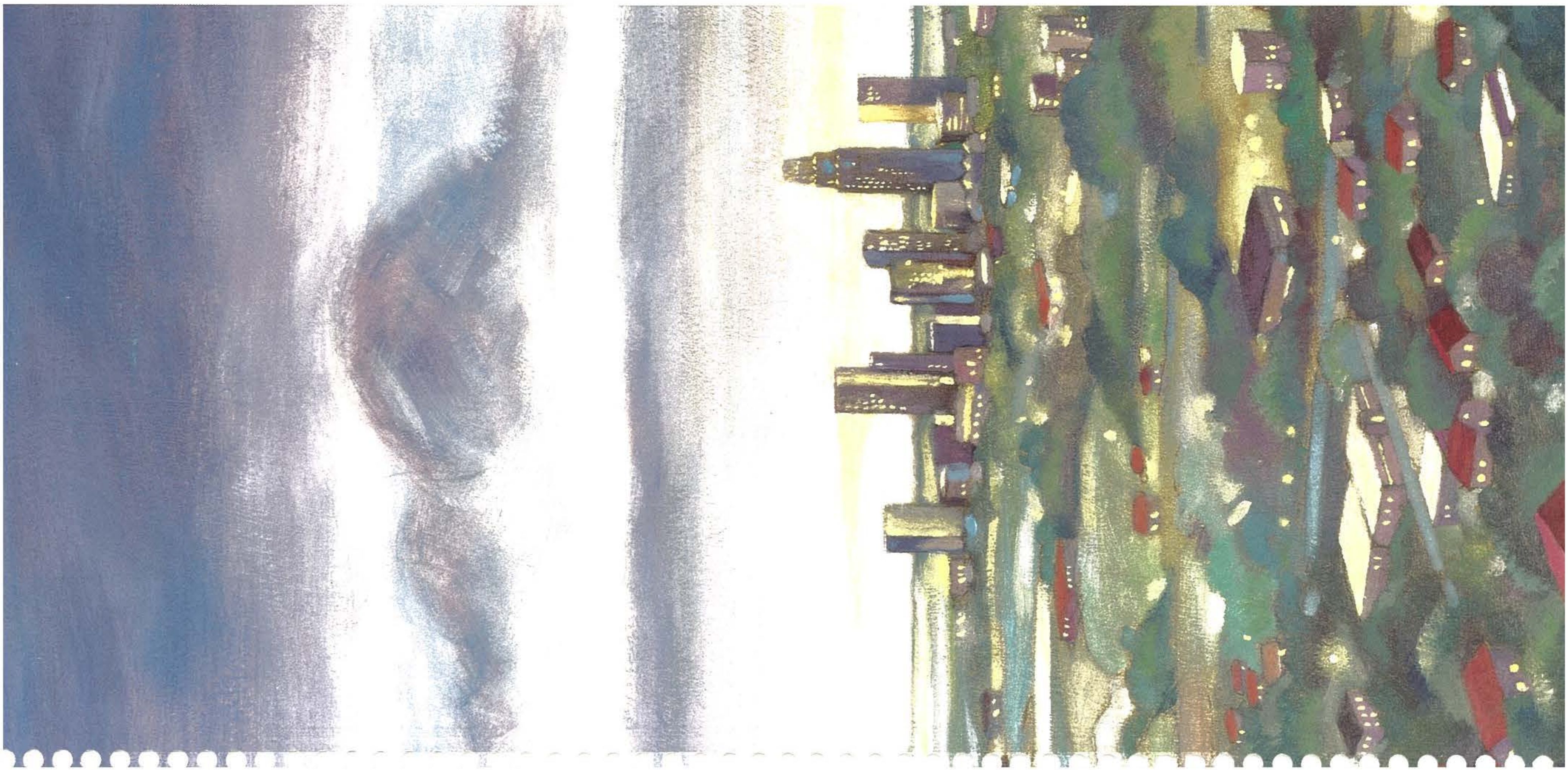
1996 Short-Term Action Plan

Integrated Resource Planning



Duke Power

About Duke Power

Headquartered in Charlotte, N.C., Duke Power was founded in 1904 and today is one of the nation's largest investor-owned electric utilities. The company serves approximately 1.8 million residential, general service and industrial customers in a 20,000 square-mile service area in North Carolina and South Carolina.

Duke Power and its subsidiary, Nantahala Power and Light Company, operate three nuclear generating stations, eight coal-fired stations, and 38 hydroelectric stations. Together these units produced 89 billion kilowatt-hours of electricity in 1995. Total 1995 operating revenues were $4.7 billion.

This 1996 Short-Term Action Plan is an update to the 1995 Integrated Resource Plan and contains a three-year view of the strategies and actions needed to implement the updated resource plan. This updated plan identifies the resources Duke will use to meet customers' electric power needs from 1996 through 2010. It reflects decisions made during the most recent planning cycle which occurred during the 1995 calendar year.

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Donald H. Denton, Jr.
Sr. VP and Chief Planning Officer

SUMMARY

"Duke Power stands at the threshold of a new era for electric utilities. Our industry has seen a dramatic upsurge in mergers, corporate restructuring, and fierce competition in the energy marketplace. As the industry moves to a more competitive business model, we expect the pace of change to quicken. This unprecedented rate of change is creating a high level of risk and uncertainty for utility planners.

One thing is clear. We must carefully manage the transition to this new environment to maintain the integrity of the electric system. The physical makeup of this complex energy delivery system will not permit an undisciplined approach to industry restructuring. We will not compromise the high reliability of our electric system for the sake of change.

Traditionally, utilities have built most of the generation needed to serve the loads of their regulated service territories. In a competitive environment, utilities cannot assume that the customers within their geographic boundaries will remain exclusively theirs. At Duke, we support the move to a more competitive environment given a fair and appropriate resolution of the existing issues, and we continually adapt our planning practices to prepare for the new energy marketplace. We have refined our planning processes to specifically deal with the types of risks and uncertainties likely to be encountered. We built our 1995 Integrated Resource Plan upon the tenets of this new framework. The 1996 Short-Term Action Plan advances this planning approach and represents the best plan to take us into the future.

Recognizing the risks and uncertainties of the future, we have developed a resource acquisition strategy that allows us to meet near-term obligations in a manner that does not expose us to long-term financial burdens. To be effective, however, we must regularly review and adjust our resource plans. As the future unfolds, our resource plan will evolve to match the requirements of the changing energy marketplace."

A Changing Business for Electric Utilities

A year has passed since we presented our 1995 resource plan, and the structure of the electric utility industry continues to evolve. While the scope and degree of change remain uncertain, our commitment to meeting our customers' expectations and our competitors' challenges remains the same. The strategy for meeting this commitment, outlined in the 1995 plan, continues to provide the flexibility we need to meet our customers' energy needs reliably and at the lowest reasonable cost.

We must consider today's dynamic business environment as we develop our resource plan. Several key resource trends are emerging from this new environment:

- Costs for new supply side resources continue to decline, making them more economically attractive.
- Emissions from new supply side resources continue to decrease, making them more environmentally attractive.
- Large customer incentives for energy efficiency options, offered in the past, are no longer cost-effective in today's competitive marketplace.

These trends along with other changes in the business environment mean that:

- Resource planning will continue to evolve with changes driven by the modified rules and regulations of a restructured industry.
- The marketplace is anticipated to drive the cost and price of new resources, relieving the need for regulation to predetermine the appropriate mix of supply side and demand side resources.
- Construction of clean, low-cost supply side resources is an acceptable approach to meeting system resource needs.

Risk and Opportunities

Although the risks inherent in the structure of our evolving electric utility industry continue to increase, the range of resource options available is also increasing. An electric utility's choice of resource options must reflect the market mandate to meet customer requirements at competitive prices and satisfy shareholder expectations. While competition presents many challenges, it also presents opportunities for growth and increased customer satisfaction. Customers expect high reliability and competitive prices, and a large number of them indicate they would switch suppliers for a small reduction in price—a risk and an opportunity for Duke Power.

We have responded to the increased demands from customers that competition brings by developing a plan that keeps our rates competitive and offers our customers innovative and valuable ways to use electricity. Our resource plan represents an appropriate strategy for balancing the perspectives of our stakeholders—customers, shareholders, and the public—while remaining flexible enough to withstand a wide range of future uncertainties. This uncertainty compels utilities to place a significant premium on flexibility in planning and resource acquisition.

Resource Planning and Acquisition Issues

We have studied the marketplace in the southeast and have determined that there is an adequate amount of capacity at reasonable prices to satisfy our near-term needs through the purchased power market. This favorable market offers us the opportunity to utilize this potential resource for a share of our future resource needs.

