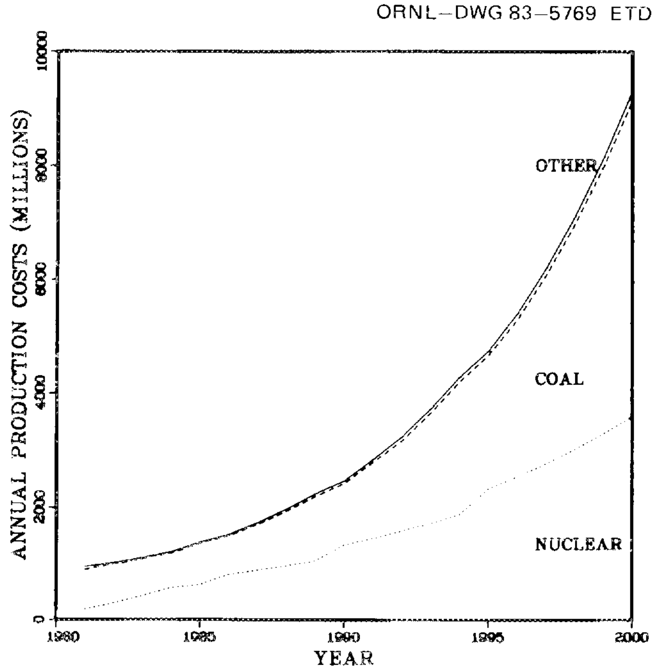


Fig. 5.18. Duke annual production cost components: Moderate load growth/0% ACES.

Table 5.5. Levelized revenue requirements for Duke scenarios[a]

| ACES penetration (%) | Load growth | Operating costs (mills/kWh) | Capital costs[b] (mills/kWh) | Total revenue requirements (mills/kWh) | Cost savings (mills/kWh) | Cost savings ($/ACES house) |
|---|---|---|---|---|---|---|
| 0 | Moderate | 30.456 | 7.509 | 37.965 | | |
| 50 | Moderate | 29.781 | 6.450 | 36.231 | 1.734 | 1161 |
| 100 | Moderate | 30.104 | 4.612 | 34.716 | 3.249 | 1099 |
| 0 | Low | 29.021 | 3.015 | 32.036 | | |
| 50 | Low | 28.922 | 1.995 | 30.917 | 1.119 | 996 |
| 100 | Low | 28.801 | 1.397 | 30.198 | 1.838 | 842 |

[a]1981 dollars.

[b]Incremental above fixed unit additions and existing system.

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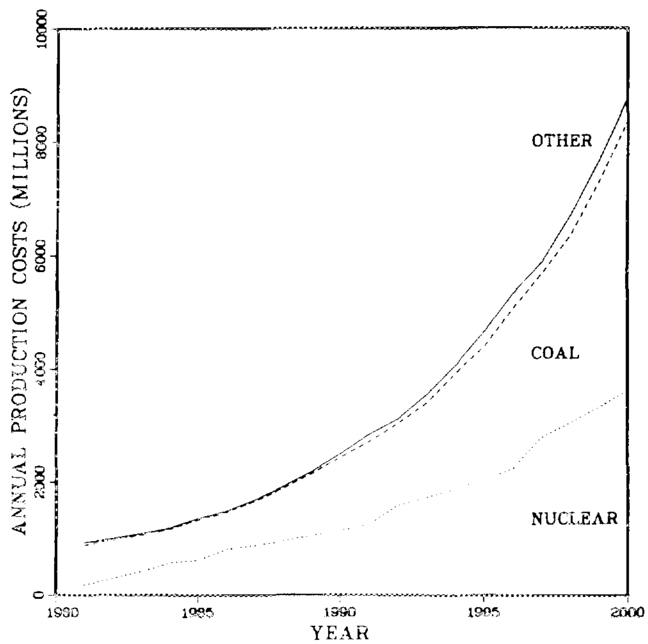


Fig. 5.19. Duke annual production cost components: Moderate load growth/100% ACES.

family houses with moderate load growth over the next 20 years would be to decrease the levelized cost of electricity over that period by 8.6%. This savings amounts to \$1099 per ACES installation. The 50% ACES case results in lower total savings of 4.6% but higher savings per ACES installation of \$1161 because half the number of installations produce greater than half the savings.

The low load growth cases exhibit similar results. The 50% ACES scenario results in a cost savings of \$996 per installation while the 100% ACES scenario results in cost savings of \$842 per installation.

# 6. CONCLUSIONS

The energy savings and load profile for an ACES installation located in the service territories of APL and Duke were calculated using the actual performance of the experimental test house located in Knoxville, correlated to local weather conditions. The results of this analysis show that an ACES installation in Little Rock, Arkansas, would use 6226 kWh (48%) less annually to supply space conditioning and water heating than an identical house equipped with a high efficiency air-to-air heat pump and resistance water heater. An ACES house located in Charlotte, North Carolina, would use 4803 kWh (41%) less energy than a conventionally equipped house.

The annual load profile of the ACES would have a positive effect on utility system loads reducing annual peak load growth and improving daily, seasonal, and annual load factors. A 100% saturation of ACES in new single family dwellings starting in 1981 in APL would reduce the system peak in the year 2000 from 6270 to 5726 MW and improve system load factor from 53.3 to 56.3% for moderate load growth scenarios. The same scenarios in Duke's service territory resulted in the annual peak load being reduced by 2,286 MW from 21,434 to 19,148 MW, and an annual load factor improvement from 61.5 to 66.4%.

The load shape changes attributable to ACES resulted in changes in the least-cost expansion plans for the two utilities. The changes included deferral of units and changes in the total number of new units built. These modified expansion plans also changed the annual production costs and mix of fuel usage for the various scenarios.

The revenue requirement savings for the two utilities ranged from $842 to $1161 per ACES installation levelized over the 20-year planning horizon for the various cases studied. These savings are the utility system savings and would be in addition to the savings that accrue to individual homeowners due to the higher efficiency of their space conditioning and water heating system.

While the favorable load management characteristics of the ACES would improve the competitiveness of the system, the magnitude of the utility cost savings are such that they are unlikely to offset the higher life-cycle costs currently estimated for the ACES system, even if the utility were to flow through the full cost savings. Consequently, unless the first cost of the ACES can be significantly reduced, its prospects for widespread commercialization appear limited.

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108. Jim Leggoe, Philadelphia Electric Company, 3201 Market Street, Philadelphia, PA 19101
109. D. C. Lim, Energy Conversion Equipment Branch, CE-113.2, Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585
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