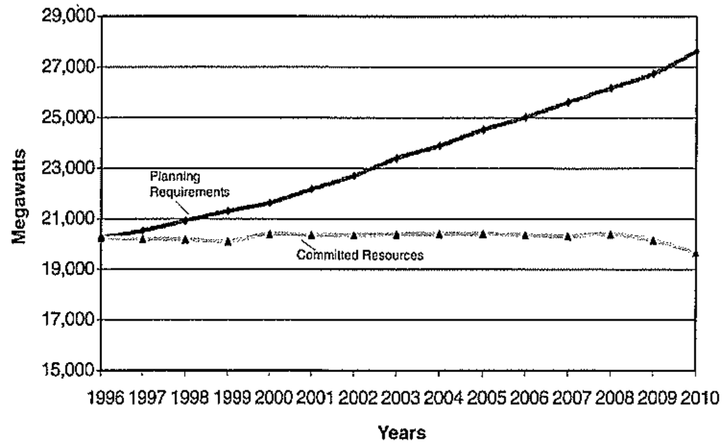
Demand side resources must enhance the satisfaction of customers that face an increasing array of energy choices and compete with the costs of supply side resources. In addition, the standard for assessing the cost-effectiveness of demand side resources must meet the economic imperatives of this changing environment. Demand side resources should not increase the cost of electricity over competitive alternatives. Collectively, demand side resources should pass the rate impact measure test, which means they will not raise rates. Our demand side portfolio accomplishes this objective with a mix of energy efficiency, interruptible, load shift, and strategic sales options.

Resource Needs and Options

The load forecast establishes the underlying need for capacity and energy and is based on the premise that Duke's customers remain on the system for the long term. Marketing initiatives add to this forecast, establishing the total resources needed. The inherent uncertainty associated with load forecasting requires us to place a premium on flexibility for planning and resource acquisition to ensure that we will be able to serve all of our future customers.

Figure 1 shows our existing and committed resources versus our planning requirements. Planning requirements include a long-term minimum planning reserve margin goal of 20 percent. Duke has found that a 20 percent minimum planning reserve margin provides an appropriate level of reliability while minimizing costs. Reliability and costs are viewed from the customer's perspective. Duke believes that its current strategy of providing this level of reserves through its mix of generating equipment and interruptible programs is appropriate. The gap between the two lines represents the additional resources needed to meet projected customer needs and maintain the integrity of our electric system.

FIGURE 1. **Committed Resources vs. Planning Requirements**



We have several flexible alternatives for meeting this potential resource need:

- Purchase short- and/or long-term capacity from the active wholesale market.
- Acquire options to purchase short- and/or long-term capacity.
- Build, contract to build, or purchase the output of new peaking, intermediate, or base load generating capacity.
- Manage system growth in demand for electricity with energy efficiency, load shift, and/or interruptible demand side resource options.

Resource Acquisition Strategy

The resource plan required in today's environment is not a set of discretely scheduled actions, but rather a strategy that takes advantage of the economy and flexibility afforded by the ability to choose, from year to year, the most attractive combination of alternatives.

Our existing resources will meet our needs until 1998. While committed resources are slightly less than planning requirements for 1997, we have determined that our 18.2 percent planning reserve margin is adequate given the availability of purchased power through 1997. To satisfy our projected resource needs for 1998 and 1999, we expect to negotiate purchase-power agreements from proposals submitted in response to our 1995 requests for proposals (RFPs). The additional resources required to meet our needs from 2000 through 2004 will be met by some combination of:

- Purchased power contracts resulting from the 1995 RFPs
- Purchased power contracts from another RFP
- Construction of a generating facility
- Additional demand side resource options

We can postpone the decision on how to secure capacity to meet the resource needs for 2005 and beyond because of the favorable lead times associated with this capacity. In all cases, we make our resource decisions based on the evolving market conditions, especially with respect to the load forecast, the market for short-term capacity, and the changing regulatory environment. We recognize that these variables will be affected by the evolution to a more competitive business environment. In these increasingly competitive and uncertain times, Duke's resource plan represents a flexible strategy, which allows us to minimize capital requirements and resource commitments.

Changes Since the 1995 IRP

Our latest planning cycle shows little change from the 1995 Integrated Resource Plan. The following is a summary of the changes:

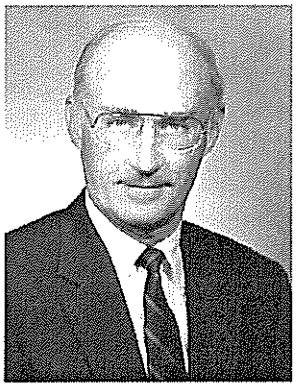
- Our latest load forecast projects slightly higher resource needs in the short term because of the prospects for improved economic activity.
- Our reduced emphasis on higher cost incentive-based energy efficiency programs have decreased the resource potential from demand side programs.
- Through 2001, our supply side plan is almost identical to the one presented in the 1995 plan. We anticipate slight increases in resource requirements in the remaining years, and the expected need for base load capacity has moved from 2004 to 2005.
- Our planning reserve margin is down slightly in the near term because of the increase in the forecast and the reduction in demand side resources.

The Right Plan for Today

Our updated resource plan continues the resource strategy reported in the 1995 Integrated Resource Plan and represents the best strategy to carry us forward because it:

- Keeps electricity rates low
- Incorporates marketing initiatives to protect revenues in major market segments where competitive threats exist
- Includes strategic sales efforts to increase revenues in markets where electricity has a significant economic and/or customer-competitive advantage
- Offers customers a variety of options for managing and reducing their energy costs
- Manages short-term financial risks by taking advantage of prevailing market prices for near-term capacity
- Allows us to remain flexible in meeting future resource needs

THE BUSINESS ENVIRONMENT



William R. Stimart, Vice President
Rates and Regulatory Affairs

"Duke Power's integrated resource planning process was designed in concert with the historical regulatory environment. In this environment, we have the obligation to provide service to all new and existing customers in our assigned service territory. In return, regulators authorize rates that ensure a fair return on our electric utility investments.

Duke recognizes that the regulatory environment is undergoing unprecedented change. There are several active initiatives around the country aimed at restructuring the electric utility industry. We support this move to a more competitive environment provided that all stakeholder issues are considered and fairly resolved. All customers must have access to the benefits of competition, and we must ensure that all suppliers are treated fairly so that no one supplier has a regulatory advantage over another. Some of the issues that must be addressed include: recovery of stranded investments, federal versus state jurisdiction over certain transactions, retail competition or customer choice, pricing, and obligation to serve.

Our resource plan and the short-term actions described in this report provide the flexibility we need to meet our customers' energy needs at competitive prices as the structure of the electric utility industry continues to evolve."

Purpose of This Document

This 1996 Short-Term Action Plan is an update to the 1995 Integrated Resource Plan and contains a three-year view of the strategies and actions that are needed to implement our resource plan in a changing electric utility industry.

The Electric Utility Industry

Competition at the wholesale level has been intense for the past several years. There is also competition in other markets, including the residential segment, where there is direct competition with other energy sources, primarily natural gas. In addition, energy efficient technologies and techniques that can significantly reduce energy consumption, improve consumer comfort, or boost process efficiency and control are increasingly available.

The emergence of this competitive environment is a result of the convergence of several economic, regulatory, and technological trends.

- Customers accustomed to choice in nonenergy markets are demanding more choices from their energy suppliers.
- In the U.S., state and federal regulators are examining a variety of active proposals on industry restructuring.
- Competition at the wholesale level is a reality as a result of legislative and regulatory actions.
- Technological improvements in gas turbine generators, declining natural gas prices, and other changes have reduced emissions and the cost of electricity generated by smaller units, providing new opportunities for non-utility generators.
- New electric end-use technologies are making electricity more competitive with other fuels.

With these prevailing trends, we must be prepared for the possibility of substantive change in the industry. Although there has always been competition at the retail level with other fuels—primarily natural gas in our service territory—the level of competition is expected to increase in the future.

For several years now, we have been refining our planning process to adapt to a wide range of possible industry futures. Our focus continues to be maximum flexibility and minimum risk in our resource planning as we stand firm in our commitment to maintain competitive rates while offering our customers innovative and valuable ways to use electricity.

The Role of Resource Planning

In a restructured electric utility industry, the resource planning process must change. If generation were fully deregulated, the forces of the competitive marketplace would determine the type, amount, and timing of new generation development, removing it from the traditional planning process.

We constantly refine our resource planning process to accommodate a wide range of roles and functions. One example of a refinement is the evaluation of purchased power proposals. Our 1995 requests for proposals for purchased power required us to develop a process for evaluating a variety of proposals for purchased power resources, each with different options, availability, and delivery schedules.

Near-Term Issues and Considerations

Supply Side Issues

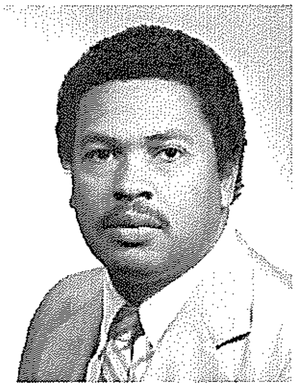
On the supply side, the key issue in the near term is the negotiation of purchased power contracts and options. Current projections about the price and availability of purchase options are favorable, but actual prices, terms, and conditions are subject to changing market conditions.

Demand Side Issues

On the demand side, there are two key issues:

- The revamping of the demand side portfolio to increase its cost effectiveness and reduce rate impacts while offering products and services that meet the needs of the competitive marketplace.
- The predictability and stability of customer loads for the long term. In a wholesale and/or retail competition environment, load forecasting becomes less certain if customers can choose their energy providers.

Resource Needs



Ronald L. Gibson, Vice President
Sales

"In a competitive world, only those companies that supply customers with competitively priced products and services will survive. Duke Power will prosper in the increasingly competitive energy marketplace by continuing to offer a wide variety of energy products and services that meet a broad range of customer needs and expectations.

Today's competitive pressures demand that we streamline operations, focus on customer needs, and build the brand recognition that will position us to thrive in the competitive marketplace. As electricity markets become more competitive and price-sensitive, we cannot establish objectives that disregard price impacts. Research shows that customers expect high reliability and competitive prices, with a large number of customers indicating they would switch suppliers for a small reduction in price.

Growth ultimately determines a company's viability and shareholder value. In today's increasingly competitive marketplace, growth can only be achieved through customer satisfaction and strategic sales. We are committed to developing programs that innovatively address these issues and to focusing our efforts in areas such as electrotechnologies where we have the most potential for growth."

ANTICIPATING ENERGY NEEDS

THE LOAD FORECAST

To determine customer energy needs, we prepare a load forecast of energy sales and peak demand using econometric and end-use analytical methodologies. The current forecast assumes that Duke will meet the energy needs of all new and existing customers within our service territory. This requirement may change in the future as a restructured industry evolves. Currently, certain wholesale customers have the option of obtaining all or a portion of their future energy needs from suppliers other than Duke Power. This situation is not reflected in the forecast (Figure 2) and represents another uncertainty that must be recognized and accounted for during the planning process.

Figure 2 shows the current forecast's peak demand and energy. The current forecast predicts an annual average growth in summer peak demand of 2.2 percent, up 0.2 percent from the previous forecast. Winter peaks are forecasted to grow 2 percent annually, up 0.1 percent from the previous forecast. Average annual territorial energy is forecasted to grow 1.9 percent annually, down 0.1 percent from the previous forecast.

FIGURE 2: Peak Demand and Energy Forecasts

Year	Summer (MW)[a]	Winter (MW)[b]	Territorial Energy (GWH)[c]
1995	16,377	—	85,842
1996	16,708	15,229	87,514
1997	16,938	15,333	89,222
1998	17,260	15,565	91,024
1999	17,579	15,930	92,941
2000	17,848	16,256	94,533
2001	18,291	16,603	96,174
2002	18,731	16,938	98,056
2003	19,306	17,308	100,312
2004	19,716	17,681	102,342
2005	20,242	18,047	104,360
2006	20,644	18,422	106,199
2007	21,128	18,805	108,053
2008	21,591	19,177	109,970
2009	22,060	19,572	111,980
2010	22,492	19,969	113,765

a. Summer peak demand is for the calendar years indicated and includes the portion of the demand of the other joint owners of the Catawba Nuclear Station (CNS) met by their retained ownership.

b. Winter peak demand is for the specified years beginning in January and includes the portion of the demand of the other joint owners of the CNS met by their retained ownership.

c. Territorial energy is the total projected energy needs of the service area, including losses and unbilled sales, and the energy requirements of the other joint owners of the CNS less their SEPA allocation.

Intense Competition Drives Marketing Initiatives

In the coming years, competition will intensify. Today, our most obvious competition comes from natural gas suppliers, but we also face competition for customers from municipalities and rural electric co-operatives that supply electricity. Tomorrow it may be from electric utilities across the United States. Already certain wholesale customers can choose suppliers, retail competition legislation is being scrutinized, and large industrial accounts are relocating their facilities based on the cost of electricity. Customers in all market segments have become more sophisticated about their energy options, more vocal about their expectations of service, and more adamant about the prices they are willing to pay. While deregulation brings many challenges, it also opens doors to opportunities for growth and increased customer satisfaction. Our goal is to retain a competitive edge through our solid reputation, cost-effective operations, power quality that protects sophisticated computers and equipment, and service that is second to none. One way to meet this goal is by offering customer options that promote efficient electric technologies and provide solutions to customers' energy, manufacturing, and quality service needs.

Electricity offers some unique opportunities to reduce environmental impacts, augment process control, improve quality, increase comfort, and lower customer energy costs. Today's demand side options must enhance the satisfaction of customers who face an increasing array of energy choices, and their costs must agree with the economic imperatives of a changing electric utility industry. Demand side resources should not increase the cost of electricity over alternative resources. Collectively, demand side resources should pass the rate impact measure (RIM) test, which means they will not raise rates. We will aggressively pursue markets for electricity where we can meet customer needs and more effectively utilize our existing generation system. By encouraging energy use throughout the year, we can spread fixed costs over more kWh, which benefits all customers.

Continue Refining Our Demand Side Portfolio

In keeping with the philosophy initiated in the 1995 plan, we are continuing to modify our demand side portfolio to eliminate or scale back those programs that raise prices for customers as a whole even though a few individual programs may not pass the RIM test. It is our objective for the demand side portfolio to pass the RIM test. In response to the changing needs of customers and the increasingly competitive utility industry, we will concentrate on educating customers about the advantages of managing their energy use and promoting new efficient electric technologies to give customers more energy choices.

We can best serve our customers by offering them a demand side portfolio that uses efficient electric technologies and provides solutions to customer energy, manufacturing, or quality service needs. Some customer needs are best met by the addition of energy efficiency improvements; other customer needs are best met by the addition of efficient electric technologies. To provide the best solutions for our customers, we work to design a balanced portfolio that encompasses strategic sales, energy efficiency, interruptible, and load shift options.

Strategic Sales. These options encourage the installation of efficient electric equipment by targeting customers who would have selected nonelectric equipment if the option were not offered. Strategic sales options improve the utilization of our generating system and provide additional sales. These options increase the need for resources since they add to system demand and/or energy requirements, but they are cost-effective when the revenues gained are greater than the cost of the options plus the cost of acquiring additional capacity and generating additional energy.

While they may raise participating customers' *electric* bills through increased kilowatt-hour sales, these options can lower their total *energy* bills. Additionally, strategic sales options can enhance customer satisfaction by improving efficiency and comfort, reducing operating costs, and increasing productivity. They contribute to a downward pressure on rates for all customers. The following strategic sales options are included in our current plan:

- Electrotechnology strategy
- High-efficiency food service appliances
- Nonresidential space heating
- Outdoor lighting

Energy Efficiency. These options encourage the installation of efficient electric equipment by targeting customers who would have selected less efficient electric equipment if the option were not offered. Energy efficiency options lower participating customers' electric bills by reducing the energy needed to power their homes and businesses. These options defer our need for new supply side resources and eliminate energy production costs that would have been incurred to supply power to less efficient equipment. Because these options promote efficient equipment that uses less energy than standard equipment, they reduce our kilowatt-hour sales.

While these options give participating customers an opportunity to lower their electric bills, energy efficiency options, traditionally promoted through the use of large customer incentives, could result in higher rates for all customers. To meet customer needs and remain a competitive energy supplier, we have modified some of our previously proposed energy efficiency options to decrease their costs and rate impacts. These modifications shift the emphasis from paying large customer incentives to educating customers. The following energy efficiency options are included in our current plan:

- High-efficiency chillers payment program
- High-efficiency compressed air systems
- High-efficiency motor systems and replacement

Energy Efficiency and Strategic Sales. While both energy efficiency and strategic sales options encourage the installation of efficient electric equipment, the markets they target are different. We combined some energy efficiency and strategic sales programs since they will influence customers in both markets. Because the additional revenues gained from strategic sales help offset the revenues lost to energy efficiency programs, using a combination of these programs helps keep rates low. A balanced portfolio includes both strategic sales and energy efficiency to meet customer needs and help keep rates competitive. The following combined energy efficiency and strategic sales programs are included in our current plan:

- ❖ New residential housing program
- ❖ Existing residential housing program and nonresidential heat pump program

Interruptible. These options reduce our system peak demand by temporarily interrupting all or part of a participating customer's electrical service. Participating customers receive bill credits that lower their electric bills. The following interruptible options are included in our current plan:

- ❖ Interruptible power service rider
- ❖ Residential load control rider—air conditioning
- ❖ Residential load control rider—water heating
- ❖ Standby generator control rider

Load Shift. These options reduce our system peak demand by shifting customer energy use to off-peak times. Customers benefit from lower electric bills and lower generating costs. The following load shift option is the only one included in our current plan:

- ❖ Residential water heating—controlled/submetered

Off-System Power Sales

One of our newest marketing initiatives is to market power outside of our existing system. This marketing activity takes advantage of recently approved market-based rates for off-system sales. Because we will only sell power when we do not need it to meet our daily and hourly system load requirements, these efforts will not impact system resource needs.

Determining Additional Resources

Existing Resources

In 1996 Duke Power's existing resources, including Nantahala Power & Light, consist of 18,730 megawatts of generating capacity. Municipal and rural electric cooperative organizations in North and South Carolina own 87.5 percent of Catawba Nuclear Station. These organizations are located in our service area and are partial-requirement customers. For planning purposes, their portion of Catawba is included in our generating capacity since their load requirements are also included in our plan.

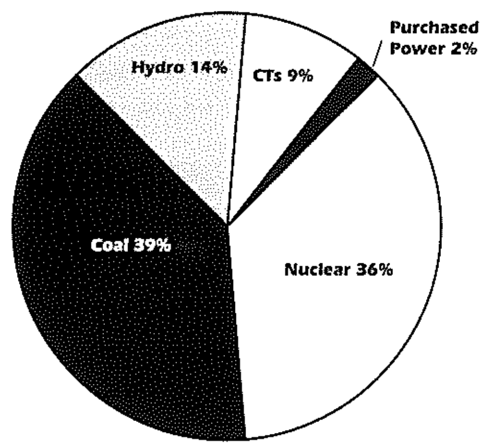
We recently offered to sell several small hydro facilities. The sale of these facilities will not have a material effect on our resource plan.

As noted in Figure 10, "Load, Capacity, and Reserves Projections," on page 30, the sale of 400 megawatts of capacity to Carolina Power and Light will end on June 30, 1999, freeing up this capacity for use on our system. Because we only consider capacity available on June 1 to meet peak requirements, these megawatts are not reflected in our existing capacity for 1999. However, the capacity will likely be available to meet summer peak demand since the summer peak normally occurs after June.

The reduction in committed resources of 1,070 megawatts from 2006 to 2010 reflected in Figure 4 represents planned retirements of units at Dan River, Allen, Lee, and Riverbend generating stations. The actual dates of these retirements could change in future analyses.

As shown in Figure 3, our generating capacity consists predominantly of coal and nuclear base load units; combustion turbines (CTs) and hydro peaking units supply the remaining bulk of our capacity.

FIGURE 3. **1996 Generating Capacity Mix**



Net Resource Needs

Figure 4 shows our existing and committed resources versus our planning requirements. Planning requirements include a long-term minimum planning reserve margin goal of 20 percent. Duke has found that a 20 percent minimum planning reserve margin provides an appropriate level of reliability while minimizing costs. Reliability and costs are viewed from the customer's perspective. Duke believes that its current strategy of providing this level of reserves through its mix of generating equipment and interruptible programs is appropriate. The gap between the two lines represents the additional resources needed to meet projected customer needs and maintain the integrity of our electric system.

FIGURE 4. **Committed Resources vs. Planning Requirements**

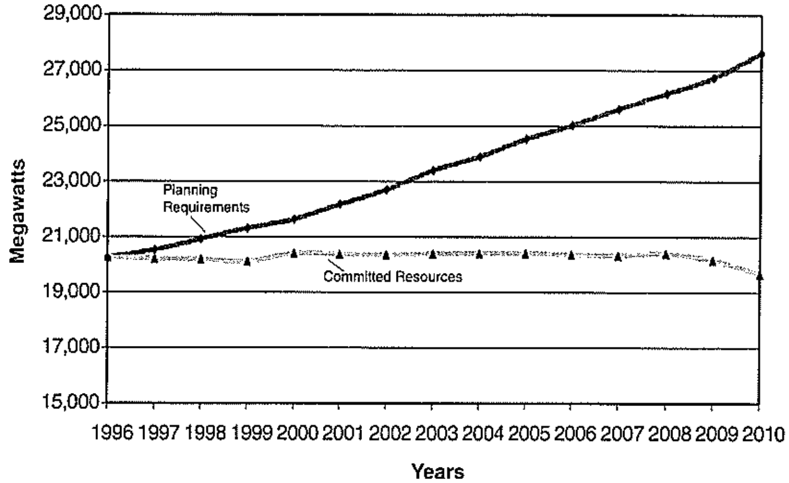


Figure 5 defines the type and magnitude of the future supply side resources needed to meet forecasted requirements. In contrast to our existing system, the majority of our projected new requirements will be for peaking resources.

FIGURE 5: Projected New Supply Side Resource Requirements (1996-2010)

Peaking (MW)	Base Load (MW)	Total (MW)
5,867	2,400	8,267

Resource Acquisition Strategy

William F. Reinke, Vice President
System Planning and Operating

"In a traditional electric utility world, Duke Power would forecast system capacity and energy requirements then design and build generation and implement demand side programs to meet those needs. Today's business environment will not support this traditional approach, especially in the generation arena. We do not plan to commit today to build significant amounts of generation in a business environment where the rules for marketing and pricing this power will change.

In this uncertain and higher risk environment, successful companies will maintain a very flexible resource acquisition strategy. To meet near-term system load requirements, we will purchase short-term capacity or acquire options to purchase capacity. We may also negotiate long-term purchases based on this capacity's availability, pricing, and terms in the evolving generation market. We will carefully analyze all resource options before we decide to acquire capacity for long-term system loads.

We began implementing this strategy in 1995 when we issued Requests for Proposals for short- and long-term purchases. We anticipate that we will be able to negotiate favorable contracts from the submitted proposals. This strategy enables us to meet our obligations until the turn of the century. Beyond that, we will make capacity decisions based on how the generation market develops over the next few years and the future needs we anticipate."

Resource Options

Construct New Generating Units

We will maintain the option to construct new generating facilities. Our long-standing history of building low-cost, highly efficient generating facilities positions us to pursue this option if needed. When a decision is required, we will determine whether to build or purchase after analyzing each resource option's availability and costs.

Purchase Short-Term Capacity

With the emergence of a robust wholesale market, short-term capacity purchases have become a major factor in resource planning. Significant amounts of short-term capacity should be available over the next few years at relatively attractive prices. These temporary purchases allow us to maintain a flexible position over the next few years.

Purchase Long-Term Capacity

To cope with the uncertainty associated with the wholesale energy market, we will consider purchasing long-term capacity from other utilities, power marketers and brokers, or other non-utility generators. The timing, amount, and duration of any purchases are a function of the proposals we receive at the time a decision is required.

Offer Demand Side Customer Options

Our demand side portfolio consists of two general types of options—those that add to system resource requirements and those that help meet system resource requirements. Strategic sales options increase the need for resource requirements (energy in all cases; capacity in some cases) while energy efficiency, interruptible, and load shift options help satisfy resource requirements. Demand side resources have been included in past resource plans; however, significant changes both in planning requirements and in the cost-effectiveness of some of these programs have diminished their appeal. Because the realities of the competitive marketplace require that our demand side resources not raise electric rates, our demand side portfolio should pass the rate impact measure (RIM) test.

Figure 6 shows the benefit/cost test results for all options in the demand side portfolio. Because our objective is for the demand side portfolio to pass the rate impact measure (RIM) test, we show RIM results for all options and for the total portfolio. We use the utility cost and total resource cost tests to evaluate the cost effectiveness of non-strategic sales options; these results are only shown for those individual non-strategic sales options in the portfolio.

FIGURE 6. Benefit/Cost Test Results for Demand Side Portfolio

Demand Side Options	Rate Impact Measure	Utility Cost	Total Resource Cost
Energy Efficiency			
High-efficiency chillers payment program [a]	0.38	0.61	1.79
High-efficiency compressed air systems	0.98	38.79	4.69
High-efficiency motor systems and replacement	0.98	37.15	5.50
Interruptible			
Interruptible power service rider [b]	n/a [c]	n/a	n/a
Residential load control rider—air conditioning	1.18	1.18	1.67
Residential load control rider—water heating [d]	n/a	n/a	n/a
Standby generator control rider	1.11	1.11	2.76
Load Shift			
Residential water heating—controlled/submetered [e]	n/a	n/a	n/a
Strategic Sales [f]			
Electrotechnology strategy	1.03	n/a	n/a
High-efficiency food service appliances	1.21	n/a	n/a
Nonresidential space heating	1.63	n/a	n/a
Outdoor lighting	1.76	n/a	n/a
Energy Efficiency and Strategic Sales [g]			
New residential housing program	1.11	0.36	0.28
Existing residential housing program and nonresidential heat pump program	1.43	0.34	0.23
Totals by Option Type			
Strategic sales	1.28	n/a	n/a
Energy efficiency, interruptible, and load shift	0.98	n/a	n/a
Demand Side Portfolio Total	**1.16**	**n/a**	**n/a**

a. Incentive payments for this program are currently suspended.
b. No customer additions were analyzed for cost-effectiveness.
c. n/a = not applicable
d. This existing program is closed to new installations.
e. This existing program is not currently marketed, and program attrition is anticipated.
f. RIM is the only test performed for strategic sales options. Strategic sales options that do not pass RIM are not implemented.
g. The utility cost and total resource cost tests are only calculated for the energy efficiency component.

We continually evaluate demand side alternatives. In the near term, we have included all the options listed in Figure 6 in our resource portfolio. The market penetration, costs, and other values for this set of options may differ from the previous analysis. For each option's current demand and energy impacts and costs, see Figures 11-16 on pages 32-37.

Resource Strategy

Maintaining Flexibility and Minimizing Risk

After considering the cost and availability of the options previously discussed in light of our expected load requirements, the most appropriate strategy is one that maintains as much flexibility as possible. We have studied the marketplace in the southeast and have determined that there is an adequate amount of capacity at reasonable prices to satisfy our near-term needs through the purchased power market. In the next three years, we will meet near-term forecasted load by relying on a combination of short- and/or long-term capacity purchases and options to purchase capacity—a strategy that benefits Duke and its customers.

Duke's Updated Resource Plan

Figure 7 shows the supply side additions and demand side resources represented in the updated resource plan.

FIGURE 7: Updated Resource Plan

Year	Supply Side[a]		Demand Side
	Peaking (MW)	Base Load (MW)	MNDC[b] (MW)
1996	900[c]		1,042
1997			983
1998	675		954
1999			882
2000	592		773
2001	296		741
2002	518		730
2003	666		769
2004	518		772
2005		600	779
2006		600	803
2007	592		836
2008	444		911
2009	222	600	976
2010	444	600	1,111

a. This capacity may be purchased, contracted, or built by Duke.

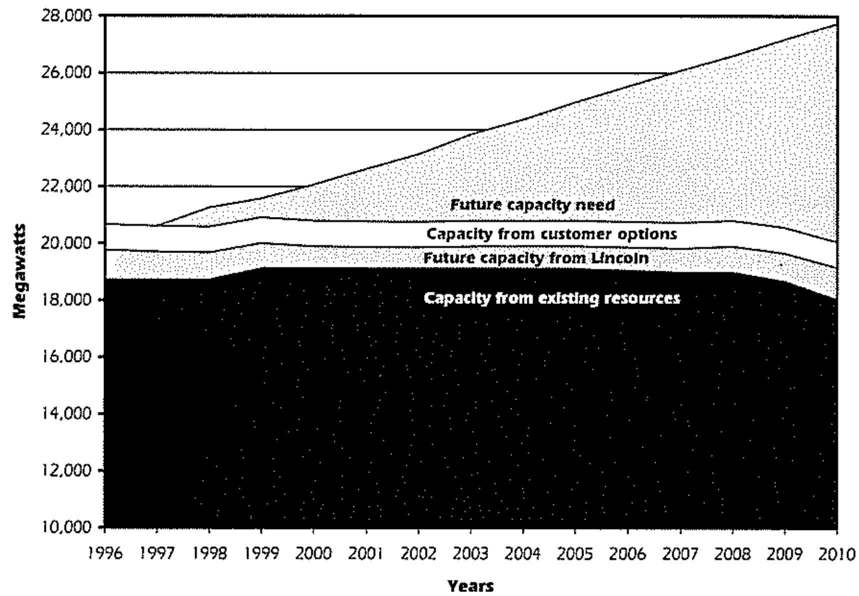
b. Maximum net dependable capacity (MNDC) represents the equivalent cumulative capacity for all demand side resources; it is the net of strategic sales and other demand side components.

c. Portion of Lincoln Combustion Turbine Station completed in 1996.

Figure 8 shows how we plan to meet these capacity needs. A portion of this need will be satisfied by the Lincoln Combustion Turbine Station, providing approximately 1,200 megawatts of peaking capacity; part of this capacity is reflected in existing resources since several units began commercial operation in 1995. Customer options, which consist of existing and new demand side resources, are projected to provide resources totalling 1,111 megawatts. Over the planning period, we project a need for 7,367 megawatts of peaking or base load capacity beyond Lincoln, which may be met by one or more of the following resource alternatives:

- Purchase short- and/or long-term capacity from the active wholesale market.
- Acquire options to purchase short- and/or long-term capacity.
- Build, contract to build, or purchase the output of new peaking, intermediate, or base load generating capacity.
- Manage system growth in demand for electricity with energy efficiency, load shift, and/or interruptible demand side resource options.

FIGURE 8. **Breakdown of Resource Options to Meet Projected Capacity Needs**



Short-Term Actions

Competition is reshaping our business. The uncertainty brought about by the changing utility industry requires us to focus on short-term resources that satisfy immediate customer energy needs while assessing all potential options for long-term resources to meet future needs.

This section describes the actions to be taken over the next three years to implement our updated resource plan.

Supply Side Actions

Several supply side actions are planned as a result of the most recent planning cycle. The most significant ones are highlighted below:

Meet Capacity Needs Beyond Lincoln

By 1998, we have projected a 675-megawatt resource need beyond the Lincoln Combustion Turbine Station. We intend to acquire this next increment of resources using the competitive bidding process we initiated in 1995.

The additional resources required to meet our needs from 2000 through 2004 will be met by some combination of:

- Purchased power contracts resulting from the 1995 RFPs
- Purchased power contracts resulting from another RFP
- Construction of a generating facility
- Additional demand side resource options

We can postpone the decision on how to secure capacity to meet the resource needs for 2005 and beyond because of the favorable lead times associated with this capacity.

Comply With Clean Air Act Amendments

The 1990 Clean Air Act Amendments require electric utilities to incorporate a two-phase reduction in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. Duke currently meets all Phase I requirements through historical initiatives, such as:

- Burning low-sulfur coal in our fossil plants
- Operating efficiently
- Using nuclear generation

A detailed compliance plan for Phase II requirements has been developed. The strategy incorporates developments in the emissions allowance market, future regulatory and legislative actions, and advances in clean air technology. All options within the preliminary strategy provide for full compliance with Phase II requirements by the year 2000.

Complete Preservation and Maintenance Program

We are working on the following in an effort to preserve, maintain, and improve our existing generation facilities:

- Replace nuclear steam generators at three units affected by stress corrosion cracking.
- Renew licenses of hydroelectric stations.
- Consider extending the lives of nuclear stations.
- Carry out a preservation and maintenance program for some existing hydroelectric stations.

Purchased Power Actions

The requests for proposals issued in 1995 yielded numerous short- and long-term proposals that we are currently evaluating to determine which ones best meet our resource needs. We anticipate delivery of short- or long-term capacity beginning in 1998 or 1999.

Demand Side Actions

Several general demand side actions are planned as a result of the most recent planning cycle. The most significant ones are highlighted below:

Focus on Education

To help maintain competitive electricity rates, we are shifting our energy efficiency focus. We've shifted from an emphasis on large, high-cost incentive-based energy efficiency options to less costly education-based options.

Implement Demand Side Competitive Bidding

Duke assessed the potential benefits of paying a third-party or customer to design and/or market demand side resource options. A request for proposals was issued, and 16 bidders responded. We entered into contracts with four of the bidders for a total projected resource of 4.7 megawatts and a projected 10-year (1994-2003) total cost of $7,008,000. The bidders must complete installation of the energy efficiency measures by the first quarter of 1997.

Implement Demand Side Resources

Figure 9 contains a three-year program implementation schedule for our demand side portfolio. The programs are separated by the type of program and include a summary of demand, energy, and cost impacts.

FIGURE 9: Demand Side Resource Projections [a]

Demand Side Options	Demand [MW] [b]			Energy [MWh] [c]			Direct Costs [$000s] [d]		
	1996	1997	1998	1996	1997	1998	1996	1997	1998
Energy Efficiency									
HE chillers payment program	(0.34)	(0.68)	(0.68)	(1,134)	(2,268)	(2,268)	1,895	0	0
HE compressed air systems	(0.96)	(2.89)	(4.82)	(5,559)	(16,677)	(27,794)	157	135	107
HE motor systems and replacement	(1.76)	(5.29)	(8.34)	(11,112)	(33,336)	(52,529)	184	185	186
Energy Efficiency Total	**(3.06)**	**(8.86)**	**(13.84)**	**(17,805)**	**(52,281)**	**(82,591)**	**2,236**	**320**	**293**
Interruptible									
Residential load control rider–A/C	(326.43)	(333.20)	(339.99)	0	0	0	10,063	10,282	10,474
Residential load control rider–water heating	(10.06)	(8.67)	(7.47)	0	0	0	1,330	1,264	1,133
Interruptible power service rider	(611.69)	(611.69)	(611.69)	0	0	0	25,183	25,194	25,204
Standby generator control rider	(48.35)	(53.44)	(58.52)	0	0	0	1,867	2,056	2,246
Interruptible Total	**(996.53)**	**(1,007.00)**	**(1,010.20)**	**0**	**0**	**0**	**38,443**	**38,796**	**39,057**
Load Shift									
Residential water heating–controlled/ submetered	0.47	0.47	0.47	0	0	0	0	0	0
Load Shift Total	**0.47**	**0.47**	**0.47**	**0**	**0**	**0**	**0**	**0**	**0**
Strategic Sales									
Electrotechnology strategy	22.19	69.16	135.58	123,460	377,833	735,199	3,909	4,260	4,735
HE food service appliances	0.61	1.91	3.33	6,890	21,646	37,756	1,051	1,105	1,166
Nonresidential space heating	0	0	0	9,169	28,230	48,136	896	671	516
Outdoor lighting	0	0	0	12,490	38,321	65,855	13,410	14,746	16,139
Strategic Sales Total	**22.80**	**71.07**	**138.91**	**152,009**	**466,030**	**886,946**	**19,266**	**20,782**	**22,556**
Energy Efficiency and Strategic Sales									
New residential housing program	(2.76)	(8.45)	(14.47)	19,977	61,350	105,648	6,284	5,936	5,562
Existing residential housing program and nonresidential heat pump program	(5.15)	(15.90)	(27.46)	27,032	81,392	136,383	9,519	8,218	9,556
Energy Efficiency and Strategic Sales Total	**(7.91)**	**(24.35)**	**(41.93)**	**47,009**	**142,742**	**242,031**	**15,803**	**14,154**	**15,118**
Demand Side Resource Total	**(984.23)**	**(968.67)**	**(934.06)**	**181,213**	**556,491**	**1,046,386**	**75,748**	**74,052**	**77,024**

a. All values in parentheses are reductions. Annual energy impacts for interruptible options depend on actual number of times programs are used.

b. These megawatts represent diversified customer load at Duke's system peak including transmission and distribution line losses. Megawatt values for each year are based on total program accomplishments to date.

c. These megawatt-hours represent annual values based on total program accomplishments to date, including transmission and distribution line losses.

d. Direct costs will be incurred in each of the subject years shown.

APPENDIX

This section includes the following information:

- Load, capacity, and reserves table
- Demand side resource projections
- Demand side evaluation results
- Lincoln Combustion Turbine Station status

LOAD, CAPACITY, AND RESERVES

Figure 10 shows the detail of the resource integration results for the 15-year planning horizon.

FIGURE 10: Load, Capacity, and Reserves Projections (Part 1 of 2)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Duke System Forecast Peak	16,708	16,938	17,260	17,579	17,848	18,291	18,731	19,306	19,716	20,242	20,644	21,128	21,591	22,060	22,492
NP&L System Forecast Peak [a]	165	170	175	179	184	189	193	198	203	208	212	217	222	226	230
Coincident Duke/NP&L Peak [b]	16,870	17,105	17,432	17,755	18,029	18,477	18,921	19,501	19,916	20,447	20,853	21,342	21,810	22,283	22,718
Cumulative System Generating Capacity															
Duke Capacity	18,319	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,152	19,085	19,085	18,778
NP&L Capacity [c]	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Annual Capacity Adjustments															
Scheduled Additions [d]	900	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Retirements [e]	0	0	0	0	0	0	0	0	0	0	(67)	(67)	0	(307)	(629)
Cumulative Generating Capacity	19,319	19,319	19,319	19,319	19,319	19,319	19,319	19,319	19,319	19,319	19,252	19,185	19,185	18,878	18,249
Cumulative Purchases [f]	311	311	311	311	311	611	611	611	611	611	611	611	611	611	611
Cumulative Sales [g]	(400)	(400)	(400)	(400)	0	0	0	0	0	0	0	0	0	0	0
Future Resource Additions [h]															
Peaking/Intermediate	0	0	675	0	592	296	518	666	518	0	0	592	444	222	444
Base Load	0	0	0	0	0	0	0	0	0	600	600	0	0	600	600
Cumulative Production Capacity	19,230	19,230	19,905	19,905	20,897	21,493	22,011	22,677	23,195	23,795	24,328	24,853	25,297	25,812	26,227
Generating Reserves (MW)	2,360	2,125	2,473	2,150	2,868	3,016	3,090	3,176	3,279	3,348	3,475	3,511	3,487	3,529	3,509
% Reserve Margin [i]	14.0	12.4	14.2	12.1	15.9	16.3	16.3	16.3	16.5	16.4	16.7	16.5	16.0	15.8	15.4
% Capacity Margin [j]	12.3	11.1	12.4	10.8	13.7	14.0	14.0	14.0	14.1	14.1	14.3	14.1	13.8	13.7	13.4
Cumulative Demand Side Capacity [k]	1,042	983	954	882	773	741	730	769	772	779	803	836	911	976	1,111

FIGURE 10: Load, Capacity, and Reserves Projections (Part 2 of 2)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Cumulative Equivalent Capacity	20,272	20,213	20,859	20,787	21,670	22,234	22,741	23,446	23,967	24,574	25,131	25,689	26,208	26,788	27,338
Equivalent Reserves (MW)	3,402	3,108	3,427	3,032	3,641	3,757	3,820	3,945	4,051	4,127	4,278	4,347	4,398	4,505	4,620
% Reserve Margin	20.2	18.2[l]	19.7	17.1[m]	20.2	20.3	20.2	20.2	20.3	20.2	20.5	20.4	20.2	20.2	20.3
% Capacity Margin	16.8	15.4	16.4	14.6	16.8	16.9	16.8	16.8	16.9	16.8	17.0	16.9	16.8	16.8	16.9

a. The Duke Power Company and Nantahala Power & Light (NP&L) systems are interconnected. For annual tables, this line shows the NP&L summer peak, not the annual system forecast peak.

b. Planning is for coincident peak demand for the Duke and NP&L systems. The forecast peaks for the individual systems are shown for reference only.

c. NP&L hydro capacity

d. Scheduled additions are units of the Lincoln Combustion Turbine Station. The first four units began commercial operation in June 1995; by March 1, 1996, the remaining 12 units began commercial operation.

e. The 67 MW capacity retirement in 2006 represents a decision date for the retirement of Dan River 2. The 67 MW capacity retirement in 2007 represents the retirement decision date for Dan River 1. The 307 MW capacity retirement in 2009 represents the retirement decision date for Dan River 3 (142 MW) and Allen 2 (165 MW). The 629 MW capacity retirement in 2010 represents retirement decision dates for Allen 1 (165 MW), Lee 1 (100 MW), Lee 2 (100 MW), Lee 3 (170 MW), and Riverbend 4 (94 MW). These dates may change if future analyses indicate it is beneficial.

f. Purchases have several components. All years include the following: purchases of 238 MW from Southeastern Power Administration (SEPA) and 73 MW from Cogeneration (COGEN) and Small Power Producers (SPP) for total firm purchases of 311 MW. A 300 MW load reduction beginning in 2001 is due to NCEMC's declared intent to build a combined cycle unit in Duke's service area. For this planning cycle, Duke assumed a net increase of 11 MW in COGEN and SPP purchases to reflect additional capacity from the UNC cogeneration facility, new capacity from the BMW cogeneration facility, and the shutdown of the Mecklenburg County cogeneration facility. A 73 MW firm purchase from the Cherokee County Cogeneration Partners facility, now expected to be available in mid-1998, was not included in this planning cycle pending Cherokee's completion of certain milestones. The Cherokee capacity will be reflected in future load, capacity, and reserves projections as additional milestones are achieved.

g. Represents 400 MW sales to Carolina Power & Light (CP&L) through June 30, 1999.

h. Future Resource Additions represent new capacity resources or capability increases that are being considered. Neither the operation date, the resource type, or the size is firm. All capacity additions after the Lincoln Combustion Turbine Station are shown as uncommitted and represent capacity required to maintain the 20 percent minimum planning reserve margin as determined in the integrated resource planning process. After Lincoln, peaking/intermediate units are added in 75 MW increments in 1998 and 74 MW increments thereafter; base load units are added in 600 MW increments.

i. Generating reserve margin is shown for reference.

j. Capacity margin is the industry standard term. A 16.67 percent capacity margin is equivalent to a 20 percent reserve margin.

k. Cumulative demand side capacity represents the demand side resource contribution used to meet the load. The demand side resources reflected in these numbers include energy efficiency and strategic sales programs and direct load control programs designed to be activated when we experience capacity problems.

l. The 18.2 percent reserve margin falls below the long-term minimum planning reserve margin of 20 percent. Duke plans to meet this need with limited-term purchases, if necessary.

m. The 17.1 percent reserve margin in 1999 is based on the assumption that any off-system sales that have not concluded by June 1 are included in the peak for that year. The actual projected peak for 1999 falls in July, not June. Because the CP&L sale concludes at the end of June 1999, the peak projected reserve margin for July is 19.3 percent.

DEMAND SIDE RESOURCE PROJECTIONS

FIGURE 11: Demand (MW) Projection Summary—1996 Through 2003 [a]

Demand Side Options	1996	1997	1998	1999	2000	2001	2002	2003
Energy Efficiency								
HE chillers payment program	(0.34)	(0.68)	(0.68)	(0.68)	(0.68)	(0.68)	(0.68)	(0.68)
HE compressed air systems	(0.96)	(2.89)	(4.82)	(6.74)	(8.67)	(10.60)	(11.56)	(11.56)
HE motor systems and replacement	(1.76)	(5.29)	(8.34)	(10.91)	(13.47)	(16.04)	(18.60)	(21.17)
Energy Efficiency Totals	**(3.06)**	**(8.86)**	**(13.84)**	**(18.33)**	**(22.82)**	**(27.32)**	**(30.84)**	**(33.41)**
Interruptible								
Residential load control rider–A/C	(326.43)	(333.20)	(339.99)	(344.92)	(347.25)	(349.62)	(352.02)	(354.45)
Residential load control rider–water heating	(10.06)	(8.67)	(7.47)	(6.40)	(2.94)	0	0	0
Interruptible power service rider	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)
Standby generator control rider	(48.35)	(53.44)	(58.52)	(63.61)	(68.70)	(73.79)	(78.88)	(83.97)
Interruptible Totals	**(996.53)**	**(1,007.00)**	**(1,017.67)**	**(1,026.62)**	**(1,030.58)**	**(1,035.10)**	**(1,042.59)**	**(1,050.11)**
Load Shift								
Residential water heating–controlled/submetered	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Load Shift Totals	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**
Strategic Sales								
Electrotechnology strategy	22.19	69.16	135.58	227.21	327.21	377.20	377.20	377.20
HE food service appliances	0.61	1.91	3.33	4.78	6.24	6.97	6.97	6.97
Nonresidential space heating	0	0	0	0	0	0	0	0
Outdoor lighting	0	0	0	0	0	0	0	0
Strategic Sales Totals	**22.80**	**71.07**	**138.91**	**231.99**	**333.45**	**384.17**	**384.17**	**384.17**
Energy Efficiency and Strategic Sales								
New residential housing program	(2.76)	(8.45)	(14.47)	(20.83)	(27.49)	(30.90)	(30.90)	(30.90)
Existing residential housing program and nonresidential heat pump program	(5.15)	(15.90)	(27.46)	(39.48)	(51.67)	(57.82)	(57.82)	(57.82)
Energy Efficiency and Strategic Sales Totals	**(7.91)**	**(24.35)**	**(41.93)**	**(60.31)**	**(79.16)**	**(88.72)**	**(88.72)**	**(88.72)**
Demand Side Option Totals	**(984.23)**	**(968.67)**	**(934.06)**	**(872.80)**	**(798.64)**	**(766.50)**	**(777.51)**	**(787.60)**

a. MW represent diversified customer load at Duke's system peak including transmission and distribution line losses. Values for each year are cumulative beginning in 1996. Values in parentheses are reductions.

FIGURE 12: Demand (MW) Projection Summary—2004 Through 2010 [a]

Demand Side Options	2004	2005	2006	2007	2008	2009	2010
Energy Efficiency							
HE chillers payment program	(0.68)	(0.68)	(0.68)	(0.68)	(0.68)	(0.68)	(0.68)
HE compressed air systems	(11.56)	(11.56)	(11.56)	(11.56)	(11.56)	(11.56)	(11.56)
HE motor systems and replacement	(23.74)	(26.30)	(28.87)	(30.15)	(30.15)	(30.15)	(30.15)
Energy Efficiency Totals	**(35.98)**	**(38.54)**	**(41.11)**	**(42.39)**	**(42.39)**	**(42.39)**	**(42.39)**
Interruptible							
Residential load control rider–A/C	(356.92)	(359.41)	(361.94)	(364.49)	(367.08)	(369.70)	(372.34)
Residential load control rider–water heating	0	0	0	0	0	0	0
Interruptible power service rider	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)	(611.69)
Standby generator control rider	(89.06)	(94.15)	(99.24)	(104.33)	(106.87)	(106.87)	(106.87)
Interruptible Totals	**(1,057.67)**	**(1,065.25)**	**(1,072.87)**	**(1,080.51)**	**(1,085.64)**	**(1,088.26)**	**(1,090.90)**
Load Shift							
Residential water heating–controlled/ submetered	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Load Shift Totals	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**
Strategic Sales							
Electrotechnology strategy	377.20	377.20	377.20	332.83	283.26	199.99	99.99
HE food service appliances	6.97	6.97	6.97	6.97	6.97	6.97	6.97
Nonresidential space heating	0	0	0	0	0	0	0
Outdoor lighting	0	0	0	0	0	0	0
Strategic Sales Totals	**384.17**	**384.17**	**384.17**	**339.80**	**290.23**	**206.96**	**106.96**
Energy Efficiency and Strategic Sales							
New residential housing program	(30.90)	(30.90)	(30.90)	(30.90)	(30.90)	(30.90)	(30.90)
Existing residential housing program and nonresidential heat pump program	(57.82)	(57.82)	(57.82)	(57.82)	(57.82)	(57.82)	(57.82)
Energy Efficiency and Strategic Sales Totals	**(88.72)**	**(88.72)**	**(88.72)**	**(88.72)**	**(88.72)**	**(88.72)**	**(88.72)**
Demand Side Option Totals	**(797.73)**	**(807.87)**	**(818.06)**	**(871.35)**	**(926.05)**	**(1,011.94)**	**(1,114.58)**

a. MW represent diversified customer load at Duke's system peak including transmission and distribution line losses. Values for each year are cumulative beginning in 1996. Values in parentheses are reductions.

FIGURE 13: Energy (MWh) Projection Summary—1996 Through 2003 [a]

Demand Side Options	1996	1997	1998	1999	2000	2001	2002	2003
Energy Efficiency								
HE chillers payment program	(1,134)	(2,268)	(2,268)	(2,268)	(2,268)	(2,268)	(2,268)	(2,268)
HE compressed air systems	(5,559)	(16,677)	(27,794)	(38,912)	(50,030)	(61,148)	(66,706)	(66,706)
HE motor systems and replacement	(11,112)	(33,336)	(52,529)	(68,692)	(84,855)	(101,018)	(117,180)	(133,343)
Energy Efficiency Totals	**(17,805)**	**(52,281)**	**(82,591)**	**(109,872)**	**(137,153)**	**(164,434)**	**(186,154)**	**(202,317)**
Interruptible[b]								
Residential load control rider–A/C	0	0	0	0	0	0	0	0
Residential load control rider–water heating	0	0	0	0	0	0	0	0
Interruptible power service rider	0	0	0	0	0	0	0	0
Standby generator control rider	0	0	0	0	0	0	0	0
Interruptible Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Load Shift								
Residential water heating–controlled/ submetered	0	0	0	0	0	0	0	0
Load Shift Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Strategic Sales								
Electrotechnology strategy	123,460	377,833	735,199	1,230,419	1,767,951	2,036,717	2,036,717	2,036,717
HE food service appliances	6,890	21,646	37,756	54,231	70,728	78,993	78,993	78,993
Nonresidential space heating	9,169	28,230	48,136	76,608	135,602	176,138	176,138	176,138
Outdoor lighting	12,490	38,321	65,855	95,092	126,033	141,929	141,929	141,929
Strategic Sales Totals	**152,009**	**466,030**	**886,946**	**1,456,350**	**2,100,314**	**2,433,777**	**2,433,777**	**2,433,777**
Energy Efficiency and Strategic Sales								
New residential housing program	19,977	61,350	105,648	152,759	202,575	228,187	228,187	228,187
Existing residential housing program and nonresidential heat pump program	27,032	81,392	136,383	191,867	247,688	275,689	275,689	275,689
Energy Efficiency and Strategic Sales Totals	**47,009**	**142,742**	**242,031**	**344,626**	**450,263**	**503,876**	**503,876**	**503,876**
Demand Side Option Totals	**181,213**	**556,491**	**1,046,386**	**1,691,104**	**2,413,424**	**2,773,219**	**2,751,499**	**2,735,336**

a. MWh represent annual values based on total program accomplishments and include transmission and distribution line losses. Values in parentheses are reductions.

b. Annual energy impacts depend on the actual number of times these programs are used.

FIGURE 14: Energy (MWh) Projection Summary—2004 Through 2010 [a]

Demand Side Options	2004	2005	2006	2007	2008	2009	2010
Energy Efficiency							
HE chillers payment program	(2,268)	(2,268)	(2,268)	(2,268)	(2,268)	(2,268)	(2,268)
HE compressed air systems	(66,706)	(66,706)	(66,706)	(66,706)	(66,706)	(66,706)	(66,706)
HE motor systems and replacement	(149,506)	(165,669)	(181,832)	(189,913)	(189,913)	(189,913)	(189,913)
Energy Efficiency Totals	**(218,480)**	**(234,643)**	**(250,806)**	**(258,887)**	**(258,887)**	**(258,887)**	**(258,887)**
Interruptible [b]							
Residential load control rider–A/C	0	0	0	0	0	0	0
Residential load control rider–water heating	0	0	0	0	0	0	0
Interruptible power service rider	0	0	0	0	0	0	0
Standby generator control rider	0	0	0	0	0	0	0
Interruptible Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Load Shift							
Residential water heating–controlled/ submetered	0	0	0	0	0	0	0
Load Shift Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Strategic Sales							
Electrotechnology strategy	2,036,717	2,036,717	2,036,717	1,789,796	1,527,971	1,075,063	537,532
HE food service appliances	78,993	78,993	78,993	78,993	78,993	78,993	78,993
Nonresidential space heating	176,138	176,138	176,138	176,138	176,138	176,138	176,138
Outdoor lighting	141,929	141,929	141,929	141,929	141,929	141,929	141,929
Strategic Sales Totals	**2,433,777**	**2,433,777**	**2,433,777**	**2,186,856**	**1,925,031**	**1,472,123**	**934,592**
Energy Efficiency and Strategic Sales							
New residential housing program	228,187	228,187	228,187	228,187	228,187	228,187	228,187
Existing residential housing program and nonresidential heat pump program	275,689	275,689	275,689	275,689	275,689	275,689	275,689
Energy Efficiency and Strategic Sales Totals	**503,876**	**503,876**	**503,876**	**503,876**	**503,876**	**503,876**	**503,876**
Demand Side Option Totals	**2,719,173**	**2,703,010**	**2,686,847**	**2,431,845**	**2,170,020**	**1,717,112**	**1,179,581**

a. MWh represent annual values based on total program accomplishments and include transmission and distribution line losses. Values in parentheses are reductions.

b. Annual energy impacts depend on the actual number of times these programs are used.

FIGURE 15: Direct Cost ($000s) Projection Summary—1996 Through 2003 [a]

Demand Side Options	1996	1997	1998	1999	2000	2001	2002	2003
Energy Efficiency								
HE chillers payment program	1,895	0	0	0	0	0	0	0
HE compressed air systems	157	135	107	110	114	118	0	0
HE motor systems and replacement	184	185	186	192	199	205	212	219
Energy Efficiency Totals	**2,236**	**320**	**293**	**302**	**313**	**323**	**212**	**219**
Interruptible								
Residential load control rider–A/C	10,063	10,282	10,474	10,673	10,877	11,079	11,297	11,522
Residential load control rider–water heating	1,330	1,264	1,133	1,024	667	0	0	0
Interruptible power service rider	25,183	25,194	25,204	25,216	25,227	25,238	25,251	25,263
Standby generator control rider	1,867	2,056	2,246	2,437	2,628	2,820	3,013	3,208
Interruptible Totals	**38,443**	**38,796**	**39,057**	**39,350**	**39,399**	**39,137**	**39,561**	**39,993**
Load Shift								
Residential water heating–controlled/ submetered	0	0	0	0	0	0	0	0
Load Shift Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Strategic Sales								
Electrotechnology strategy	3,909	4,260	4,735	4,895	5,058	0	0	0
HE food service appliances	1,051	1,105	1,166	1,230	1,218	0	0	0
Nonresidential space heating	896	671	516	621	901	0	0	0
Outdoor lighting	13,410	14,746	16,139	17,599	19,128	0	0	0
Strategic Sales Totals	**19,266**	**20,782**	**22,556**	**24,345**	**26,305**	**0**	**0**	**0**
Energy Efficiency and Strategic Sales								
New residential housing program	6,284	5,936	5,562	5,667	5,811	0	0	0
Existing residential housing program and nonresidential heat pump program	9,519	8,218	9,556	7,744	7,945	0	0	0
Energy Efficiency and Strategic Sales Totals	**15,803**	**14,154**	**15,118**	**13,411**	**13,756**	**0**	**0**	**0**
Demand Side Option Totals	**75,748**	**74,052**	**77,024**	**77,408**	**79,773**	**39,460**	**39,773**	**40,212**

a. Direct costs are annual values.

FIGURE 16: Direct Cost ($000s) Projection Summary—2004 Through 2010 [a]

Demand Side Options	2004	2005	2006	2007	2008	2009	2010
Energy Efficiency							
HE chillers payment program	0	0	0	0	0	0	0
HE compressed air systems	0	0	0	0	0	0	0
HE motor systems and replacement	227	234	242	0	0	0	0
Energy Efficiency Totals	**227**	**234**	**242**	**0**	**0**	**0**	**0**
Interruptible							
Residential load control rider–A/C	11,756	11,997	12,248	12,508	12,777	13,058	13,349
Residential load control rider–water heating	0	0	0	0	0	0	0
Interruptible power service rider	25,277	25,290	25,305	25,319	25,335	25,351	25,367
Standby generator control rider	3,404	3,600	3,799	3,998	3,907	3,927	3,947
Interruptible Totals	**40,437**	**40,887**	**41,352**	**41,825**	**42,019**	**42,336**	**42,663**
Load Shift							
Residential water heating–controlled/submetered	0	0	0	0	0	0	0
Load Shift Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Strategic Sales							
Electrotechnology strategy	0	0	0	0	0	0	0
HE food service appliances	0	0	0	0	0	0	0
Nonresidential space heating	0	0	0	0	0	0	0
Outdoor lighting	0	0	0	0	0	0	0
Strategic Sales Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Energy Efficiency and Strategic Sales							
New residential housing program	0	0	0	0	0	0	0
Existing residential housing program and nonresidential heat pump program	0	0	0	0	0	0	0
Energy Efficiency and Strategic Sales Totals	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Demand Side Option Totals	**40,664**	**41,121**	**41,594**	**41,825**	**42,019**	**42,336**	**42,663**

a. Direct costs are annual values.

Demand Side Evaluation Results

Figure 17 shows demand side accomplishments for options in the marketplace during the 1994 calendar year. These accomplishments are based on 1994 evaluation results.

FIGURE 17: 1994 Demand Side Evaluation Results

	Programs	Number of Customers	Total Impacts		Cost ($000)
			Demand (MW)	Energy (MWh)	
Residential	High-efficiency heat pump and central air conditioning payment program	18,224	(7.29)	(9,950)	$14,624
Residential	Duct sealing payment program for new residential structures	4,560	(1.64)	(2,549)	6,049
Residential	Residential load control rider–air conditioning [a]	215,341	(488.82)	0	24,254
	Total Residential		**(497.75)**	**(12,499)**	**$44,927**
Commercial/Industrial	Manufactured housing payment program	2,990	(1.55)	(8,803)	2,092
Commercial/Industrial	High-efficiency chillers payment program	102	(1.39)	(7,630)	3,344
Commercial/Industrial	Interruptible power service rider [a]	240	(683.06)	0	26,600
Commercial/Industrial	Standby generator control rider [a]	121	(48.02)	(769)	1,609
	Total Commercial/Industrial		**(734.02)**	**(17,202)**	**$33,845**
	Pilots and Other				**7,605**
	Grand Total		**(1,231.77)**	**(29,701)**	**$86,177**

a. Annual energy impacts depend on the actual number of times these options are used, the length of the interruptions, and the time of day the interruption takes place.

Lincoln Combustion Turbine Station Status

Duke has completed construction and begun commercial operation of the Lincoln Combustion Turbine Station, a 16-unit combustion turbine facility in Lincoln County, North Carolina. All necessary federal and state permits have been received to operate the facility. The final cost is expected to remain within the $406,355,000 estimate of December 20, 1995.